ISO TARIFF APPENDIX F

Rate Schedules

ISO TARIFF APPENDIX F
Schedule 1

Grid Management Charge

Part A – Monthly Calculation of Grid Management Charge (GMC)

The Grid Management Charge consists of eight separate service charges: (1) the Core Reliability Services – Demand Charge, (2) the Core Reliability Services – Energy Exports Charge; (3) Energy Transmission Services Net Energy Charge, (4) the Energy Transmission Services Uninstructed Deviations Charge, (5) the Forward Scheduling Charge, (6) the Congestion Management Charge, (7) the Market Usage Charge, and (8) the Settlements, Metering, and Client Relations Charge.

1. The rate in $/MW for the Core Reliability Services – Demand Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total of the forecasted Scheduling Coordinators' metered non-coincident peak hourly demand in MW for all months during the year (excluding the portion of such Demand associated with Energy Exports, if any, as may be modified in accordance with Part F of this Schedule 1), reduced by thirty-four (34) percent of the sum of all Scheduling Coordinators' metered non-coincident peaks occurring during the hours ending 0100 through 0600, or during the hours ending 2300 through 2400, every day, including Sundays and holidays; provided that if a Scheduling Coordinator's metered non-coincident peak hour during the month occurs during the hours ending 0100 through 0600, or during the hours ending 2300 through 2400, every day, the rate shall be sixty-six (66) percent of the standard Core Reliability Services – Demand rate.

2. The rate in $/MWh for the Core Reliability Services – Energy Export Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total of the forecasted Scheduling Coordinators' metered volume of Energy Exports in MWh, as may be modified in accordance with Part F of this Schedule 1, for all months during the year.

3. The rate in $/MWh for the Energy Transmission Services Net Energy Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total annual forecasted Metered Control Area Load.

4. The rate in $/MWh for the Energy Transmission Services Uninstructed Deviations Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the absolute value of total annual forecasted net uninstructed deviations (netted within a Settlement Interval summed over the calendar month) in MWh.

5. The rate in $ per Schedule for the Forward Scheduling Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the annual forecasted number of non-zero MW Final Hour-Ahead Schedules, as may be modified in accordance with Part F of this Schedule 1, including all awarded Ancillary Service bids; provided that the Forward Scheduling charge attributable to Final Hour-Ahead Schedules for Inter-Scheduling Coordinator Energy and Ancillary Service Trades

for each Scheduling Coordinator is fifty (50) percent of the standard Forward Scheduling Charge.

6. The rate in $/MWh for the Congestion Management Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total annual forecasted Scheduling Coordinators' inter-zonal scheduled flow (excluding flows pursuant to Existing Contracts) per path in MWh.

7. The rate in $/MWh for the Market Usage Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the annual forecasted total purchases and sales (including out-of-market transactions) of Ancillary Services, Supplemental Energy, Instructed Imbalance Energy, and net Uninstructed Imbalance Energy (with uninstructed deviations being netted within a Settlement Interval summed over the calendar month) in MWh.

8. The rate for the Settlements, Metering, and Client Relations Charge will be fixed at $500.00 per month, per Scheduling Coordinator Identification Number ("SC ID") with an invoice value other than $0.00 in the current trade month.

The rates for the foregoing charges shall be adjusted automatically each year, effective January 1 for the following twelve months, in the manner set forth in Part D of this Schedule.

Part B – Quarterly Adjustment, If Required

Each component rate of the Grid Management Charge will be adjusted automatically on a quarterly basis, up or down, so that rates reflect the annual revenue requirement as stated in the ISO's filing or posting on the ISO Home Page, as applicable, if the estimated billing determinant volumes for that component, on an annual basis, change by 5% or more during the year. Such adjustment may be implemented not more than once per calendar quarter, and will be effective the first day of the next calendar month.

The rates will be adjusted in accordance with the following formula:

According to the formulae listed in Appendix F, Schedule 1, Part A with the billing determinant(s) readjusted on a going-forward basis to reflect the 5% or greater change from the estimated billing determinant provided in the annual informational filing.

Part C – Costs Recovered through the GMC

As provided in Section 8 of the ISO Tariff, the Grid Management Charge includes the following costs, as projected in the ISO's budget for the year to which the Grid Management Charge applies:

- Operating costs (as defined in Section 8.2.2)
- Financing costs (as defined in Section 8.2.3), including Start-Up and Development costs and
- Operating and Capital Reserve costs (as defined in Section 8.2.4)

Such costs, for the ISO as a whole, are allocated to the eight service charges that comprise the Grid Management Charge: (1) Core Reliability Services - Demand Charge, (2) Core Reliability Services – Energy Export Charge, (3) Energy Transmission Services Net Energy Charge, (4) Energy Transmission Services Uninstructed Deviations Charge, (5) Forward Scheduling Charge, (6) Congestion Management Charge, (7) Market Usage Charge, and (8) Settlements, Metering, and Client Relations Charge, according to the factors listed in Part E of this Schedule 1, and

adjusted annually for:

- any surplus revenues from the previous year as deposited in the Operating and Capital Reserve Account, as defined under Section 8.5, or deficiency of revenues, as recorded in a memorandum account;

divided by:

- forecasted annual billing determinant volumes;

adjusted quarterly for:

- a change in the volume estimate used to calculate the individual Grid Management Charge components, if, on an annual basis, the change is 5% or more.

The Grid Management Charge revenue requirement formula is as follows:

Grid Management Charge revenue requirement =

- Operating Expenses + Debt Service + [(Coverage Requirement x Senior Lien Debt Service) and/or (Cash Funded Capital Expenditures)] - Interest Earnings - Other Revenues - Reserve Transfer

Where,

- Operating Expenses = O&M Expenses plus Taxes Other Than Income Taxes and Penalties O&M Expenses = Transmission O&M Expenses (Accounts 560-574) plus Customer Accounting Expenses (Accounts 901-905) plus Customer Service and Informational Expenses (Accounts 906-910) plus Sales Expenses (Accounts 911-917) plus Administrative & General Expenses (Accounts 920-935)
- Taxes Other Than Income Taxes = those taxes other than income taxes which relate to ISO operating income (Account 408.1)
- Penalties = payments by the ISO for penalties or fines incurred for violation of WECC reliability criteria (Account 426.3)
- Debt Service = for any fiscal year, scheduled principal and interest payments, sinking fund payments related to balloon maturities, repayment of commercial paper notes, net payments required pursuant to a payment obligation, or payments due on any ISO notes. This amount includes the current year accrued principal and interest payments due in April of the following year.
- Coverage Requirement = 25% of the Senior Lien Debt Service.
- Senior Lien Debt Service = all Debt Service that has a first lien on ISO Net Operating Revenues (Account 128 subaccounts).
- Cash Funded Capital Expenditures = Post current fiscal year capital additions (Accounts 301-399) funded on a pay-as-you-go basis.
- Interest Earnings = Interest earnings on Operating and Capital Reserve balances (Account 419). Interest on bond or note proceeds specifically designated for capital projects or capitalized interest is excluded.

- Other Revenues = Amounts booked to Account 456 subaccounts. Such amounts include but are not limited to application fees, WECC reliability coordinator reimbursements, Line Operator Charges, and fines assessed and collected by the ISO.
- Reserve Transfer = the projected reserve balance for December 31 of the prior year less the Reserve Requirement as adopted by the ISO Governing Board and FERC. If such amount is negative, the amount may be divided by two, so that the reserve is replenished within a two-year period. (Account 128 subaccounts)
- Reserve Requirement = 15% of Annual Operating Expenses.

A separate revenue requirement shall be established for each component of the Grid Management Charge by developing the revenue requirement for the ISO as a whole and then assigning such costs to the seven service categories using the allocation factors provided in Appendix F, Schedule 1, Part E of this Tariff.

Part D – Information Requirements

Budget Schedule

The ISO will convene, prior to the commencement of the Annual Budget process, an initial meeting with stakeholders to: (a) receive ideas to control ISO costs; (b) receive ideas for projects to be considered in the capital budget development process; and, (c) receive suggestions for reordering ISO priorities in the coming year.

Within 2 weeks of the initial meeting, the ideas presented by the stakeholders shall be communicated in writing to the ISO's officers, directors and managers as part of the budget development process, and a copy of this communication shall be made available to stakeholders.

Subsequent to the initial submission of the draft budget to the finance committee of the ISO Governing Board, the ISO will provide stakeholders with the following information: (a) proposed capital budget with indicative projects for the next subsequent calendar year, a budget-to-actual review for capital expenditures for the previous calendar year, and a budget-to-actual review of current year capital costs; and, (b) expenditures and activities in detail for the next subsequent calendar year (in the form of a draft of the budget book for the ISO Governing Board), budget-to-actual review of expenditures and activities for the previous calendar year, and a budget-to-actual review of expenditures for the current year. Certain of this detailed information which is deemed commercially sensitive will only be made available to parties that pay the ISO's GMC (or regulators) who execute a confidentiality agreement.

The ISO shall provide such materials on a timely basis to provide stakeholders at least one full committee meeting cycle to review and prepare comments on the draft annual budget to the finance committee of the ISO Governing Board.

At least one month prior to the ISO Governing Board meeting scheduled to consider approval of the proposed budget, the ISO will hold a meeting open to all stakeholders to discuss the details of the ISO's budget and revenue requirement for the forthcoming year. To the extent that such a meeting will deal with complex matters of budgetary and policy import, the ISO will endeavor to host a workshop on the ISO's budget preparation process in advance of the meeting to better prepare stakeholders.

Prior to a final recommendation by the finance committee of the ISO Governing Board on the ISO's draft annual budget, the ISO shall respond in writing to all written comments on the draft annual budget submitted by stakeholders and/or the ISO shall issue a revised draft budget indicating in detail the manner in which the stakeholders' comments have been taken into consideration.

The ISO will provide no fewer than 45 days for stakeholder review of its annual budget between initial budget posting and final approval of the budget by the ISO Governing Board.

Budget Posting

After the approval of the annual budget by the ISO Governing Board, the ISO will post on its Internet site the ISO operating and capital budget to be effective during the subsequent fiscal year, and the billing determinant volumes used to develop the rate for each component of the Grid Management Charge, together with workpapers showing the calculation of such rates.

Annual Filing

If the Grid Management Charge revenue requirement for Budget Year 2008 does not exceed $195 million, the ISO shall not be required to make a Section 205 filing to adjust the GMC charges calculated in accordance with this Schedule 1 to recover such Revenue Requirement. In order for the ISO to adjust the GMC charges to collect a Grid Management Charge Revenue Requirement for Budget Year 2008 that exceeds $195 million, the ISO must submit an application to FERC under Section 205. In any event, the ISO shall submit a filing under Section 205 for approval of the GMC charges to be effective the earlier of January 1, 2009 or the effective date of amendments to the ISO Tariff implementing a new market design based on a nodal system of Congestion Management employing locational marginal pricing, such as the ISO's Market Redesign and Technology Upgrade ("MRTU"). In such filing, the ISO may revise the GMC rates set forth in this Schedule 1, but shall not be required to do so.

Periodic Financial Reports

The ISO will create periodic financial reports consisting of an income statement, balance sheet, statement of operating reserves, and such other reports as are required by the ISO Governing Board. The periodic financial reports will be posted on the ISO's Website not less than quarterly.

Part E – Cost Allocation

1. The Grid Management Charge revenue requirement, determined in accordance with Part C of this Schedule 1, shall be allocated to the eight service charges specified in Part A of this Schedule 1 as follows, subject to Section 2 of this Part E. Expenses projected to be recorded in each cost center shall be allocated among the eight charges in accordance with the allocation factors listed in Table 1 to this Schedule 1, subject to Section 2 of this Part E. In the event the ISO budgets for projected expenditures for cost centers are not specified in Table 1 to Schedule 1, such expenditures shall be allocated based on the allocation factors for the respective ISO division hosting that newly-created cost center. Such divisional allocation factors are specified in Table 1 to this Schedule 1.

Debt service expenditures for the ISO's year 2000 (or subsequently refinanced) bond offering shall be allocated among the eight charges in accordance with the allocation factors listed in Table 1 to this Schedule 1, subject to Section 2 of this Part E. Capital expenditures shall be allocated among the eight charges in accordance with the allocation factors listed in Table 2 to this Schedule 1, subject to Section 2 of this Part E, for the system for which the capital expenditure is projected to be made.

Any costs allocated by the factors listed in Table 1 and Table 2 to the Settlements, Metering, and Client Relations category that would remain un-recovered after the assessment of the charge for that service specified in Section 8 of Part A of this Schedule 1 on forecasted billing determinant volumes shall be reallocated to the remaining GMC service categories in the ratios set forth in Table 3 to this Schedule 1.

2. The allocation of costs in accordance with Section 1 and Tables 1 and 2 of this Part E shall be adjusted as follows:

Costs allocated to the Energy Transmission Services category in the following tables are further apportioned to the Energy Transmission Services Net Energy and Energy Transmission Services Uninstructed Deviations subcategories in 80% and 20% ratios, respectively.

Twenty (20) percent of the costs allocated to the Forward Scheduling Charge in the following Tables shall be reallocated to the Congestion Management Charge. A portion of the costs allocated to the Forward Scheduling Charge, associated with the fifty (50) percent reduction in the standard Forward Scheduling Charge to be applied to Final Hour-Ahead Schedules for Inter-Scheduling Coordinator Energy and Ancillary Service Trades as specified in Part A of this Schedule 1, shall be reallocated to the remaining GMC service categories in the ratios set forth in Table 3 to this Schedule 1.

Table 1
O&M, Debt Service, and Other Expense Recoveries Cost Allocation Factors

CC #	Cost Center	CRS	ETS	FS	CM	MU	SMCR	Total
1100	**CEO Division**	**44.01%**	**21.51%**	**3.78%**	**4.61%**	**10.45%**	**15.63%**	**100%**
1111	CEO - General	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
1241	MD02	6.95%	0%	13.86%	10.91 %	28.38%	39.90%	100%
1521	Grid Planning	62.50%	37.50%	0%	0%	0%	0%	100%
1300	**Finance Division**	**44.04%**	**21.49%**	**3.62%**	**4.22%**	**10.31%**	**16.32%**	**100%**
1311	CFO - General	44.04%	21.49%	3.62%	4.22%	10.31%	16.32%	100%
1321	Accounting	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
1331	Financial Planning and Treasury	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
1351	Facilities	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
1361	Security & Corporate Services	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%

1400	**Information Services Division**	**38.25%**	**7.16%**	**9.74%**	**4.78%**	**9.23%**	**30.85%**	**100%**
1411	Chief Information Officer	38.25%	7.16%	9.74%	4.78%	9.23%	30.85%	100%
1422	Corporate & Enterprise Applications	33.28%	7.06%	1.16%	25.28 %	12.58%	20.63%	100%
1424	Asset Management	35.30%	6.12%	10.91 %	4.88%	10.50%	32.29%	100%
1431	End User Support	37.80%	14.44%	8.29%	3.5%	9.32%	26.65%	100%
1432	Computer Operations and Infrastructure Services	34.15%	9.21%	11.76 %	3.08%	8.69%	33.11%	100%
1433	Network Services	43.38%	11.88%	9.39%	2.61%	9.23%	23.51%	100%
1441	Outsourced Contracts	42.25%	10.62%	10.25 %	2.53%	9.07%	25.28%	100%
1442	Production Support	25.09%	0.17%	17.98 %	2.62%	7.52%	46.62%	100%
1451	Information Support Services	25.09%	0.17%	17.98 %	2.62%	7.52%	46.62%	100%
1461	Control Systems	96.44%	2.44%	0%	0%	0.56%	0.56%	100%
1462	Field Data Acquisition System (FDAS)	21.43%	0%	0%	0%	0%	78.57%	100%
1463	Operations Systems Services	50.44%	2.91%	6.01%	1.21%	5.95%	33.49%	100%
1466	Enterprise Applications	47.98%	7.30%	1.19%	1.34%	3.47%	38.72%	100%
1467	Settlement Systems Services	27.34%	11.20%	1.83%	2.05%	5.32%	52.25%	100%
1468	Corporate Application Support and Administration	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
1469	Analytical and Reporting Applications	10%	0%	0%	65%	25%	0%	100%
1471	IT Planning	25.09%	0.17%	17.98 %	2.62%	7.52%	46.62%	100%

1481	Markets and Scheduling System Services	46.85%	2.86%	23.68%	2.5%	17.64%	6.48%	100%
1482	Market Systems Support Services	44.94%	1.05%	18.51%	6.17%	23.78%	5.54%	100%
1500	**Grid Operations Division**	**66.71%**	**33.29%**	**0%**	**0%**	**0%**	**0%**	**100%**
1511	VP Grid Operations	66.71%	33.29%	0%	0%	0%	0%	100%
1542	Outage Coordination	95.11%	4.89%	0%	0%	0%	0%	100%
1543	Loads and Resources	48.95%	51.05%	0%	0%	0%	0%	100%
1544	Real-Time Scheduling	60%	40%	0%	0%	0%	0%	100%
1545	Grid Operations	67.47%	32.53%	0%	0%	0%	0%	100%
1546	Security Coordination	100%	0%	0%	0%	0%	0%	100%
1547	Engineering and Maintenance	46.42%	53.58%	0%	0%	0%	0%	100%
1548	OSAT Group - General	93.2%	6.80%	0%	0%	0%	0%	100%
1549	Operations Training	50.48%	49.52%	0%	0%	0%	0%	100%
1554	Special Projects Engineering	42.86%	57.14%	0%	0%	0%	0%	100%
1555	Operations Support Group	55.56%	44.44%	0%	0%	0%	0%	100%
1558	Transmission Maintenance	58.46%	41.54%	0%	0%	0%	0%	100%
1559	Operations Application Support	60%	40%	0%	0%	0%	0%	100%
1561	Operations Engineering South	65.32%	34.68%	0%	0%	0%	0%	100%
1562	Operations Engineering North	55.15%	44.85%	0%	0%	0%	0%	100%
1563	Operations Coordination	74.55%	25.45%	0%	0%	0%	0%	100%
1564	Operations Scheduling	100%	0%	0%	0%	0%	0%	100%
1565	Pre-Scheduling and Support	76.92%	23.08%	0%	0%	0%	0%	100%

1566	Regional Coordination - General	100%	0%	0%	0%	0%	0%	100%
1600	**Legal and Regulatory Division**	**35.80%**	**21.78%**	**3.73%**	**7.18%**	**16.97%**	**14.54%**	**100%**
1611	VP General Counsel - General	35.80	21.78%	3.73%	7.18%	16.97%	14.54%	100%
1631	Legal and Regulatory	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
1641	Market Analysis	15.32%	26.33%	0%	19.90 %	31.38%	7.07%	100%
1642	Market Surveillance Committee	25%	25%	0%	25%	25%	0%	100%
1651	ISO Governing Board	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
1661	Compliance - General	21.90%	20.37%	11.90 %	0%	28.50%	17.33%	100%
1662	Compliance - Audits	8.33%	0%	0%	0%	50%	41.67%	100%
1700	**Market Services Division**	**17.14%**	**2.43%**	**9.46%**	**9.39%**	**20.35%**	**41.23%**	**100%**
1711	VP Market Services - General	17.14%	2.43%	9.46%	9.39%	20.35%	41.23%	100%
1721	Billing and Settlements-General	25%	0%	0%	0%	0%	75%	100%
1722	Business Development Support	0%	0%	0%	0%	0%	100%	100%
1723	RMR Settlements	80.30%	19.70%	0%	0%	0%	0%	100%
1724	BBS - PSS	0%	0%	0%	0%	0%	100%	100%
1725	BBS - FSS	0%	0%	0%	0%	0%	100%	100%
1731	Contracts and Special Projects	43.17%	6.83%	0%	0%	0%	50%	100%
1741	Client Relations	0%	0%	0%	0%	0%	100%	100%
1751	Market Operations - General	30.66%	0%	15.33 %	15.33 %	34.85%	3.83%	100%

1752	Manager of Markets	27.31%	5.46%	27.31 %	21.84 %	18.08%	0%	100%
1753	Market Engineering	21.32%	0%	0%	28.43 %	43.15%	7.11%	100%
1755	Business Solutions	5.91%	0%	47.27 %	11.82 %	29.10%	5.91%	100%
1756	Market Quality - General	0%	0%	0%	0%	70.93%	29.07%	100%
1757	Market Integration	7.38%	0%	29.52%	29.52%	26.20%	7.38%	100%
1800	**Corporate and Strategic Development Division**	**44.04%**	**21.49%**	**3.62%**	**4.21%**	**10.31%**	**16.33%**	**100%**
1811	VP Corporate and Strategic Development - General	44.04%	21.49%	3.62%	4.21%	10.31%	16.33%	100%
1821	Communications	44.01%	22.51%	3.78%	4.61%	10.45%	15.63%	100%
1831	Strategic Development	44.01%	22.51%	3.78%	4.61%	10.45%	15.63%	100%
1841	Human Resources	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
1851	Project Office	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
1861	Regulatory Policy	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
Other Revenue and Credits								
	SC Application and Training Fees	0%	0%	0%	0%	0%	100%	100%
	WECC Reimbursement/NERC Reimbursement	100%	0%	0%	0%	0%	0%	100%
	Interest Earnings	36.64%	12.29%	9.34%	4.97%	11.47%	25.30%	100%
Debt Service Related Allocations		33.49%	7.93%	15.26%	5.19%	9.44%	28.69%	100%

Table 2

Capital Cost Allocation Factors

System	CRS	ETS	FS	CM	MU	SMCR	Total
ACC Upgrades (Communication between ISO & IOUs)	100%	0%	0%	0%	0%	0%	100%
Ancillary Services Management (ASM) Component of SA	15%	0%	40%	0%	45%	0%	100%
Application Development Tools	23.46%	0.18%	21.78%	2.68%	6.86%	45.04%	100%
Automated Dispatch System (ADS)	50%	0%	25%	0%	20%	5%	100%
Automated Load Forecast System (ALFS)	70%	0%	10%	0%	20%	0%	100%
Automatic Mitigation Procedure (AMP)	85%	0%	0%	0%	15%	0%	100%
Backup systems (Legato/Quantum)	23%	0%	22%	3%	7%	45%	100%
Balance of Business Systems (BBS)	0%	0%	0%	0%	0%	100%	100%
Balancing Energy Ex Post Price (BEEP) Component of SA	50%	0%	20%	10%	20%	0%	100%
Bill's Interchange Schedule (BITS)	85%	0%	0%	0%	15%	0%	100%
CaseWise (process modeling tool)	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
CHASE	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Common Information Model (CIM)	100%	0%	0%	0%	0%	0%	100%
Compliance (Blaze)	19.17%	16.27%	9.5%	0%	32.83%	22.23%	100%
Congestion Management (CONG) (Component of SA)	10%	0%	0%	65%	25%	0%	100%

Congestion Reform-DSOW	50%	0%	0%	50%	0%	0%	100%
Congestion Revenue Rights (CRR)	0%	0%	0%	80%	20%	0%	100%
DataWarehouse	24.46%	18.27%	6.40%	8.74%	24.30%	17.82%	100%
Dept. of Market Analysis Tools (SAS/MARS)	15.32%	26.33%	0%	19.90%	31.38%	7.07%	100%
Dispute Tracking System (Remedy)	0%	0%	0%	0%	0%	100%	100%
Documentum	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Electronic Tagging (Etag)	100%	0%	0%	0%	0%	0%	100%
Energy Management System (EMS)	100%	0%	0%	0%	0%	0%	100%
Engineering Analysis Tools	60%	40%	0%	0%	0%	0%	100%
Evaluation of Market Separation	0%	0%	0%	50%	50%	0%	100%
Existing Transmission Contracts Calculator (ETCC)	25%	0%	20%	15%	20%	20%	100%
FERC Study Software	0%	0%	0%	0%	100%	0%	100%
Firm Transmission Right (FTR) and Secondary Registration System (SRS)	0%	0%	15%	60%	15%	10%	100%
Global Resource Reliability Management Application (GRRMA)	75%	15%	0%	0%	10%	0%	100%
Grid Operations Training Simulator (GOTS)	56%	44%	0%	0%	0%	0%	100%
Hour-Ahead Data AnalysisTool, Day-Ahead Data AnalysisTool,	0%	0%	100%	0%	0%	0%	100%
Human Resources	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%

IBM Contract	37.26%	14.44%	9.54%	3.52%	9.10%	26.13%	100%
Integrated Forward Market (IFM)	10%	0%	35%	0%	55%	0%	100%
Internal Development	23.46%	0.18%	21.78%	2.68%	6.86%	45.04%	100%
Interzonal Congestion Management reform - Real Time	50%	0%	0%	50%	0%	0%	100%
Land and Building Costs	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Local Area Network (LAN)	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Locational Marginal Pricing (LMPM)	10%	0%	35%	0%	55%	0%	100%
Market Transaction System (MTS)	0%	0%	0%	0%	100%	0%	100%
Masterfile	20%	0%	20%	0%	55%	5%	100%
MD02 Capital	6.95%	0%	13.86%	10.91%	28.38%	39.90%	100%
Meter Data Acquisition System (MDAS)	0%	0%	0%	0%	0%	100%	100%
Miscellaneous (2004 related projects)	23.46%	0%	21.78%	2.68%	6.86%	45.04%	100%
Monitoring (Tivoli)	23.46%	0%	21.78%	2.68%	6.86%	45.04%	100%
New Resource Interconnection (NRI)	100%	0%	0%	0%	0%	0%	100%
New System Equipment (replacement of owned equipment)	23.46%	0.18%	21.78%	2.68%	6.86%	45.04%	100%
NT/web servers	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
NT-servers	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Oracle Enterprise Manager (OEM)	27%	0.%	18%	5%	9%	41%	100%

Office Automation - desktop/laptop (OA)	44%	27%	4%	4%	10%	17%	100%
Office equipment (scanner, printer, copier, fax, Communication Equipment)	44%	21%	4%	4%	10%	17%	100%
Open Access Same Time Information System (OASIS)	10%	0%	25%	10%	35%	20%	100%
Operational Meter Analysis and Reporting (OMAR)	0%	0%	0%	0%	0%	100%	100%
Oracle Corporate Financials	44%	21%	4%	4%	10%	17%	100%
Oracle Licenses	27%	0%	18%	5%	9%	41%	100%
Oracle Market Financials BBS	0%	0%	0%	0%	0%	100%	100%
Out of Sequence Market Operation Settlements Information System (OOS)	5%	5%	0%	0%	90%	0%	100%
Outage Scheduler (OS)	50%	0%	10%	20%	20%	0%	100%
Participating Intermittent Resource Project (PIRP)	0%	0%	93.92%	0%	6.08%	0%	100%
Physical Facilities Software Application/Furniture/Leasehold Improvements	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Process Information System (PI)	80%	0%	0%	0%	10%	10%	100%
Rational Buyer	100%	0%	0%	0%	0%	0%	100%
Real Time Energy Dispatch System (REDS)	100%	0%	0%	0%	0%	0%	100%
Real Time Nodal Market	35%	0%	10%	0%	55%	0%	100%
Reliability Management System (RMS)	100%	0%	0%	0%	0%	0%	100%

Remedy (related to Transmission Registry, New Resource Interconnection, and Resource Registry)	100%	0%	0%	0%	0%	0%	100%
Remote Intelligent Gateway (RIG) & Data Processing Gateway (DPG)	100%	0%	0%	0%	0%	0%	100%
Resource Register (RR)	100%	0%	0%	0%	0%	0%	100%
RMR Application Validation Engine (RAVE)	100%	0%	0%	0%	0%	0%	100%
Scheduling & Logging for ISO California (SLIC)	65%	0%	15%	5%	15%	0%	100%
Scheduling Architecture (SA)	23.96%	0%	19.84%	25.87%	30.33%	0%	100%
Scheduling Infrastructure (SI)	0%	0%	93.92%	0%	6.08%	0%	100%
Scheduling Infrastructure Business Rules (SIBR)	0%	0%	93.92%	0%	6.08%	0%	100%
Security Constrained Economic Dispatch (SCED)	40%	0%	0%	0%	60%	0%	100%
Security- External/Physical	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Security-ISS (CUDA)	23%	0%	22%	3%	7%	45%	100%
Settlements and Market Clearing	0%	0%	0%	0%	0%	100%	100%
Sign Board (Symon Board maint.)	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Startup Costs through 3/31/98, Working Capital-3 months	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Storage (EMC symmetrix)	18.67%	9.55%	13.71%	4.21%	11.77%	42.09%	100%
System Equipment Buyouts (lease buyouts)	43.27%	1.02%	7.34%	1.79%	11.03%	35.56%	100%

Telephone/PBX	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Training Systems	23.46%	0.18%	21.78%	2.68%	6.86%	45.04%	100%
Transmission Constrained Unit Commitment (TCUC) Must Offer Obligation	100%	0%	0%	0%	0%	0%	100%
Transmission Map Plotting & Display	50%	50%	0%	0%	0%	0%	100%
Trustee Costs, Interest-Capitalized, User Groups	53.60%	0.55%	10.62%	15.74%	17.48%	2%	100%
Utilities - System i.e. Print drivers	23.46%	0.18%	21.78%	2.68%	6.86%	45.04%	100%
Vitria (Middleware)	23.46%	0.18%	21.78%	2.68%	6.86%	45.04%	100%
Wide Area Network (WAN)	40.80%	2.14%	18.68%	1.31%	7.60%	29.48%	100%
Capital Expenditures for Systems not Specified	32.20%	7.40%	15%	5.50%	10.60%	29.30%	100%

Table 3

Reallocation Factors for Projected Unrecovered Portion of Settlements, Metering, and Client Relations Revenue Requirement

	CRS	**ETS**	**FS**	**CM**	**MU**	**SMCR**	**Total**
Functional Association of Settlements, Metering, and Client Relations	0.0%	70.34%	0.0%	8.23%	21.43%	0.0%	100.0%

Part F – Other Modifications to the Rates

Consistent with a Settlement Agreement accepted by the FERC in Docket Nos. ER04-115-000, et al., GMC rates and charges shall be calculated consistent with the following additional requirements during the period that the GMC rates and charges specified in that Settlement Agreement remain in effect:

1. The GMC chargeable to a Scheduling Coordinator for transactions representing transfers from the Mohave generation facility to the Loads of the Mohave co-owners located outside of the ISO Control Area, will be reduced by excluding 65 percent of those Loads from the Energy Transmission Services Net Energy Charge and the Core Reliability Services – Energy Exports Charge. Such excluded Load shall not be included in the denominators used to calculate the rates for the Energy Transmission Services – Net Energy Charge and the Core Reliability Services – Energy Export Charge.

2. The Forward Scheduling Charge assessed against Schedules submitted by PG&E solely in its role as Path 15 facilitator will be reduced by excluding 65 percent of the number of such Schedules from the Forward Scheduling Charge. Such excluded Schedules shall not be included in the denominator upon which the Forward Scheduling Charge is calculated.

3. San Diego Gas & Electric is the Scheduling Coordinator for transactions on those portions of the Southwest Power Link ("SWPL") which are owned by the Arizona Public Service Company ("APS") and the Imperial Irrigation District ("IID"), and are scheduled by SDG&E under a designated SCID. Schedules submitted to the ISO under that designated SCID shall not be subject to GMC charges. In lieu of GMC charges, SDG&E will pay the ISO a Line Operator Charge, as agreed to in the SWPL Operations Agreement, entered into by the ISO and SDG&E on May 23, 2005, and submitted to the Commission as a rate schedule pursuant to the Federal Power Act.

ISO TARIFF APPENDIX F
Schedule 2
Other Charges

Voltage Support Service

The user rate per unit of purchased Voltage Support will be calculated in accordance with the formula in ISO Tariff Section 8.12.4

Regulation Service

Regulation Obligation:

The amount of Regulation required will be calculated in accordance with Section 8.2.3 of the ISO Tariff.

Regulation Rates:

The formulas for calculating the amount of and charges for Regulation Service are referenced in ISO Tariff Sections 8.6.1, 8.11, and 8.12.

The ISO will calculate the user rate for Regulation in each Zone for each Settlement Period in accordance with Section 8.12.1.

Spinning Reserve Service

Spinning Reserve Obligation:

The amount of Spinning Reserve required as a component of Operating Reserves is specified in Section 8.2.3 of the ISO Tariff.

Spinning Reserve Rates:

The formulas for calculating the amount of and charges for Spinning Reserve Service are referenced in ISO Tariff Sections 8.11.2 and 8.12.2.

The ISO will calculate the user rate for Spinning Reserve in each Zone for each Settlement Period in accordance with ISO Tariff Section 8.12.2.

Non-Spinning Reserve Service

Non-Spinning Reserve Obligation:

The amount of Non-Spinning Reserve required as a component of Operating Reserves is specified in Section 8.2.3.

Non-Spinning Reserve Rates:

The formulas for calculating the amount of and charges for Non-Spinning Reserve Service are referenced in ISO Tariff Sections 8.11.3 and 8.12.3.

The ISO will calculate the user rate for Non-Spinning Reserve in each Zone for each Settlement Period in accordance with ISO Tariff Section 8.12.3.

Replacement Reserves

The formulas for calculating the amount of and charges for Replacement Reserve Service are referenced in ISO Tariff Sections 8.11.3A and 8.12.3A.

Black Start Capability

The user rate per unit of purchased Black Start capability for each Settlement Period will be calculated in accordance with ISO Tariff Section 8.12.5.

Imbalance Energy Charges

Rates for Imbalance Energy will be calculated in accordance with the formula in ISO Tariff Section 11.2.4.1.

Replacement Reserve Charge

The Replacement Reserve Charge will be calculated in accordance with ISO Tariff Sections 8.12.3A and 11.2.4.1.

Unaccounted for Energy

Rates for UFE will be calculated in accordance with ISO Tariff Section 11.2.4.1.

Transmission Losses Imbalance Charges

Transmission Losses for each hour will be calculated in accordance with ISO Tariff Sections 27.2.1.2.

Access Charges

The High Voltage Access Charge and Transition Charge is set forth in ISO Tariff Schedule 3 of Appendix F. The Low Voltage Access Charge of each Participating TO is set forth in that Participating TO's TO Tariff or comparable document.

Usage Charges

The amount payable by Scheduling Coordinators is determined in accordance with ISO Tariff Section 27.1.2.1.4. Usage Charges will be calculated in accordance with ISO Tariff Section 27.1.2.1.

Default Usage Charge

The Default Usage Charge will be used in accordance with ISO Tariff Section 27.1.2.1.

Grid Operations Charge for Intra-Zonal Congestion

Intra-Zonal Congestion during the initial period of operation will be managed in accordance with ISO Tariff Sections 27.1.1.6.1 and 27.1.1.6.2.

Wheeling Access Charges

The Wheeling Access Charge for transmission service is set forth in Section 26.1.4.1 of the ISO Tariff and Appendix II of the TO Tariffs.

Charge for Failure to Conform to Dispatch Instructions

The Charge for Failure to Conform to Dispatch Instructions will be determined in accordance with ISO Tariff Section 34.8.

Reliability Must-Run Charge

The Reliability Must-Run Charge will be determined in accordance with ISO Tariff Section 30.6.1.1.

FERC Annual Charge Recovery Rate

The FERC Annual Charge Recovery Rate will be determined in accordance with ISO Tariff Section 11.2.11.

ISO TARIFF APPENDIX F
Schedule 3
Access Charge

1. Objectives and Definitions

1.1 Objectives

(a) The Access Charge will remain utility-specific until a New Participating TO executes the Transmission Control Agreement, at which time the Access Charge will change as discussed below.

(b) The Access Charge is the charge assessed for using the ISO Controlled Grid. It consists of three components, the High Voltage Access Charge (HVAC), the Transition Charge and the Low Voltage Access Charge (LVAC).

(c) The HVAC ultimately will be based on one ISO Grid-wide rate. Initially, the HVAC will be based on TAC Areas, which will transition 10% per year to the ISO Grid-wide rate. In the first year after the Transition Date described in Section 4.2 of this Schedule 3, the HVAC will be a blend based on 10% ISO Grid-wide and 90% TAC Area.

(d) New High Voltage Facility additions and capital additions to Existing High Voltage Facilities will be immediately included in the ISO Grid-wide component of the HVAC. The Transmission Revenue Requirement for New High Voltage Facilities will not be included in the calculation of the Transition Charge.

(e) The LVAC will remain utility-specific and will be determined by each Participating TO. The LVAC of Non-Load-Serving Participating TOs may also be project specific. Each Participating TO will charge for and collect the LVAC, subject to Section 26.1 of the ISO Tariff and Section 13 of this Schedule 3.

(f) The cost-shift associated with transitioning from utility-specific rates to one ISO Grid-wide rate will be mitigated in accordance with the ISO Tariff, including this schedule.

1.2 Definitions

(a) Master Definition Supplement

Unless the context otherwise requires, any word or expression defined in the Master Definition Supplement shall have the same meaning where used in this Schedule 3.

(b) Special Definitions for this Appendix

When used in this Schedule 3 with initial capitalization, the following terms shall have the meanings specified below.

"High Voltage Utility-Specific Rate" means a Participating TO's High Voltage Transmission Revenue Requirement divided by such Participating TO's forecasted Gross Load.

"TAC Benefit" means the amount, if any, for each year by which the cost of Existing High Voltage Transmission Facilities associated with deliveries of Energy to Gross Loads in the PTO Service Territory is reduced by the implementation of the High

Voltage Access Charge described in Schedule 3 to Appendix F. The Tac Benefit of a New Participating TO shall not be less than zero.

"Transition Date" means the date defined in Section 4.2 of this Schedule.

2. Assessment of High Voltage Access Charge and Transition Charge.
All UDCs and MSS Operators in a PTO Service Territory serving Gross Loads directly connected to the transmission facilities or Distribution System of a UDC or MSS Operator in a PTO Service Territory shall pay to the ISO a charge for transmission service on the High Voltage Transmission Facilities included in the ISO Controlled Grid. The charge will be based on the High Voltage Access Charge applicable to the TAC Area in which the point of delivery is located and the applicable Transition Charge. A UDC or MSS Operator that is also a Participating TO shall pay, or receive payment of, if applicable, the difference between (i) the High Voltage Access Charge and Transition Charge applicable to its transactions as a UDC or MSS Operator; and (ii) the disbursement of High Voltage Access Charge revenues to which it is entitled pursuant to Section 26.1.3 of the ISO Tariff.

3. TAC Areas.

3.1 TAC Areas are based on the Control Areas in California prior to the ISO Operations Date. Three TAC Areas will be established based on the Original Participating TOs: (1) a Northern Area consisting of the PTO Service Territory of Pacific Gas and Electric Company and the PTO Service Territory of any entity listed in Section 3.3 or 3.5 of this Schedule; (2) an East Central Area consisting of the PTO Service Territory of Southern California Edison Company and the PTO Service Territory of any entity listed in Section 3.4, 3.5 or 3.6 (as indicated therein) of this Schedule 3; and (3) a Southern Area consisting of the PTO Service Territory of San Diego Gas & Electric Company. Participating TOs that are not in one of the above cited PTO Service Territories are addressed below.

3.2 If the Los Angeles Department of Water and Power joins the ISO and becomes a Participating TO, its PTO Service Territory will form a fourth TAC Area, the West Central Area.

3.3 If any of the following entities becomes a Participating TO, its PTO Service Territory will become part of the Northern Area: Sacramento Municipal Utility District, Western Area Power Administration - Sierra Nevada Region, the Department of Energy California Labs, Northern California Power Agency, City of Redding, Silicon Valley Power, City of Palo Alto, City and County of San Francisco, Alameda Bureau of Electricity, City of Biggs, City of Gridley, City of Healdsburg, City of Lodi, City of Lompoc Utility Department, Modesto Irrigation District, Turlock Irrigation District, Plumas County Water Agency, City of Roseville Electric Department, City of Shasta Lake, and City of Ukiah or any other entity owning or having contractual rights to High Voltage or Low Voltage Transmission Facilities in Pacific Gas and Electric Company's Control Area prior to the ISO Operations Date.

3.4 If any of the following entities becomes a Participating TO, its PTO Service Territory will become part of the East Central Area: City of Anaheim Public Utility Department, City of Riverside Public Utility Department, City of Azusa Light and Water, City of Banning Electric, City of Colton, City of Pasadena Water and Power Department, The Metropolitan Water District of Southern California and City of Vernon or any other entity owning or having contractual rights to High Voltage or Low Voltage Transmission Facilities in Southern California Edison Company's Control Area prior to the ISO Operations Date.

3.5 If the California Department of Water Resources becomes a Participating TO, its High Voltage Transmission Revenue Requirements associated with High Voltage Transmission Facilities in the Northern Area would become part of the High Voltage Transmission Revenue Requirement for the Northern Area while the remainder would be included in the East Central Area.

3.6 If the City of Burbank Public Service Department (Burbank) and/or the City of Glendale Public Service Department (Glendale) become Participating TOs after or at the same time as the Los Angeles Department of Water and Power becomes a Participating TO, then the PTO Service Territory of Burbank and/or Glendale would become part of the West Central Area. Otherwise, if Burbank or Glendale becomes a Participating TO, prior to Los Angeles, its PTO Service Territory will become part of the East Central Area. Once either Burbank or Glendale are part of the East Central Area, they will not move to the West Central Area if such area is established.

3.7 If the Imperial Irrigation District or an entity outside the State of California should apply to become a Participating TO, the ISO Governing Board will review the reasonableness of integrating the entity into one of the existing TAC Areas. If the entity cannot be integrated without the potential for significant cost shifts, the ISO Governing Board may establish a separate TAC Area.

4. Transition Date

4.1 New Participating TOs shall provide the ISO with a notice of intent to join and execute the Transmission Control Agreement by either January 1 or July 1 of any year and provide the ISO with an application within 15 days of such notice of intent.

4.2 The transition shall begin on either January 1 or July 1 after the date the first New Participating TO's execution of the Transmission Control Agreement takes effect (Transition Date). The Transition Date shall be the same for the Northern Area, East Central Area and the Southern Area. The Transition Date shall also be the same for the West Central Area, should it come into existence in accordance with Section 3.2 of this Schedule 3, unless the ISO provides additional information demonstrating the need for a deferral. The 10-year transition defined in Section 5.8 of Schedule 3 shall start from that date. If the West Central TAC Area is created after the Transition Date, the applicable High Voltage Access Charge shall transition to an ISO Grid-wide High Voltage Access Charge over the period remaining from the Transition Date, on the same schedule as the other TAC Areas.

4.3 Application to Additional TAC Areas. For any TAC Areas other than those specified in Section 4.2 of this Schedule 3, created after the Transition Date, including any TAC Area created as a result of the application of Section 3.7 of this Schedule 3, whether and over what period the applicable High Voltage Access Charge shall transition to an ISO Grid-wide charge shall be determined by the ISO Governing Board.1

4.4 Application to Wheeling Access Charges. The transition described in this Section 4 shall also apply, on the same schedule, to High Voltage Wheeling Access Charges.

4.5 Conversion of Existing Rights. During the process by which a New Participating TO executes the Transmission Control Agreement, the ISO and potential New Participating TO that has an obligation to serve Load shall determine the amount of FTRs to be allocated to the New Participating TO for each Existing Right that the New Participating TO converts to Converted Rights. In making that determination, the ISO will consider the amount of contracted transmission capacity, the firmness of the contracted transmission capacity, and other characteristics of the contracted transmission capacity to determine the amount of FTRs to be given to the New Participating TO in accordance with Section 36.4.3 of the ISO Tariff.

5. Determination of the Access Charge.

5.1 The Access Charge consists of a High Voltage Access Charge (HVAC) that is based on a TAC Area component and an ISO Grid-wide component, a Transmission Charge, and a Low Voltage

Access Charge (LVAC) that is based on a utility-specific rate established by each Participating TO in accordance with its TO Tariff.

5.2 Each Participating TO will develop, in accordance with Section 6 of this Schedule 3, a High Voltage Transmission Revenue Requirement ($HVTRR_{PTO}$) consisting of a Transmission Revenue Requirement for Existing High Voltage Facility ($EHVTRR_{PTO}$) and a Transmission Revenue Requirement for New High Voltage Facility ($NHVTRR_{PTO}$). The $HVTRR_{PTO}$ includes the TRBA adjustment described in Section 6.1 of this Schedule 3.

5.3 The Gross Load amount in MWh shall be established by each Participating TO and filed at FERC with each Participating TO's Transmission Revenue Requirement (GL_{PTO}).

5.4 The HVAC applicable to each UDC or MSS Operator serving Gross Load in the PTO Service Territory, shall be based on a TAC Area component ($HVAC_A$) and an ISO Grid-wide component ($HVAC_I$).

$$HVAC = HVAC_A + HVAC_I$$

5.5 The Existing Transmission Revenue Requirement for the TAC Area component ($ETRR_A$) is the summation of each Participating TO's $EHVTRR_{PTO}$ in that TAC Area. The Gross Load in the TAC Area (GL_A) is the summation of each Participating TO's Gross Load in that TAC Area (GL_{PTO}). The TAC Area component will be based on the product of Existing Transmission Revenue Requirement for the TAC Area ($ETRR_A$) and the applicable annual transition percentage (%TA) in Section 5.8 of this Schedule 3, divided by the Gross Load in the TAC Area (GL_A).

$$ETRR_A = \Sigma\ EHVTRR_{PTO}$$

$$GL_A = \Sigma\ GL_{PTO}$$

$$HVAC_A = (ETRR_A * \%TA) / GL_A$$

5.6 The Existing Transmission Revenue Requirement for the ISO Grid-wide component ($ETRR_I$) will be the summation of all TAC Areas' $ETRR_A$ multiplied by the applicable annual transition percentage (%IGW) in Section 5.8 of this Schedule 3. The New Transmission Revenue Requirement (NTRR) is the summation of each Participating TO's $NHVTRR_{PTO}$. The ISO Grid-wide component will be based on the $ETRR_I$ plus the NTRR, divided by the summation of all Gross Loads in the TAC Areas (GL_A).

$$ETRR_I = \Sigma\ ETRR_A * \%IGW$$

$$HVAC_I = (ETRR_I + NTRR) / \Sigma\ GL_A$$

The foregoing formulas will be adjusted, as necessary to take account of new TAC Areas.

5.7 The Transition Charge shall be calculated separately for each Participating TO by

dividing (i) the net difference between (1) the Participating TO’s payment responsibility, if any, under Section 26.5 of the ISO Tariff and Section 7 of this Schedule 3; and (2) the amount, if any, payable to the Participating TO in accordance with Section 26.5 of the ISO Tariff and Section 7 of this Schedule 3; by (ii) the total of all forecasted Gross Load in the PTO Service Territory of the Participating TO, including the UDC and/or MSS Operator. If greater than zero, the

Transition Charge shall be collected with the High Voltage Access Charge. If less than zero, the Transition Charge shall be credited with the High Voltage Access Charge. The amount of each Participating TO's NHVTRR shall not be included in the Transition Charge calculation.

5.8 The High Voltage Access Charge shall transition over a 10-year period from TAC Area to ISO Grid-wide. The transition percentage to be used for each year will be based on the following:

Year	**TAC Area High Voltage (%TA)**	**ISO Grid-Wide High Voltage (%IGW)**
1	90%	10%
2	80%	20%
3	70%	30%
4	60%	40%
5	50%	50%
6	40%	60%
7	30%	70%
8	20%	80%
9	10%	90%
10	0%	100%

5.9 After the completion of the transition period described in Section 4 of this Schedule 3, the High Voltage Access Charge shall be equal to the sum of the High Voltage Transmission Revenue Requirements of all Participating TOs, divided by the sum of the Gross Loads of all Participating TOs.

6. High Voltage Transmission Revenue Requirement.

6.1 The High Voltage Transmission Revenue Requirement of a Participating TO will be determined consistent with ISO procedures posted on the ISO Home Page and shall be the sum of:

(a) the Participating TO's High Voltage Transmission Revenue Requirement (including costs related to Existing Contracts associated with transmission by others and deducting transmission revenues actually expected to be received by the Participating TO related to transmission for others in accordance with Existing Contracts, less the sum of the Standby Transmission Revenues); and

(b) the annual high voltage TRBA adjustment, which shall be based on the principal balance in the high voltage TRBA as of September 30 and shall be calculated as a dollar amount based on the projected Transmission Revenue Credits as adjusted for the true up of the prior year's difference between projected and actual credits. A Non-Load-Serving Participating TO shall include any over- or under-recovery of its annual High Voltage Transmission Revenue Requirement in its high voltage TRBA. If the annual high voltage TRBA adjustment involves only a partial year of operations, the Non-Load-Serving Participating TO's over- or under-recovery shall be based on a partial year revenue requirement, calculated by multiplying the Non-Load-Serving Participating TO's High Voltage Transmission Revenue Requirement by the number of days the High Voltage Transmission Facilities were under the ISO's Operational Control divided by the number of days in the year.

7. Limitation

(a) During each year of the transition period described in this Schedule 3, the increase in the total payment responsibility applicable to Gross Loads in the PTO Service Territory of an Original Participating TO attributable to the total for the year of (i) the amount applicable for the Original Participating TO under Section 26.5 of the ISO Tariff; plus (ii) the amount applicable to the implementation of the High Voltage Access Charge shall not exceed the amount specified in paragraph (b) of this section. This limitation shall be calculated individually for each Original Participating TO, provided that, if the net effect of clauses (i) and (ii) of this paragraph is positive for one or more Original Participating TOs for any year, the combined net effect shall be allocated among all Original Participating TOs in proportion to the amounts specified in paragraph (b) of this section. This limitation shall be applied by the ISO’s calculation annually of amounts payable by New Participating TOs to Original Participating TOs such that the combined effect of clauses (i) and (ii) of this paragraph, and the payments received by each Original Participating TO shall not exceed the amounts specified in paragraph (b) of this section. The amount receivable by the Original Participating TO from the New Participating TOs to implement the limitation in paragraph (b) of this section, shall be credited through the Transition Charge established pursuant to Section 5.7 of this Schedule 3. Payment responsibility under this section, if any, shall be allocated among New Participating TOs in proportion to their TAC Benefits.

(b) The maximum annual amounts for Original Participating TO shall be as follows:

(i) For Pacific Gas and Electric Company and Southern California Edison Company, the maximum annual amount shall be thirty-two million dollars ($32,000,000.00) each; and

(ii) For San Diego Gas & Electric Company, the maximum annual amount shall be eight million dollars ($8,000,000.00).

8. Updates to High Voltage Access Charges.

8.1 High Voltage Access Charges and High Voltage Wheeling Access Charges shall be adjusted: (1) on January 1 and July 1 of each year when necessary to reflect the addition of any New Participating TO and (2) on the date FERC makes effective a change to the High Voltage Transmission Revenue Requirements of any Participating TO. Using the High Voltage

Transmission Revenue Requirement accepted or authorized by FERC, consistent with Section 9 of this Schedule 3, for each Participating TO, the ISO will recalculate on a monthly basis the High Voltage Access Charge and Transition Charge applicable during such period. Revisions to the Transmission Revenue Balancing Account adjustment shall be made effective annually on January 1 based on the principal balance in the TRBA as of September 30 of the prior year and a forecast of Transmission Revenue Credits for the next year.

8.2 For service provided by a Participating TO prior to the Transition Date, no refund ordered by FERC or amount accrued to that Participating TO's Transmission Revenue Balancing Account related to such service shall be reflected in the High Voltage Access Charge, Low Voltage Access Charge, the High Voltage Transmission Revenue Requirement, or the Low Voltage Transmission Revenue Requirement of a Participating TO. For service provided by a Participating TO following the Transition Date, any refund associated with a Participating TO's Transmission Revenue Requirement that has been accepted by FERC, subject to refund, shall be provided as ordered by FERC. Such refund shall be invoiced separately from the Market Invoice.

8.3 If the Participating TO withdraws one or more of its transmission facilities from the ISO Operational Control in accordance with Section 3.4 of the Transmission Control Agreement, then the ISO will no longer collect the TRR for that transmission facility through the ISO's Access Charge effective upon the date the transmission facility is no longer under the Operational Control of the ISO. The withdrawing Participating TO shall be obligated to provide the ISO will all necessary information to implement the withdrawal of the Participating TO's transmission facilities and to make any necessary filings at FERC to revise its TRR. The ISO shall revise its transmission Access Charge to reflect the withdrawal of one or more transmission facilities from ISO Operational Control.

8.4

9. Approval of Updated High Voltage Revenue Requirements

9.1 Participating TOs will make the appropriate filings at FERC to establish their Transmission Revenue Requirements for their Low Voltage Access Charges and the applicable High Voltage Access Charges, and to obtain approval of any changes thereto. All such filings with the FERC will include a separate appendix that states the HVTRR, LVTRR (if applicable) and the appropriate Gross Load data and other information required by the FERC to support the Access Charges. The Participating TO will provide a copy of its filing to the ISO and the other Participating TOs in accordance with the notice provisions in the Transmission Control Agreement.

9.2 Federal power marketing agencies whose transmission facilities are under ISO Operational Control shall develop their High Voltage Transmission Revenue Requirements pursuant to applicable federal laws and regulations, including filing with FERC. All such filings with FERC will include a separate appendix that states the HVTRR, LVTRR (if applicable) and the appropriate Gross Load data and other information required by the FERC to support the Access Charges. The procedures for public participation in a federal power marketing agency's ratemaking process shall be posted on the federal power marketing agency's website. The federal power marketing agency shall also post on the website the Federal Register Notices and FERC orders for rate making processes that impact the federal power marketing agency's High Voltage Transmission Revenue Requirement. The Participating TO will provide a copy of its filing to the ISO and the other Participating TOs in accordance with the notice provisions in the Transmission Control Agreement.

10. Disbursement of High Voltage Access Charge and Transition Charge Revenues.

10.1 High Voltage Access Charge and Transition Charge revenues shall be calculated for disbursement to each Participating TO on a monthly basis as follows:

(a) the amount determined in accordance with Section 26.1.2 of the ISO Tariff ("Billed HVAC/TC");

(b)

(i) for a Participating TO that is a UDC or MSS Operator and has Gross Load in its TO Tariff in accordance with Appendix F, Schedule 3, Section 9, then calculate the amount each UDC or MSS Operator would have paid and the Participating TO would have received by multiplying the High Voltage Utility-Specific Rates for the Participating TO whose High Voltage Facilities served such UDC and MSS Operator times the actual Gross Load of such UDCs and MSS Operators ("Utility-specific HVAC"); or

(ii) for a Non-Load-Serving Participating TO, then calculate the Non-Load-Serving Participating TO's portion of the total Billed HVAC/TC in subsection (a) based on the ratio of the Non-Load-Serving Participating TO's High Voltage Transmission Revenue Requirement to the sum of all Participating TOs' High Voltage Revenue Requirements.

(c) if the total Billed HVAC/TC in subsection (a) received by the ISO less the total dollar amounts calculated in Utility-specific HVAC in subsection (b)(i) and subsection (b)(ii) is different from zero, the ISO shall allocate the positive or negative difference among those Participating TOs that are subject to the calculations in subsection (b)(i) based on the ratio of each Participating TO's High Voltage Transmission Revenue Requirement to the sum of all of those Participating TOs' High Voltage Transmission Revenue Requirements that are subject to the calculations in subsection (b)(i). This monthly distribution amount is the "HVAC Revenue Adjustment";

(d) the sum of the HVAC revenue share determined in subsection (b) and the HVAC Revenue Adjustment in subsection (c) will be the monthly disbursement to the Participating TO.

10.2 If the same entity is both a Participating TO and a UDC or MSS Operator, then the monthly High Voltage Access Charge and Transition Charge amount billed by the ISO will be the charges payable by the UDC or MSS Operator in accordance with Section 26.1.2 of the ISO Tariff less the disbursement determined in accordance with Section 10.1(d). If this difference is negative, that amount will be paid by the ISO to the Participating TO.

11. Determination of Transmission Revenue Requirement Allocation Between High Voltage and Low Voltage Transmission Facilities.

11.1 Each Participating TO shall allocate its Transmission Revenue Requirement between the High Voltage Transmission Revenue Requirement and Low Voltage Transmission Revenue Requirement based on the Procedure for Division of Certain Costs Between the High and Low Voltage Transmission Access Charges contained in Section 12 of this Schedule.

12. Procedure for Division of Certain Costs Between the High and Low Voltage Transmission Access Charges.

12.1 Division of Costs:

(a) Substations
Costs for substations and substation equipment, including transformers:

(i) If the Participating TO has substation TRR information by facility and voltage, then the TRR for facilities and equipment at or above 200 kV should be allocated to the HVTRR and the TRR for facilities and equipment below 200 kV should be allocated to the LVTRR;

(ii) If the Participating TO has substation TRR information by facility but not by voltage, then the TRR for facilities and equipment should be allocated to the HVTRR and to the LVTRR based on the ratio of gross substation investment allocated to HVTRR to gross substation investment allocated to LVTRR pursuant to Section 12.1(a)(i); or

(iii) If the Participating TO does not have substation TRR information by facility or voltage, then the TRR for facilities and equipment should be allocated to the HVTRR and to the LVTRR based on the Participating TO's transmission system-wide gross plant ratio. The system-wide gross plant ratio is determined once the costs that can be split between High Voltage and Low Voltage for all facilities has been developed in accordance with Sections 12.1(a) through (c), then the resulting cost ratio between High Voltage and Low Voltage shall be used as the system-wide gross plant ratio.

(iv) Costs of transformers that step down from high voltage (200 kV or above) to low voltage, to the extent the Participating TO does not have the revenue requirement information available on a voltage basis, should be allocated consistent with the procedures for substations addressed above.

(b) Transmission Towers and Land with Circuits on Multiple Voltages
For transmission towers that have both High Voltage and Low Voltage facilities on the same tower, the cost of these assets should be allocated two-thirds to the HVTRR and one-third to the LVTRR. If the transmission tower has only High Voltage facilities, then the costs of these assets should be allocated entirely to the HVTRR. If the transmission tower has only Low Voltage facilities, then the TRR of these assets should be allocated entirely to the LVTRR. Provided that the Participating TO does not have land cost information available on a voltage basis, in which case the costs should be allocated based on the bright-line of the voltage levels, the costs for land used for transmission

rights-of-way for towers that have both High Voltage and Low Voltage wires should be allocated two-thirds to the HVTRR component and one-third to the LVTRR.

(c) Operation and Maintenance, Transmission Wages & Salaries, Taxes, Depreciation and Amortization, and Capital Costs
If the Participating TO can delineate costs for transmission operations and maintenance (O&M), transmission wages and salaries, taxes, depreciation and amortization, or capital costs on a voltage basis, the costs shall be applied on a bright-line voltage basis. If the costs for O&M, transmission wages and salaries, taxes, depreciation and amortization, or capital costs, are not available on voltage levels, the allocation to the HVTRR and the LVTRR should be based on the Participating TO's system-wide gross plant ratio defined in Section 12.1(a).

(d) Existing Transmission Contracts
If the take-out point for the Existing Contract is a High Voltage Transmission Facility, the Existing Contract revenue will be credited to the HVTRR of the Participating TO receiving such revenue. Similarly, the Participating TO that is paying charges under such an Existing Contract may include the costs in its HVTRR. If the take-out point for the Existing Contract is a Low Voltage Transmission Facility, the Existing Contract revenue will be credited to the HVTRR and the LVTRR of the receiving Participating TO based on the ratio of the Participating TO's HVTRR to its LVTRR, prior to any adjustments for such revenues. The Participating TO that is paying the charges under the Existing Contract will include the costs in its HVTRR and LVTRR in the same ratio as the revenues are recognized by the Participating TO receiving the payments.

(e) Division of the TRBAA between HVTRR and LVTRR

(i) Wheeling revenues associated with transactions exiting the ISO Controlled Grid at High Voltage Scheduling Points or Take-Out Points shall be reflected as High Voltage components;

(ii) Wheeling revenues associated with transactions exiting the ISO Controlled Grid at Low Voltage Scheduling Points or Take-Out Points shall be attributed between High Voltage and Low Voltage TRBAA components based on the High Voltage and Low Voltage Wheeling Access Charge rates assessed to such transactions by the ISO and/or the Participating TO;

(iii) Any Low Voltage Access Charge amounts paid pursuant to Section 26.1 of the ISO Tariff for the Low Voltage Transmission Facilities of a Non-Load-Serving Participating TO shall be reflected as a component of the low voltage TRBA adjustment associated with the Low Voltage Access Charge;

(iv) FTR revenues shall be assigned to High Voltage or Low Voltage components based on the voltage of the path related to the FTR;

(v) Usage Charge revenues shall be allocated between High Voltage and Low Voltage components on a gross plant basis; and

(vi) Other Transmission Revenue Credits shall be allocated between High Voltage and Low Voltage components on a gross plant basis.

13. Low Voltage Access Charge for a Non-Load-Serving Participating TO. Pursuant to Section 26.1 of the ISO Tariff, the provisions of this Section 13 of this Schedule 3 shall apply to a Non-Load-Serving Participating TO that has Low Voltage Transmission Facilities.

13.1 Low Voltage Transmission Revenue Requirement. The Low Voltage Transmission Revenue Requirement of a Non-Load-Serving Participating TO shall be calculated separately for each individual project that includes one or more Low Voltage Transmission Facilities or shall be calculated for a group of Low Voltage Transmission Facilities if all are part of projects directly connected to the facilities of the same Participating TO(s). The Low Voltage Transmission Revenue Requirement will be determined consistent with ISO procedures posted on the ISO Home Page and shall be the sum of:

(a) the Non-Load-Serving Participating TO's Low Voltage Transmission Revenue Requirement for the relevant Low Voltage Transmission Facility or group of facilities; and

(b) the annual low voltage TRBA adjustment for the relevant Low Voltage Transmission Facility or group of facilities, which shall be based on the principal balance in the low voltage TRBA as of September 30 and shall be calculated as a dollar amount based on the projected Transmission Revenue Credits as adjusted for the true up of the prior year's difference between projected and actual credits. In accordance with Section 26.1 of the ISO Tariff, the Non-Load-Serving Participating TO shall include any over- or under-recovery of its annual Low Voltage Transmission Revenue Requirement in its low voltage TRBA. If the annual low voltage TRBA adjustment involves only a partial year of operations, the Non-Load-Serving Participating TO's over- or under-recovery shall be based on a partial year revenue requirement, calculated by multiplying the Non-Load-Serving Participating TO's Low Voltage Transmission Revenue Requirement by the number of days the Low Voltage Transmission Facilities were under the ISO's Operational Control divided by the number of days in the year.

13.2 Updates to Low Voltage Access Charges. Unless otherwise agreed by the affected Participating TOs, a Non-Load-Serving Participating TO shall adjust its Low Voltage Access Charges and Low Voltage Wheeling Access Charges (1) when necessary to reflect any new transmission addition directly connecting a Participating TO to the Low Voltage Transmission Facilities of the Non-Load-Serving Participating TO; (2) on the date FERC makes effective a change to the Low Voltage Transmission Revenue Requirement of the Non-Load-Serving Participating TO; and (3) on the date FERC makes effective a change to Gross Load of a Participating TO directly connected to the Non-Load-Serving Participating TO. Using the Low Voltage Transmission Revenue Requirement accepted or authorized by FERC, consistent with Section 9 of this Schedule 3, for the Non-Load-Serving Participating TO, the ISO will recalculate on a monthly basis the Low Voltage Access Charge applicable during such period. Revisions to the low voltage TRBA adjustment shall be made effective annually on January 1 based on the principal balance in the low voltage TRBA as of September 30 of the prior year and a forecast of Transmission Revenue Credits for the next year.

For service provided by a Non-Load-Serving Participating TO following the Transition Date, any refund associated with a Non-Load-Serving Participating TO's Transmission Revenue Requirement that has been accepted by FERC, subject to refund, shall be provided as ordered by FERC. Such refund shall be invoiced separately from the Market Invoice.

If the Non-Load-Serving Participating TO withdraws one or more of its transmission facilities from the ISO Operational Control in accordance with Section 3.4 of the Transmission Control Agreement, then the ISO will no longer collect the TRR for that transmission facility through the ISO's Access Charge effective upon the date the transmission facility is no longer under the Operational Control of the ISO. The withdrawing Non-Load-Serving Participating TO shall be obligated to provide the ISO will all necessary information to implement the withdrawal of the Participating TO's transmission facilities and to make any necessary filings at FERC to revise its TRR. The ISO shall revise its transmission Access Charge to reflect the withdrawal of one or more transmission facilities from ISO Operational Control.

13.3 Approval of Updated Low Voltage Transmission Revenue Requirement. A Non-Load-Serving Participating TO will make the appropriate filings at FERC to establish its Transmission Revenue Requirement for its Low Voltage Access Charge, and to obtain approval of any changes thereto. All such filings with the FERC will include a separate appendix that states the LVTRR and other information required by the FERC to support the Low Voltage Access Charge. The Non-Load-Serving Participating TO will provide a copy of its filing to the ISO and the other Participating TOs in accordance with the notice provisions in the Transmission Control Agreement.

Federal power marketing agencies whose transmission facilities are under ISO Operational Control shall develop their Low Voltage Transmission Revenue Requirements pursuant to applicable federal laws and regulations, including filing with FERC. All such filings with FERC will include a separate appendix that states the LVTRR and other information required by the FERC to support the Access Charges. The procedures for public participation in a federal power marketing agency's ratemaking process shall be posted on the federal power marketing agency's website. The federal power marketing agency shall also post on the website the Federal Register Notices and FERC orders for rate making processes that impact the federal power marketing agency's Low Voltage Transmission Revenue Requirement. The Non-Load-Serving Participating TO will provide a copy of its filing to the ISO and the other Participating TOs in accordance with the notice provisions in the Transmission Control Agreement.

13.4 Disbursement of Low Voltage Access Charge Revenues. Unless otherwise agreed by the affected Participating TOs, Low Voltage Access Charge revenues of a Non-Load-Serving Participating TO shall be calculated for disbursement to that Non-Load-Serving Participating TO on a monthly basis as the sum of Low Voltage Access Charges billed by the ISO to the UDCs or MSS Operators of Participating TOs pursuant to Section 26.1 of the ISO Tariff.

13.5 Payment of Low Voltage Access Charge. Notwithstanding the separate accounting for the Low Voltage Access Charge specified in Section 26.1 of ISO Tariff and this Section 13 of this Schedule 3, if the same entity is both a Participating TO and a UDC or MSS Operator, then the monthly High Voltage Access Charge and Transition Charge amount, and any Low Voltage Access Charge amount pursuant to this Section 13 of this Schedule 3, billed by the ISO will be the charges payable by the UDC or MSS Operator in accordance with Sections 26.1.2 and 26.1 of the ISO Tariff less the disbursement determined in accordance with Section 10.1(d) of this Schedule 3. If this difference is negative, that amount will be paid by the ISO to the Participating TO.

ISO TARIFF APPENDIX F
Schedule 4

Participating Intermittent Resources Forecasting Fee

A charge up to $.10 per MWh shall be assessed on the metered Energy from Participating Intermittent Resources. The amount of the charge shall be specified in the ISO Tariff.

Participating Intermittent Resources Process Fee

A Process Fee charge shall be assessed, for each calendar quarter, to each Exporting Participating Intermittent Resource that exported Energy in the quarter. On an annualized basis, the aggregate quarterly charges shall total to $10,000. The charge is not volumetric, and shall be calculated as follows:

($10,000/4)/N = $quarterly charge
N = number of Participating Intermittent Resources exporting Energy in the quarter

Participating Intermittent Resources Export Fee

A Participating Intermittent Resources Export Fee shall be assessed to Exporting Participating Intermittent Resources each calendar quarter. The Participating Intermittent Resources Export Fee shall be calculated as the product of (1) the sum of all settlement costs avoided by Participating Intermittent Resources for the preceding calendar quarter, or portion thereof, consisting of Charge Types 1597 [FERC Must-offer Obligation Capacity Payment System Allocation], 1697 [Tier 1 MLCC Allocation for System Needs], 1797 [Tier 1 MLCC Allocation of Resource Adequacy for System Needs], 1897 [Tier 1 MLCC Allocation of RCST for System Needs], and 4487 [Allocation of Excess Cost for Instructed Energy], but excluding charges for Uninstructed Energy associated with Charge Type 4407 and Transmission Loss Obligation associated with Charge Type 4450, (2) by the ratio of the total MW/h generated by an Exporting Participating Intermittent Resource during the calendar quarter, or portion thereof (based on metered output), by the total MW/h generated by all Participating Intermittent Resources during the calendar quarter, or portion thereof (based on metered output), and (3) by the percentage of the Exporting Participating Intermittent Resource's capacity deemed exporting under EIRP 5.3 or Export Percentage.

Participating Intermittent Resources Export Fee per Participating Intermittent Resource =

Program Costs x (MW/h individual Participating Intermittent Resource/MW/h all Participating Intermittent Resources) x Export Percentage

ISO TARIFF APPENDIX F

SCHEDULE 5

STATION POWER CHARGES

The ISO shall assess a charge of $500 to the Scheduling Coordinator representing the owner of one or more Generating Units that submits an application to establish a Station Power Portfolio or to change the configuration of Station Power meters or the generating facilities included in a Station Power Portfolio. If the generating facilities in a single Station Power Portfolio are scheduled by more than one Scheduling Coordinator, then the Scheduling Coordinator representing the most installed capacity shall be assessed the application charge.

A charge of $200 will be assessed to the SC of Generating Units that have Station Power meters each time the ISO is required to shift meter data to a unique load identifier pursuant to the Station Power Protocol. For example, if a Scheduling Coordinator has two Station Power meters, and both Remote Self Supply and Third Party Supply is attributed to each Station Power meter in a single Netting Period, then the ISO must shift meter data to a total of four unique load identifiers and the charge would be $800 in that month (2 meters X 2 load IDs X $200).

All revenue collected by the ISO pursuant to this Schedule 5 shall be considered “Other Revenues” and applied as a credit to the Grid Management Charge revenue requirement in accordance with Schedule 1 of Appendix F.

ISO TARIFF APPENDIX F
Schedule 6

RCST SCHEDULES

Monthly RCST Charge

The Monthly RCST Charge shall be calculated by multiplying the monthly shaping factors by the target annual capacity price ($73/kW-yr).

Monthly Shaping Factors

	SP-15	NP-15/ZP-26
Jan	6.7%	4.9%
Feb	5%	4.9%
Mar	5%	5.6%
Apr	5.8%	4.6%
May	6.3%	4.8%
Jun	8.3%	5.1%
Jul	15.8%	13.7%
Aug	17.5%	15.3%
Sept	11.7%	13.8%
Oct	5.8%	8.7%
Nov	6.3%	8.8%
Dec	5.8%	9.8%
Total	100%	100%

Availability

The target Availability for a resource designated under RCST is 95%. Incentives and penalties for availability above and below the target are as set forth in the table below, entitled “Availability Factor Table.” The ISO will calculate availability on a monthly basis using actual availability data. The “Availability Factor” for each month shall be calculated using the following curve:

AVAILABILITY FACTOR TABLE

Availability (excluding only Scheduled Maintenance)	**Capacity Payment Factor**	**Availability Factor**
100%	3.3%	1.139
99%	3.3%	1.106
98%	3.3%	1.073
97%	2.5%	1.040
96%	1.5%	1.015
95%	-	1.000
94%	-1.5%	.985
93%	-1.5%	.970
92%	-1.5%	.955
91%	-1.5%	.940
90%	-1.5%	.925
89-80%	-1.7%*	.908-.755
79-41%	-1.9%*	.736-.014
-40%	-	0.0

***The “Capacity Payment Factor” decreases by 1.7% and 1.9% respectively for every 1% decrease in availability.

The capacity payment will be adjusted upward from the 95% Availability starting point by the positive percentages listed as the Capacity Payment Factor above, by the amounts listed for each availability factor above 95%, so that, for example, if a 97% Availability is achieved for the month (as described below), then the capacity payment for that month would be the monthly value for 95% plus an additional 4% (1.5% for the first percent Availability above 95%, and 2.5% for the second percent Availability above 95%). Reductions in capacity payment will be made correspondingly according to the Capacity Payment Factor above for monthly availability levels falling short of the 95% availability starting point.

Calculation of the Monthly PER

The ISO shall calculate the Monthly Peak Energy Rent (“Monthly PER”) as follows: immediately following the end of the month the ISO will determine all those hours during which the Reference Resource would have been dispatched (based on Reference Resource characteristics) to provide either energy or non-spinning reserves and will calculate, on a per kW-Month basis, the total dollar amount of rent (earnings in excess of proxy unit variable costs calculated using Reference Resource unit characteristics) that would have been earned by the Reference Resource. The Reference Resource will be assumed to have been dispatched for energy in any hour in which the hourly energy price described below is greater than the Reference Resource variable cost; the ISO shall use its day ahead Non-spinning Reserve price to calculate the rent for all hours in which the Reference Resource is not assumed dispatched to provide energy (i.e., any hour where the hourly price is less than the Reference Resource variable costs).

Hourly price profiles will be determined using the shaping factors for SP-15 and NP15/ZP-26 that appear below. Hourly energy prices shall be the weighted average of: (1) the applicable zonal on/off peak day-ahead index prices set forth in Platts Megawatt Daily, shaped to hourly profiles using the factors set forth below, and (2) the applicable zonal ISO hourly average real-time energy prices. For 2006, the index/ex post weighting will be 50/50, respectively. For 2007, the index/ex post weighting will be 75/25, respectively.

The assumed heat rate of the Reference Resource will be 10,500 BTU/kWh. Variable operations and maintenance costs shall be based on the Energy Information Administration AEO Electricity Market Module Assumptions, which are currently $3.36/MWh. An emissions allowance of $0.71/MWh shall be used to estimate variable costs. Gas prices for the Reference Resource will be based on a daily gas price based on Equation C1-8 (Gas) of the Schedules to the Reliability Must Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company or Pacific Gas and Electric Company) or, if the resource is served from one of those three Service Areas then from the nearest of those Service Areas.

NP-15

	Mon-Fri JAN-MAY	Mon-Fri JUN-SEPT	Mon-Fri OCT-DEC	Sat JAN-MAY	Sat JUN-SEPT	Sat OCT-DEC	Sun JAN-MAY	Sun JUN-SEPT	Sun OCT-DEC
N1	1.05454758	1.00584021	0.99435526	1.43649	1.120844	1.073148	0.755403	0.759704	0.783346
N2	0.85716711	0.86062114	0.91898795	1.032749	1.092377	0.978957	0.600188	0.683139	0.701588
N3	0.75399836	0.79068297	0.92144851	0.758585	0.91744	0.921009	0.458319	0.636187	0.68291
N4	0.71058351	0.79900018	0.89479611	0.680278	0.892744	0.911836	0.444573	0.616409	0.662295
N5	0.78267681	0.8161591	0.94516384	0.630256	0.909543	0.926083	0.362844	0.5641	0.662342
N6	1.02256586	0.86829359	1.10962719	0.623168	0.709153	0.947344	0.293086	0.335463	0.707489
N7	0.75351629	0.46629678	0.84979936	0.459933	0.363102	0.835985	0.324748	0.244038	0.795325
N8	0.88610975	0.66277777	0.86218587	0.741872	0.587123	0.805198	0.576432	0.514076	0.804009
N9	0.93647065	0.72748598	0.87228518	0.967023	0.960062	0.891018	0.923411	0.756354	0.873764
N10	0.98013307	0.83355915	0.99306313	1.050452	0.998448	0.917894	1.087891	0.848836	0.970588
N11	1.05081328	0.91348904	0.97923559	1.079888	0.984474	1.02248	1.303241	0.94756	1.027355
N12	1.068781	0.96178966	0.98802244	1.086984	1.03194	0.961419	1.304385	1.158765	1.097895
N13	1.06644102	1.07695356	0.99576872	1.083005	1.00669	0.992817	1.283414	1.168292	1.059999
N14	1.09775977	1.22226563	1.06440722	1.072448	1.0038	1.04347	1.281892	1.283789	1.110655
N15	1.09364901	1.38229366	1.11766171	1.053707	1.124805	1.05608	1.263359	1.309879	1.150637
N16	1.0841716	1.44680734	1.14665908	1.048562	1.135933	1.056274	1.316946	1.317595	1.140864
N17	1.02358917	1.3710053	1.1033917	1.049893	1.362503	1.087482	1.311524	1.567664	1.232842
N18	0.9788975	1.21057642	0.95748393	1.049616	1.327635	1.081109	1.30229	1.71578	1.406331
N19	0.94570613	1.03868542	1.10717179	1.036387	1.126072	1.09328	1.321985	1.367096	1.419466
N20	0.96174495	0.91022871	1.13578926	1.048527	0.943973	1.193558	1.393578	1.139089	1.494944
N21	1.11577915	0.94038191	1.03355639	1.133815	1.001619	1.076201	1.778309	1.551657	1.39373
N22	0.95643767	0.8354037	0.79351865	1.037886	1.04182	0.885733	1.392837	1.473652	1.062792
N23	1.56132501	1.66415743	1.17445625	1.670367	1.287221	1.205472	1.150247	1.253671	0.972486
N24	1.25713576	1.19524538	1.04116487	1.168106	1.070678	1.036151	0.769097	0.787205	0.786348

SP-15

Weekday January through June

Hour	January	February	March	April	May	June
1	0.9	0.97	1.018	0.973	0.951	0.945
2	0.858	0.908	0.896	0.902	0.839	0.826
3	0.839	0.885	0.828	0.849	0.756	0.745
4	0.836	0.876	0.821	0.824	0.717	0.727
5	0.887	0.977	0.948	0.878	0.879	0.794
6	1.155	1.11	1.068	1.008	1.086	0.908
7	0.898	0.933	0.79	0.779	0.6	0.474
8	1.007	1	0.892	0.92	0.778	0.613
9	1.017	1.004	0.941	0.94	0.875	0.711
10	1.011	1.019	0.983	0.991	0.976	0.806
11	0.976	0.994	1.027	1.024	1.035	1.04
12	0.98	0.99	1.038	1.038	1.074	1.087
13	0.972	0.994	1.055	1.075	1.126	1.127
14	0.983	0.984	1.06	1.098	1.193	1.201
15	0.955	0.963	1.039	1.072	1.175	1.247
16	0.896	0.932	0.994	1.031	1.147	1.26
17	0.899	0.905	0.956	0.965	1.089	1.216
18	1.171	1.044	0.983	0.914	0.997	1.12
19	1.158	1.136	1.167	0.944	0.882	1.012
20	1.075	1.067	1.082	1.06	0.965	0.965
21	1.059	1.06	1.048	1.14	1.153	1.119
22	0.941	0.975	0.946	1.009	0.935	0.999
23	1.371	1.213	1.305	1.383	1.536	1.733
24	1.153	1.062	1.117	1.183	1.235	1.322

Saturday January through June

Hour	January	February	March	April	May	June
1	0.999	1.073	1.104	0.982	1.071	1.064
2	0.905	0.971	0.922	0.917	0.957	0.882
3	0.899	0.962	0.889	0.883	0.839	0.828
4	0.875	0.93	0.868	0.855	0.814	0.803
5	0.91	0.917	0.88	0.904	0.826	0.788
6	0.972	0.993	0.88	0.969	0.836	0.818
7	0.795	0.854	0.777	0.761	0.603	0.411
8	0.874	0.906	0.844	0.848	0.728	0.522
9	0.992	1.015	0.932	0.929	0.885	0.645
10	1.028	1.037	0.997	0.999	0.984	0.806
11	1.005	1.048	1.027	1.042	1.047	1.055
12	1.005	1.033	1.027	1.053	1.069	1.089
13	0.978	1.009	1.032	1.054	1.096	1.122
14	0.939	0.967	0.983	1.042	1.093	1.165
15	0.882	0.939	0.963	1.022	1.086	1.203
16	0.871	0.892	0.949	0.973	1.071	1.255
17	0.945	0.899	0.934	0.962	1.063	1.254
18	1.196	1.03	1.016	0.912	1.011	1.17
19	1.195	1.155	1.199	1.047	0.934	1.075
20	1.141	1.076	1.165	1.113	1.058	0.984
21	1.114	1.104	1.133	1.165	1.237	1.143
22	1.04	1.036	1.022	1.076	1.035	1.102
23	1.323	1.117	1.331	1.327	1.478	1.622
24	1.117	1.038	1.126	1.164	1.18	1.194

Sunday January through June

Hour	January	February	March	April	May	June
1	0.897	0.85	0.787	0.869	0.794	0.854
2	0.806	0.792	0.762	0.771	0.7	0.7
3	0.745	0.802	0.716	0.732	0.628	0.622
4	0.706	0.802	0.695	0.722	0.594	0.519
5	0.707	0.794	0.707	0.696	0.623	0.469
6	0.782	0.793	0.72	0.671	0.585	0.445
7	0.818	0.873	0.691	0.711	0.471	0.372
8	0.882	0.912	0.819	0.826	0.635	0.522
9	0.975	1.007	0.945	0.926	0.757	0.631
10	1.035	1.073	1.029	1.002	0.87	0.75
11	1.03	1.065	1.069	1.059	1.059	1.019
12	1.049	1.063	1.112	1.101	1.126	1.141
13	1.043	1.065	1.147	1.118	1.176	1.268
14	1.029	1.061	1.141	1.127	1.239	1.341
15	1.003	1.033	1.11	1.097	1.279	1.44
16	0.98	1.004	1.115	1.11	1.295	1.482
17	1.039	1.006	1.091	1.052	1.336	1.528
18	1.324	1.161	1.179	1.033	1.363	1.403
19	1.37	1.305	1.421	1.191	1.231	1.321
20	1.338	1.248	1.366	1.35	1.327	1.242
21	1.286	1.213	1.288	1.469	1.471	1.381
22	1.166	1.144	1.191	1.318	1.263	1.291
23	1.079	1.066	1.082	1.127	1.239	1.339
24	0.912	0.869	0.816	0.922	0.938	0.92

Weekday July through December

Hour	July	August	September	October	November	December
1	1.002	0.994	1.083	1.04	0.966	1.001
2	0.89	0.903	0.92	0.879	0.834	0.883
3	0.81	0.835	0.782	0.751	0.706	0.814
4	0.767	0.813	0.749	0.69	0.723	0.805
5	0.796	0.841	0.822	0.829	0.879	0.903
6	0.914	0.982	1.049	1.08	1.266	1.088
7	0.493	0.547	0.634	0.763	0.899	0.895
8	0.632	0.637	0.751	0.858	0.98	1.012
9	0.728	0.743	0.786	0.837	0.977	1.012
10	0.837	0.822	0.859	0.9	0.957	1.005
11	0.983	0.999	0.966	0.96	0.959	0.983
12	1.051	1.056	1.013	0.975	0.943	0.93
13	1.097	1.106	1.078	1.013	0.933	0.906
14	1.183	1.179	1.15	1.076	0.946	0.894
15	1.257	1.24	1.213	1.147	0.93	0.87
16	1.284	1.264	1.236	1.152	0.93	0.863
17	1.255	1.235	1.197	1.129	0.999	0.967
18	1.183	1.149	1.11	1.019	1.221	1.194
19	1.065	1.05	1.052	1.073	1.207	1.213
20	0.982	1.05	1.051	1.122	1.137	1.174
21	1.034	1.028	1.031	1.048	1.046	1.085
22	0.935	0.895	0.876	0.927	0.936	0.998
23	1.623	1.493	1.371	1.497	1.427	1.316
24	1.197	1.14	1.223	1.235	1.2	1.191

Saturday July through December

Hour	July	August	September	October	November	December
1	1.065	1.107	1.206	1.202	1.145	1.108
2	0.952	0.984	1.046	1.038	0.952	0.982
3	0.88	0.939	0.919	0.871	0.784	0.86
4	0.85	0.847	0.844	0.766	0.753	0.843
5	0.871	0.832	0.863	0.778	0.821	0.875
6	0.841	0.862	0.848	0.885	1.014	0.909
7	0.451	0.494	0.542	0.609	0.745	0.76
8	0.539	0.56	0.622	0.63	0.893	0.845
9	0.682	0.679	0.733	0.663	0.961	0.997
10	0.778	0.788	0.814	0.943	0.977	1.015
11	0.956	0.918	0.971	1.017	1.027	1.022
12	1.019	1.029	1.045	1.039	1.002	1
13	1.087	1.103	1.125	1.068	0.924	0.984
14	1.16	1.183	1.149	1.108	0.91	0.921
15	1.236	1.252	1.194	1.105	0.889	0.818
16	1.284	1.298	1.216	1.124	0.89	0.775
17	1.301	1.252	1.205	1.073	1.003	1.005
18	1.251	1.215	1.17	1.103	1.237	1.212
19	1.132	1.097	1.086	1.157	1.228	1.211
20	1.029	1.111	1.097	1.208	1.172	1.173
21	1.076	1.077	1.074	1.176	1.1	1.139
22	1.02	0.943	0.957	0.976	1.041	1.124
23	1.395	1.358	1.185	1.389	1.41	1.291
24	1.147	1.07	1.09	1.071	1.12	1.133

Sunday July through December

Hour	July	August	September	October	November	December
1	0.834	0.81	0.884	0.868	0.916	0.889
2	0.739	0.729	0.688	0.685	0.788	0.809
3	0.679	0.672	0.527	0.562	0.613	0.698
4	0.655	0.653	0.489	0.574	0.576	0.634
5	0.61	0.657	0.463	0.558	0.586	0.68
6	0.496	0.647	0.512	0.613	0.62	0.747
7	0.445	0.549	0.527	0.573	0.666	0.777
8	0.587	0.618	0.619	0.697	0.776	0.848
9	0.719	0.704	0.713	0.708	0.997	0.985
10	0.877	0.854	0.901	0.829	1.103	1.052
11	1.005	0.991	1.035	1.102	1.143	1.067
12	1.106	1.154	1.178	1.163	1.151	1.052
13	1.167	1.151	1.318	1.154	1.125	1.029
14	1.254	1.25	1.353	1.24	1.138	0.993
15	1.339	1.358	1.347	1.252	1.085	0.929
16	1.432	1.43	1.354	1.272	1.063	0.92
17	1.447	1.467	1.375	1.235	1.279	1.146
18	1.383	1.396	1.372	1.407	1.346	1.351
19	1.301	1.278	1.314	1.481	1.395	1.387
20	1.194	1.243	1.336	1.517	1.296	1.317
21	1.336	1.322	1.359	1.477	1.217	1.279
22	1.217	1.171	1.24	1.18	1.097	1.241
23	1.221	1.053	1.171	1.115	1.096	1.188
24	0.956	0.843	0.923	0.735	0.927	0.983

ISO TARIFF APPENDIX G

Must-Run Agreements

To be filed upon settlement

ISO TARIFF APPENDIX H

Methodology for Developing the Weighted Average Rate for Wheeling Service

ISO TARIFF APPENDIX H
Methodology for Developing the Weighted Average Rate for Wheeling Service

The weighted average rate payable for Wheeling over joint facilities at each Scheduling Point shall be calculated as follows, applying the formula separately to the applicable Wheeling Access Charges:

$$\mathrm{WBAC} = \sum \left(P_n \times \frac{Q_n}{\sum Q_n} \right)$$

Where:

WBAC = Weighted-average Wheeling Access Charge for each ISO Scheduling Point

P_n = The applicable Wheeling Access Charge rate for a TAC Area or Participating TO_n in $/kWh as set forth in Section 26.1.4 of the ISO Tariff and Section 5 of the TO Tariff.

Q_n = The Available Transfer Capacity (in MW), whether from transmission ownership or contractual entitlements, of each Participating TO_n for each ISO Scheduling Point which has been placed within the ISO Controlled Grid. Available Transfer Capacity shall not include capacity associated with Existing Rights of a Participating TO as defined in Section 16.2 of the ISO Tariff.

n = the number of Participating TOs from 1 to n

ISO TARFF APPENDIX I

ISO Congestion Management Zones

ISO TARIFF APPENDIX I
ISO Congestion Management Zones

1. **Active Zones**
   A. Northern Zone (NP15)
   B. Central Zone (ZP26)
   C. Southern Zone (SP15)

2. **Inactive Zones**
   A. Humboldt Zone
   B. San Francisco Zone

Note: The ISO's Initial Congestion Management Zones were described in the Joint Application of the IOUs for Authorization to Convey Operational Control of Designated Jurisdictional Facilities to an ISO filed April 29, 1996, Docket No. EC96-19-000.

ISO TARIFF APPENDIX J

End-Use Meter Standards and Capabilities

ISO TARIFF APPENDIX J

End-Use Meter Standards and Capabilities

End-Use Meter Standards & Capabilities Part A

End Use Meter Standards. All metering shall be of a revenue class metering accuracy in accordance with the ANSI C12 standards on metering and any other requirements of the relevant UDC or Local Regulatory Authority that may apply. Such requirements may apply to meters, current transformers and potential transformers, and associated equipment. ANSI C12 metering standards include the following:

ANSI C12.1 - American National Standard Code For Electricity Metering

ANSI C12.4 - American National Standard For Mechanical Demand Registers

ANSI C12.5 - American National Standard For Thermal Demand Meters

ANSI C12.6 - American National Standard For Marking And Arrangement Of Terminals For Phase-Shifting Devices Used In Metering

ANSI C12.7 - American National Standard For Watt-hour Meter Sockets

ANSI C12.8 - American National Standard For Test Blocks And Cabinets Forinstallation Of Self-Contained A-Base Watt-hour Meters

ANSI C12.9 - American National Standard For Test Switches For Transformer-Rated Meters

ANSI C12.10 - American National Standard For Electromechanical Watt-hour Meters

ANSI C12.11 - American National Standard For Instrument Transformers For Revenue Metering, 10 kV BIL Through 350 kV BIL

ANSI C12.13 - American National Standard For Electronic Time-Of -Use Registers For Electricity Meters

ANSI C12.14 - American National Standard For Magnetic Tape Pulse Recorders For Electricity Meters

ANSI C12.15 - American National Standard For Solid-State Demand Registers For Electromechanical Watt-hour Meters

ANSI C12.16 - American National Standard For Solid-State Electricity Meters

ANSI C12.17 - American National Standard For Cartridge-Type Solid-State Pulse Recorders For Electricity Metering

ANSI C12.18 - American National Standard For Protocol Specification For ANSI Type 2 Optical Port

Part B

PARTICIPATING SELLERS METER STANDARDS AND CAPABILITIES

ISO TARIFF APPENDIX K

Ancillary Service Requirements Protocol

ISO TARIFF APPENDIX K

Ancillary Service Requirements Protocol

PART A
CERTIFICATION FOR REGULATION

A 1 A Generator wishing to provide Regulation as an Ancillary Service from a Generating Unit whether pursuant to the ISO's auction or as part of a self-provision arrangement must meet the following operating characteristics and technical requirements in order to be certified by the ISO to provide Regulation service unless granted a temporary exemption by the ISO in accordance with criteria which the ISO shall publish on the ISO's internet "Home Page;"

A 1.1 Operating Characteristics

A 1.1.1 the rated capacity of the Generating Unit must be 1 MW or greater unless the Generating Unit is participating in an aggregation arrangement approved by the ISO;

A 1.1.2 the maximum amount of Regulation to be offered must be reached within a period that may range from a minimum of 10 minutes to a maximum of 30 minutes, as such period may be specified by the ISO and published on the ISO's internet "Home Page;"

A 1.2 Technical Requirements

A 1.2.1 Control

A 1.2.1.1 a direct, digital, unfiltered control signal generated from the ISO EMS through a standard ISO direct communication and direct control system, must meet the minimum performance standards for communications and control which will be developed and posted by the ISO on its internet "Home Page;"

A 1.2.1.2 the Generating Unit power output response (in MW) to a control signal must meet the minimum performance standards for control and unit response which will be developed and posted by the ISO on its internet "Home Page." As indicated by the Generating Unit power output (in MW), the Generating Unit must respond immediately, without manual Generating Unit operator intervention, to control signals and must sustain its specified ramp rate, within specified Regulation limits, for each minute of control response (MW/minute);

A 1.2.2 Monitoring:

the Generating Unit must have a standard ISO direct communication and direct control system to send signals to the ISO EMS to dynamically monitor, at a minimum the following:

A 1.2.2.1 actual power output (MW);

A 1.2.2.2 high limit, low limit and rate limit values as selected by the Generating Unit operator; and

A 1.2.2.3 in-service status indication confirming availability of Regulation service.

A 1.2.3 **Voice Communications:**

ISO approved primary and back-up voice communication must be in place between the ISO Control Center and the operator controlling the Generating Unit at the generating site and between the Scheduling Coordinator and the operator. The primary dedicated voice communication between the ISO Control Center and the operator controlling the Generating Unit at the generating site must be digital voice communication, as provided by a standard ISO direct communication and direct control system; and

A 1.3 the communication and control system and the Generating Unit must pass a qualification test to demonstrate the overall ability to provide Regulation meeting the performance requirements of the ASRP for Regulation.

A 2 A Generator wishing to be considered for certification for Regulation service by the ISO must make a written request to the ISO, giving details of the technical capability of the Generating Units concerned and identifying the Scheduling Coordinator through whom the Generator intends to offer Regulation service. The Generator shall at the same time send a copy of its request to that Scheduling Coordinator. Technical review request forms will be available from the ISO.

A 3 No later than one week after receipt of the Generator's request, the ISO shall provide the Generator with a listing of required interface equipment for Regulation, including a standard ISO direct communication and direct control system. The ISO shall send a copy of the listing to the Generator's Scheduling Coordinator.

A 4 The Generator may propose alternatives that the Generator believes may provide an equivalent level of communication and control for consideration by the ISO. Such proposals shall be in writing and contain sufficient detail for the ISO to make a determination of suitability. The ISO may request additional information, if required, to assist in its evaluation of the proposal.

A 5 The ISO shall respond by accepting the alternative proposal, rejecting the alternative proposal, or suggesting modifications to the alternative proposal. Such acceptance, rejection, or suggested revision must be provided not later than six weeks after the proposal is received by the ISO. The Generator and the ISO shall keep the Scheduling Coordinator informed of this process by each sending to the Scheduling Coordinator a copy of any written communication which it sends to the other.

A 6 Upon agreement as to any alternative method of communication and control to be used by the Generator, the ISO shall provisionally approve the proposal in writing providing a copy to the Generator's Scheduling Coordinator at the same time. If agreed by the ISO, the Generator may then proceed to procure and install the equipment and make arrangements for the required communication and control.

A 7 Design, acquisition, and installation of the ISO-approved communication and control equipment shall be under the control of the ISO. The ISO shall bear no cost responsibility or functional responsibility for such equipment, except that the ISO shall arrange for and monitor the maintenance of the communication and control system at the Generator's expense, unless otherwise agreed by the ISO and the Generator. The ISO shall be responsible for the design, acquisition and installation of any necessary modifications to the ISO EMS at its own cost.

A 8 The ISO, in cooperation with the Generator shall perform testing of the communication and control equipment to ensure that the communication and control system performs to meet the ISO requirements.

A 9 When the ISO is satisfied that the communication and control systems meet the ISO's requirements, the Generator shall request in writing that the ISO conduct a certification test with a suggested primary date and time and at least two alternative dates and times. The ISO shall, within two Business Days of receipt of the Generator's request, accept a proposed time if possible or suggest at least three alternatives to the Generator. If the ISO responds by suggesting alternatives, the Generator shall, within two Business Days of receipt of the ISO's response, respond in turn by accepting a proposed alternative if possible or suggesting at least three alternatives, and this procedure shall continue until agreement is reached on the date and time of the test. The Generator shall inform its Scheduling Coordinator of the agreed date and time of the test.

A 10 Testing shall be performed by the ISO, with the cooperation of the Generator. Such tests shall include, but not be limited to, the following:

A 10.1 confirmation of control communication path performance;

A 10.2 confirmation of primary and secondary voice circuits for receipt of Dispatch instructions;

A 10.3 confirmation of the Generating Unit control performance; and

A 10.4 confirmation of the ISO EMS control to include changing the Generating Unit output over the range of Regulation proposed at different Set Points, from minimum to maximum output, and at different rates of change from the minimum to the maximum permitted by the design of the Generating Unit.

A 11 Upon successful completion of the test, the ISO shall certify the Generating Unit as being permitted to provide Regulation as an Ancillary Service and shall provide a copy of the certificate to the Scheduling Coordinator at the same time. The ISO shall change its Generating Unit data base to reflect the permission for the Generating Unit to provide Regulation service.

A 12 The Scheduling Coordinator may bid Regulation service from the certified Generating Unit into the Markets starting with the Day-Ahead Market for the hour ending 0100 on the second Trading Day after the ISO issues the certificate.

A 13 The certification to provide Regulation shall remain in force until:

(a) withdrawn by the Scheduling Coordinator or the Generator by written notice to the ISO to take effect at the time notified in the notice, which must be the end of a Trading Day; or

(b) if the Generating Unit obtained ISO certification on the basis of a prior communication and control technology, until revoked by the ISO for failure to comply with the requirement set forth in A 13.1 that the Generating Unit install an ISO-specified standard ISO direct communication and direct control system (unless exempted by the ISO).

A 13.1 Unless exempted by the ISO, if the Generating Unit obtained ISO certification on the basis of a prior communication and control technology, the ISO shall provide written notice to the Generator of the Generator’s obligation to install an ISO-specified standard direct communication and direct control system along with a required date for said work to be completed as mutually agreed upon by the ISO and the Generator. Failure to meet the completion date shall be grounds for the revocation of certification, provided that the ISO must provide the Generator with at least ninety (90) days advance notice of the proposed revocation.

A 14 THE CERTIFICATION MAY BE REVOKED BY THE ISO ONLY UNDER PROVISIONS

OF THE ASRP OR THE ISO TARIFF.

PART B

CERTIFICATION FOR SPINNING RESERVE

B 1 A Generator wishing to provide Spinning Reserve as an Ancillary Service from a Generating ,Unit or System Resource whether pursuant to the ISO's auction or as part of a self-provision arrangement must meet the following requirements in order to be certified by the ISO to provide Spinning Reserve service:

B 1.1 the rated capacity of the Generating Unit must be 1 MW or greater unless the Generating Unit is participating in an aggregation arrangement approved by the ISO;

B 1.2 the minimum governor performance of the Generating Unit or System Resource shall be as follows:

B 1.2.1 5% drop;

B 1.2.2 governor deadband must be plus or minus 0.036Hz; and

B 1.2.3 the power output must change within one second for any frequency deviation outside the governor deadband.

B 1.3 the operator of the Generating Unit or System Resource must have a means of receiving Dispatch instructions to initiate an increase in real power output (MW) within one minute of the ISO Control Center determination that Energy from Spinning Reserve capacity must be Dispatched;

B 1.4 the Generating Unit or System Resource must be able to increase its real power output (MW) by the maximum amount of Spinning Reserve to be offered within ten minutes;

B 1.5 ISO approved voice communications services must be in place to provide both primary and alternate voice communication between the ISO Control Center and the operator controlling the Generating Unit or System Resource; and

B 1.6 The communication system and the Generating Unit or System Resource must pass a qualification test to demonstrate the overall ability to meet the performance requirements of the ASRP for Spinning Reserve.

B 2 A Generator or System Unit wishing to be considered for certification for Spinning Reserve service by the ISO must make a written request to the ISO, giving details of the technical capability of the Generating Units or System Resources concerned and identifying the Scheduling Coordinator through whom the Generator or System Unit intends to offer Spinning Reserve service. The Generator or System Unit shall at the same time send a copy of its request to that Scheduling Coordinator. Technical review request forms will be available from the ISO.

B 3 No later than one week after receipt of the request, the ISO shall provide the Generator or System Unit with a listing of acceptable communication options and interface equipment options for Spinning Reserve. The ISO shall send a copy of the listing to the Generator's or System Unit's Scheduling Coordinator.

B 4 The Generator or System Unit may elect to implement any of the approved options defined by the ISO, and, if it wishes to proceed with its request for certification, shall give written notice to the ISO of its selected communication option, with a copy to its Scheduling Coordinator.

B 5 When it receives the Generator's or System Unit's notice, the ISO shall notify the Generator or System Unit and the Scheduling Coordinator in writing no later than two weeks after receipt of the notice confirming receipt of the notice and issuing provisional approval of the selected options. Upon receipt of the ISO acknowledgment, the Generator or System Unit may proceed as indicated below to secure the necessary facilities and capabilities required.

B 6 The Generator or System Unit may also propose alternatives that it believes may provide an equivalent level of control for consideration by the ISO. Such proposals shall be in writing and contain sufficient detail for the ISO to make a determination of suitability. The ISO may request additional information, if required, to assist in its evaluation of the proposal.

B 7 The ISO shall respond by accepting the alternative proposal, rejecting the alternative proposal, or suggesting modifications to the alternative proposal. Such acceptance, rejection, or suggested revision must be provided not later than six weeks after the proposal is received by the ISO. The Generator or the System Unit and the ISO shall keep the Scheduling Coordinator informed of this process by each sending to the Scheduling Coordinator a copy of any written communication which it sends to the other.

B 8 Upon agreement as to the method of communication and control to be used by the Generator or System Resource, the ISO shall provisionally approve the Generator's proposal or the System Resource's proposal in writing providing a copy to the Generator's or System Resource's Scheduling Coordinator at the same time. The Generator or System Resource may then proceed to procure and install the equipment and make arrangements for the required communication.

B 9 Design, acquisition, and installation of the Generator's equipment or the System Resource's equipment shall be under the control of the respective Generator or System Resource. The ISO shall bear no cost responsibility or functional responsibility for such equipment. The ISO shall be responsible for the design, acquisition and installation of any necessary modifications to its own equipment at its own cost.

B 10 The Generator or System Resource shall perform its own testing of its equipment to ensure that the control system performs to meet the ISO requirements.

B 11 When it is satisfied that its plant, equipment and communication systems meet the ISO's requirements, the Generator or System Resource shall request in writing that the ISO conduct a certification test with a suggested primary date and time and at least two alternative dates and times. The ISO shall, within two Business Days of receipt of the request, accept a proposed time if possible or suggest at least three alternatives to the Generator or System Resource. If the ISO responds by suggesting alternatives, the Generator or System Resource shall, within two Business Days of receipt of the ISO's response, respond in turn by accepting a proposed alternative if possible or suggesting at least three alternatives, and this procedure shall continue until agreement is reached on the date and time of the test. The Generator or System Resource shall inform its Scheduling Coordinator of the agreed date and time of the test.

B 12 Testing shall be performed under the direction of the ISO. Such tests shall include, but not be limited to, the following:

B 12.1 confirmation of control communication path performance for Dispatch instruction;

B 12.2 confirmation of primary and secondary voice circuits for receipt of Dispatch instructions;

B 12.3 confirmation of the Generating Unit or System Resource performance to include changing the Generating Unit or System Resource output over the range of Spinning Reserve proposed from minimum to maximum output, and at different rates of change from the minimum to the maximum permitted by the design of the Generating Unit or System Resource; and

B 12.4 testing the drop characteristic of the Generating Unit or System Resource by simulating frequency excursions outside the allowed deadband and measuring the response of the Generating Unit or System Resource.

B 13 Upon successful completion of the test the ISO shall certify the Generating Unit or System Resource as being permitted to provide Spinning Reserve as an Ancillary Service and shall provide a copy of the certificate to the Scheduling Coordinator at the same time. The ISO shall change the Generating Unit or System Resource data base to reflect the ability of the Generating Unit to provide Spinning Reserve.

B 14 The Scheduling Coordinator may bid Spinning Reserve from the certified Generating Unit or System Resource into the Markets starting with the Day-Ahead Market for the hour ending 0100 on the Second Trading Day after the ISO issues the certificate.

B 15 The certification to provide Spinning Reserve shall remain in force until withdrawn by the Scheduling Coordinator or the Generator or System Resource by written notice to the ISO to take effect at the time notified in the notice, which must be the end of a Trading Day.

B 16 The certification may be revoked by the ISO only under provisions of the ASRP or the I SO Tariff.

PART C

CERTIFICATION FOR NON-SPINNING RESERVE

C 1 An Ancillary Service Provider wishing to provide Non-Spinning Reserve as an Ancillary Service from a Generating Unit or System Resource whether pursuant to the ISO's auction or as part of a self-provision arrangement must meet the following requirements in order to be certified by the ISO to provide Non-Spinning Reserve service:

C 1.1 the rated capacity of the Generating Unit or System Resource must be 1 MW or greater unless the Generating Unit is participating in an aggregation arrangement approved by the ISO;

C 1.2 the Generating Unit must be able to increase output as soon as possible to the value indicated in a Dispatch instruction, reaching the indicated value within ten minutes after issue of the instruction and be capable of maintaining output for 2 hours.

C 2 An Ancillary Service Provider wishing to provide Non-Spinning Reserve as an Ancillary Service from Curtailable Demand whether pursuant to the ISO's auction or as part of a self-provision arrangement must meet the following requirements in order to be certified by the ISO to provide Non-Spinning Reserve service:

C 2.1 the operator must be able to completely disconnect the required Load pursuant to a Dispatch instruction within ten minutes after issue of the instruction;

C 2.2 the minimum change in the electrical consumption of the Load must be at least 1 MW; and

C 2.3 the Load must be capable of being interrupted for at least two hours.

C 3 An Ancillary Service Provider wishing to provide Non-Spinning Reserve as an Ancillary Service, whether pursuant to the ISO's auction or as part of a self-provision arrangement, must also meet the following requirements in order to be certified by the ISO to provide Non-Spinning Reserve service:

C 3.1 the operator of the Generating Unit, System Resource or the Curtailable Demand must have a means of receiving a Dispatch instruction to initiate an increase in real power output or a reduction in Demand (MW) within one minute of the ISO Control Center's determination that Non-Spinning Reserve capacity must be Dispatched; and

C 3.2 the communication system and the Generating Unit, System Resource or Load must pass a qualification test to demonstrate the overall ability to meet the performance requirements of the ASRP for Non-Spinning Reserve.

C 4 An Ancillary Service Provider wishing to be considered for certification for Non-Spinning Reserve service must make a written request to the ISO, giving details of the technical capability of the Generating Unit, System Resource or Load concerned and identifying the Scheduling Coordinator through whom the Ancillary Service Provider intends to offer Non-Spinning Reserve. The Ancillary Service Provider shall at the same time send a copy of the request to that Scheduling Coordinator. Technical Review request forms will be available from the ISO.

C 5 No later than one week after receipt of the Ancillary Service Provider's request, the ISO shall provide the Ancillary Service Provider with a listing of acceptable communication options and interface equipment options for Non-Spinning Reserve. The ISO shall send a copy of the listing to the Ancillary Service Provider's Scheduling Coordinator.

C 6 The Ancillary Service Provider may elect to implement any of the certification, the Ancillary Service Provider shall give written notice to the ISO of its selected communication option and interface equipment option, with a copy to its Scheduling Coordinator.

C 7 When it receives the Ancillary Service Provider's notice, the ISO shall notify the Ancillary Service Provider and the Scheduling Coordinator in writing no later than two weeks after receipt of the notice confirming receipt of the notice and issuing provisional approval of the selected options. Upon receipt of the ISO acknowledgment the Ancillary Service Provider may proceed as indicated below to secure the necessary facilities and capabilities required.

C 8 The Ancillary Service Provider may also propose alternatives that it believes may provide an equivalent level of control for consideration by the ISO. Such proposals shall be in writing and contain sufficient detail for the ISO to make a determination of suitability. The ISO may request additional information, if required, to assist in its evaluation of the proposal.

C 9 The ISO shall respond by accepting the alternative proposal, rejecting the alternative proposal, or suggesting modifications to the alternative proposal. Such acceptance, rejection, or suggested revision must be provided not later than six weeks after the proposal is received by the ISO. The Ancillary Service Provider and the ISO shall keep the Scheduling Coordinator informed of this process by each sending to the Scheduling Coordinator a copy of any written communication which it sends to the other.

C 10 Upon agreement as to the method of communication and control to be used by the Ancillary Service Provider, the ISO shall provisionally approve the proposal in writing providing a copy to the Ancillary Service Provider's Scheduling Coordinator at the same time. The Ancillary Service Provider may then proceed to procure and install the equipment and make arrangements for the required communication.

C 11 Design, acquisition, and installation of the Ancillary Service Provider's equipment shall be under the control of the Ancillary Service Provider. The ISO shall bear no cost responsibility or functional responsibility for such equipment. The ISO shall be responsible for the design, acquisition and installation of any necessary modifications to the ISO's equipment at its own cost.

C 12 The Ancillary Service Provider shall perform its own testing of its equipment to ensure that the control system performs to meet the ISO requirements.

C 13 When it is satisfied that its plant, equipment and communication systems meet the ISO's requirements, the Ancillary Service Provider shall request in writing that the ISO conduct a certification test with a suggested primary date and time and at least two alternative dates and times. The ISO shall, within two Business Days of receipt of the Ancillary Service Provider's request, accept a proposed time if possible or suggest at least three alternatives. If the ISO responds by suggesting alternatives, the Ancillary Service Provider shall, within two Business Days of receipt of the ISO's response, respond in turn by accepting a proposed alternative if possible or suggesting at least three alternatives, and this procedure shall continue until agreement is reached on the date and time of the test. The Ancillary Service Provider shall inform its Scheduling Coordinator of the agreed date and time of the test.

C 14 Testing shall be performed under the direction of the ISO. Such tests shall include, but not be limited to, the following:

C 14.1 confirmation of control communication path performance;

C 14.2 confirmation of primary and secondary voice circuits for receipt of Dispatch instructions;

C 14.3 confirmation of the Generating Unit, System Resource or Load control performance; and

C 14.4 confirmation of the range of Generating Unit or System Resource control to include changing the output over the range of Non-Spinning Reserve proposed.

C 15 Upon successful completion of the test, the ISO shall certify the Generating Unit, System Resource or Load as being permitted to provide Non-Spinning Reserve as an Ancillary Service and shall provide a copy of the certificate to the Scheduling Coordinator at the same time. The ISO shall change its data base to reflect the permission for the Generating Unit or Load to provide Non-Spinning Reserve service.

C 16 The Scheduling Coordinator may bid Non-Spinning Reserve service from the certified Generating Unit or Load into the Markets starting with the Day-Ahead Market for the hour ending 0100 on the second Trading Day after the ISO issues the certificate.

C 17 The certification to provide Non-Spinning Reserve shall remain in force until withdrawn by the Scheduling Coordinator or the Ancillary Service Provider by written notice to the ISO to take effect at the time notified in the notice, which must be the end of a Trading Day.

C 18 The certification may be revoked by the ISO only under provisions of the ASRP or the ISO Tariff.

PART D

CERTIFICATION FOR REPLACEMENT RESERVE

D 1 An Ancillary Service Provider wishing to provide Replacement Reserve as an Ancillary Service from a Generating Unit or System Resource whether pursuant to the ISO's auction or as part of a self-provision arrangement must meet the following requirements in order to be certified by the ISO to provide Replacement Reserve service:

D 1.1 the rated capacity of the Generating Unit or System Resource must be 1 MW or greater unless the Generating Unit is participating in an aggregation arrangement approved by the ISO;

D 1.2 the operator of the Generating Unit must be able to increase output as quickly as possible to a value indicated in a Dispatch instruction, reaching the indicated value in sixty minutes or less after issue of the instruction.

D 2 An Ancillary Service Provider wishing to provide Replacement Reserve as an Ancillary Service from Curtailable Demand whether pursuant to the ISO's auction or as part of a self-provision arrangement must meet the following requirements in order to be certified by the ISO to provide Replacement Reserve service:

D 2.1 the operator must be able to completely disconnect the required Load pursuant to a Dispatch instruction within sixty minutes after issue of the instruction;

D 2.2 the minimum change in the electrical consumption of the Load must be at least 1 MW; and

D 2.3 the Load must be capable of being interrupted for at least two hours.

D 3 An Ancillary Service Provider wishing to provide Replacement Reserve as an Ancillary Service, whether pursuant to the ISO's auction or as part of a self-provision arrangement, must also meet the following requirements in order to be certified by the ISO to provide Replacement Reserve service:

D 3.1 the operator of the Generating Unit, System Resource or the Curtailable Demand must have a means of receiving a Dispatch instruction to initiate an increase in real power output or a reduction in Demand (MW) within one minute of the ISO Control Center's determination that Replacement Reserve capacity must be Dispatched; and

D 3.2 the communication system and the Generating Unit or Load must pass a qualification test to demonstrate the overall ability to meet the performance requirements of the ASRP for Replacement Reserve.

D 4 An Ancillary Service Provider wishing to be considered for certification for Replacement Reserve service must make a written request to the ISO, giving details of the technical capability of the Generating Unit, System Resource or the Load concerned and identifying the Scheduling Coordinator through whom the Ancillary Service Provider intends to offer Replacement Reserve. The Ancillary Service Provider shall at the same time send a copy of its request to that Scheduling Coordinator. Technical Review request forms will be available from the ISO.

D 5 No later than one week after receipt of the Ancillary Service Provider's request, the ISO shall provide the Ancillary Service Provider with a listing of acceptable communication options and interface equipment options for Replacement Reserve. The ISO shall send a copy of the listing to the Ancillary Service Provider's Scheduling Coordinator.

D 6 The Ancillary Service Provider may elect to implement any of the options defined by the ISO, and, if it wishes to proceed with its request for certification, the Ancillary Service Provider shall give written notice to the ISO of its selected communication option and interface equipment option, with a copy to its Scheduling Coordinator.

D 7 When it receives the Ancillary Service Provider's notice, the ISO shall notify the Ancillary Service Provider and the Scheduling Coordinator in writing no later than two weeks after receipt of the notice confirming receipt of the notice and issuing provisional approval of the selected options. Upon receipt of the ISO acknowledgment the Ancillary Service Provider may proceed as indicated below to secure the necessary facilities and capabilities required.

D 8 The Ancillary Service Provider may also propose alternatives that it believes may provide an equivalent level of control for consideration by the ISO. Such proposals shall be in writing and contain sufficient detail for the ISO to make a determination of suitability. The ISO may request additional information, if required, to assist in its evaluation of the proposal.

D 9 The ISO shall respond by accepting the alternative proposal, rejecting the alternative proposal, or suggesting modifications to the alternative proposal. Such acceptance, rejection, or suggested revision shall be provided not later than six weeks after the proposal is received by the ISO. The Ancillary Service Provider and the ISO shall keep the Scheduling Coordinator informed of this process by each sending to the Scheduling Coordinator a copy of any written communication which it sends to the other.

D 10 Upon agreement as to the method of communication and control to be used by the Ancillary Service Provider, the ISO shall provisionally approve the proposal in writing providing a copy to the Ancillary Service Provider's Scheduling Coordinator at the same time. The Ancillary Service Provider may then proceed to procure and install the equipment and make arrangements for the required communication.

D 11 Design, acquisition, and installation of the Ancillary Service Provider's equipment shall be under the control of the Ancillary Service Provider. The ISO shall bear no cost responsibility or functional responsibility for such equipment. The ISO shall be responsible for the design, acquisition and installation of any necessary modifications to the ISO's equipment at its own cost.

D 12 The Ancillary Service Provider shall perform its own testing of its equipment to ensure that the control system performs to meet the ISO requirements.

D 13 When it is satisfied that its plant, equipment and communication systems meet the ISO's requirements, the Ancillary Service Provider shall request in writing that the ISO conduct a certification test with a suggested primary date and time and at least two alternative dates and times. The ISO shall, within two Business Days of receipt of the Ancillary Service Provider's request, accept a proposed time if possible or suggest at least three alternatives. If the ISO responds by suggesting alternatives, the Ancillary Service Provider shall, within two Business Days of receipt of the ISO's response, respond in turn by accepting a proposed alternative if possible or suggesting at least three alternatives, and this procedure shall continue until agreement is reached on the date and time of the test. The Ancillary Service Provider shall inform its Scheduling Coordinator of the agreed date and time of the test.

D 14 Testing shall be performed under the direction of the ISO. Such tests shall include, but not be limited to, the following:

D 14.1 confirmation of control communication path performance;

D 14.2 confirmation of primary and secondary voice circuits for receipt of Dispatch instructions;

D 14.3 confirmation of the Generating Unit, System Resource or Load control performance; and

D 14.4 confirmation of the range of Generating Unit or System Resource control to include changing the Generating Unit output over the range of Replacement Reserve proposed.

D 15 Upon successful completion of the test the ISO shall certify the Generating Unit, System Resource or Load as being permitted to provide Replacement Reserve as an Ancillary Service and shall provide a copy of the certificate to the Scheduling Coordinator at the same time. The ISO shall change its data base to reflect the permission for the Generating Unit or Load to provide Replacement Reserve service.

D 16 The Scheduling Coordinator may bid Replacement Reserve service from the certified Generating Unit or Load into the Markets starting with the Day-Ahead Market for the hour ending 0100 on the second Trading Day after the ISO issues the certificate.

D 17 The certification to provide Replacement Reserve shall remain in force until withdrawn by the Scheduling Coordinator or the Ancillary Service Provider by written notice to the ISO to take effect at the time notified in the notice, which must be the end of a Trading Day.

D 18 **THE CERTIFICATION MAY BE REVOKED BY THE ISO ONLY UNDER PROVISIONS OF THE ASRP OR THE ISO TARIFF.**

PART E

CERTIFICATION FOR VOLTAGE SUPPORT

E 1 A Generator wishing to provide Voltage Support as an Ancillary Service from a Generating Unit must meet the following requirements in order to be certified by the ISO to provide Voltage Support service:

E 1.1 the rated capacity of the Generating Unit must be 1 MW or greater unless the Generating Unit is participating in an aggregation arrangement approved by the ISO;

E 1.2 the Generating Unit must be able to produce VARs at lagging power factors less than 0.90 and absorb VARs at leading power factors more than 0.95 within the safe operating parameters for the Generating Unit;

E 1.3 the Generating Unit must be able to produce or absorb VARs outside the 0.90 lag to 0.95 lead bandwidth over a range of real power outputs which the Generator expects to produce when offering Voltage Support;

E 1.4 the Generating Unit must be able to produce or absorb VARs at the boundary of the Generating Unit's capability curve by reducing real power output to either absorb or produce additional VARs within the safe operating parameters for the Generating Unit; and

E 1.5 metering and SCADA equipment must be in place to provide both real and reactive power data from the Generating Unit providing Voltage Support to the ISO Control Center.

E 2 A Generator wishing to be considered for certification for Voltage Support service by the ISO must make a written request to the ISO, giving details of the technical capability of the Generating Unit concerned and identifying the Scheduling Coordinator through whom the Generator intends to offer Voltage Support service. The Generator shall at the same time send a copy of its request to that Scheduling Coordinator. The details of the Generating Unit's technical capability must include the Generating Unit name plate data, performance limits, and capability curve. The Generator must also define the operating limitations in both real and reactive power (lead and lag) to be observed when Voltage Support is being provided to the ISO for both normal and reduced real power output conditions. Technical Review request forms will be available from the ISO.

E 3 No later than one week after receipt of the Generator's request, the ISO shall provide the Generator with a listing of acceptable communication options and interface equipment options for Voltage Support. The ISO shall send a copy of the listing to the Generator's Scheduling Coordinator.

E 4 The Generator may elect to implement any of the approved options defined by the ISO, and, if it wishes to proceed with its request for certification, the Generator shall give written notice to the ISO of its selected communication option and interface equipment option, with a copy to its Scheduling Coordinator.

E 5 When it receives the Generator's notice the ISO shall notify the Generator and the Scheduling Coordinator in writing no later than two weeks after receipt of the notice confirming receipt of the notice and issuing provisional approval of the selected options. Upon receipt of the ISO acknowledgment the Generator may proceed as indicated below to secure the necessary facilities and capabilities required.

E 6 The Generator may also propose alternatives that the Generator believes may provide an equivalent level of control for consideration by the ISO. Such proposals shall be in writing no later than two weeks after receipt of the notice and contain sufficient detail for the ISO to make a determination of suitability. The ISO may request additional information, if required, to assist in its evaluation of the proposal.

E 7 The ISO shall respond by accepting the alternative proposal, rejecting the alternative proposal, or suggesting modifications to the alternative proposal. Such acceptance, rejection, or suggested revision shall be provided not later than six weeks after the proposal is received by the ISO. The Generator and the ISO shall keep the Scheduling Coordinator informed of this process by each sending to the Scheduling Coordinator a copy of any written communication which it sends to the other.

E 8 Upon agreement as to the method of communication and control to be used by the Generator, the ISO shall provisionally approve the proposal in writing providing a copy to the Generator's Scheduling Coordinator at the same time. The Generator may then proceed to procure and install the equipment and make arrangements for the required communication.

E 9 Design, acquisition, and installation of the Generator's equipment are under the control of the Generator. The ISO shall bear no cost responsibility or functional responsibility for such equipment.

E 10 The ISO shall be responsible for the design, acquisition and installation of any necessary modifications to the ISO's equipment at its own cost.

E 11 The Generator shall perform its own testing of its equipment to ensure that the control system performs to meet the ISO requirements.

E 12 When it is satisfied that its plant, equipment and communication systems meet the ISO's requirements, the Generator shall request in writing that the ISO conduct a certification test with a suggested primary date and time and at least two alternative dates and times. The ISO shall, within two Business Days of receipt of the Generator's request, accept a proposed time if possible or suggest at least three alternatives to the Generator. If the ISO responds by suggesting alternatives, the Generator shall, within two Business Days of receipt of the ISO's response, respond in turn by accepting a proposed alternative if possible or suggesting at least three alternatives, and this procedure shall continue until agreement is reached on the date and time of the test. The Generator shall inform its Scheduling Coordinator of the agreed date and time of the test.

E 13 Testing shall be performed under the direction of the ISO. Such tests shall include, but not be limited to, the following:

E 13.1 confirmation of control communication path performance;

E 13.2 confirmation of primary and secondary voice circuits for receipt of Dispatch instructions;

E 13.3 confirmation of the Generating Unit automatic voltage regulator performance; and

E 13.4 confirmation of the range of Voltage Support service over a range of Generating Unit real power outputs to verify the ability to both produce and absorb reactive power at different operating levels including minimum and maximum real power output.

E 14 Upon successful completion of the test, the ISO shall certify the Generating Unit as being permitted to provide Voltage Support as an Ancillary Service and shall provide a copy of the certificate to the Scheduling Coordinator at the same time. The ISO shall change the Generating Unit data base to reflect the permission for the Generating Unit to provide Voltage Support.

E 15 The Scheduling Coordinator may bid Supplemental Energy for Voltage Support from the certified Generating Unit into the market starting with the market for the hour ending 0100 on the first Trading Day after the ISO issues the certificate.

E 16 The certification to provide Voltage Support shall remain in force until withdrawn by the Scheduling Coordinator or the Generator by written notice to the ISO to take effect at the time notified in the notice, which must be the end of a Trading Day.

E 17 The certification may be revoked by the ISO only under provisions of the ASRP or the ISO Tariff.

PART F

CERTIFICATION FOR BLACK START

F 1 A Generator wishing to provide Black Start capacity from a Generating Unit as an Ancillary Service must meet the requirements stated in Appendix D of the ISO Tariff in order to be certified by the ISO to provide Black Start capacity. In addition, the Generating Unit must have a rated capacity 1 MW or greater unless the Generating Unit is participating in an aggregation arrangement approved by the ISO.

F 2 A Generator wishing to be considered for certification for Black Start service by the ISO must make a written request to the ISO. Such request must clearly identify the facilities related to the Generating Unit from which the Generator wishes to provide Black Start and shall identify the Scheduling Coordinator through whom the Generator wishes to offer Black Start service. The Generator shall send a copy of its request to its Scheduling Coordinator at the same time as it sends it to the ISO. The Generator's written request must include at least the following:

F 2.1 identification of the Generating Unit including Location Code;

F 2.2 a single-line electrical diagram of the Generating Unit connections including auxiliary power busses and the connection to the station switchyard;

F 2.3 a description of the fuel supply used for Black Start including on-site storage and resupply requirements;

F 2.4 a single-line electrical diagram showing the transmission connection from the Generating Unit station switchyard to a connection point on the ISO Controlled Grid;

F 2.5 a description of the Generating Unit capability to provide both real and reactive power, any start-up and shut-down requirements, any staffing limitations; and

F 2.6 a description of the primary, alternate and emergency back-up communications systems currently available to the Generator for communications to the ISO Control Center.

F 3 Upon receipt of the Generator's written request the ISO shall review the information provided and respond in writing within two weeks of receipt of the request, providing a copy of its response to the Generator's Scheduling Coordinator. The ISO response may be any of the following:

F 3.1 acceptance of the proposal as presented;

F 3.2 rejection of the proposal as presented with a rationale for such rejection; or

F 3.3 a request for additional information needed by the ISO to properly evaluate the request.

F 4 A Generator receiving a rejection may submit a written request for reconsideration by the ISO within 60 days of the date of the rejection notice. A request for reconsideration must address the rationale provided by the ISO. The ISO shall respond to a request for reconsideration within 60 days of the date of that request.

F 5 A Generator receiving a request for additional information shall provide such information within 60 days of such request providing a copy at the same time to its Scheduling Coordinator. The ISO shall review the information and respond within 120 days of the date of the ISO's request for additional information providing a copy at the same time to the Generator's Scheduling Coordinator.

F 6 Upon acceptance by the ISO of the Generator's request and agreement as to the method of communication and control to be used by the Generator, the ISO shall provisionally approve the proposal in writing providing a copy at the same time to the Generator's Scheduling Coordinator. The Generator may then proceed to procure and install the equipment and make arrangements for the required communication.

F 7 Design, acquisition, and installation of the Generator's equipment shall be under the control of the Generator. The ISO shall bear no cost responsibility or functional responsibility for such equipment. The ISO shall be responsible for the design, acquisition and installation of any necessary modifications to its own equipment at its own cost.

F 8 The Generator shall perform its own testing of its equipment to ensure that the Black Start system performs to meet the ISO requirements.

F 9 When it is satisfied that its plant, equipment and communication systems meet the ISO's requirements, the Generator shall request in writing that the ISO conduct a certification test with a suggested primary date and time and at least two alternative dates and times. The ISO shall, within two Business Days of receipt of the Generator's request, accept a proposed time if possible or suggest at least three alternatives to the Generator. If the ISO responds by suggesting alternatives, the Generator shall, within two Business Days of receipt of the ISO's response, respond in turn by accepting a proposed alternative if possible or suggesting at least three alternatives, and this procedure shall continue until agreement is reached on the date and time of the test. The Generator shall inform its Scheduling Coordinator of the agreed date and time of the test.

F 10 Testing shall be performed under the direction of the ISO. Such tests shall include, but not be limited to, the following:

F 10.1 confirmation of control communication path performance;

F 10.2 confirmation of primary, secondary, and emergency voice circuits for receipt of Dispatch instructions;

F 10.3 confirmation of the Generating Unit performance; and

F 10.4 simulation of a Black Start event.

F 11 Upon successful completion of the test, the ISO shall certify the Generating Unit as being permitted to provide Black Start capacity as an Ancillary Service and shall provide a copy of the certificate to the Scheduling Coordinator at the same time. The ISO shall change its Generating Unit data base to reflect the permission for the Generating Unit to provide Black Start service.

F 12 The certification to provide Black Start shall remain in force until withdrawn by the Scheduling Coordinator or the Generator by written notice to the ISO to take effect at the time noticed in the notice, which must be the end of a Trading Day.

F 13 The certification may be revoked by the ISO only under provisions of the ASRP or the ISO Tariff.

ISO TARIFF APPENDIX L

Methodology to Assess Available Transfer Capability

METHODOLOGY TO ASSESS AVAILABLE TRANSFER CAPABILITY

L.1 Description of Terms

The following descriptions augment existing definitions found in Appendix A "Master Definitions Supplement."

L.1.1 Available Transfer Capability (ATC) is a measure of the transfer capability in the physical transmission network resulting from system conditions and that remains available for further commercial activity over and above already committed uses.

ATC is defined as the Total Transfer Capability (TTC) less applicable operating Constraints due to system conditions and Outages (i.e., OTC), less the Transmission Reliability Margin (TRM), less the total of Existing Transmission Commitments (ETC), less the Capacity Benefit Margin (CBM).

L.1.2 Total Transfer Capability (TTC) is defined as the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission system by way of all transmission lines (or paths) between those areas. In collaboration with owners of rated paths and the WECC Operating Transfer Capability Policy Committee (OTCPC), the ISO utilizes Rated Path Methodology to establish the TTC of ISO branch groups.

L.1.3 Operating Transfer Capability (OTC) is the TTC reduced by any operational Constraints caused by seasonal derates or Outages. ISO Regional Transmission Engineers determine OTC through studies using computer modeling.

L.1.4 Existing Transmission Commitments (ETC) include Existing Contracts, and as appropriate, Firm Transmission Rights, and Transmission Ownership Rights.

L.1.5 Transmission Reliability Margin (TRM) is that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. TRM reserves sufficient transmission capacity from the Day-Ahead (DA) Market to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. This DA implementation avoids real time schedule curtailments that would otherwise be necessary due to:

- Load forecast error
- Anticipated uncertainty in transmission system topology
- Unscheduled Flow
- Simultaneous path interactions
- Variations in generation dispatch
- Operating reserve actions

The level of TRM for each branch group will be determined by ISO Regional Transmission Engineers (RTE).

L.1.6 Capacity Benefit Margin (CBM) is that amount of transmission transfer capability reserved by Load Serving Entities (LSEs) to ensure access to generation from interconnected systems to meet generation reliability requirements. In the DA Market, CBM may be used to provide reliable delivery of Energy to ISO Control Area Loads and to meet ISO responsibility for resource reliability requirements in real time. The purpose of this DA implementation is to avoid real time schedule curtailments and firm load interruptions that would otherwise be necessary. CBM may be used to reestablish Operating Reserves. CBM is not available for non-firm transmission in the ISO Control Area. CBM may be used only after:

- all non-firm sales have been terminated,
- Direct-control Load management has been implemented,
- customer interruptible demands have been interrupted,
- if the LSE calling for its use is experiencing a Generation deficiency and its transmission service provider is also experiencing transmission constraints relative to imports of Energy on its transmission system.

The level of CBM for each branch group is determined by the amount of estimated capacity needed to serve firm Load and provide Operating Reserves based on historical, scheduled, and/or forecast data using the following equation to set the maximum CBM:

CBM = (Demand + Reserves) - Resources

Where:

- Demand = forecasted area demand
- Reserves = reserve requirements
- Resources = internal area resources plus resources available on other branch groups

L.2 ATC Algorithm

ATC = OTC – (TRM + ETC + CBM)

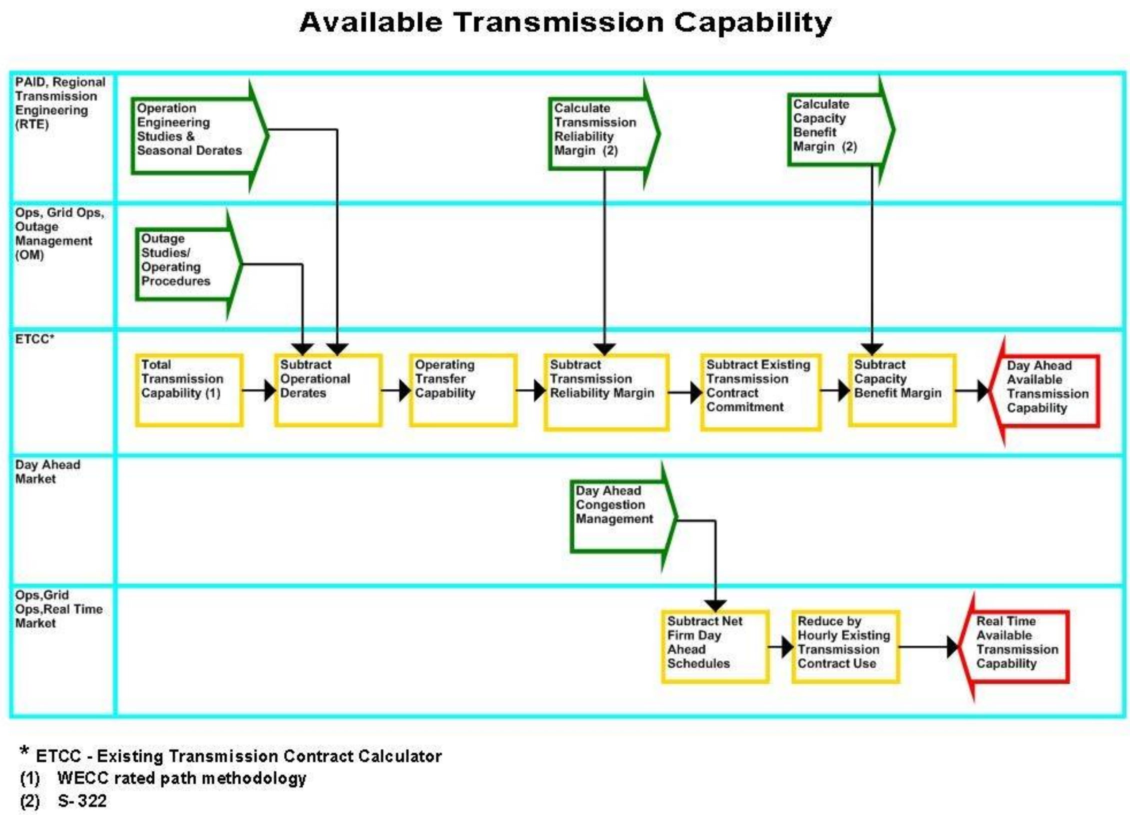
or

ATC = (TTC – Operating Constraints) - (TRM + ETC + CBM)

Where:

OTC = TTC – Operating Constraints
TTC = Total Transfer Capability
OTC = Operating Transfer Capability
TRM = Transmission Reliability Margin
ETC = Existing Transmission Commitments
CBM = Capacity Benefit Margin

L.3 ATC Process Flowchart



L.4 TTC – OTC Determination

All transfer capabilities are developed to ensure that power flows are within their respective operating limits, both pre-Contingency and post-Contingency. Operating limits are developed based on thermal, voltage and stability concerns according to industry reliability criteria (WECC/NERC) for transmission paths. The process for developing TTC or OTC is the same with the exception of inclusion or exclusion of operating Constraints based on system conditions being studied. Accordingly, further description of the process to determine either OTC or TTC will refer only to TTC.

L.4.1 Transfer capabilities for studied configurations may be used as a maximum transfer capability for similar conditions without conducting additional studies. Increased transfer capability for similar conditions must be supported by conducting appropriate studies.

L.4.1.2 At ISO, studies for all major inter-area paths (mostly 500 kV) OTC are governed by the California Operating Studies Subcommittee (OSS) as one of four sub-regional Study Groups of the WECC OTCPC (i.e., for California Sub-region), which provides detailed criteria and methodology. For transmission system elements below 500 kV the methodology for calculating these flow limits is detailed in C.4.3 and is applicable to the operating horizon.

L.4.2 **Transfer capability** may be limited by the physical and electrical characteristics of the systems including any one or more of the following:

- **Thermal Limits** – Thermal limits establish the maximum amount of electric current that a transmission line or electrical facility can conduct over a specified time-period as established by the Transmission Owner.

- **Voltage Limits** – System voltages and changes in voltages must be maintained within the range of acceptable minimum and maximum limits to avoid a widespread collapse of system voltage.

- **Stability Limits** – The transmission network must be capable of surviving disturbances through the transient and dynamic time-periods (from milliseconds to several minutes, respectively) following the disturbance so as to avoid generator instability or uncontrolled, widespread interruption of electric supply to customers.

L.4.3 **Determination of transfer capability** is based on computer simulations of the operation of the interconnected transmission network under a specific set of assumed operating conditions. Each simulation represents a single "snapshot" of the operation of the interconnected network based on the projections of many factors. As such, they are viewed as reasonable indicators of network performance and may ultimately be used to determine Available Transfer Capability. The study is meant to capture the worst operating scenario based on the RTE experience and good engineering judgment.

L.4.3.1 **System Limits** – The transfer capability of the transmission network may be limited by the physical and electrical characteristics of the systems including thermal, voltage, and stability consideration. Once the critical Contingencies are identified, their impact on the network must be evaluated to determine the most restrictive of those limitations. Therefore, the TTC_1 becomes:

$$TTC_1 = \text{lesser of \{Thermal Limit, Voltage Limit, Stability Limit\} following } N\text{-}1_{worst}$$

L.4.3.2 Parallel path flows will be considered in determining transfer capability and must be sufficient in scope to ensure that limits throughout the interconnected network are addressed. In some cases, the parallel path flows may result in transmission limitations in systems other than the transacting systems, which can limit the TTC between two transacting areas. This will be labeled TTC_2. Combined with C.4.3.1 above TTC becomes:

$$TTC = \text{lesser of } \{TTC_1 \text{ or } TTC_2)$$

L.5 Developing a Power Flow Base-Case

L.5.1 **Base-cases** will be selected used to model reality to the greatest extent possible including attributes like area Generation, area load, intertie flows, etc. At other times (*e.g.,* studying longer range horizons), it is prudent to stress a base-case by making one or more attributes (load, Generation, line flows, path flows, etc.) of that base-case more extreme than would otherwise be expected.

L.5.2. **Power Flow Base-Cases Separated By Geographic Region**
The standard RTE base-cases are split into five geographical regions in the ISO Controlled Grid including the Bay Area, Fresno Area, North Area, SDG&E Area, and SCE Area.

L.5.3. Power Flow Base-Cases Selection Methodology

The RTE determines the studied geographical area of the procedure. This determines the study base-cases from the Bay Area, Fresno Area, North Area, SCE Area, or SDG&E Area.

The transfer capability studies may require studying a series of base-cases including both peak and off-peak operation conditions.

L.5.4 Update a Power Flow Base-Case

After the RTE has obtained one or more base-case studies, the base-case will be updated to represent the current grid conditions during the applicable season. The following will be considered to update the base-cases:

- Recent Transmission Network Changes and Updates
- Overlapping Scheduled and Forced Outages
- Area Load Level
- Major Path Flows
- Generation level
- Voltage Levels
- Operating Requirements

L.5.4.1 Outage Consideration

Unless detailed otherwise, the RTE considers modeling outages of:

- Transmission lines, 500 kV
- Transformers, 500/230 kV
- Large Generating Units
- Generating Units within the studied area
- Transmission elements within the studied area

At the judgment of the RTE, only the necessary outages will be modeled to avoid an unnecessarily burdensome and large number of base-cases.

L.5.4.2 Area Load Level

Base-case demand levels should be appropriate to the current studied system conditions and customer demand levels under study and may be representative of peak, off-peak or shoulder, or light demand conditions. The RTE estimates the area load levels to be utilized in the peak, partial-peak and/or off-peak base-cases. The RTE will utilize the current ISO load forecasting program (e.g., ALFs), ProcessBook (PI) or other competent method to estimate load level for the studied area. Once the RTE has determined the correct load levels to be utilized, the RTE may scale the scale the base-case loads to the area studied, as appropriate.

L.5.4.3 Modify Path Flows

The scheduled electric power transfers considered representative of the base system conditions under analysis and agreed upon by the parties involved will be used for modeling. As needed, the RTE may estimate select path flows depending on the studied area. In the event that it is not possible to estimate path flows, the RTE will make safe assumptions about the path flows. A safe assumption is more extreme or less extreme (as conservative to the situation) than would otherwise be expected.
If path flow forecasting is necessary, if possible the RTE will trend path flows on previous similar days.

L.5.4.4 Generation Level

Utility and non-utility Generating Units will be updated to keep the swing Generating Unit at a reasonable level. The actual unit-by-unit Dispatch in the studied area is more vital than in the un-studied areas. The RTE will examine past performance of select Generating Units to estimate the Generation levels, focusing on the Generating Units within the studied area. In the judgment of the RTE, large Generating Units outside the studied area will also be considered.

L.5.4.5 Voltage Levels

Studies will maintain appropriate voltage levels, based on operation procedures for critical buses for the studied base-cases. The RTE will verify that bus voltage for critical busses in within tolerance. If a bus voltage is outside the tolerance band, the RTE will model the use of voltage control devices (e.g., synchronous condensers, shunt capacitors, shunt reactors, series capacitors, generators).

L.6 Contingency Analysis

The RTE will perform Contingency analysis studies in an effort to determine the limiting conditions, especially for scheduled Outages, including pre- and post-Contingency power flow analysis modeling pre- and post-Contingency conditions and measuring the respective line flows, and bus voltages.

Other studies like reactive margin and stability may be performed as deemed appropriate.

L.6.1 Operating Criteria and Study Standards

Using standards derived from NERC and WECC Reliability Standards and historical operating experience, the RTE will perform Contingency analysis with the following operating criteria:

Pre-Contingency

- All pre-Contingency line flows shall be at or below their normal ratings.
- All pre-Contingency bus voltages shall be within a pre-determined operating range.

Post-Contingency

- All post-Contingency line flows shall be at or below their emergency ratings.
- All post-Contingency bus voltages shall be within a pre-determined operating range.

The RTE models the following Contingencies:

- Generating Unit Outages (including combined cycle Generating Unit Outages which are considered single Contingencies).
- Line Outages
- Line Outages combined with one Generating Unit Outage
- Transformer Outages
- Synchronous condenser Outages
- Shunt capacitor or capacitor bank Outages
- Series capacitor Outages
- Static VAR compensator Outages
- Bus Outages – bus Outages can be considered for the following ongoing Outage conditions.
    - For a circuit breaker bypass-and-clear Outage, bus Contingencies shall be taken on both bus segments that the bypassed circuit breaker connects to.
    - For a bus segment Outage, the remaining parallel bus segment shall be considered as a single Contingency.
    - Credible overlapping Contingencies – Overlapping Contingencies typically include transmission lines connected to a common tower or close proximity in the same right-of-way.

L.6.2 Manual Contingency Analysis

If manual Contingency analysis is used, the RTE will perform pre-Contingency steady-state power flow analysis and determines if pre-Contingency operating criteria is violated. If pre-Contingency operating criteria cannot be preserved, the RTE records the lines and buses that are not adhering to the criteria. If manual post-Contingency analysis is used the RTE obtains one or more Contingencies in each of the base cases. For each Contingency resulting in a violation or potential violation in the operating criteria above, the RTE records the critical post-Contingency facility loadings and bus voltages.

L.6.3 Contingency Analysis Utilizing a Contingency Processor

For a large area, the RTE may utilize a Contingency processor.

L.6.4 Determination of Crucial Limitations

After performing Contingency analysis studies, the RTE analyzes the recorded information to determine limitations. The limitations are conditions where the pre-Contingency and/or post-Contingency operating criteria cannot be conserved and may include a manageable overload on the facilities, low post-Contingency bus voltage, etc. If no crucial limitations are determined, the RTE determines if additional studies are necessary.

L.7 Traditional Planning Methodology to Protect Against Violating Operating Limits

After performing Contingency analysis studies, the RTE next develops the transfer capability and develops procedures, nomograms, RMR Generation requirements, or other constraints to ensure that transfer capabilities respect operating limits.

L.8 Limits for Contingency Limitations

Transfer limits are developed when the post-Contingency loading on a transmission element may breach the element's emergency rating. The type of limit utilized is dependent on the application and includes one of the following limits:

- Simple Flow Limit - best utilized when the derived limit is repeatable or where parallel transmission elements feed radial load.

- RAS or SPS – existing remedial action schemes (RAS) or special protection systems (SPS) may impact the derivation of simple flow limits. When developing the limit, the RTE determines if the RAS or SPS will be in-service during the Outage and factors the interrelationship between the RAS or SPS and the derived flow limit. RTE will update the transfer limits in recognition of the changing status and/or availability of the RAS or SPS.

ISO TARIFF APPENDIX M

Transmission Rights/Curtailment Instructions Template

TRANSMISSION RIGHTS/CURTAILMENT INSTRUCTIONS TEMPLATE

(a) Contract Ref #	(b) Ind Imp	(c) Contact Person
[a single number]	[yes/no]	[phone number] [name(s)]

Submitted By PTO:
Date Received By ISO:
Date Accepted By ISO:

	(e) Path Name(s) and Location(s)						(i)(j) Types and Amounts of Transmission Service			(k) DA	(l) HA	(m) RT	(n) Service Period	
(d) Contract Name(s)/Number(s)	Path Name(s)	POR Zone	POD Zone	(f) Party	(g) SC ID	(h) ER/NCR	Firm /1/	CF /1/	N-F	(hour-ending)	(minutes)	(yes/no)	Beginning	Ending
[name/number 1]		[zone name]	[zone name]	[party 1] [party 2] [party n]	[sc id 1] [sc id 2] [sc id n]	[er] [ncr] [er]	[MW] ["] ["]	[MW] ["] ["]	[MW] ["] ["]	[1400]	[30] [n/a] [20]	[yes] [no] [yes]	[hh/dd/mm/yy] ["] ["]	[hh/dd/mm/yy] ["] ["]
[name/number 2]		[zone name]	[zone name]	[party 1] [party 2] [party n]	[sc id 1] [sc id 2] [sc id n]	[er] [ncr] [er]	[MW] ["] ["]	[MW] ["] ["]	[MW] ["] ["]	[1400]	[20] [n/a] [20]	[yes] [no] [yes]	["] ["] ["]	["] ["] ["]
[name/number n]		[zone name]	[zone name]	[party 1] [party 2] [party n]	[sc id 1] [sc id 2] [sc id n]	[er] [ncr] [er]	[MW] ["] ["]	[MW] ["] ["]	[MW] ["] ["]	[1500]	[20] [n/a] [20]	[yes] [no] [yes]	["] ["] ["]	["] ["] ["]

(o) Non-Emergency Curtailments [If other than pro rata, attach spreadsheet for ISO to use in allocating curtailments to rights holders between the indicated Zones. Otherwise, indicate "pro rata" here.]
(p) Emergency Curtailments [Describe special procedures/requirements here. Indicate "N/A" if none.]

/1/ Priorities for firm and conditional firm transmission service are indicated in Schedules using Adjustment Bids as described in the SP.

ISO TARIFF APPENDIX N

Settlements and Billing

PART A
[Not Used]

PART B
GRID OPERATIONS CHARGE COMPUTATION

B 1 Purpose of charge

The Grid Operations Charge is a charge which recovers Redispatch costs incurred due to Intra-Zonal Congestion pursuant to Section 27.1.3 of the ISO Tariff. The Grid Operations Charge is paid by or charged to Scheduling Coordinators in order for the ISO to recover and properly redistribute the costs of adjusting the Balanced Schedules submitted by Scheduling Coordinators.

B 2 Fundamental formulae

B 2.1 Payments to Scheduling Coordinators with incremented schedules

When it becomes necessary for the ISO to increase the output of a Scheduling Coordinator's Generating Unit$_i$ or System Resource$_i$ or reduce a Curtailable Demand$_i$ in order to relieve Congestion within a Zone, the ISO will pay the Scheduling Coordinator. The amount that ISO pays the Scheduling Coordinator$_j$ is the price specified in the Scheduling Coordinator's Imbalance Energy bid for the Generating Unit$_i$ or System Resource$_i$ or Curtailable Demand$_i$ multiplied by the quantity of Energy Dispatched. The formula for calculating the payment to Scheduling Coordinator$_j$ for each block$_b$ of Energy of its bid curve in Trading Interval$_t$ is:

$$INC_{bijt} = adjinc_{bijt} * \Delta inc_{bijt}$$

B 2.1.1 Total Payment for Trading Interval

The formula for calculating payment to Scheduling Coordinator$_j$ whose Generating Unit$_i$ or System Resource$_i$ has been increased or Curtailable Demand$_i$ reduced for all the relevant blocks$_b$ of Energy in the Imbalance Energy bid curve of that Generating Unit or System Resource or Curtailable Demand in the same Trading Interval$_t$ is:

$$PayTI_{ijt} = \sum_b INC_{bijt}$$

B 2.2 Charges to Scheduling Coordinators with decremented schedules

When it becomes necessary for the ISO to decrease the output of a Scheduling Coordinator's Generating Unit$_i$ or System Resource$_i$ in order to relieve Congestion within a Zone, the ISO will make a charge to the Scheduling Coordinator. The amount that the ISO will charge Scheduling Coordinator$_j$ for decreasing the output of Generating Unit$_i$ is the decremental reference price specified for the Scheduling Coordinator as determined in accordance with Section 27.1.1.6.1 multiplied by the quantity of Energy Dispatched. The amount that the ISO will charge Scheduling Coordinator$_j$ for decreasing the output of System Resource$_i$ is the price specified in the Scheduling Coordinator's Imbalance Energy bid for System Resource$_i$ multiplied by the quantity of Energy Dispatched. The formula for calculating the charge to Scheduling Coordinator$_j$ for each block$_b$ of Energy in its decremental reference price or Imbalance Energy Bid in Trading Interval$_t$ is:

$$DEC_{bijt} = adjdec_{bijt} * \Delta dec_{bijt}$$

B 2.2.1 Total Charge for Trading Interval

The formula for calculating the charge to Scheduling Coordinator$_j$ whose Generating Unit$_i$ or System Resource$_i$ has been decreased for all the relevant blocks$_b$ of Energy at the decremental reference price for Generating Unit$_i$, or Imbalance Energy bid for System Resource$_i$ in the same Trading Interval$_t$ is:

$$ChargeTI_{ijt} = \sum_b DEC_{bijt}$$

B 2.3 Not Used

B 2.4 Net ISO Redispatch costs

The Trading Interval net Redispatch cost encountered by ISO to relieve Intra-Zonal Congestion is the sum of the amounts paid by the ISO to those Scheduling Coordinators whose Generation or System Resource was increased or Curtailable Demand was decreased during the Trading Interval less the sum of the amounts received by the ISO from those Scheduling Coordinators whose Generating Units or System Resource were decreased during the Trading Interval. The fundamental formula for calculating the net Redispatch cost is:

$$REDISP_{CONGt} = \sum_j PayTI_{ijt} - \sum_j ChargeTI_{ijt}$$

Note that $REDISP_{CONGt}$ can be either positive or negative. This means that it is possible for the ISO to generate either a net cost or a net income, for any given Trading Interval. In the event the ISO does not make use of equal amounts of incremental and decremental dispatched MWHs, then the net Redispatch cost becomes the sum of the amounts paid (or charged) by the ISO to those Scheduling Coordinators whose Generation or System Resource was increased (or decreased) or Curtailable Demand was decreased (or increased) during the Trading Interval less the sum of the amounts received by the ISO from Scheduling Coordinators through the Imbalance Energy Market.

B 2.5 Grid Operations Price

The grid operations price is the Trading Interval rate used by the ISO to apportion net Trading Interval Redispatch costs to Scheduling Coordinators within the Zone with Intra-

Zonal Congestion. The grid operations price is calculated using the following formula: $$GOP_t = \frac{REDISP_{CONG_t}}{\sum_j QCharge_{jt} + \sum_j Export_{jt}}$$

B 2.6 Grid Operations Charge

The Grid Operations Charge is the vehicle by which the ISO recovers the net Redispatch costs. It is allocated to each Scheduling Coordinator in proportion to the Scheduling Coordinator's Demand in the Zone with Intra-Zonal Congestion and exports from the Zone with Intra-Zonal Congestion. The formula for calculating the Grid Operations Charge for Scheduling Coordinator$_j$ in Trading Interval$_t$ is:

$$GOC_{jt} = GOP_t * \left(QCharge_{jt} + EXPORT_{jt}\right)$$

B 3 Meaning of terms of formulae

B 3.1 INC_{bijt} - $

The payment from the ISO due to Scheduling Coordinator$_j$ whose Generating Unit$_i$ or System Resource$_i$ is increased or Curtailable Load$_i$ is reduced within a block$_b$ of Energy in its Imbalance Energy bid in Trading Interval$_t$ in order to relieve Intra-Zonal Congestion.

B 3.2 $adjinc_{bijt}$ - $/MWh

The incremental cost for the rescheduled Generating Unit$_i$ or System Resource$_i$ or Curtailable Load$_i$ taken from the relevant block$_b$ of Energy in the Imbalance Energy bid submitted by the Scheduling Coordinator$_j$ or generated by the ISO for the Trading Interval$_t$.

B 3.3 ∆incbijt - MW

The amount by which the Generating Unit$_i$ or System Resource$_i$ or Curtailable Load$_i$ of Scheduling Coordinator$_j$ for Trading Interval$_t$ is increased by the ISO within the relevant block$_b$ of Energy in its Imbalance Energy bid.

B 3.4 $PayTI_{jit}$ - $

The Trading Interval payment to Scheduling Coordinator$_j$ whose Generating Unit$_i$ has been increased or System Resource$_i$ or Curtailable Load$_i$ reduced in Trading Interval$_t$ of the Trading Day.

B 3.5 DEC_{bijt} - $

The charge to Scheduling Coordinator$_j$ whose Generating Unit$_i$ or System Resource$_i$ is decreased for Trading Interval$_t$ within a block$_b$ of Energy at the decremental reference price for Generating Unit$_i$ or in the Imbalance Energy bid for System Resource$_i$.

B 3.6 $adjdec_{bijt}$ - $/MWh

The decremental cost for the rescheduled Generating $Unit_i$ or System $Resource_i$ taken from the relevant $block_b$ of Energy at the decremental reference price for Generating $Unit_i$ or Imbalance Energy bid for System $Resource_i$ submitted by Scheduling $Coordinator_j$ or generated by the ISO for the Trading $Interval_t$.

B 3.7 Δdec_{bijt} - MW

The amount by which the Generating $Unit_i$ or System $Resource_i$ of Scheduling $Coordinator_j$ for Trading $Interval_t$ is decreased by ISO within the relevant $block_b$ of Energy at the decremental reference price for Generating $Unit_i$ or Imbalance Energy bid for System $Resource_i$.

B 3.8 $ChargeTI_{ijt}$ - $

The Trading Interval charge to Scheduling $Coordinator_j$ whose Generating $Unit_i$ or System $Resource_i$ has been decreased in Trading $Interval_t$ of the Trading Day.

B 3.9 Not Used

B 3.10 Not Used

B 3.10.1 Not Used

B 3.10.2 Not Used

B 3.11 $REDISP_{CONGt}$ - $

The Trading Interval net cost to ISO to redispatch in order to relieve Intra-Zonal Congestion during Trading $Interval_t$.

B 3.12 GOP_t - $/MWh

The Trading Interval grid operations price for Trading $Interval_t$ used by the ISO to recover the costs of Redispatch for Intra-Zonal Congestion Management.

B 3.13 GOC_{jt} - $

The Trading Interval Grid Operations Charge by the ISO for Trading $Interval_t$ for Scheduling $Coordinator_j$ in the relevant Zone with Intra-Zonal Congestion.

B 3.14 $QCHARGE_{jt}$ – MWh

The Trading Interval metered Demand within a Zone for Trading $Interval_t$ for Scheduling $Coordinator_j$ whose Grid Operations Charge is being calculated.

B 3.15 $EXPORT_{jt}$ – MWh

The total Energy for Trading $Interval_t$ exported from the Zone to a neighboring Control Area by Scheduling $Coordinator_j$.

PART C

ANCILLARY SERVICES CHARGES COMPUTATION

C 1 Purpose of charges

The Ancillary Services charges reimburse the ISO for the costs of purchasing Ancillary Services in the Day-Ahead and Hour-Ahead Markets. Each Scheduling Coordinator that does not self-provide Ancillary Services must purchase these services from the ISO. The ISO will in turn purchase these Ancillary Services from Scheduling Coordinators in the markets. Ancillary Services purchased and resold by the ISO includes Regulation, Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve. Any references in this Part C to the Ancillary Service "Regulation" shall be read as referring to "Regulation Up" or "Regulation Down".

This Part C also addresses the payments by ISO to Scheduling Coordinators for the Dispatch of energy from Dispatched Ancillary Services Units and for the Dispatch of Supplemental Energy in the Real Time Market. The ISO recovers the costs of real-time Dispatch of such energy through the Imbalance Energy charges described in Part D of this Appendix.

The reference to a Scheduling Coordinator by Zone refers to the Demand of that Scheduling Coordinator which is located in the Zone. A Generation Unit, Load, or System Resource located in another Control Area is considered to be located in the Zone in which its contract path enters the ISO Controlled Grid.

The ISO will purchase Ancillary Services for each Trading Interval in both the Day-Ahead and Hour-Ahead Markets. Separate payments will be calculated for each service for each Trading Interval and in each market for each Generating Unit, Load and System Resource. The ISO will then calculate a total payment for each Scheduling Coordinator for each Trading Interval for each service for each Zone in each market for all the Generating Units, Loads and System Resources that the Scheduling Coordinator represents. The ISO will charge Scheduling Coordinators for Ancillary Services, other than for energy, which they purchase from the ISO by calculating and applying charges to each Scheduling Coordinator for each Trading Interval for each service in each Zone in each market.

The ISO will allocate the Ancillary Services capacity charges, for both the Day-Ahead Market and the Hour-Ahead Market, on a Zonal basis if the Day-Ahead Ancillary Services Market is procured on a Zonal basis. The ISO will allocate the Ancillary Services capacity charges, for both the Day-Ahead Market and the Hour-Ahead Market, on an ISO Control Area wide basis if the Day-Ahead Ancillary Services Market is defined on an ISO Control Area wide basis.

C 2 Fundamental formulas

C 2.1 ISO payments to Scheduling Coordinators

C 2.1.1 Day-Ahead Market

(a) Regulation. When the ISO purchases Regulation capacity in the Day-Ahead Market, Scheduling Coordinators for Generating Units that provide this capacity will receive payments for each Trading Interval of the Day-Ahead Market. The payment for a given Generating Unit which provides Regulation capacity over a given Trading Interval will be the total quantity of Regulation capacity provided times the Zonal Market Clearing Price for that Trading Interval in that Zone. The required Regulation capacity is defined in Appendix A. Regulation Up and Regulation Down payments shall be calculated separately. This payment for Scheduling Coordinator j for providing Regulation Up capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$AGCUpPayDA_{ijxt} = AGCUpQDA_{ijxt} * PAGCUpDA_{xt}$$

This payment for Scheduling Coordinator j for providing Regulation Down capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$AGCDownPayDA_{ijxt} = AGCDownQDA_{ijxt} * PAGCDownDA_{xt}$$

The total Regulation Up payment to each Scheduling Coordinator for a given Trading Interval in the Day-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$AGCUpPayTotalDA_{jxt} = \sum_i AGCUpPayDA_{ijxt}$$

The total Regulation Down payment to each Scheduling Coordinator for a given Trading Interval in the Day-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$AGCDownPayTotalDA_{jxt} = \sum_i AGCDownPayDA_{ijxt}$$

(b) Spinning Reserve. When ISO purchases Spinning Reserve capacity in the Day-Ahead Market. Scheduling Coordinators for Generating Units and System Resources that provide this capacity will receive payments for each Trading Interval of the Day-Ahead Market. The payment for a given Generating Unit or

System Resource which provides Spinning Reserve capacity over a given Trading Interval will be the total quantity of Spinning Reserve capacity provided times the Zonal Market Clearing Price for that Trading Interval in that Zone. The required Spinning Reserve capacity is defined in Appendix A. This payment for Scheduling Coordinator j for providing Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$SpinPayDA_{ijxt} = SpinQDA_{ijxt} * PSpinDA_{xt}$$

The total Spinning Reserve payment to each Scheduling Coordinator for a given Trading Interval in the Day-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$SpinPayTotalDA_{jxt} = \sum_i SpinPayDA_{ixt}$$

(c) *Non-Spinning Reserve*. When the ISO purchases Non-Spinning Reserve capacity in the Day-Ahead Market, Scheduling Coordinators for Generating Units, Loads and System Resources that provide this capacity will receive payments for each Trading Interval of the Day-Ahead Market. The payment for a given Generating Unit, Load or System Resource which provides Non-Spinning Reserve capacity over a given Trading Interval will be the total quantity of Non-Spinning Reserve capacity provided times the Zonal Market Clearing Price for that Trading Interval in that Zone. The required Non-Spinning Reserve capacity is defined in Appendix A. This payment for Scheduling Coordinator j for providing Non-Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

(d) $$NonSpinPayDA_{ijxt} = NonSpinQDA_{ijxt} * PNonSpinDA_{xt}$$

The total Non-Spinning Reserve payment to each Scheduling Coordinator for a given Trading Interval in the Day-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$NonSpinPayTotalDA_{jxt} = \sum_i NonSpinPayDA_{ijxt}$$

(d) *Replacement Reserve*. When the ISO purchases Replacement Reserve capacity in the Day-Ahead Market, Scheduling Coordinators for Generating Units, Loads and System Resources that provide this capacity will receive payments for each Trading Interval of the Day-Ahead Market. The payment for a given Generating Unit, Load or System Resource which provides Replacement Reserve capacity over a given Trading Interval will be the total

quantity of Replacement Reserve capacity provided times the Zonal Market Clearing Price for that Trading Interval in that Zone. The required Replacement Reserve capacity is defined in Appendix A. This payment for Scheduling Coordinator j for providing Replacement Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$ReplPayDA_{ijxt} = ReplQDA_{ijxt} * PReplDA_{xt}$$

The total Replacement Reserve payment to each Scheduling Coordinator for a given Trading Interval in the Day-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$ReplPayTotalDA_{jxt} = \sum_{i} ReplPayDA_{ijxt}$$

C 2.1.2 Hour-Ahead Market

(a) *Regulation*. When the ISO purchases Regulation capacity in the Hour-Ahead Market, Scheduling Coordinators for Generating Units that provide this capacity will receive payment for the Trading Interval of the Hour-Ahead Market. The payment for a given Generating Unit which provides Regulation capacity over the Trading Interval will be the total quantity of Regulation capacity provided times the Zonal Market Clearing Price for that Trading Interval in that Zone. The required Regulation capacity is defined in Appendix A. Regulation Up and Regulation Down payments shall be calculated separately. This payment for Scheduling Coordinator j for providing Regulation Up capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$AGCUpPayHA_{ijxt} = AGCUpQIHA_{ijxt} * PAGCUpHA_{xt}$$

This payment for Scheduling Coordinator j for providing Regulation Down capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$AGCDownPayHA_{ijxt} = AGCDownQIHA_{ijxt} * PAGCDownHA_{xt}$$

When a Scheduling Coordinator buys back, in the Hour-Ahead Market, Regulation capacity which it sold to the ISO in the Day-Ahead Market, the payment which the ISO receives will be the total quantity of Regulation capacity bought back times the Zonal Hour-Ahead Market Clearing Price for that Trading Interval in that Zone.

This payment to the ISO from Scheduling Coordinator j to buy back Regulation Up capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$AGCUpReceiveHA_{ijxt} = AGCUpQDHA_{ijxt} * PAGCUpHA_{xt}$$

This payment to the ISO from Scheduling Coordinator j to buy back Regulation Down capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$AGCDownReceiveHA_{ijxt} = AGCDownQDHA_{ijxt} * PAGCDownHA_{xt}$$

The total Regulation payment for the Trading Interval of the Hour-Ahead Market to each Scheduling Coordinator for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval and then deducting therefrom any amount payable by the Scheduling Coordinator to the ISO for Regulation bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Trading Interval on behalf of resources located in the Zone. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$AGCDownPayTotalHA_{jxt} = \sum_i AGCDownPayHA_{ijxt} - \sum_i AGCDownReceiveHA_{ijxt}$$

$$AGCUpPayTotalHA_{jxt} = \sum_i AGCUpPayHA_{ijxt} - \sum_i AGCUpReceiveHA_{ijxt}$$

(b) Spinning Reserve. When the ISO purchases Spinning Reserve capacity in the Hour-Ahead Market, Scheduling Coordinators for Generating Units and System Resources that provide this capacity will receive payments for the Trading Interval of the Hour-Ahead Market. The payment for a given Generating Unit or System Resource which provides Spinning Reserve capacity over the Trading Interval will be the total quantity of Spinning Reserve capacity provided times the Zonal Market Clearing Price for that Trading Interval in that Zone. This payment for Scheduling Coordinator j for providing Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$SpinPayHA_{ijxt} = SpinQIHA_{ijxt} * PSpinHA_{xt}$$

When a Scheduling Coordinator buys back in the Hour-Ahead Market Spinning Reserve capacity which it sold to the ISO in the Day-Ahead Market, the payment which the ISO receives will be the total quantity of Spinning Reserve capacity bought back times the Zonal Hour-Ahead Market Clearing Price for that Trading Interval in that Zone.

This payment to the ISO from Scheduling Coordinator j to buy back Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$SpinReceiveHA_{ijxt} = SpinQDHA_{ijxt} * PSpinHA_{xt}$$

The total Spinning Reserve payment to each Scheduling Coordinator for the Trading Interval of the Hour-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval and then deducting therefrom any amount payable by the Scheduling Coordinator to the ISO for Spinning Reserve bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Trading Interval on behalf of resources located in the Zone. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$SpinPayTotalHA_{jxt} = \sum_i SpinPayHA_{ijxt} - \sum_i SpinReceiveHA_{ijxt}$$

(c) <u>*Non-Spinning Reserve*</u>*.* When the ISO purchases Non-Spinning Reserve capacity in the Hour-Ahead Market, Scheduling Coordinators for Generating Units, Loads and System Resources that provide this capacity will receive payment for the Trading Interval of the Hour-Ahead Market. The payment for a given Generating Unit, Load or System Resource which provides Non-Spinning Reserve capacity over the Trading Interval will be the total quantity of Non-Spinning Reserve capacity provided times the Zonal Market Clearing Price for that Trading Interval in that Zone. This payment for Scheduling Coordinator j for providing Non-Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$NonSpinPayHA_{ijxt} = NonSpinQIHA_{ijxt} * PNonSpinHA_{xt}$$

When a Scheduling Coordinator buys back in the Hour-Ahead Market Non-Spinning Reserve capacity which it sold to the ISO in the Day-Ahead Market, the payment which the ISO receives will be the total quantity of Non-Spinning Reserve capacity bought back times the Zonal Hour-Ahead Market Clearing Price for that Trading Interval in that Zone.

This payment to the ISO from Scheduling Coordinator j to buy back Non-Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$NonSpinReceiveHA_{ijxt} = SpinQDHA_{ijxt} * PNonSpinHA_{xt}$$

The total Non-Spinning Reserve payment to each Scheduling Coordinator for the Trading Interval of the Hour-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval and then deducting therefrom any amount payable by the Scheduling

Coordinator to the ISO for Non-Spinning Reserve bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Trading Interval on behalf of resources located in the Zone. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$NonSpinPayTotalHA_{jxt} = \sum_i NonSpinPayHA_{ijxt} - \sum_i NonSpinReceiveHA_{ijxt}$$

(d) *Replacement Reserve.* When the ISO purchases Replacement Reserve capacity in the Hour-Ahead Market, Scheduling Coordinators for Generating Units, Loads and System Resources that provide this capacity will receive payments for the Trading Interval of the Hour-Ahead Market. The payment for a given Generating Unit, Load or System Resource which provides Replacement Reserve capacity over the Trading Interval will be the total quantity of Replacement Reserve capacity provided times the Zonal Market Clearing Price for that Trading Interval in that Zone. This payment for Scheduling Coordinator j for providing Replacement Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$ReplPayHA_{ijxt} = ReplQIHA_{ijxt} * PReplHA_{xt}$$

When a Scheduling Coordinator buys back in the Hour-Ahead Market Replacement Reserve capacity which it sold to the ISO in the Day-Ahead Market, the payment which the ISO receives will be the total quantity of Replacement Reserve capacity bought back times the Zonal Hour-Ahead Market Clearing Price for that Trading Interval in that Zone.

This payment to the ISO from Scheduling Coordinator j to buy back Replacement Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$ReplReceiveHA_{ijxt} = ReplQDHA_{ijxt} * PReplHA_{xt}$$

The total Replacement Reserve payment to each Scheduling Coordinator for the Trading Interval of the Hour-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval and then deducting therefrom any amount payable by the Scheduling Coordinator to the ISO for Replacement Reserve bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Trading Interval on behalf of resources located in the Zone. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$ReplPayTotalHA_{jxt} = \sum_i ReplPayHA_{ijxt} - \sum_i ReplReceiveHA_{ijxt}$$

C 2.2 ISO allocation of charges to Scheduling Coordinators

C 2.2.1 Day-Ahead Market

(a) *Regulation*. The ISO will charge the Zonal cost of providing Regulation capacity that is not self-provided by Scheduling Coordinators, in the Day-Ahead Market, through the application of a charge to each Scheduling Coordinator for each Trading Interval. This charge will be computed by multiplying the Regulation user rate for the Trading Interval by the Scheduling Coordinator's Regulation obligation, for which it has not self-provided, for the same period.

The Zonal Regulation user rate for the Day-Ahead Market is calculated by dividing the total cost to ISO of purchasing Regulation Capacity within the Zone, for the Trading Interval, by the total ISO Regulation MW purchases for the Trading Interval within the Zone. Regulation Up and Regulation Down payments shall be calculated separately.

The Day-Ahead Regulation Up user rate in Zone x for Trading Interval t is calculated as follows:

$$AGCUpRateDA_{xt} = \frac{\sum_{j} AGCUpPayTotalDA_{jxt}}{AGCUpPurchDA_{xt}}$$

where,

$AGCUpPayTotalDA_{ixt}$ = Total Regulation Up payments for the Settlement Period t in the Day-Ahead Market for the Zone x.

The Day-Ahead Regulation Down user rate in Zone x for Trading Interval t is calculated as follows:

$$AGCDownRateDA_{xt} = \frac{\sum_{j} AGCDownPayTotalDA_{jxt}}{AGCDownPurchDA_{xt}}$$

where,

$AGCDownPayTotalDA_{jxt}$ = Total Regulation Down payments for the Settlement Period t in the Day-Ahead Market for the Zone x.

The Regulation capacity charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t is calculated as follows:

$$AGCUpChgDA_{jxt} = AGCUpOblig_{jxt} * AGCUpRateDA_{xt}$$

$$AGCDownChgDA_{jxt} = AGCDownOblig_{jxt} * AGCDownRateDA_{xt}$$

(b) *Spinning Reserve*. The ISO will charge the Zonal cost of providing Spinning Reserve capacity that is not self-provided by Scheduling Coordinators, in the Day-Ahead Market, through the application of a charge to each Scheduling

Coordinator for each Trading Interval. This charge will be computed by multiplying the Spinning Reserve capacity user rate for the Trading Interval by the Scheduling Coordinator's Spinning Reserve obligation, for which it has not self-provided, for the same period. The Zonal Spinning Reserve capacity user rate for the Day-Ahead Market is calculated by dividing the total cost to ISO of purchasing Spinning Reserve capacity within the Zone, for the Trading Interval, by the total ISO Spinning Reserve MW purchases for the Trading Interval within the Zone. The Day-Ahead Spinning Reserve capacity user rate in Zone x for Trading Interval t is calculated as follows:

$$SpinRateDA_{xt} = \frac{\sum_{j} SpinPayTotalDA_{jxt}}{SpinPurchDA_{xt}}$$

The Spinning Reserve capacity charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t is calculated as follows:

$$SpinChgDA_{jxt} = SpinOblig_{jxt} * SpinRateDA_{xt}$$

(c) <u>Non-Spinning Reserve</u>. The ISO will charge the Zonal cost of providing Non-Spinning Reserve capacity that is not self-provided by Scheduling Coordinators, in the Day-Ahead Market, through the application of a charge to each Scheduling Coordinator for each Trading Interval. This charge will be computed by multiplying the Non-Spinning Reserve capacity user rate for the Trading Interval by the Scheduling Coordinator's Non-Spinning Reserve obligation, for which it has not self-provided, for the same period.

The Zonal Non-Spinning Reserve capacity user rate for the Day-Ahead Market is calculated by dividing the total cost to ISO of purchasing Non-Spinning Reserve capacity within the Zone, for the Trading Interval, by the total ISO Non-Spinning Reserve MW purchases for the Trading Interval within the Zone. The Day-Ahead Non-Spinning Reserve capacity user rate in Zone x for Trading Interval t is calculated as follows:

$$NonSpinRateDA_{xt} = \frac{\sum_{j} NonSpinPayTotalDA_{jxt}}{NonSpinPurchDA_{xt}}$$

The Non-Spinning Reserve capacity charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t is calculated as follows:

$$NonSpinChgDA_{jxt} = NonSpinOblig_{jxt} * NonSpinRateDA_{xt}$$

**C 2.2.2		Hour-Ahead Market**

(a) *Regulation.* The ISO will charge the Zonal net cost of providing Regulation capacity that is not self-provided by Scheduling Coordinators, in the Hour-Ahead Market through the application of a charge to each Scheduling Coordinator for the Trading Interval concerned. This charge will be computed by multiplying the Regulation user rate for the Trading Interval by the Scheduling Coordinator's Regulation obligation, for which it has not self-provided, for the same period.

The Zonal Regulation capacity user rate for the Hour-Ahead Market is calculated by dividing the total cost to the ISO of purchasing Regulation capacity within the Zone less any amounts payable to the ISO by Scheduling Coordinators for Regulation bought back from the ISO in the Hour-Ahead Market on behalf of resources located in the Zone, for the Trading Interval, by the total ISO Regulation capacity MW purchases for the Trading Interval within the Zone. Regulation Up and Down payments shall be calculated separately. The Hour-Ahead Regulation Up capacity user rate in Zone x for Trading Interval t is calculated as follows:

$$AGCUpRateHA_{xt} = \frac{\sum_{j} AGCUpPayTotalHA_{jxt}}{AGCUpPurchHA_{xt}}$$

where,

$AGCUpPayTotalHa_{jxt}$= Totlal Regulation Up payments for the Settlement Period t in the Hour-Ahead Market for Zone x.

The Hour-Ahead Regulation Down capacity user rate in Zone x for Trading Interval t is calculated as follows:

$$AGCDownRateHA_{xt} \frac{\sum_{j} AGCDownPayTotalHA_{jxt}}{AGCDownPurchHA_{xt}}$$

where,

$AGCDownPayTotalHA_{xt}$ = Total Regulation Down payments for the Settlement Period t in the Hour-Ahead Market for Zone x.

The Regulation capacity charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t is calculated as follows:

$AGCUpChgHA_{jxt} = (AGCUpOblig_{jxt} * AGCUpRateHA_{xt})$

$AGCDownChgHA_{jxt} = (AGCDownOblig_{jxt} * AGCDownRateHA_{xt})$

(b) Spinning Reserve. The ISO will charge the Zonal net cost of providing Spinning Reserve capacity that is not self-provided by Scheduling Coordinators, in the Hour-Ahead Market, through the application of a charge to each Scheduling Coordinator for the Trading Interval. This charge will be computed by multiplying the Spinning Reserve capacity user rate for the Trading Interval by the Scheduling Coordinator's Spinning Reserve obligation, for which it has not self-provided, for the same period. The Zonal Spinning Reserve capacity user rate for the Hour-Ahead Market is calculated by dividing the total cost to ISO of purchasing Spinning Reserve capacity within the Zone less any amounts payable to the ISO by Scheduling Coordinators for Spinning Reserve bought back from the ISO in the Hour-Ahead Market on behalf of resources located in the Zone, for the Trading Interval, by the total ISO Spinning Reserve MW purchases for the Trading Interval within the Zone. The Hour-Ahead Spinning Reserve capacity user rate in Zone x for Trading Interval t is calculated as follows:

$$SpinRateHA_{xt} = \frac{\sum_j SpinPayTotalHA_{jxt}}{SpinPurchHA_{xt}}$$

The Spinning Reserve capacity charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t is calculated as follows:

$$SpinChgHA_{jxt} = (SpinOblig_{jxt} * SpinRateHA_{xt})$$

(c) Non-Spinning Reserve. The ISO will charge the Zonal net cost of providing Non-Spinning Reserve capacity that is not self-provided by Scheduling Coordinators, in the Hour-Ahead Market, through the application of a charge to each Scheduling Coordinator for the Trading Interval. This charge will be computed by multiplying the Non-Spinning Reserve capacity user rate for the concerned Trading Interval by the Scheduling Coordinator's Non-Spinning Reserve obligation, for which it has not self-provided, for the same period. The Zonal Non-Spinning Reserve capacity user rate for the Hour-Ahead Market is calculated by dividing the total cost to ISO of purchasing Non-Spinning Reserve capacity within the Zone less any amounts

(d) payable to the ISO by Scheduling Coordinators for Non-Spinning Reserve bought back from the ISO in the Hour-Ahead Market on behalf of resources in the Zone, for the Trading Interval, by the total ISO Non-Spinning Reserve MW purchases for the Trading Interval within the Zone. The Hour-Ahead Non-Spinning Reserve capacity user rate in Zone x for Trading Interval t is calculated as follows:

$$NonSpinRateHA_{xt} = \frac{\sum_j NonSpinPayTotalHA_{jxt}}{NonSpinObligTotal_{xt}}$$

The Non-Spinning Reserve capacity charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t is calculated as follows:

$NonSpinChgHA_{jxt} = (NonSpinOblig_{jxt} * NonSpinRateHA_{xt})$

C 2.2.3 Replacement Reserve

The user rate per unit of Replacement Reserve obligation for each Settlement Period t for each Zone x shall be as follows:

$$ReplRate_{xt} = \frac{(PRepResDA_{xt} * OrigReplReqDA_{xt}) + (PRepResHA_{xt} * OrigReplReqHA_{xt})}{OrigReplReqDA_{xt} + OrigReplReqHA_{xt}}$$

where:

$OrigReplReqDA_{xt}$ = Replacement Reserve requirement net of self-provision in the Day-Ahead Market before consideration of any substitutions pursuant to Section 8.2.3.6.

$OrigReplReqHA_{xt}$ = Incremental change in the Replacement Reserve requirement net of self-provision between the Day-Ahead Market and the Hour-Ahead Market before consideration of any substitutions pursuant to Section 8.2.3.

$PRepResDA_{xt}$ is the Market Clearing Price for Replacement Reserve in the Day-Ahead Market for Zone *x* in Settlement Period *t*.

$PRepResHA_{xt}$ is the Market Clearing Price for Replacement Reserve in the Hour-Ahead Market for Zone *x* in Settlement Period *t*.

For each Settlement Period t, each Scheduling Coordinator shall pay to the ISO a sum calculated as follows for each Zone x:

$ReplRate_{xt} * ReplOblig_{jxt}$

where

$ReplOblig_{jxt} = DevReplOblig_{jxt} + RemRepl_{jxt} - SelfProv_{jxt} + NetInterSCTrades_{jxt}$ $DevReplOblig_{jxt}$ is the Scheduling Coordinator's obligation for deviation Replacement Reserve in Zone x in the Settlement Period t and $RemRepl_{jxt}$ is the Scheduling Coordinator's obligation for remaining Replacement Reserve in Zone x for Settlement Period t.

$SelfProv_{jxt}$ is Scheduling Coordinator's Replacement Reserve self-provision in Zone x for Settlement Period t.

$NetInterSCTrades_{jxt}$ is the sale of Replacement Reserve less the purchase of Replacement Reserve through Inter-Scheduling Coordinator Trades by Scheduling Coordinator j in Zone x for Settlement Period t.

Deviation Replacement Reserve for Scheduling Coordinator i in Zone x for Settlement Period t is calculated as follows:

If $ReplObligTotal_{xt} > TotalDeviations_{xt}$ then:

$$DevReplOblig_{xjt} = \left[Max\left(0, \sum_i GenDev_{ijxt}\right) - Min\left(0, \sum_i LoadDev_{ijxt}\right)\right]$$

If $ReplObligTotal_{xt} < TotalDeviations_{xt}$ then:

$$DevReplOblig_{xjt} = \frac{ReplObligTotal_{xt}}{TotalDeviations_{xt}} * \left[Max\left(0, \sum_i GenDev_{ijxt}\right) - Min\left(0, \sum_i LoadDev_{ijxt}\right)\right]$$

where,

$$TotalDeviations_{xt} = \sum_j \left[Max\left(0, \sum_i GenDev_{ijxt}\right) - Min\left(0, \sum_i LoadDev_{ijxt}\right)\right] GenDev_{ijxt}$$

= The deviation between scheduled and actual Energy generation for Generator i represented by Scheduling Coordinator I in Zone x during Settlement Period t as referenced in SABP Part D.

$LoadDev_{ijxt}$ = The deviation between scheduled and actual Load consumption for resource I represented by Scheduling Coordinator in Zone x during Settlement Period t as referenced in SABP Part D.

$DevReplOblig_{xt}$ is total deviation Replacement Reserve in Zone x for Settlement Period t.

$ReplObligTotal_{xt}$ is total Replacement Reserve Obligation in Zone x for Settlement Period t.

Remaining Replacement Reserve for Scheduling Coordinator j in Zone x for Settlement Period t is calculated as follows:

$$RemRepl_{xjt} = \frac{MeteredDemand_{jxt}}{TotalMeteredDemand_{xt}} * TotalRemRepl_{xt}$$

where:

$MeteredDemand_{jxt}$ is the Scheduling Coordinator's total metered Demand excluding exports in Zone x for Settlement Period t.

$TotalMeteredDemand_{xt}$ is total metered Demand excluding exports in Zone x for Settlement Period t.

$TotalRemRepl_{xt} = Max[0, ReplObligTotal_{xt} - DevReplOblig_{xt}]$

C 2.2.4 Rational Buyer Adjustments

(a) If, in any Settlement Period, no quantity of Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve is purchased in the Day-Ahead Market or the Hour-Ahead Market due to the operation of Section 8.2.3.6 of the ISO Tariff, then in lieu of the user rate determined in accordance with Section C 2.2.1, C 2.2.2, or C 2.2.3, as applicable, the user rate for the affected Ancillary Service for that Settlement Period shall be determined as follows:

(i) If the affected market is a Day-Ahead Market, the user rate for the affected Ancillary Service shall be set at the lowest capacity reservation price for an unaccepted qualified capacity bid in a Day-Ahead Market for that Ancillary Service or for another Ancillary Service that meets the requirements for the affected Ancillary Service. If there are no such unaccepted bids, the user rate for the affected Ancillary Service shall be the lowest Market Clearing Price for the same Settlement Period established in the Day-Ahead Market for another Ancillary Service that meets the requirements for the affected Ancillary Service.

(ii) If the affected market is an Hour-Ahead Market, the user rate for the affected Ancillary Service shall be set at the lowest capacity reservation price for an unaccepted qualified capacity bid in the Hour-Ahead Market for the same Settlement Period for that Ancillary Service or for another Ancillary Service that meets the requirements for the affected Ancillary Service. If there are no such unaccepted bids, the user rate for the affected Ancillary Service shall be the user rate for the same Ancillary Service in the Day-Ahead Market in the same Settlement Period.

(b) With respect to each Settlement Period, in addition to the user rates determined in accordance with Sections C 2.2.1 through C 2.2.3, or Section C 2.2.4(a), as applicable, each Scheduling Coordinator shall be charged an additional amount equal to its proportionate share, based on total purchases by Scheduling Coordinators of Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve of the amount, if any, by which (i) the total payments to Scheduling Coordinators pursuant to Section C 2.1 for the Day-Ahead Market and Hour-Ahead Market and all Zones, exceed (ii) the total amounts charged to Scheduling Coordinators pursuant to Sections C 2.2.1 through C 2.2.3, for the Day-Ahead Market and Hour-Ahead Market and all Zones. If total amounts charged to Scheduling Coordinators exceed the total payments to Scheduling Coordinators, each Scheduling Coordinator will be refunded its proportionate share, based on total purchases by Scheduling Coordinators of Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve.

C 2.2.5 Real-Time Market

(a) The ISO will charge the costs of purchasing Instructed Imbalance Energy output from Dispatched Spinning Reserve, Non-Spinning Reserve, Replacement Reserve and Supplemental Energy resources through the Instructed Imbalance Energy settlement process.

(b) The ISO will charge the costs of purchasing Uninstructed Imbalance Energy (including incremental and decremental Energy from Generating Units providing Regulation) through the Uninstructed Imbalance Energy settlement process.

(c) The ISO will charge the costs of Regulation Energy Payment Adjustments as calculated in accordance with Section 8.11.5 of the ISO Tariff, in accordance with Section 11.2.9.

C 3 Meaning of terms of formulae

C 3.1 $AGCUpPayDA_{ijxt}$ - $

The payment for Scheduling Coordinator j for providing Regulation Up capacity in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.

$AGCDownPayDA_{ijxt}$ - $

The payment for Scheduling Coordinator j for providing Regulation Down capacity in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.

C 3.2 $AGCUpQDA_{ijxt}$ – MW

The total quantity of Regulation Up capacity provided in the ISO Day-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

$AGCDownQDA_{ijxt}$ – MW

The total quantity of Regulation Down capacity provided in the ISO Day-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.3 $PAGCUpDA_{xt}$ - $/MW

In the case of Capacity made available in accordance with the ISO's Final Day-Ahead Schedules, the Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those Units subject to the cap for Regulation Up Capacity in the Day-Ahead Market for Trading Interval t in Zone x. In the case of Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 8.7, the bid price for the unit for Regulation Up Capacity in Zone x for Trading Interval t.

$PAGCDownDA_{xt}$ - $/MW

In the case of Capacity made available in accordance with the ISO's Final Day-Ahead Schedules, the Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those Units subject to the cap for Regulation Down Capacity in the Day-Ahead Market for Trading Interval t in Zone x. In the case of Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 8.7, the bid price for the unit for Regulation Down Capacity in Zone x for Trading Interval t.

C 3.4 $AGCUpPayTotalDA_{jxt}$ - $

The total payment for Regulation Up capacity to Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.

$AGCDownPayTotalDA_{jxt}$ - $

The total payment for Regulation Down capacity to Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.

C 3.5 $AGCUpPayHA_{ijxt}$ - $

The payment for Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Regulation Up capacity in the Hour-Ahead Market from a resource i in Zone x for Trading Interval t.

$AGCDownPayHA_{ijxt}$ - $

The payment for Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Regulation Down capacity in the Hour-Ahead Market from a resource i in Zone x for Trading Interval t.

C 3.5.1 $AGCUpReceiveHA_{ijxt}$ - $

The payment from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead Regulation Up capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.

$AGCDownReceiveHA_{ijxt}$ - $

The payment from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead Regulation Down capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.

C 3.6 $AGCUpQIHA_{ijxt}$ – MW

The total quantity of incremental (additional to Day-Ahead) Regulation Up capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

$AGCDownQIHA_{ijxt}$ – MW

The total quantity of incremental (additional to Day-Ahead) Regulation Down capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.7 $AGCUpQDHA_{ijxt}$ – MW

The total quantity of decremental (less than Day-Ahead) Regulation Up capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

$AGCDownQDHA_{ijxt}$ – MW

The total quantity of decremental (less than Day-Ahead) Regulation Down capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.7.1 $PAGCUpHA_{xt}$ - $/MW

The Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for incremental (additional to Day-Ahead) Regulation Up capacity in the Hour-Ahead Market for Trading Interval t in Zone x. On buyback condition, MCP applies.

$PAGCDownHA_{xt}$ - $/MW

The Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for incremental (additional to Day-Ahead) Regulation Down capacity in the Hour-Ahead Market for Trading Interval t in Zone x. On buyback condition, MCP applies.

C 3.8 $AGCUpPayTotalHA_{jxt}$ - $

The total payment for incremental (additional to Day-Ahead) Regulation Up capacity to Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t, after deduction of payments from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Regulation Up capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.

$AGCDownPayTotalHA_{jxt}$ - $

The total payment for incremental (additional to Day-Ahead) Regulation Down capacity to Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t, after deduction of payments from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Regulation Down capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.

C 3.9 $AGCUpRateDA_{xt}$ - $/MW

The Day-Ahead Regulation Up capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.

$AGCDownRateDA_{xt}$ - \$/MW

The Day-Ahead Regulation Down capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.

C 3.10 $AGCUpObligTotal_{xt}$ – MW

The net total Regulation Up obligation in Zone x for Trading Interval t as defined in Appendix A. This net total equals the total obligation minus that self-provided.

$AGCDownObligTotal_{xt}$ – MW

The net total Regulation Down obligation in Zone x for Trading Interval t as defined in Appendix A. This net total equals the total obligation minus that self-provided.

C 3.11 $AGCUpChgDA_{jxt}$ - \$

The Regulation Up charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.

$AGCDownChgDA_{jxt}$ - \$

The Regulation Down charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.

C 3.12 $AGCUpOblig_{jxt}$ – MW

The net Regulation Up obligation for Scheduling Coordinator j in Zone x for Trading Interval t as defined in Appendix A. This net obligation equals the obligation minus that self-provided.

$AGCDownOblig_{jxt}$ – MW

The net Regulation Down obligation for Scheduling Coordinator j in Zone x for Trading Interval t as defined in Appendix A. This net obligation equals the obligation minus that self-provided.

C 3.13 $AGCUpRateHA_{xt}$ - \$/MW

The Hour-Ahead incremental (additional to Day-Ahead) Regulation Up capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.

$AGCDownRateHA_{xt}$ - \$/MW

The Hour-Ahead incremental (additional to Day-Ahead) Regulation Down capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.

C 3.14 $AGCUpChgHA_{jxt}$ - $

The incremental (additional to Day-Ahead) Regulation Up charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t.

$AGCDownChgHA_{jxt}$ - $

The incremental (additional to Day-Ahead) Regulation Down charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t.

C 3.15 $EnQPay_{ijxt}$ - $

The payment for Scheduling Coordinator j for Instructed Imbalance Energy output from a resource i in the Real Time Market in Zone x for Trading Interval t.

C 3.16 [NOT USED]

C 3.17 [NOT USED]

C 3.18 [NOT USED]

C 3.19 $SpinPayDA_{ijxt}$ - $

The payment for Scheduling Coordinator j for providing Spinning Reserve capacity in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.

C 3.20 $SpinQDA_{ijxt}$ – MW

The total quantity of Spinning Reserve capacity provided in the Day-Ahead Market by resource i represented by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.20A $REPA_{ijxt}$ - $

The Regulation Energy Payment Adjustment payable for real-time incremental or decremental Energy provided from Regulation resource i of Scheduling Coordinator j in Zone x in Trading Interval t.

C 3.20B RUP_{ijxt} – MW

The upward Regulation capacity of Regulation resource i in Zone x included in the Final Schedule for Ancillary Services of Scheduling Coordinator j for Trading Interval t, weighted in proportion to the ISO's need for upward Regulation.

C3.20C RDN_{ijxt} – MW

The downward Regulation capacity of Regulation resource i in Zone x included in the Final Schedule for Ancillary Services of Scheduling Coordinator j for Trading Interval t, weighted in proportion to the ISO's need for downward Regulation.

C 3.20D CUP – number

The constant established by the ISO and subject to change by resolution of the ISO Governing Board. Initially this shall be set at 1. The ISO may modify the value of CUP within a range of 0-1 either generally in regard to all hours or specifically in regard to particular times of the day, after the ISO Governing Board approves such modifications, by a notice issued by the Chief Executive Officer of the ISO and posted on the ISO Internet "Home Page," at http//www.caiso.com, or such other Internet address as the ISO may publish from time to time, specifying the date and time from which the modification shall take effect, which shall be not less than seven (7) days after the Notice is issued.

C 3.20E CDN – number

The constant established by the ISO and subject to change by resolution of the ISO Governing Board. Initially this shall be set at 1. The ISO may modify the value of CDN within a range of 0-1 either generally in regard to all hours or specifically in regard to particular times of the day, after the ISO Governing Board approves such modifications, by a notice issued by the Chief Executive Officer of the ISO and posted on the ISO Internet "Home Page," at http//www.caiso.com, or such other Internet address as the ISO may publish from time to time, specifying the date and time from which the modification shall take effect, which shall be not less than seven (7) days after the Notice is issued.

C 3.21 $PSpinDA_{xt}$ -$/MW

In the case of Capacity made available in accordance with the ISO's Final Day-Ahead Schedules, the Day-Ahead Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for Spinning Reserve Capacity in Zone x for Trading Interval t. In the case of Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 8.7, the bid price for the unit for Spinning Reserve Capacity in Zone x for Trading Interval t.

C 3.22 $SpinPayTotalDA_{jxt}$ - $

The total payment to Scheduling Coordinator j for Spinning Reserve capacity in the Day-Ahead Market in Zone x for Trading Interval t.

C 3.23 $SpinPayHA_{ijxt}$ - $

The payment for Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Spinning Reserve capacity in the Hour-Ahead Market from a resource i in Zone x for Trading Interval t.

C 3.23.1 $SpinReceiveHA_{Ijxt}$ - $

The payment from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Spinning Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.

C 3.24 SpinQIHA$_{ijxt}$ – MW

The total quantity of incremental (additional to Day-Ahead) Spinning Reserve capacity provided in the Hour-Ahead Market by resource i represented by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.25 SpinQDHA$_{ijxt}$ – MW

The total quantity of decremental (less than Day-Ahead) Spinning Reserve capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.25.1 PSpinHA$_{xt}$ -$/MW

The Hour-Ahead Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for incremental (additional to Day-Ahead) Spinning Reserve capacity in Zone x for Trading Interval t. On Buyback condition, MCP applies charge for HA.

C 3.26 SpinPayTotalHA$_{jxt}$ - $

The total payment to Scheduling Coordinator j for incremental (additional to Day-Ahead) Spinning Reserve capacity in the Hour-Ahead Market in Zone x for Trading Interval t, after deduction of payments from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Spinning Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.

C 3.27 SpinRateDA$_{xt}$ - $/MW

The Day-Ahead Spinning Reserve capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.

C 3.28 SpinObligTotal$_{xt}$ – MW

The net total Spinning Reserve capacity obligation in Zone x for Trading Interval t as defined in Appendix A. This net total equals the total obligation minus that self-provided.

C 3.29 SpinChgDA$_{jxt}$ - $

The Spinning Reserve capacity charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.

C 3.30 SpinOblig$_{jxt}$ – MW

The net Spinning Reserve capacity obligation for Scheduling Coordinator j in Zone x for Trading Interval t as defined in Appendix A. This net obligation equals the obligation minus that self-provided.

C 3.31 $SpinRateHA_{xt}$ - $/MW

The Hour-Ahead incremental (additional to Day-Ahead) Spinning Reserve capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.

C 3.32 $SpinChgHA_{jxt}$ - $

The incremental (additional to Day-Ahead) Spinning Reserve capacity charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t.

C 3.33 $NonSpinPayDA_{ijxt}$ - $

The payment for Scheduling Coordinator j for providing Non-Spinning Reserve capacity in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.

C 3.34 $NonSpinQDA_{ijxt}$ – MW

The total quantity of Non-Spinning Reserve capacity provided from resource i in the Day-Ahead Market by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.35 $PNonSpinDA_{xt}$ - $/MW

In the case of Capacity made available in accordance with the ISO's Final Day-Ahead Schedules, the Day-Ahead Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for Non-Spinning Reserve Capacity for Trading Interval t in Zone x. In the case of Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 8.7, the bid price for the unit for Non-Spinning Reserve Capacity in Zone x for Trading Interval t.

C 3.36 $NonSpinPayTotalDA_{jxt}$ - $

The total payment to Scheduling Coordinator j for providing Non-Spinning Reserve capacity in the Day-Ahead Market in Zone x for Trading Interval t.

C 3.37 $NonSpinPayHA_{ijxt}$ - $

The payment for Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Non-Spinning Reserve capacity in the Hour-Ahead Market from a resource i in Zone x for Trading Interval t.

C 3.37.1 $NonSpinReceiveHA_{ijxt}$ - $

The payment from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Non-Spinning Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.

C 3.38 NonSpinQIHA$_{ijxt}$ – MW

The total quantity of incremental (additional to Day-Ahead) Non-Spinning Reserve capacity provided from resource i in the Hour-Ahead Market by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.39 NonSpinQDHA$_{ijxt}$ – MW

The total quantity of decremental (less than Day-Ahead) Non-Spinning Reserve capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.39.1 PNonSpinHA$_{xt}$ - $/MW

The Hour-Ahead Zonal Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for incremental (additional to Day-Ahead) Non-Spinning Reserve capacity for Trading Interval t in Zone x. On Buyback condition, MCP applies.

C 3.40 NonSpinPayTotalHA$_{jxt}$ - $

The total payment to Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Non-Spinning Reserve capacity in the Hour-Ahead Market in Zone x for Trading Interval t, after deduction of payments from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Non-Spinning Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead market in Zone x for Trading Interval t.

C 3.41 NonSpinRateDA$_{xt}$ - $/MW

The Day-Ahead Non-Spinning Reserve capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.

C 3.42 NonSpinObligTotal$_{xt}$ – MW

The net total Non-Spinning Reserve capacity obligation in Zone x for Trading Interval t as defined in Appendix A. This net total obligation equals the total minus that self-provided.

C 3.43 NonSpinChgDA$_{jxt}$ - $

The Non-Spinning Reserve Capacity charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.

C 3.44 NonSpinOblig$_{jxt}$ – MW

The net Non-Spinning Reserve capacity obligation for Scheduling Coordinator j in Zone x for Trading Interval t as defined in Appendix A. This net obligation is the obligation minus that self-provided.

C 3.45 NonSpinRateHA$_{xt}$ - $/MW

The Hour-Ahead incremental (additional to Day-Ahead) Non-Spinning Reserve capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.

C 3.46 NonSpinChgHA$_{jxt}$ - $

The incremental (additional to Day-Ahead) Non-Spinning Reserve Capacity charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t.

C 3.47 NonSpinObligHA$_{jxt}$ – MW

The net incremental (additional to Day-Ahead) Non-Spinning Reserve capacity obligation in the Hour-Ahead Market for Scheduling Coordinator j in Zone x for Trading Interval t as defined in Appendix A. This net obligation is the obligation minus that self-provided.

C 3.48 ReplPayDA$_{ijxt}$ - $

The payment for Scheduling Coordinator j for providing Replacement Reserve capacity in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.

C 3.49 ReplQDA$_{ijxt}$ – MW

The total quantity of Replacement Reserve capacity provided in the Day-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.50 PReplDA$_{xt}$ -$/MW

In the case of Capacity made available in accordance with ISO's Final Day-Ahead Schedules, the Day-Ahead Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units not subject to the cap for Replacement Reserve Capacity in Zone x for Trading Interval t. In the case of Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 8.7, the bid price for the unit for Replacement Reserve Capacity in Zone x for Trading Interval t.

C 3.51 ReplPayTotalDA$_{jxt}$ - $

The total payment to Scheduling Coordinator j for providing Replacement Reserve capacity in the Day-Ahead Market in Zone x for Trading Interval t.

C 3.51.1 ReplReceiveHA$_{ijxt}$ - $

The payment from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Replacement Reserve capacity which the ISO had purchased from Scheduling

Coordinator j in the Day-Ahead Market from a resource i in the Zone x for Trading Interval t.

C 3.52 $ReplPayHA_{ijxt}$ - $

The payment for Scheduling Coordinator j for providing of incremental (additional to Day-Ahead) Replacement Reserve capacity in the Hour-Ahead Market from a resource i in Zone x for Trading Interval t.

C 3.53 $ReplQIHA_{ijxt}$ – MW

The total quantity of incremental (additional to Day-Ahead) Replacement Reserve capacity provided in the Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.54 $ReplQDHA_{ijxt}$ – MW

The total quantity of decremental (less than Day-Ahead) Replacement Reserve capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.54.1 $PReplHA_{xt}$ -$/MW

The Hour-Ahead Market Clearing Price for Non-FERC jurisdictional units or the bid price for FERC jurisdictional units for incremental (additional to Day-Ahead) Replacement Reserve capacity in Zone x for Trading Interval t. On Buyback condition, MCP applies.

C 3.55 $ReplPayTotalHA_{jxt}$ - $

The total payment to Scheduling Coordinator j for providing of incremental (additional to Day-Ahead) Replacement Reserve capacity in the Hour-Ahead Market in Zone x for Trading Interval t, after deduction of payments from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Replacement Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market in Zone x from Trading Interval t.

C 3.56 $ReplRateDA_{xt}$ - $/MW

The Day-Ahead Replacement Reserve capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.

C 3.57 $ReplChgDA_{jxt}$ - $

The Replacement Reserve capacity charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.

C 3.58 $ReplRateHA_{xt}$ – $/MW

The Hour-Ahead incremental (additional to Day-Ahead) Spinning Reserve capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.

C 3.59 $ReplChgHA_{jxt}$ - $

The incremental (additional to Day-Ahead) Replacement Reserve capacity charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t.

C 3.60 $ReplObligTotal_{xt}$ – MW

The net total Replacement Reserve capacity obligation in the Day-Ahead and Hour-Ahead Markets in Zone x for Trading Interval t as defined in Appendix A. This net total obligation is the total obligation minus that self-provided.

C 3.61 $ReplPayTotal_{jxt}$ - $

The total payment to Scheduling Coordinator j for providing Replacement Reserve capacity in the Day-Ahead and Hour-Ahead Markets in Zone x for Trading Interval t.

C 3.62 $PavgRepl_{xt}$ - $/MW

The average price paid for Replacement Reserve capacity in the Day-Ahead Market and the Hour-Ahead Market in Zone x in Trading Interval t.

C 3.63 $UnDispReplChg_{jxt}$ - $

The undispatched Replacement Reserve Capacity charge for Scheduling Coordinator j in the Day-Ahead and Hour-Ahead Markets in Zone x for Trading Interval t.

C 3.64 $ReplOblig_{jxt}$ – MW

The Replacement Reserve capacity obligation in the Day-Ahead and Hour-Ahead Markets for Scheduling Coordinator j in Zone x for Trading Interval t as defined in Appendix A.

C 3.65 $ReplQDisp_{xt}$ – MWh

The Dispatched Replacement Reserve capacity in the Day-Ahead Market in Zone x in Trading Interval t.

C 3.66 $AGCUpPurchDA_{xt}$ – MW

The total quantity of Regulation Up capacity provided in the Day-Ahead Market in Zone x for Trading Interval t, not including self-provided quantities.

$AGCDownPurchDA_{xt}$ – MW

The total quantity of Regulation Down capacity provided in the Day-Ahead Market in Zone x for Trading Interval t, not including self-provided quantities.

C 3.67 $SpinPurchDA_{xt}$ – MW

The total quantity of Spinning Reserve capacity provided in the Day-Ahead Market in Zone x for Trading Interval t, not including self-provided quantities.

C 3.68 $NonSpinPurchDA_{xt}$ – MW

The total quantity of Non-Spinning Reserve capacity provided in the Day-Ahead Market in Zone x for Trading Interval t, not including self-provided quantities.

C 3.69 $AGCUpPurchHA_{xt}$ – MW

The net quantity of Regulation Up capacity provided in the Hour-Ahead Market in Zone x for Trading Interval t, not including self-provided quantities.

$AGCDownPurchHA_{xt}$ – MW

The net quantity of Regulation Down capacity provided in the Hour-Ahead Market in Zone x for Trading Interval t, not including self-provided quantities.

C 3.70 $SpinPurchHA_{xt}$ – MW

The net quantity of Spinning Reserve capacity provided in the Hour-Ahead Market in Zone x for Trading Interval t, not including self-provided quantities.

C 3.71 $NonSpinPurchDA_{xt}$ – MW

The net quantity of Non-Spinning Reserve capacity provided in the Hour-Ahead Market in Zone x for Trading Interval t, not including self-provided quantities.

PART D
IMBALANCE ENERGY CHARGE COMPUTATION

D 1 Purpose of charge

The Imbalance Energy charge is the term used for allocating the cost of not only the Imbalance Energy (the differences between scheduled and actual Generation and Demand), but also any Unaccounted for Energy (UFE) and any errors in the forecasted Transmission Losses as represented by the GMMs. Any corresponding cost of Dispatched Replacement Reserve Capacity that is not allocated as an Ancillary Service is also included along with the Imbalance Energy charge.

D 2 Fundamental formulae

D 2.1.1 Uninstructed Imbalance Energy Charges on Scheduling Coordinators

Uninstructed Imbalance Energy attributable to each Load Take-Out Point, Generating Unit, System Unit, or System Resource for which a Scheduling Coordinator has a Final Hour-Ahead Schedule or Metered Quantity, for each Settlement Interval shall be deemed to be sold or purchased, as the case may be, by the ISO and charges or payments for Uninstructed Imbalance Energy shall be settled by debiting or crediting, as the case may be, the Scheduling Coordinator with an amount for each Settlement Interval.

Uninstructed Imbalance Energy within a Settlement Interval shall be settled in two tiers that are defined in relation to the expected Energy associated with the Final Hour-Ahead Schedule, if any, and the Dispatch Instruction as follows:

1) Deviations from the expected Energy associated with a Dispatch Instruction resulting in: 1) under delivery of Instructed Imbalance Energy that is also equal to or greater than the Final Hour-Ahead Schedule, or 2) over delivery of Instructed Imbalance Energy that is also less than or equal to the Final Hour-Ahead Schedule constitutes tier 1 Uninstructed Imbalance Energy that shall be settled at a Resource-Specific Settlement Interval Ex Post Price as described in Part D 2.4.

2) Deviations from the expected Energy associated with a Dispatch Instruction resulting in: 1) over delivery of Instructed Imbalance Energy that is also greater than the Final Hour-Ahead Schedule, or 2) under delivery of Instructed Imbalance Energy that is also less than the Final Hour-Ahead Schedule constitutes tier 2 Uninstructed Imbalance Energy and shall be settled at the Zonal Settlement Interval Ex Post Price as described in Part D 2.5.

Imbalance Energy is calculated as follows:

Generator Calculation for ISO Metered Entities:

$$IE_{i,h,o} = ME_{i,h,o} - SE_{i,h,o}$$

Load Calculation:

$$IE_{i,h,o} = SE_{i,h,o} - ME_{i,h,o}$$

System Resource Calculation:

$$IE_{i,h,o} = \sum_{1}^{k}\sum_{1}^{v} REAL\_TIME\_FLOW_{i,h,o,k,v} - SE_{i,h,o}$$

where,

$$SE_{i,h,o} = \frac{HAfin_{i,h}}{6}$$

$ME_{i,h,o}$ actual Meter Data for each resource *i* of each Settlement Interval *o* for each hour *h*.

Uninstructed Imbalance Energy is calculated as follows:

$$UIE_{i,h,o} = E_{i,h,o} - IIE\_REG_{i,h,o}$$

where:

$$\begin{aligned} E_{i,h,o} = {} & IE_{i,h,o} - \sum_{1}^{k} IIE\_LOSS_{i,h,o,k} - \sum_{1}^{k} IIE\_ML_{i,h,o,k} - \\ & \sum_{1}^{k}\sum_{1}^{m} IIE\_PREDISPATCH_{i,h,o,k,m} - \sum_{1}^{k} RE\_STANDARD_{i,h,o,k} - \sum_{1}^{k} RED_{i,h,o,k} \\ & - \sum_{1}^{k}\sum_{1}^{m} IIE\_ECON_{i,h,o,k,m} - \sum_{1}^{k}\sum_{1}^{L} OOS\_P_{i,h,o,k,L} - \sum_{1}^{k}\sum_{1}^{L} OOS\_N_{i,h,o,k,L} - \sum_{1}^{k}\sum_{1}^{m} RIE_{i,h,o,k,m} \\ & - \sum_{1}^{k} IIE\_RERATE_{i,h,o,k} \end{aligned}$$

$IIE\_REG_{i,h,o}$ is the Regulating Energy for resource *i* during Settlement Interval *o* in hour *h*

$$UIE\_1_{i,h,o} = \begin{cases} \min\Big(UIE_{i,h,o}, -\min\Big(0, \sum_1^k\sum_1^m IIE\_ECON_{i,h,o,k,m} + \sum_1^k\sum_1^m IIE\_PREDISPATCH_{i,h,o,k,m} \\ \quad + \sum_1^k\sum_1^L OOS\_P_{i,h,o,k,L} + \sum_1^k\sum_1^L OOS\_N_{i,h,o,k,L} + \sum_1^k RED_{i,h,o,k} & \therefore UIE_{i,h,o} \geq 0 \\ \quad + \sum_1^k IIE\_LOSS_{i,h,o,k} + \sum_1^k\sum_1^m RIE_{i,h,o,k,m} + \sum_1^k IIE\_ML_{i,h,o,k} + \sum_1^k RERATE_{i,h,o,k}\Big)\Big) \\ \max\Big(UIE_{i,h,o}, -\max\Big(0, \sum_1^k\sum_1^m IIE\_ECON_{i,h,o,k,m} + \sum_1^k\sum_1^m IIE\_PREDISPATCH_{i,h,o,k,m} \\ \quad + \sum_1^k\sum_1^L OOS\_P_{i,h,o,k,L} + \sum_1^k\sum_1^L OOS\_N_{i,h,o,k,L} + + \sum_1^k RED_{i,h,o,k} & \therefore UIE_{i,h,o} < 0 \\ \quad + \sum_1^k IIE\_LOSS_{i,h,o,k} + \sum_1^k\sum_1^m RIE_{i,h,o,k,m} + \sum_1^k IIE\_ML_{i,h,o,k} + \sum_1^k RERATE_{i,h,o,k}\Big)\Big) \end{cases}$$

$$UIE\_2_{i,h,o} = UIE_{i,h,o} - UIE\_1_{i,h,o}$$

$$UIEC_{i,h,o} = \left(-1 * UIE\_1_{i,h,o} * STLMT\_PRICE_{i,h,o}\right) + \left(-1 * UIE\_2_{i,h,o} * ZONAL\_EX\_POST\_PRICE_{j,h,o}\right)$$

D 2.1.2 Instructed Imbalance Energy Charges on Scheduling Coordinators

Standard Ramping Energy is Energy associated with a Standard Ramp and shall be deemed delivered and settled at a price of zero dollars per MWh.

Ramping Energy Deviation is Energy produced or consumed due to hourly schedule changes in excess of Standard Ramping Energy and shall be paid or charged, as the case may be, at a Resource-Specific Settlement Interval Ex Post Price calculated using the applicable Dispatch Interval Ex Post Prices as described in this Part D 2.4. For Scheduling Coordinators scheduling a MSS that has elected to follow its Load, this Ramping Energy Deviation will account for the units following Load.

Ramping Energy Deviation shall be settled as an explicit component of Instructed Imbalance Energy for each resource *i* in Dispatch Interval *k* of Settlement Interval *o* for hour *h*, and calculated as follows:

$$REDC_{i,h,o} = \left(\sum_1^k RED_{i,h,o,k}\right) * STLMT\_PRICE_{i,h,o}$$

Hourly Predispatched energy from System Resources is an explicit component of Instructed Imbalance Energy for each interchange resource *i* in Dispatch Interval *k* of Settlement Interval *o* for hour *h*, and settled pursuant to Sections 11.2.4.1.1 and 11.2.4.1.1.2 of the ISO Tariff. The settlement calculation is as follows:

If (

($COST\_AT\_STLMT\_PRICE_{i,h,o} >= 0$

And

$BID\_COST_{i,h,o} >=0$)

Then

$$IIEC\_PREDISPATCH_{i,h,o} = (-1) *$$

$$\left[min\left(COST\_AT\_STLMT\_PRICE_{i,h,o}, BID\_COST_{i,h,o}\right) + (STLMT\_PRICE_{i,h,o} * PRE\_DISP\_ABC\_BQ_{i,h,o})\right]$$

Else

$IIEC\_PREDISPATCH_{i,h,o} = (-1) *$

$[BID\_COST_{i,h,o} + (STLMT\_PRICE_{i,h,o} * PRE\_DISP\_ABC\_BQ_{i,h,o})]$

Where

$COST\_AT\_STLMT\_PRICE_{i,h,o} =$

$$\left(\sum_{1}^{k} IIE\_PREDISPATCH_{i,h,o,k}\right) * STLMT\_PRICE_{i,h,o}$$

$BID\_COST_{i,h,o} =$

$\sum_{1}^{k}\sum_{1}^{m} IIE\_PREDISPATCH\_FOR\_SEGMENT_{i,h,o,k,m} * IIE\_PRICE_{i,h,o,k,m}$ for the portion of incremental energy bid segments with $IIE\_PRICE_{i,h,o,k,m}$ less than or equal to the Maximum Bid Level and all decremental energy bid segments with $IIE\_PRICE_{i,h,o,k,m}$ limited to the Bid Floor when $IIE\_PRICE_{i,h,o,k,m}$.is less than the Bid Floor.

))

where

$PRE\_DISP\_ABC\_BQ_{i,h,o} = \sum_{1}^{k}\sum_{1}^{m} IIE\_PREDISPATCH\_FOR\_SEGMENT_{i,h,o,k,m}$ for the portion of incremental energy bid segments with $IIE\_PRICE_{i,h,o,k,m}$ greater than the Maximum Bid Level.

The amount of Instructed Imbalance Energy that will be deemed delivered in each Dispatch Interval will be based on Dispatch Instructions, as provided for in Section 34.3, and Final Hour-Ahead Schedules. The amount of Instructed Imbalance Energy to be settled in a Settlement Interval will be equal to the sum of all Instructed Imbalance Energy for all Dispatch Intervals within the relevant Settlement Interval. Instructed Imbalance Energy for each Settlement Interval shall be settled at the relevant Resource Specific Settlement Interval Ex Post Price. Generating Units, Participating Loads, and System Units may be eligible to recover their Energy Bid costs in accordance with Section 11.2.4.1.1.1. Instructed Imbalance Energy from System Resources shall be settled in accordance with Section 11.2.4.1.1.2.

The Instructed Imbalance Energy amount for each resource *i* in Settlement Interval *o* for hour *h* shall be determined as follows:

$$IIEC_{i,h,o} = (-1) * \begin{pmatrix} \sum_1^k \sum_1^m IIE\_ECON_{i,h,o,k,m} + \sum_1^k \sum_1^m RIE_{i,h,o,k,m} \\ + \sum_1^k IIE\_RERATE_{i,h,o,k} + \sum_1^k IIE\_ML_{i,h,o,k} \end{pmatrix} * STLMT\_PRICE_{i,h,o}$$

$$+ \; IIEC\_OOS_{i,h,o} + REDC_{i,h,o} + IIEC\_REG_{i,h,o} + IIEC\_PREDISPATCH_{i,h,o}$$

Uninstructed Imbalance Energy is Imbalance Energy due to non-compliance with a Dispatch Instruction and shall be settled as provided for in SABP Part D Section 2.1.1.

D 2.2 Unaccounted for Energy Charge

The Unaccounted for Energy Charge on Scheduling Coordinator *g* in Settlement Interval *o* of Settlement Period *h* for each relevant Zone *j* is calculated in the following manner:

The UFE for each utility Service Area *s,* for which separate UFE calculation is performed, is calculated as follows,

$$UFE_{UDC,s,h,o} = \sum_{q \in UDC_s} I_{a,q,j,h,o} - \sum_{q \in UDC_s} E_{a,q,j,h,o} + \sum_{i \in UDC_s} G_{a,i,j,h,o} - \sum_{i \in UDC_s} L_{a,i,j,h,o} - TL_{s,h,o}$$

The Transmission Loss $TL_{s,h,o}$ in Settlement Interval *o* of Settlement Period *h* for utility Service Area *s* is calculated as follows:

$$TL_{s,h,o} = \left(\sum_i \left[G_{a,i,j,h,o} * (1 - GMM_{a,i,h}) \right] + \sum_q \left[I_{a,q,j,h,o} * (1 - GMM_{a,q,h}) \right] \right) * \frac{PFL_{s,h}}{\sum_s PFL_{s,h}}$$ Where

$PFL_{s,h}$ are the Transmission Losses for utility Service Area *s* as calculated by a power flow solution for Settlement Period *h*, consistent with the calculation of final forecasted Generation Meter Multipliers.

Each metered demand point *z* in utility Service Area *s*, either ISO grid connected or connected through UDC *s*, is allocated a portion of the UFE as follows:

$$UFE_{i,j,h,o} = UFE_{UDC,s,h,o} * \frac{L_{i,j,h,o}}{\sum_{i \in UDC_s} L_{i,j,h,o}}$$

The UFE charge for Scheduling Coordinator *g* for Settlement Interval *o* of Settlement Period *h* in Zone *j* is calculated as a charge or payment using the applicable Zonal Settlement Interval Ex Post Price as follows:

$$UFEC_{g,j,h,o} = \left(\sum_{i \in SCg} UFE_{i,j,h,o,} \right) * ZONAL\_EX\_POST\_PRICE_{j,h,o}$$

D 2.3 Hourly Ex Post Price

The Hourly Ex Post Price is the Energy-weighted average of the Dispatch Interval Ex Post Prices in each Zone *j* during each Settlement Period using the absolute value of Instructed Imbalance Energy procured from all Participating Generators, Participating Load, System Units, and System Resources in each applicable Dispatch Interval. The Hourly Ex Post Price may vary between Zones if Congestion is present.

$$HP_{j,h} = \frac{\sum_{1}^{p} \sum_{1}^{i} \left| IIE\_TOTAL_{j,i,h,p} \right| * EX\_POST\_PRICE_{j,h,o,p}}{\sum_{1}^{p} \sum_{1}^{i} \left| IIE\_TOTAL_{j,i,h,p} \right|}$$

where,

p is the Dispatch Interval index for hour *h*.

D 2.4 Resource-Specific Settlement Interval Ex Post Price

The Resource-Specific Settlement Interval Ex Post Price is the weighted-average of the Dispatch Interval Ex Post Prices in each Settlement Interval using the Instructed Imbalance Energy from the respective Participating Generator, Participating Load, or System Resource, in each applicable Dispatch Interval. If there is no Instructed Imbalance Energy from a Participating Generator, Participating Load, or System Resource, in any of the applicable Dispatch Intervals, the Resource-Specific Settlement Interval Ex Post Price for that resource would be the simple average of the applicable Dispatch Interval Ex Post Prices in the Settlement Interval.

The Resource-Specific Settlement Interval Ex Post Price is calculated as follows:

$$STLMT\_PRICE_{i,h,o} = \frac{\sum_{1}^{k} IIE\_TOTAL_{i,h,o,k} * EX\_POST\_PRICE_{j,h,o,k}}{\sum_{1}^{k} IIE\_TOTAL_{i,h,o,k}}$$

Where:

$$IIE\_TOTAL_{i,h,o,k} = \sum_{1}^{m} IIE\_ECON_{i,h,o,k,m} + \sum_{1}^{m} IIE\_PREDISPATCH_{i,h,o,k,m} + IIE\_ML_{i,h,o,k} + \sum_{1}^{m} RIE_{i,h,o,k,m} + \sum_{1}^{L} OOS\_P_{i,h,o,k,L} + \sum_{1}^{L} OOS\_N_{i,h,o,k,L} + IIE\_LOSS_{i,h,o,k} + RED_{i,h,o,k} + \sum_{1}^{k} IIE\_RERATE_{i,h,o,k}$$

D 2.5 Zonal Settlement Interval Ex Post Price

The Zonal Settlement Interval Ex Post Price is the weighted-average of the Dispatch Interval Ex Post Prices in each Settlement Interval using the absolute value of Instructed Imbalance Energy procured from all Participating Generators, Participating Load, System Units, and System Resources in each applicable Dispatch Interval. If there is no Instructed Imbalance Energy from a Participating Generator, Participating Load, or System Resource, in any of the applicable Dispatch Intervals, the Zonal Settlement Interval Ex Post Price for that Zone would be the simple average of the applicable Dispatch Interval Ex Post Prices in the Settlement Interval.

The Zonal Settlement Interval Ex Post Price is calculated as follows:

$ZONAL\_EX\_POST\_PRICE_{j,h,o}$ =

$$\frac{\sum_{p=1}^{2}\sum_{1}^{i} \left| IIE\_TOTAL_{i,h,p} \right| * EX\_POST\_PRICE_{j,h,o,p}}{\sum_{p=1}^{2}\sum_{1}^{i} \left| IIE\_TOTAL_{i,h,p} \right|}$$

where p is the Dispatch Interval index for hour h.

D 2.6 Calculation of Unrecovered Cost Payment for Generating Units, System Units, Dynamically Scheduled System Resources, and Curtailable Demand.

As set forth in 11.2.4.1.1.1, Generating Units, System Units, dynamically scheduled System Resources, and Curtailable Demand resources will be eligible to recover their bid costs (less than or equal to the Maximum Bid Level) for extra-marginal Energy dispatched above Pmin, if such costs are not recovered from the net of expected revenues earned through participation in the ISO's Real Time Market during the Trade Day (24-hour period).

The Unrecovered Cost Payment for each resource i shall be determined for the Trade Day *d* then evenly divided over n-Settlement Intervals as follows:

$$COST\_RECOVERY_{i,d} = min(0, \sum_{1}^{h}\sum_{1}^{o} (MR\_DEFICIT_{i,h,o} + MR\_SURPLUS_{i,h,o}))$$

where,

$MR\_DEFICIT_{i,h,o}$ = Market Revenue deficit for resource i in hour h for Settlement interval o based on the difference between the expected revenues earned in the Settlement Interval and and/or its bid cost;$MR\_SURPLUS_{i,h,o}$= Market Revenue surplus for resource i in hour h for Settlement interval o based on the difference between the expected revenues earned in the Settlement Interval and/or its bid cost.

Resource i shall receive a share of its total cost recovery in each Settlement Interval o that is included in the $COST\_RECOVERY_{i,d}$ calculation.

$COST\_RECOVERY_{i,h,o} = COST\_RECOVERY_{i,d} / n$

where,

n is the number of Settlement Intervals o that are included in the $COST\_RECOVERY_{i,d}$ calculation for resource i in Trade Day d.

Calculation of Market Revenue Surplus or Deficit

The market revenue surplus or deficit for each resource i will be computed for each Settlement Interval o based on the difference between the revenues earned in the Settlement Interval at the relevant 10-minute Ex Post price and the resource's bid cost (less than or equal to the Maximum Bid Level) as follows:

$$MR\_DIFF_{i,h,o} = \left(\sum_{1}^{k}\sum_{1}^{m} IIE\_ECON_{i,h,o,k,m} + \sum_{1}^{k}\sum_{1}^{m} RIE_{i,h,o,k,m}\right) * STLMT\_PRICE_{i,h,o} - BID\_COST_{i,h,o} - BID\_COST\_RIE_{i,h,o}$$

for all incremental energy bid segments m with $IIE\_PRICE_{i,h,o,k,m}$ and $RIE\_PRICE_{i,h,o,k,m}$ less than or equal to the Maximum Bid Level and all decremental energy bid segments m with $IIE\_PRICE_{i,h,o,k,m}$ and $RIE\_PRICE_{i,h,o,k,m}$ greater than or equal to the Bid Floor.

$MR\_DEFICIT_{i,h,o} = min(0,\ MR\_DIFF_{i,h,o})$

$MR\_SURPLUS_{i,h,o} = \max(0,\ MR\_DIFF_{i,h,o})$

where,

$$BID\_COST_{i,h,o} = \left(\sum_{1}^{k}\sum_{1}^{m} IIE\_ECON_{i,h,o,k,m} * IIE\_PRICE_{i,h,o,k,m}\right)$$

$$BID\_COST\_RIE_{i,h,o} = \sum_{1}^{k}\sum_{1}^{m} RIE_{i,h,o,k,m} * RIE\_PRICE_{i,h,o,k,m}$$

D 2.6.1 Tolerance Band and Performance Check

The ISO shall determine the Tolerance Band for each Settlement Interval *o* for PGA resources and dynamically scheduled System Resources based on the data from the Master File as follows:

$TOLERANCE\_BAND_{i,h,o}$ = $\pm \max\left(FIX\_LIM\ , TOL\_PERCENT\ * P\max_i\right)/6$

where,

FIX_LIM is a fixed MW limit and is initially equal to 5 MW.

TOL_PERCENT is a fixed percentage and is initially equal to 3%.$Pmax_i$ is the maximum operating capacity in MW of resource *i* specified in the Master File.

The ISO shall determine the Tolerance Band for each Settlement Interval o *for PLA resources as follows*:

$TOLERANCE\_BAND_{i,h,o}$ = $\pm\ max\left(FIX\_LIM,\ TOL\_PERCENT * HAfin_{i,h}\right)/6$

where $HAfin_{i,h}$ *is the* Final Hour Ahead Energy Schedule.

Resources must operate within their relevant Tolerance Band in order to receive any above-Ex Post Price payments. The ISO shall determine the performance status of the resource for each Settlement Interval o. A resource shall have met its performance requirement if its $UIE_{i,h,o}$ is within its relevant Tolerance Band. A resource meeting its performance requirement in Settlement Interval o will have a $PERF\_STAT_{i,h,o} = 1$. A resource that has not met its performance requirement in Settlement Interval *o* will have a $PERF\_STAT_{i,h,o} = 0$.

Must-offer resources that produce a quantity of Energy above Minimum Load due to an ISO Dispatch Instruction during a Waiver Denial Period are not subject to the Tolerance Band requirement for purposes of receiving Minimum Load Cost Compensation, as defined in Section 40.8. Accordingly, the $PERF\_STAT_{i,h,o}$ for eligible must-offer resources, as defined in Section 40.8, shall be set to 1, irrespective of deviations outside of the Tolerance Band, for the purpose of determining eligibility for Minimum Load Cost Compensation during a Waiver Denial Period. The Tolerance Band shall be used to apply UDP during a Waiver Denial Period.

Non-dynamically scheduled System Resources do not have a Tolerance Band. Non-Participating Load Agreement (PLA) load resources are not subject to the performance requirement.

D 2.6.2 Unrecovered Costs Neutrality Allocation

For each Settlement Interval *o*, the total Unrecovered Costs for Trade Day *d* shall be allocated pro-rata to each Scheduling Coordinator *g* based on its Metered Demand, calculated as follows:

$URC\_ALLOC_{g,h,o} = M_{g,h,o} * Per\ Unit\ Price$

where,

$M_{g,h,o}$ = the Metered Demand in the ISO control area for Scheduling

Coordinator *g* in Settlement Interval *o* for hour *h*;

$$Per\ Unit\ Price = \frac{-1 * \sum_{1}^{i} COST\_RECOVERY_{i,h,o}}{\sum_{1}^{g} M_{g,h,o}}$$

D 2.6.3 Calculation of Unrecovered Bid Cost Payment for System Resources

As set forward in Section 11.2.4.1.1.2, System Resources that are pre-dispatched hourly incremental or decremental Instructed Imbalance Energy will be settled based on their Energy bid costs for each Settlement Interval for the quantity of Energy delivered in each Settlement Interval. The hourly pre-dispatched Instructed Imbalance Energy is first settled as set forth in Section D 2.1.2. An additional uplift payment for any applicable Settlement Interval shall be determined when settlement as set forth in Section D 2.1.2 is insufficient recovery of its bid costs for the Settlement Interval. For pre-dispatched hourly Instructed Imbalance Energy, where the resource-specific settlement amount is positive and the bid-cost is positive, an uplift payment is determined for each Settlement Interval based on the minimum of zero or the difference between the resource-specific settlement amount and the bid cost settlement amount as follows:

The predispatched uplift payment for each applicable Settlement Interval is calculated as follows:

$$PREDISPATCH\_PMT_{i,h,o} = PREDISPATCH\_UPLIFT_{i,h} / n$$

If (

$(COST\_AT\_STLMT\_PRICE_{i,h,o} >= 0$

And

$BID\_COST_{i,h,o} >= 0)$

Then

$$PREDISPATCH\_UPLIFT_{i,h,o} = \min\left(0,\ COST\_AT\_STLMT\_PRICE_{i,h,o} - BID\_COST_{i,h,o}\right)$$

Where

$$COST\_AT\_STLMT\_PRICE_{i,h,o} =$$

$$\left(\sum_{1}^{k} IIE\_PREDISPATCH_{i,h,o,k}\right) * STLMT\_PRICE_{i,h,o}$$

$$BID\_COST_{i,h,o} =$$

$$\sum_{1}^{k}\sum_{1}^{m} IIE\_PREDISPATCH\_FOR\_SEGMENT_{i,h,o,k,m} * IIE\_PRICE_{i,h,o,k,m}$$

Else

$$PREDISPATCH\_UPLIFT_{i,h,o} = 0 \;)$$

for the portion of incremental energy bid segments with $IIE\_PRICE_{i,h,o,k,m}$ less than or equal to the Maximum Bid Level and all decremental energy bid segments with $IIE\_PRICE_{i,h,o,k,m}$ limited to the Bid Floor when $IIE\_PRICE_{i,h,o,k,m}$ is less than the Bid Floor.

D 2.6.4 Allocation of Unrecovered Cost Payments for Hourly Pre-dispatched System Resources

For each Settlement Interval *o*, the total uplift payments ($PREDISPATCH\_PMT_{i,h,o}$) for all hourly pre-dispatched System Resources will be included in the Excess Cost Payments to be allocated to a Scheduling Coordinator's Net Negative Deviation through allocation of excess costs and/or ISO metered Demand through excess cost neutrality allocation.

D 2.6.5 Excess Cost Payments for Instructed Incremental Energy Bids above the Maximum Bid Level

Incremental Instructed Imbalance Energy above the Maximum Bid Level will receive an additional Excess Cost Payment subject to operating within a resource's Tolerance Band.

Excess cost payments are calculated as follows:

$$EXCESS\_COST_{i,h,o} = \Bigg[\Bigg(\sum_{1}^{k}\sum_{1}^{m} IIE\_ECON_{i,h,o,k,m} + \sum_{1}^{k}\sum_{1}^{m} IIE\_PREDISPATCH_{i,h,o,k,m} + \sum_{1}^{k}\sum_{1}^{m} RIE_{i,h,o,k,m}\Bigg) * STLMT\_PRICE_{i,h,o} - BID\_COST_{i,h,o} - BID\_COST\_RIE_{i,h,o}\Bigg] * PERF\_STAT_{i,h,o}$$

for the portion of energy bid segments with $IIE\_PRICE_{i,h,o,k,m}$ and $RIE\_PRICE_{i,h,o,k,m}$ greater than the Maximum Bid Level.

D 2.7 Transmission Loss Obligation

The transmission loss obligation charge shall be determined as follows:

For Generators:

$$TL_{i,h,o} = ME_{i,h,o} * (1 - GMMa_h)$$

For System Resources, the transmission loss obligation shall be determined as follows:

$TL_{i,h,o}$ =

$$\sum_{1}^{k}\sum_{1}^{v} REAL\_TIME\_FLOW_{i,h,o,k,v} * (1 - GMMa_h)$$

The transmission loss charge will be calculated based on the following formulation:

$TLC_{i,h,o}$ =

$$-\sum_{1}^{k} IIE\_LOSS_{i,h,o,k} * STLMT\_PRICE_{i,h,o} + TL_{i,h,o} * STLMT\_PRICE_{i,h,o}$$

D 2.8 Uninstructed Deviation Penalty Charges

The ISO will calculate but not assess charges for UDP according to this Section 2.8 until the first day of the month two months after the software that calculates UDP is put into service.

For negative Uninstructed Deviation Penalty billable quantities where $UDP\_BQ_{h,o} < 0$ and $ZONAL\_EX\_POST\_PRICE_{j,h,o} > 0$,

$UDP\_NEG\_Amt_i\ AMT_{i\ h,o}$ =

$$-1 * UDP\_BQ_{i,h,o} * ZONAL\_EX\_POST\_PRICE_{j,h,o} * .5$$

For positive UDP billable quantities where $UDP\_BQ_{i,h,o} > 0$ and $ZONAL\_EX\_POST\_PRICE_{j,h,o} > 0$, then

$$UDP\_POS\_AMT_{i,h,o} = UDP\_BQ_{i,o,h} * ZONAL\_EX\_POST\_PRICE_{j,h,o}$$

where,

$UDP\_BQ_{i,o,h}$ is the Uninstructed Deviation Penalty (UDP) billable quantity in MWh for a resource, or aggregated resource, denoted by i for Settlement Interval *o* of hour *h.*

$UDP\_POS\_AMT_{i,o,h}$ or $UDP\_NEG\_AMT_{i,o,h}$ are the penalty amounts in Dollars for either an aggregated or individual resource *i* for Settlement Interval *o* of hour *h.*

The ISO will not calculate UDP settlement amounts for Settlement Intervals when the corresponding Zonal Settlement Interval Ex Post Price is negative or zero.

For an MSS that has elected to follow its own Load, the Scheduling Coordinator for the MSS Operator will be assessed the Uninstructed Deviation Penalty charges based on the Deviation Band and Deviation Price in Section 4.9.9.2 of the ISO Tariff.

D 2.9 Minimum Load Cost Compensation

The ISO shall calculate a Must-Offer Generator's Minimum Load Cost Compensation (MLCC), pursuant to section 40.8.1 of the ISO Tariff, as the Minimum Load Cost for each resource *i* during Settlement Interval *o* of hour *h,* as defined in section 40.8.4 of the ISO Tariff.

D 3 Meaning of terms in the formulae

D 3.1 [Not Used]

D 3.2 $COST\_AT\_STLMT\_PRICE_{i,h,o}$ - $/MWh

The sum of all dollar amounts from each dispatched bid segment for Energy quantities settled at the Resource-Specific Ex Post Price, for resource i during Settlement Interval o of hour h, and limited to those bid segments with Energy Bid prices below the Maximum Bid Level.

D 3.3 $BID\_COST_{i,h,o}$ - $/MWh

The sum of all dollar amounts from each dispatched bid portion of Energy quantities settled at the maximum of either the corresponding Energy Bid price for those bids with Energy Bid prices below the Maximum Bid Level or the Bid Floor, for resource i during Settlement Interval o during hour h.

D 3.4 $PRE\_DISP\_ABC\_BQ_{i,h,o}$ - MWh

The pre-dispatched Energy from all Energy Bids with any Energy Bid price above the Maximum Bid Level, for resource i during Settlement Interval o during hour h.

D 3.5 $IIE\_PREDISPATCH\_FOR\_SEGMENT_{i,h,o,k,m}$ - MWh

The pre-dispatched Energy for resource i during Dispatch Interval k of Settlement Interval o of hour h for bid segment m.

D 3.6 [Not Used]

D 3.6.1 [Not Used]

D 3.6.2 [Not Used]

D 3.6.3 [Not Used]

D 3.7 **$G_{a,i,j,h,o}$ – MWh**

The total actual metered Generation of Generator i in Zone j during Settlement Interval o during Settlement Period h.

D 3.8 **[Not Used]**

D 3.9 **[Not Used]**

D 3.9.1 **[Not Used]**

D 3.10 **[Not Used]**

D 3.11 **[Not Used]**

D 3.12 **$GMM_{a,i,h}$ – fraction**

The final forecasted Generation Meter Multiplier (GMM) for a Generator i in Settlement Period h as calculated by the ISO at the hour-ahead stage (but after close of the Hour-Ahead Market).

D 3.13 **$GMM_{a,j,h}$ – fraction**

The forecasted Generation Meter Multiplier for an Energy import at Scheduling Point q in Settlement period h as provided to the Scheduling Coordinator by the ISO after close of the Hour-Ahead Market.

D 3.14 **[Not Used]**

D 3.15 **$L_{a,i,j,h,o}$ – MWh**

The actual metered Demand of Demand i in Zone j in Settlement Interval o during Settlement Period h.

D 3.15.1 **[Not Used]**

D 3.15.2 **[Not Used]**

D 3.16 **[Not Used]**

D 3.17 **[Not Used]**

D 3.17.1 **[Not Used]**

D 3.18 **[Not Used]**

D 3.19 **$I_{a,q,j,h,o}$ – MWh**

The total actual Energy import of Scheduling Coordinator g through Scheduling Point q in Settlement Interval o during Settlement Period h. This is deemed to be equal to the scheduled Energy over the same interval.

D 3.20 **[Not Used]**

D 3.21 [Not Used]

D 3.22 [Not Used]

D 3.23 $E_{a,q,j,h,o}$ – MWh

The total actual Energy export of Scheduling Coordinator g through Scheduling Point q in Settlement Interval o for Settlement Period *h*. This is deemed to be equal to the total scheduled Energy export during the same interval.

D 3.24 [Not Used]

D 3.25 [Not Used]

D 3.25.1 [Not Used]

D 3.26 $UFEC_{jxt}$ – $

The Unaccounted for Energy Charge for Scheduling Coordinator j in Zone x in Settlement Period t. It is the cost for the Energy difference between the net Energy delivered into each utility Service Area, adjusted for utility Service Area Transmission Losses (calculated in accordance with ISO Tariff Section 27.2.1.), and the total metered Demand within that utility Service Area adjusted for distribution losses using Distribution System loss factors approved by the Local Regulatory Authority.

This Energy difference (UFE) is attributed to meter measurement errors, power flow modeling errors, energy theft, statistical Load profile errors, and distribution loss deviations.

D 3.27 $UFE_{UDC,bkt}$ – MWh

The Unaccounted for Energy (UFE) for utility Service Area k.

D 3.28 UFE – MWh

The portion of Unaccounted for Energy (UFE) allocated to metering point z.

D 3.29 [Not Used]

D 3.30 [Not Used]

D 3.31 [Not Used]

D 3.32 [Not Used]

D 3.33 [Not Used]

D 3.34 [Not Used]

D 3.35 [Not Used]

D 3.36 [Not Used]

D 3.37 TLs,h,o – MWh

The Transmission Losses per Settlement Interval *o* in Settlement Period hour h in utility Service Area *s*.

D 3.38 [Not Used]

D 3.39 [Not Used]

D 3.40 [Not Used]

D 3.41 [Not Used]

D 3.42 [Not Used]

D 3.43 [Not Used]

D 3.44 [Not Used]

D 3.45 [Not Used]

D 3.46 [Not Used]

D 3.47 [Not Used]

D 3.48 [Not Used]

D 3.49 $EX\_POST\_PRICE_{j,h,o,k}$ – $/MWh

The Ex-Post Price in Dispatch Interval *k* of Settlement Interval *o* in Settlement Period *h* in Zone *j.*

D 3.50 $HRLY\_EX\_POST\_PRICE_{j,h}$ – $/MWh

The energy-weighted Ex Post Price for Settlement Period *h* in Zone *j*.

D 3.51 $STLMT\_PRICE_{i,h,o}$ – $/MWh

The 10-minute Settlement price (Resource-Specific Settlement Interval Ex Post Price) for resource *i* in the Settlement Interval *o* for the Settlement Period *h.*

D 3.52 **$SE_{i,h,o}$ – MWh**

The Scheduled Energy from resource *i* during Settlement Interval *o* of Settlement Period *h.*

D 3.53 **$TOLERANCE\_BAND_{i,h,o}$ – MWh**

The Tolerance Band limit for resource *i* during Settlement Interval *o* of Settlement Period *h*.

D 3.54 **$IIE\_ECON_{i,h,o,k,m}$ – MWh**

The dispatched incremental or decremental Instructed Imbalance Energy (IIE) for resource *i* during Dispatch Interval *k* in Settlement Interval *o* of Settlement Period *h* for bid segment *m.*

Decremental Energy shall be represented as a negative quantity.

$IIE\_ECON_{i,h,o,k,m}$ shall be comprised of any of the four *IIE_TYPE*'s: SUPP, SPIN, NSPN or RPLC and be associated with its respective $IIE\_PRICE_{i,h,o,k,m}$

D 3.55 **$IIE\_PRICE_{i,h,o,k,m}$ – \$/MWh**

The bid price for energy bid segment *m* for resource *i* during Dispatch Interval *k* in Settlement Interval *o* of Settlement Period *h* for bid segment *m*

D 3.56 **$IIE\_PREDISPATCH_{i,h,o,k,m}$ – MWh**

The Settlement Period pre-dispatched Energy for resource *i* during Dispatch Interval *k* of Settlement Interval *o* of Settlement Period *h* for bid segment *m* (MWh).

D 3.57 **$RIE_{i,h,o,k,m}$ – MWh**

The Residual Energy for resource *i* during Dispatch Interval *k* in Settlement Interval *o* of Settlement Period *h* for bid segment *m.*

D 3.58 **$RIE\_PRICE_{i,h,o,k,m}$ – \$/MWh**

The reference bid price for the Residual Energy for resource *i* during Dispatch Interval *k* in Settlement Interval *o* of Settlement Period *h* for bid segment *m.*

D 3.59 **$OOS\_PRICE_{i,h,o,k,L}$ – \$/MWh**

The Settlement price for the Instructed Out of Stack Energy for resource *i* during Dispatch Interval *k* in Settlement Interval *o* of Settlement Period *h* for index number *L.*

D 3.60 **$IIE\_REG_{i,h,o}$ – MWh**

The Regulating Energy for resource *i* during Settlement Interval *o* in Settlement Period *h.*

D 3.61 $IIE\_PREDISPATCH_{i,h,p}$ – MWh

The Settlement Period pre-dispatched Energy for resource *i* during Dispatch Interval *p* of Settlement Period *h*.

D 3.62 $E_{i,h,o}$ – MWh

Calculated as the difference of $IE_{i,h,o}$ and $IIE\_TOTAL_{i,h,o,k}$ and is equal to the sum of Uninstructed Imbalance Energy and Regulating Energy of resource *i* during Settlement Interval *o* in Settlement Period *h.*

D 3.63 $IIEC_{i,h,o}$ – $

The Instructed Imbalance Energy payment (charge) for resource *i* during Settlement Interval *o* of Settlement Period *h.*

D 3.64 $IIEC\_OOS_{i,h,o}$ – $

The total OOS Energy payment (charge) for resource *i* during Settlement Interval *o* of Settlement Period *h.*

D 3.65 $IIEC\_OOS\_P_{i,h,o}$ – $

The incremental Instructed OOS Imbalance Energy payment (charge) for resource *i* during Settlement Interval *o* of Settlement Period *h.*

D 3.66 $IIEC\_OOS\_N_{i,h,o}$ – $

The decremental Instructed OOS Imbalance Energy payment (charge) for resource *i* during Settlement Interval *o* of Settlement Period *h*.

D 3.67 $IIE\_LOSS_{i,h,o,k}$ – MWh

The transmission loss self-provided Energy from resource *i* during Dispatch Interval *k* in Settlement Interval *o* of Settlement Period *h*.

D 3.68 $IIE\_ML_{i,h,o,k}$ – MWh

The Imbalance Energy due to Minimum Load from resource *i* during Dispatch Interval *k* in Settlement Interval *o* of Settlement Period *h*.

D 3.69 $IIE\_TOTAL_{i,h,o,k}$ – MWh

The total Instructed Imbalance Energy from all energy sources except Regulation for resource *i* during Dispatch Interval *k* in Settlement Interval *o* of Settlement Period *h.*

D 3.70 $IIE\_RERATE_{i,h,o,k}$ – MWh

The SLIC derated Pmin or Pmax value as a result of a Scheduling Coordinator modifying its operating output level for a given resource *i* during Dispatch Interval *k* in Settlement Interval *o* of Settlement Period *h.*

D 3.71 **$UIE_{i,h,o}$ – MWh**

The total Uninstructed Imbalance Energy from resource *i* during Settlement Interval *o* of Settlement Period *h.*

D 3.72 **$UIE\_1_{i,h,o}$ – MWh**

The Uninstructed Imbalance Energy attributed to non-compliance of *IIE_ECON* from resource *i* during Settlement Interval *o* of Settlement Period *h.*

D 3.73 **$UIE\_2_{i,h,o}$ – MWh**

The Uninstructed Imbalance Energy exclusive of UIE_1 from resource *i* during Settlement Interval *o* of Settlement Period *h.*

D 3.74 **$UIEC_{i,h,o}$ – $**

The Uninstructed Imbalance Energy payment (charge) for resource *i* during Settlement Interval *o* of Settlement Period *h.*

D 3.75 **$ZONAL\_EX\_POST\_PRICE_{j,h,o}$ – $/MWh**

The energy weighted average Ex Post Price for Imbalance Energy for Zone *j* in Settlement Interval *o* for Settlement Period *h.*

D 3.76 **$ME_{i,h,o}$ – MWh**

The Metered Energy from resource *i* during Settlement Interval *o* of Settlement Period *h.*

D 3.77 **$RED_{i,h,o,k}$ – MWh**

The Ramping Energy Deviation from resource *i* during Dispatch Interval *k* in Settlement Interval *o* of Settlement Period *h.*

D 3.78 **$REDC_{i,h,o}$ – $**

The Ramping Energy Deviation payment (charge) for resource *i* during Settlement Interval *o* of Settlement Period *h*.

D 3.79 **$MR\_ML_{i,h,o}$ – $**

The expected Real Time Market revenue from Minimum Load Energy for resource *i* in Settlement Interval *o* for Settlement Period *h.*

D 3.80 **$COST\_RECOVERY_{i,d}$ – $**

The Unrecovered Cost Payment for resource *i* for Trading Day *d.*

D 3.81 **$MR\_DIFF_{i,h,o}$**

is the market revenue surplus or deficit for resource *i* in Settlement Period *h* for Settlement Interval *o.*

D 3.82 **$MR\_DEFICIT_{i,h,o}$ – $**

The market revenue deficit for resource *i* in Settlement Period *h* for Settlement Interval *o.*

D 3.83 **$MR\_SURPLUS_{i,h,o}$ – $**

The market revenue surplus for resource *i* in Settlement Period *h* for Settlement Interval *o.*

D 3.84 **$PERF\_STAT_{i,h,o}$ – True/False**

The performance status of resource *i* for Settlement Interval *o* of Settlement Period *h*. The performance status is equal to 1 (compliant) or 0 (non-compliant).

D 3.85 **$BID\_COST_{i,h,o}$ – $**

The bid costs for IIE, except OOS Energy and RIE, for resource *i* in Settlement Period *h* for Settlement interval *o*.

D 3.86 **$BID\_COST\_RIE_{i,h,o}$ – $**

The bid costs for RIE for resource *i* in Settlement Period *h* for Settlement Interval *o.*

D 3.87 **$PREDISPATCH\_PMT_{i,h,o}$ – $**

The unrecovered bid cost payment for a Settlement Period pre-dispatched System Resource *i* in Settlement Interval *o* for Settlement Period *h.*

D 3.88 **$EXCESS\_COST_{i,h,o}$ – $**

The excess cost payment for resource *i* in Settlement Interval *o* for Settlement Period *h.*

D 3.89 **$TL_{i,h,o}$ – MWh**

The Transmission Loss Obligation for resource *i* during Settlement Interval *o* of Settlement Period *h.*

D 3.90 **$EXCESS\_COST\_ALLOC_{g,h,o}$ – $**

The excess cost allocation for Scheduling Coordinator *g* in Settlement Period *h* for Settlement Interval *o.*

D 3.91 $REAL\_TIME\_FLOW_{i,h,o,k,v}$ – MW*h*

The real-time actual flow for intertie resource *i* during Dispatch Interval *k* during Settlement Interval *o* of Settlement Period *h* for Real Time Flow Type index v. Real Time Flow Type index *v* must be one of the following Energy types: FIRM NFIRM, SUPP, WHEEL, DYN, ESPN, ENSPN, OOM, ERPLC.

D 3.92 $RE\_STANDARD_{i,h,o,k}$ – MWh

The Standard Ramping Energy from resource *i* during Dispatch Interval *k* of Settlement Interval *o* of Settlement Period *h.*

D 3.93 $OOS\_P_{i,h,o,k,L}$ – MWh

The incremental Out of Stack Energy for resource *i* during Dispatch Interval *k* in Settlement Interval *o* of Settlement Period *h* for index number *L.*

D 3.94 $OOS\_N_{i,h,o,k,L}$ – MWh

The decremental Out of Stack Energy for resource *i* during Dispatch Interval *k* in Settlement Interval *o* of Settlement Period *h* for index number *L.*

D 3.95 $URC\_ALLOC_{g,h,o}$ – $

The unrecovered cost neutrality allocation for Scheduling Coordinator *g* in Settlement Interval *o* for Settlement Period *h.*

D 3.96 $IIE\_TYPE_{i,h,o,k,m}$

is the energy type for $IIE\_ECON_{i,h,o,k,m.}$ Energy type is one of the following: Supplemental, Spin, Non-Spin or Replacement Reserve Energy.

PART E

USAGE CHARGE COMPUTATION

E 1 Purpose of Charge

The Usage Charge is payable by Scheduling Coordinators who schedule Energy across Congested Inter-Zonal Interfaces pursuant to Section 27.1.1.5 of the ISO Tariff. Scheduling Coordinators who counter-schedule across Congested Inter-Zonal Interfaces are entitled to Usage Charge Payments. The right to schedule across a Congested Inter-Zonal Interface is determined through the ISO's Congestion Management procedures.

The following categories of Payments and Charges are covered in this Part E:

(a) Usage Charges payable by Scheduling Coordinators for Energy transfers scheduled across Congested Inter-Zonal Interfaces and which contribute to Congestion.

(b) Usage Charge rebates payable to Scheduling Coordinators for Energy transfers scheduled across Congested Inter-Zonal Interfaces and which contribute to relieving Congestion.

(c) Credits of net Usage Charge revenues to Participating TOs and FTR Holders.

(d) Debits of net Usage Charge revenues to Participating TOs and FTR Holders.

(e) Debits and rebates of Usage Charge to Scheduling Coordinators as set out in E 2.3.3.

E 2 Fundamental Formulae

E 2.1 ISO Usage Charges on Scheduling Coordinators

Each Scheduling Coordinator j whose Final Schedule includes the transfer of Energy scheduled across one or more Congested Inter-Zonal Interfaces shall (save to the extent that the transfer involves the use of transmission capacity represented by Existing Rights) pay, or be paid, Usage Charges in Trading Interval t calculated in accordance with the following formulae:

In the Day-Ahead Market:

$$UC_{jtd} = \sum_{x} NetZoneImp_{jtxd} * \lambda_{dxt}$$

In the Hour-Ahead Market:

$$UC_{jth} = \sum_{x} (NetZoneImp_{jtxh} - NetZoneImp_{jtxd}) * \lambda_{hxt}$$

E 2.2 Payments of Usage Charges to Scheduling Coordinators

Each Scheduling Coordinator j whose Final Schedule includes the transfer of Energy from one Zone to another in a direction opposite that of Congestion shall (save to the extent that the transfer involves the use of transmission capacity represented by Existing Rights) receive a Usage Charge payment from the ISO calculated in accordance with the formulae described in Section E 2.1.

E 2.3 ISO Credits and Debits to Transmission Owners and FTR Holders of Usage Charge Revenues

E 2.3.1 Day-Ahead Market

The ISO will pay to the Participating TO n and FTR Holder n its share of the total net Usage Charge revenue for Trading Interval t in the Day-Ahead Market in accordance with the following formula:

$$PayUC_{ntd} = \sum_{y} \mu_{ytd} * K_{yn} * L_{ytd}$$

E 2.3.2 Hour-Ahead Market

The ISO will pay to the Participating TO n and FTR Holder n its share of the total net Usage Charge revenue for Trading Interval t in the Hour-Ahead Market in accordance with the following formula:

$$PayUC_{nth} = \sum_{y} \mu_{yth} * K_{yn} * (L_{yth} - L_{ytd})$$

Under normal operating conditions, (L_{yth} - L_{ytd}) is positive and Participating TOs and FTR Holders will receive a refund on the net Usage Charge for the relevant Trading Interval t in the Hour-Ahead Market.

E 2.3.3 Debits to Participating TOs and FTR Holders and Debits/Rebates to Scheduling Coordinators

If, after the close of the Day-Ahead Market, Participating TOs instruct the ISO to reduce interface limits based on operating conditions or an unscheduled transmission Outage occurs and as a result of either of those events, Congestion is increased and Available Transfer Capacity is decreased in the Inter-Zonal Interface in the Hour-Ahead Market, the (L_{yth} - L_{ytd}) will be negative. In this case:

(a) Participating TOs and FTR Holders will be charged for the Usage Charge payments they received for the relevant Trading Interval t in the Day-Ahead Market with respect to the reduced interface limits;

(b) Any Scheduling Coordinator whose Schedule was adjusted for the relevant Trading Interval t in the Hour-Ahead Market due to the reduced interface limits will be credited with μ_{yth} for each MW of the adjustment; and

(c) Each Scheduling Coordinator will be charged an amount equal to it proportionate share, based on Schedules in the Day-Ahead Market in the direction of Congestion, of the difference between $\mu_{yth}(L_{yth} - L_{ytd})$ and the total amount charged to Participating TOs and FTR Holders in accordance with item (a) above.

The ISO will issue a notice to Scheduling Coordinators of the operating hour, and extent, for which the derate will apply in the relevant Hour-Ahead Markets. The timing and form of such notices shall be set forth in ISO procedures.

E 3 Meaning of terms of formulae

E 3.1 UC_{jtd} ($)

The Usage Charge payable by or to Scheduling Coordinator j for the relevant Trading Interval t in the Day-Ahead Market.

E 3.2 UC_{jth} - $

The Usage Charge payable by or to Scheduling Coordinator j for Trading Interval t in the Hour-Ahead Market.

E 3.3 $NetZoneImp_{jtxd}$ (MWh)

The net Zonal import scheduled by Scheduling Coordinator j in Zone x for the relevant Trading Interval t in the Day-Ahead Market. For Zones internal to the ISO Control Area, net Zonal import equals scheduled Demand minus scheduled Generation plus transfers. For zones external to the ISO Control Area (i.e., for Scheduling Points), net zonal import equals scheduled imports (i.e., out of the ISO Control Area) minus scheduled exports (i.e., into the ISO Control Area).

E 3.4 $NetZoneImp_{jtxh}$ (MWh)

The net Zonal import scheduled by the Scheduling Coordinator j in Zone x for the relevant Trading Interval t in the Hour-Ahead Market. For Zones internal to the ISO Control Area, net Zonal import equals scheduled Demand minus scheduled Generation plus transfers. For Zones external to the ISO Control Area (i.e., for Scheduling Points), net zonal import equals scheduled imports (i.e., out of the ISO Control Area) minus scheduled exports (i.e., into the ISO Control Area).

E 3.5 λ_{dxt} ($/MWh)

The reference Zonal marginal price for Zone x for the relevant Trading Interval t in the Day-Ahead Market, as calculated by the ISO's Congestion Management computer optimization algorithm.

E 3.6 λ_{hxt} ($/MWh)

The reference Zonal marginal price for Zone x for the relevant Trading Interval t in the Hour-Ahead Market, as calculated by the ISO's Congestion Management computer optimization algorithm.

E 3.7 $PayUC_{ntd}$ ($)

The amount calculated by the ISO to be paid to or by the Participating TO n (in respect of its Transmission Revenue Balancing Account) and FTR Holder n for the relevant Trading Interval t in the Day-Ahead Market.

E 3.7.1 **$PayUC_{nth}$** **($)**

The amount calculated by the ISO to be paid to the Participating TO n (in respect of its Transmission Revenue Balancing Account) and FTR Holder n for the relevant Trading Interval t in the Hour-Ahead Market.

E 3.8 **μ_{ytd}** **($/MW)**

The Day-Ahead Congestion price (shadow price) at Inter-Zonal Interface y for Trading Interval t. This price is calculated by the ISO's Congestion Management computer optimization algorithm.

E 3.8.1 **μ_{yth}** **($/MW)**

The Hour-Ahead Congestion price (shadow price) at Inter-Zonal Interface y for Trading Interval t. This price is calculated by the ISO's Congestion Management computer optimization algorithm.

E 3.9 **K_{ytn}** **(%)**

The percentage of the Inter-Zonal Congestion revenue allocation for Participating TO n and FTR Holder n of the Congested Inter-Zonal interface y for the relevant Trading Interval t for both Day-Ahead and Hour-Ahead Markets.

E 3.10 **L_{ytd}** **(MW)**

The total loading of Inter-Zonal Interface y for Trading Interval t in the Day-Ahead as calculated by the ISO's Congestion Management optimization algorithm.

E 3.11 **L_{yth}** **(MW)**

The total loading of Inter-Zonal Interface y for Trading Interval t in the Hour-Ahead as calculated by the ISO's Congestion Management optimization algorithm.

PART F

WHEELING ACCESS CHARGES COMPUTATION

F 1 Purpose of Charge

The Wheeling Access Charge is paid by Scheduling Coordinators for Wheeling as set forth in Section 26.1.4 of the ISO Tariff. The ISO will collect the Wheeling revenues from Scheduling Coordinators on a Trading Interval basis and repay these to the Participating TOs based on the ratio of each Participating TO's Transmission Revenue Requirement to the sum of all Participating TOs' Revenue Requirements.

F 2 Fundamental Formulae

F 2.1 ISO Charges on Scheduling Coordinators for Wheeling

The ISO will charge Scheduling Coordinators scheduling a Wheeling Out or a Wheeling Through, the product of the Wheeling Access Charge and the total of the hourly schedules of Wheeling in MWh for each Trading Interval at each Scheduling Point associated with that transaction pursuant to Section 26.1.4 of the ISO Tariff.

F 2.1.1 Wheeling Access Charge

The Wheeling Access Charge for each Participating TO shall be as specified in Section 26.1.4 of the ISO Tariff.

F 2.1.2 [Not Used]

F 2.2 ISO Payments to Transmission Owners for Wheeling

The ISO will pay all Wheeling revenues to Participating TOs on the basis of the ratio of each Participating TO's Transmission Revenue Requirement ("TRR") (less the TRR associated with Existing Rights) to the sum of all Participating TOs' TRRs (less the TRRs associated with Existing Rights) as specified in Section 26.1.4.3 of the ISO Tariff. The Low Voltage Wheeling Access Charge shall be disbursed to the appropriate Participating TO. The sum to be paid to Participating TO_n for a Trading Interval is calculated as follows:

$$PayTO_n = \frac{TRR_n}{\sum_n TRR_n} * \sum_j totalWChrg_j$$

F 3 Meaning of terms in formulae

F 3.1 $WABC_q$ ($/kWh)

The Weighted Average Rate for Wheeling Service for Scheduling Point q.

F 3.2 P_n ($/kWh)

The applicable Wheeling Access Charge rate for TAC Area or Participating TO n in $/kWh as set forth in Section 26.1.4 of the ISO Tariff and Section 4.6 of the TO Tariff.

F 3.3 Q_n (MW)

The Available Transfer Capacity, whether from transmission ownership or contractual entitlements, of each Participating TO n for each ISO Scheduling Point which has been placed within the ISO Controlled Grid. Available Transfer Capacity does not include capacity associated with Existing Rights of a Participating TO as defined in Section 16.2 of the ISO Tariff.

F 3.4 $WChg_{jq}$ ($)

The Wheeling Charges by the ISO on Scheduling Coordinator j for Scheduling Point q in Trading Interval t. Both Wheeling Out and Wheeling Through transactions are included in this term.

F 3.5 $QChargeW_{jqt}$ (kWh)

The summation of kWh wheeled over Scheduling Point q by Scheduling Coordinator j in Trading Interval t. Both Wheeling Out and Wheeling Through transactions are included in this term.

PART G

VOLTAGE SUPPORT and BLACK START CHARGES COMPUTATION

G 1 Purpose of charge

G 1.1 Voltage Support (VS) and Black Start (BS) charges are the charges made by the ISO to recover costs it incurs under contracts entered into between the ISO and those entities offering to provide VS or BS. Each Scheduling Coordinator pays an allocated proportion of the VS&BS charge to the ISO so that the ISO recovers the total costs incurred.

G 1.2 All Generating Units are required by the ISO Tariff to provide reactive power by operating within a power factor range of 0.90 lag and 0.95 lead. Additional short-term Voltage Support required by the ISO is referred to as supplemental reactive power. If the ISO requires the delivery of this supplemental reactive power by instructing a Generating Unit to operate outside its mandatory MVar range, the Scheduling Coordinator representing this Generating Unit will only receive compensation if it is necessary to reduce the MW output to achieve the MVar instructed output. Supplemental reactive power charges to Scheduling Coordinators are made on a Trading Interval basis. As of the ISO Operations Date the ISO will contract for long-term Voltage Support Service with the Owner of Reliability Must-Run Units under Reliability Must-Run Contracts.

G 1.3 The ISO will procure Black Start capability through contracts let on an annual basis. The quantities and locations of the Black Start capability will be determined by the ISO based on system analysis studies. Charges to Scheduling Coordinators for instructed Energy output from Black Start units are made on a Trading Interval basis.

G 2 Fundamental formulae

G 2.1 Payments to Scheduling Coordinators for providing Voltage Support

Payments to Scheduling Coordinators for additional Voltage Support service comprise:

G 2.1.1 Lost Opportunity Cost Payments (supplemental reactive power) to Scheduling Coordinators for Generating Units

When the ISO obtains additional Voltage Support by instructing a Generating Unit to operate outside its mandatory MVar range by reducing its MW output the ISO will select Generating Units based on their Supplemental Energy Bids ($/MWh). Subject to any locational requirements the ISO will select the Generating Unit with the highest decremental Supplemental Energy Bid to reduce MW output by such amount as is necessary to achieve the instructed MVar reactive energy production. Each Trading Interval the ISO will pay Scheduling Coordinator j for that Generating Unit i in Zone x, the lost opportunity cost ($) resulting from the reduction of MW output in Trading Interval t in accordance with the following formula:

$$VSST_{xijt} = Max\ \{0, P_{xt} - Sup_{xdecit}\} * DEC_{xit}$$

G 2.1.2 Long-term contract payments to Scheduling Coordinators for Reliability Must-Run Units for Generating Units and other Voltage Support Equipment

The ISO will pay Scheduling Coordinator j for the provision of Voltage Support from its Reliability Must-Run Units located in Zone x in month m a sum ($VSLT_{xjm}$) consisting of:

(a) the total of the Ancillary Service Pre-empted Dispatch Payments if the ISO has decreased the output of the Reliability Must-Run Units for the provision of Voltage Support outside the power factor range of the Reliability Must-Run Unit in any Trading Interval in month m and/or

(b) (if applicable) the total payments for the provision of Voltage Support in month m requested by the ISO from the synchronous condensers of the Reliability Must-Run Units,

calculated in each case in accordance with the terms of the relevant Reliability Must-Run Contract. Data on these payments will not be generated by the ISO. Such data will be based on the invoices issued by the Owners of Reliability Must-Run Generating Units pursuant to their Reliability Must-Run Contracts and will be verified by the ISO.

G 2.2 Charges to Scheduling Coordinators for Voltage Support

G 2.2.1 User Rate

The user rate ($/MWh) for the lost opportunity cost for Voltage Support referred to in G 2.1.1 in Zone x for Trading Interval t will be calculated using the following formula:

$$VSSTRate_{xt} = \frac{\sum_{ij} VSST_{xijt}}{\sum_{j} QChargeVS_{xjt}}$$

The user rate ($/MWh) for month m for long-term Voltage Support referred to in G2.1.2 in Zone x will be calculated using the following formula:

$$VSSTRate_{xm} = \frac{\sum_{j} VSLT_{xjm}}{\sum_{jm} QChargeVS_{xjt}}$$

G 2.2.2 Voltage Support Charges

The lost opportunity cost Voltage Support charge ($) payable to recover the sums under G 2.1.1 for Zone x for Trading Interval t for Scheduling Coordinator j will be calculated using the following formula:

$$VSSTCharge_{xjt} = VSSTRate_{xt} * QChargeVS_{xjt}$$

The monthly long-term Voltage Support charge ($) payable to recover sums under G 2.1.2 for Zone x for month m for Scheduling Coordinator j will be calculated using the following formula:

$$VSLTCharge_{xjm} = VSLTRate_{xm} * \sum_{m} QChargeVS_{xjt}$$

G 2.3 Payments to Participating Generators for Black Start

Payments to Participating Generators that provide Black Start Energy or capability shall be made in accordance with the agreements they have entered into with the ISO for the provision of Black Start services and shall be calculated as follows:

G 2.3.1 Black Start Energy Payments

Whenever a Black Start Generating Unit provides a Black Start in accordance with the ISO's instructions, the ISO will pay the Black Start Generator for that Unit for the Generating Unit's energy output and start-up costs. The ISO will pay Black Start Generator for Generating Unit i, the Black Start energy and start-up costs ($) in Trading Interval t in accordance with the following formula:

$$BSEn_{ijt} = (EnQBS_{ijt} * EnBid_{ijt}) + BSSUP_{ijt}$$

G 2.3.2 Black Start Energy Payments to Owners of Reliability Must-Run Units

Whenever a Reliability Must-Run Unit provides a Black Start in accordance with the ISO's instructions, the ISO will pay the Scheduling Coordinator of the Reliability Must-Run Unit the Generating Unit's Energy and start-up costs. The ISO will pay Scheduling Coordinator j for Reliability Must-Run Unit i the Black Start Energy and start-up costs ($) in Trading Interval t in accordance with the following formula:

$$BSEn_{ijt} = (EnQBS_{ijt} * EnBid_{ijt}) + (BSSUP_{ijt})$$

G 2.4 Charges to Scheduling Coordinators for Black Start

G 2.4.1 User Rate

The user rate ($/MWh) for Black Start Energy payments referred to in G 2.3.1 and G 2.3.2 for Trading Interval t will be calculated using the following formula:

$$BSRate_{t} = \frac{\sum_{ij} BSEn_{ijt}}{\sum_{j} QChargeBlackStart_{jt}}$$

G 2.4.2 Black Start Charges

The user charge ($/MWh) for Black Start Energy to recover the costs of payments under G 2.3.1 and G 2.3.2 for Trading Interval t for Scheduling Coordinator j will be calculated using the following formula:

$$BSCharge_{jt} = BSRate_t * QChargeBlackStart_{jt}$$

G 3 Meaning of Terms in the Formulae

G 3.1 $VSST_{xijt}$ ($)

The lost opportunity cost paid by the ISO to Scheduling Coordinator j for Generating Unit i in Zone x, resulting from the reduction of MW output in Trading Interval t.

G 3.2 P_{xt} ($/MWh)

The Hourly Ex Post Price for Imbalance Energy in Trading Interval t in Zone x.

G 3.3 Sup_{xdecit} ($/MWh)

The Supplemental Energy Bid submitted by Scheduling Coordinator j for Generating Unit i in Zone x in Trading Interval t, whose output is reduced by the ISO to provide additional short-term Voltage Support.

G 3.4 Dec_{xit} (MW)

The reduction in MW by Scheduling Coordinator j for Generating Unit i in Zone x in Trading Interval t, in order to provide short-term additional Voltage Support.

G 3.5 $VSLT_{xjm}$ ($)

The payment from the ISO to Scheduling Coordinator j for its Reliability Must-Run Units in Zone x for Voltage Support in month m calculated in accordance with the relevant Reliability Must-Run Contract.

G 3.6 $VSSTRate_{xt}$ ($/MWh)

The Trading Interval lost opportunity cost Voltage Support user rate charged by the ISO to Scheduling Coordinators for Trading Interval t for Zone x.

G 3.7 $VSLTRate_{xm}$ ($/MWh)

The monthly long-term Voltage Support user rate charged by the ISO to Scheduling Coordinators for month m for Zone x.

G 3.8 $QChargeVS_{xjt}$ (MWh)

The charging quantity for Voltage Support for Scheduling Coordinator j for Trading Interval t in Zone x equal to the total metered Demand (including exports to neighboring Control Areas) for Scheduling Coordinator j in Zone x for Trading Interval t.

G 3.9 $\mathbf{VSSTCharge_{xjt}}$ ($)

The lost opportunity cost Voltage Support user charge for Zone x for Trading Interval t for Scheduling Coordinator j.

G 3.10 $\mathbf{VSLTCharge_{xjm}}$ ($)

The long-term charge for Voltage Support for month m for Zone x for Scheduling Coordinator j.

G 3.11 $\mathbf{BSEn_{ijt}}$ ($)

The ISO payment to Scheduling Coordinator j (or Black Start Generator j) for that Generating Unit i providing Black Start Energy in Trading Interval t.

G 3.12 $\mathbf{EnQBS_{ijt}}$ (MWh)

The energy output, instructed by the ISO, from the Black Start capability of Generating Unit i from Scheduling Coordinator j (or Participating Generator j) for Trading Interval t.

G 3.13 $\mathbf{EnBid_{ijt}}$ ($/MWh)

The price for Energy output from the Black Start capability of Generating Unit i of Scheduling Coordinator j or (Black Start Generator j) for Trading Interval t calculated in accordance with the applicable Reliability Must-Run Contract or Interim Black Start Agreement.

G 3.14 $\mathbf{BSSUP_{ijt}}$ ($)

The start-up payment for a Black Start successfully made by Generating Unit i of Scheduling Coordinator j (or Black Start Generator j) in Trading Interval t calculated in accordance with the applicable Reliability Must-Run Contract or Interim Black Start Agreement.

G 3.15 $\mathbf{BSRate_{t}}$ ($/MWh)

The Black Start Energy payment user rate charged by the ISO to Scheduling Coordinators for Trading Interval t.

G 3.16 $\mathbf{QChargeBlackstart_{jt}}$ (MW)

The charging quantity for Black Start for Scheduling Coordinator j for Trading Interval t equal to the total metered Demand (excluding exports to neighboring Control Areas) of Scheduling Coordinator j for Trading Interval t.

PART H
[NOT USED]

PART I

DRAFT SAMPLE OF INVOICE

Independent System Operator
MARKET INVOICE

CUSTOMER 1		Invoice:	181
101 N. Harbor Blvd.		Date:	20-JUN-97
Anaheim	CA 92808	Customer Number:	1000

Please send payment to:

1000 South Fremont Avenue
Building A-11
Alhambra CA 91803

For all inquiries contact:
1-800-ISO-HELP

Comments:

Charges settlement date: 20-JUN-97 to 20-JUN-97

Charge Type	Description	Amount
0001	0001-Day-Ahead Spinning Reserve due SC	-$845.00
0002	0002-Day-Ahead Non-Spinning Reserve due SC	-$1,025.00
0003	0003-Day-Ahead AGC/Regulation due SC	-$1,025.00
0004	0004-Day-Ahead Replacement Reserve due SC	-$1,385.00
0051	0051-Hour-Ahead Spinning Reserve due SC	-$1,565.00
0052	0052-Hour-Ahead Non-Spinning Reserve due SC	-$1,745.00
0053	0053-Hour-Ahead AGC/Regulation due SC	-$1,925.00
0054	0054-Hour-Ahead Replacement Reserve due SC	-$2,105.00
0101	0101-Day-Ahead Spinning Reserve due ISO	$22,075.00
0102	0102-Day-Ahead Non-Spinning Reserve due ISO	$23,935.00
0103	0103-Day-Ahead AGC/Regulation due ISO	$25,795.00
0104	0104-Day-Ahead Replacement Reserve due ISO	$27,655.00
0251	0251-Hour-Ahead Intra-Zonal Congestion Settlement due ISO	$385.00
0252	0252-Hour-Ahead Intra-Zonal Congestion Charge/Refund due ISO	$4,925.00
0253	0253-Hour-Ahead Inter-Zonal Congestion Settlement due ISO	$5,285.00
0301	0301-Ex-Post A/S Energy due SC	-$6,005.00
0302	0302-Ex-Post Supplemental Reactive Power due SC	-$6,365.00
0303	0303-Ex-Post Replacement Reserve due ISO (Dispatched)	$6,725.00
0304	0304-Ex-Post Replacement Reserve due ISO (Undispatched)	$7,085.00
Invoice Total		

Independent System Operator

FERC FEES INVOICE

CUSTOMER 1 101 N. Harbor Blvd. Anaheim CA 92808	Invoice: 181 Date: 20-JUN-97 Customer Number: 1000
Please send payment to: 1000 South Fremont Avenue Building A-11 Alhambra CA 91803	For all inquiries contact: 1-800-ISO-HELP

Comments:

Charges settlement date: 20-JUN-97 to 20-JUN-97

Charge Type	Description	Amount
[Charge type to be determined]	____ FERC Annual Charges due ISO	**[Sample charge]**
Invoice Total		________

PART J

SETTLEMENT AND BILLING OF RELIABILITY MUST-RUN CHARGES AND PAYMENTS

1 Objectives, Definitions and Scope

1.1 Objectives

The objective of this Part J is to inform RMR Owners which are responsible for preparation of invoices, and Responsible Utilities, which are responsible for payment of Reliability Must-Run Charges pursuant to Section 30.6.1.2 of the ISO Tariff, of the manner in which the RMR Charges referred to in Section 30.6.1.1 of the ISO Tariff shall be verified and settled and of the procedures regarding the billing, invoicing and payment of these RMR Charges.

1.2 Definitions

1.2.1 Master Definitions Supplement

Unless the context otherwise requires, any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Part J. A reference to a paragraph is to a paragraph of this Part J. References to Parts are to Parts of Appendix N.

1.2.3 Special Definitions for this Part J

In this Part J the following words and expressions shall have the following meanings:

“Adjusted RMR Invoice” means the monthly invoice issued by the RMR Owner to the ISO for adjustments made to the Revised Estimated RMR Invoice pursuant to the RMR Contract, reflecting actual data for the billing month.

“Business Day” shall have the meaning ascribed to it in the RMR Contract.

“Estimated RMR Invoice” means the monthly invoice issued by the RMR Owner to the ISO for estimated RMR Payments or Refunds pursuant to the RMR Contract.

“Facility Trust Account” means, for each RMR Contract, the account established and operated by the ISO to and from which all payments under this Part J shall be made. Each Facility Trust Account will have two segregated commercial bank accounts, a RMR Owner Facility Trust Account and a Responsible Utility Facility Trust Account.

“Prior Period Change” means any correction, surcharge, credit, refund or other adjustment pertaining to a billing month which is discovered after the Revised Adjusted RMR Invoice for such billing month has been issued.

"Prior Period Change Worksheet" means a worksheet prepared by the RMR Owner and submitted to the ISO following discovery of a necessary change to an RMR invoice after the Revised Adjusted RMR Invoice for the billing month has been issued.

"Responsible Utility Facility Trust Account" means a segregated commercial bank account under the Facility Trust Account containing funds held in trust for the Responsible Utility.

"RMR Invoice" means any Estimated RMR Invoice, Revised Estimated RMR Invoice, Adjusted RMR Invoice, or Revised Adjusted RMR Invoice.

"RMR Owner Facility Trust Account" means a segregated commercial bank account under the Facility Trust Account containing funds held in trust for the RMR Owner.

"RMR Payment" means any amounts which the ISO is obligated to pay to RMR Owners under RMR Contracts, net of any applicable credits under RMR Contracts.

"RMR Payments Calendar" means the Payments Calendar issued by the ISO pursuant to Section 3 of this Part J.

"RMR Refund" means any amounts which RMR Owners are obligated to pay the ISO and the ISO is obligated to pay Responsible Utilities under RMR Contracts, or resulting from an order by the Federal Energy Regulatory Commission, for deposit into the Responsible Utility Facility Trust Account.

"RMR Security" means the form of security provided by a Responsible Utility to cover its liability under this Part J pursuant to Section 30.6.1.1.3 of the ISO Tariff.

1.2.4 Rules of Interpretation and Other Terms and Conventions

The rules of interpretation set out in the ISO Tariff.

1.3 Scope of Application to Parties

This Part J applies to the RMR Payments owed RMR Owners by the ISO, the RMR Charges owed by the Responsible Utilities to the ISO and the RMR Refunds owed to the ISO by RMR Owners and owed to the Responsible Utilities by the ISO for costs incurred under the RMR Contract.

For the avoidance of doubt, this Part J shall not apply to charges for Energy or Ancillary Services which are payable by the ISO under Sections 8 and 11 of the ISO Tariff to Scheduling Coordinators representing RMR Owners. Such payments shall be made by the ISO to such Scheduling Coordinators pursuant to Section 11 of the ISO Tariff and the provisions of Appendix N. The RMR Owners shall account for such payments received by or due to their Scheduling Coordinators in each RMR Invoice.

1.4 Relationship of this Part J with Appendix N

Parts B, G and H of Appendix N shall apply as appropriate to this Part J. Unless otherwise specified, other provisions of Appendix N shall not apply to this Part J.

1.5 Relationship of this Part J *with* the ISO Tariff

For the avoidance of doubt, Sections 11.3 to 11.24 inclusive of the ISO Tariff shall not apply to this Part J.

2 Accounts

2.1 Facility Trust Account

The ISO shall establish a Facility Trust Account for each RMR Contract. Each Facility Trust Account shall consist of two segregated commercial bank accounts: an RMR Owner Facility Trust Account, which will be held in trust for the RMR Owner, and a Responsible Utility Facility Trust Account, which will be held in trust for the Responsible Utility. RMR Charges paid by the Responsible Utility to the ISO in connection with the RMR Contract will be deposited into the RMR Owner Facility Trust Account and RMR Payments from the ISO to the RMR Owner will be withdrawn from such Account, all in accordance with this Part J, Section 30.6.1.1 of the ISO Tariff and the RMR Contract. RMR Refunds received by the ISO from the RMR Owner in accordance with the RMR Contract will be deposited into the Responsible Utility Facility Trust Account and such RMR Refunds will be withdrawn from such Account and paid to the Responsible Utility in accordance with this Part J., Section 30.6.1.1 of the ISO Tariff, and the RMR Contract. The RMR Owner Facility Trust Account and the Responsible Utility Facility Trust Account shall have no other funds commingled in them at any time.

2.2 RMR Owner's Settlement Accounts

Each RMR Owner shall establish and maintain a settlement account at a commercial bank located in the United States and reasonably acceptable to the ISO which can effect money transfers via Fed-Wire where payments to and from the Facility Trust Accounts shall be made in accordance with this Part J. Each RMR Owner shall notify the ISO of its settlement account details upon entering into its RMR Contract with the ISO and may notify the ISO from time to time of any changes by giving at least 15 days notice before the new account becomes operational.

3 RMR Payments Calendar

The ISO shall issue an RMR Payments Calendar for the purposes of this Part J which shall contain those dates set forth in Section 9.1 (b) of the RMR Contract and the following information:

(a) the date on which RMR Owners are required to issue to the ISO, with a copy to the Responsible Utility, their Estimated RMR Invoice pursuant to their RMR Contract;

(b) the date on which the ISO is required to initiate proposed adjustments to the Estimated RMR Invoice to the Responsible Utility and to the RMR Owner;

(c) the date by which the RMR Owners are required to issue their Revised Estimated RMR Invoice reflecting appropriate revisions to the original Estimated RMR Invoice agreed upon by the Responsible Utility and the RMR Owner (In the event no revisions are required, Owner shall submit an e-mail to the ISO and Responsible Utility stating there are no revisions and the Estimated RMR Invoice should be deemed as the Revised Estimated RMR Invoice.);

(d) the date on which the ISO is required to issue to the Responsible Utility or RMR Owner, with an e-mail notification to both parties, the ISO Invoice based on the Revised Estimated RMR Invoice;

(e) the date on which RMR Owners are required to issue to the ISO, with a copy to the Responsible Utility, their Adjusted RMR Invoice pursuant to their RMR Contract;

(f) the date on which the ISO is required to initiate proposed adjustments to the Adjusted RMR Invoice to the Responsible Utility and the RMR Owner;

(g) the date by which the RMR Owners are required to issue their Revised Adjusted RMR Invoice reflecting appropriate revisions to the original Adjusted RMR Invoice agreed upon by the Responsible Utility and the RMR Owner. (In the event no revisions are required, Owner shall submit an e-mail to the ISO and Responsible Utility stating there are no revisions and the Adjusted RMR Invoice should be deemed as the Revised Adjusted RMR Invoice.);

(h) the date on which the ISO is required to issue to the Responsible Utility or the RMR Owner, with an e-mail notification to both parties, the ISO Invoice based on the Revised Adjusted RMR Invoice;

(i) the dates by which the Responsible Utility and RMR Owner must have notified the ISO of any dispute in relation to the ISO Invoice, Estimated or Adjusted RMR Invoices (including the Revised Estimated and Revised Adjusted RMR Invoice) or the ISO's proposed adjustments;

(j) the date and time by which Responsible Utilities or RMR Owners are required to have made payments into the RMR Owner Facility Trust Account or Responsible Utility Facility Trust Account in payment of the ISO Invoices relating

to each Revised Estimated RMR Invoice and each Revised Adjusted RMR Invoice;

(k) the date and time by which the ISO is required to have made payments into the RMR Owners' Facility Trust Accounts or Responsible Utilities' Facility Trust Accounts in payment of the Revised Estimated RMR Invoice and the Revised Adjusted RMR Invoice pursuant to their RMR Contract;

If the day on which any ISO Invoice, any RMR Invoice, or payment is due, is not a Business Day, such statement or invoice shall be issued or payment shall be due on the next succeeding Business Day.

Information relating to charges for Energy or Ancillary Services which are payable by the ISO pursuant to Sections 8 and 11 of the ISO Tariff and Appendix N to the Scheduling Coordinators representing the RMR Owners will be contained in the RMR Payments Calendar pursuant to Section 11.24.

4 Information to be provided by RMR Owners to the ISO

Each RMR Invoice and any Prior Period Change Worksheet shall include, or be accompanied by, information about RMR Payments and RMR Refunds in sufficient detail to enable the ISO to verify all RMR Charges and all RMR Refunds, and such information shall be copied to the Responsible Utility. Each RMR Invoice shall separately show the amounts due for services from each Reliability Must-Run Unit.

This information shall be provided in an electronic form in accordance with the RMR Invoice template developed jointly and agreed to by the ISO, Responsible Utilities and RMR Owners in accordance with the RMR Contracts and the principles in Schedule O to those Contracts, and maintained on the ISO Home Page.

5 Validation of RMR Charges and RMR Refunds

The ISO shall validate, based on information provided by each RMR Owner pursuant to paragraph 4, the amount due form the relevant Responsible Utility for RMR Charges and the amount due to the relevant Responsible Utility for RMR Refunds applicable to the Reliability Must-Run Generation and Ancillary Services of that RMR Owner, but shall not represent or warrant the accuracy or completeness of the information provided by the RMR Owner. The ISO shall provide copies of its exception report and information to the relevant Responsible Utility and RMR Owner.

The ISO shall not be obligated to pay the Responsible Utility any RMR Refunds unless and until the ISO has received corresponding RMR Refunds into the Responsible Utility Facility Trust Account from the RMR Owner.

6 Description of the Billing Process

6.1 Issuance of RMR Invoices by the RMR Owner

Each RMR Owner shall provide any RMR Invoice to the ISO in the electronic form, mutually agreed by the parties, which may be updated

by agreement of the ISO, Responsible Utilities and RMR Owners from time to time in accordance with the requirements of Schedule O of the RMR Contract, on each of the days specified in the RMR Payments Calendar, and shall send to the relevant Responsible Utility a copy of that invoice on the day of issue.

6.2 Review of the RMR Invoice by the ISO

The ISO shall review each RMR Invoice within the period specified in the RMR Payments Calendar and is required to initiate proposed adjustments to that invoice to the RMR Owner and the relevant Responsible Utility. Once the ISO initiates proposed adjustments, the RMR Owner shall issue a Revised Estimated RMR Invoice or Revised Adjusted RMR Invoice.

6.3 Issuance of ISO Invoices by the ISO

The ISO shall provide to the Responsible Utility and the RMR Owner on the dates specified in the RMR Payments Calendar ISO Invoices showing:

(a) the amounts which, on the basis of the Revised Estimated RMR Invoice or the Revised Adjusted RMR Invoice, as the case may be, and pursuant to paragraph 5 of this Part J, are to be paid by or to the relevant Responsible Utility and RMR Owner;

(b) the Payment Date, being the date on which such amounts are to be paid and the time for such payment;

(c) details (including the account number, bank name and Fed-Wire transfer instructions) of the RMR Owner Facility Trust Account to which any amounts owed by the Responsible Utility are to be paid, or of the RMR Responsible Utility Facility Trust Account to which any amounts owed by the RMR Owner are to be paid.

6.4 Resolving Disputes Relating to Invoices

6.4.1 Review of the Invoices by the Responsible Utility

Each Responsible Utility shall have the review period specified in the RMR Payments Calendar to review RMR Invoices, and ISO Invoices, validate, and propose adjustments to such invoices and notify the ISO of any dispute. Notwithstanding the above, each Responsible Utility shall have the review time specified in ISO Tariff Section 30.6.1.1 to dispute such invoice.

6.4.2 Dispute Notice

If a Responsible Utility disputes any item or calculation relating to any Revised RMR Invoice, or any ISO Invoice, it shall provide the ISO, with a copy to the RMR Owner, via email or such other communication mode as the parties may mutually agree upon, a notice of dispute at any time from the receipt of the copy of such invoice from the RMR Owner or the ISO to the expiration of the period for review set out in Section 6.4.1. The ISO shall initiate a corresponding dispute with the RMR Owner under the RMR Contract.

6.4.3 Contents of Dispute Notice

The notice of dispute shall state clearly the Revised Estimated RMR Invoice, Revised Adjusted RMR Invoice, or ISO Invoice in dispute, the item disputed (identifying specific Reliability Must-Run Units and time periods), the reasons for the dispute, and the proposed amendment (if appropriate) and shall be accompanied by all available evidence reasonably required to support the claim.

6.4.4 Prior Period Change Agreed to by the RMR Owner

Subject to paragraph 6.4.5 or 6.4.6 of this Part J, if the RMR Owner agrees with the proposed change, the change shall be shown in a Prior Period Change Worksheet and included in the next appropriate May or December Estimated RMR Invoice as specified in Article 9.1 of the RMR Contract.

6.4.5 Dispute Involving the RMR Owner

If the dispute relates to an item originating in any RMR Invoice the applicable provisions of the RMR Contract and Section 30.6.1.1.1 of the ISO Tariff shall apply.

6.4.6 Dispute Involving an Alleged Error or Breach or Default of the ISO's Obligations Under Section 5.2.7 of the ISO Tariff

If the dispute relates to an alleged error or breach or default of the ISO's obligations under Section 30.6.1.1. of the ISO Tariff, the applicable provisions of the RMR Contract and Section 30.6.1.1.1 of the ISO Tariff shall apply.

6.4.7 Payment Pending Dispute

Subject to Section 30.6.1.1.1 of the ISO Tariff, if there is any dispute relating to an item originating in an RMR Invoice that is not resolved prior to the Payment Date, the Responsible Utility shall be obligated to pay any amounts shown in the relevant ISO Invoice on the Payment Date irrespective of whether any such dispute has been resolved or is still pending. The Responsible Utility may notify the ISO that the payment is made under protest, in which case the ISO shall notify the RMR Owner that payment is made under protest. In accordance with Section 9.6 of the RMR Contract, if such dispute is subsequently resolved in favor of the Responsible Utility that made the payment under protest, then any amount agreed or determined to be owed by the RMR Owner to the ISO shall be repaid by the RMR Owner to the ISO, with interest at the interest rate specified in the RMR Contract from the date of payment by the ISO to the RMR Owner of the disputed amount to the date of repayment by the RMR Owner, as specified in Section 6.4.4 of this Part J. If RMR Owner does not agree to make the change pursuant to Section 6.4.4, then such repayment shall be made by ISO's deduction of such amount from the next ISO Invoices until extinguished, or if the RMR Contract has terminated, by paying a RMR Refund in such amount to the Responsible Utility Facility Trust Account, subject to the limitation of Section 30.6.1.1.1.1 of the ISO Tariff.

7 Payment Procedures

7.1 Payment Date

The Payment Date for RMR Payments to and RMR Refunds from RMR Owners shall be the Due Date specified in the RMR Contract and in the RMR Payments Calendar and the same shall be the Payment Date for the ISO and Responsible Utilities in relation to RMR Charges, provided that the RMR Owner has furnished the Responsible Utility and the ISO with the Revised Estimated RMR Invoice or the Revised Adjusted RMR Invoice no less than 9 calendar days before the Due Date. The Payment Date shall be stated on the ISO Invoice.

7.2 Payment Method

All payments and refunds by the ISO to RMR Owners and Responsible Utilities shall be made via Fed-Wire.

However, if the RMR Owner is also the Responsible Utility, at the discretion of the RMR Owner, payments and refunds may be made by memorandum account instead of wire transfer.

7.3 Payment by RMR Owners and Responsible Utilities

Each RMR Owner shall remit to the Responsible Utility Facility Trust Account the amount shown on the relevant ISO Invoice as payable by that RMR Owner not later than 10:00 am on the Payment Date.

Subject to Section 30.6.1.1 of the ISO Tariff, each Responsible Utility shall remit to the RMR Owner Facility Trust Account the amount shown on the relevant ISO Invoice not later than 10:00 am on the Payment Date.

7.4 Payment by the ISO

The ISO shall verify the amounts available for distribution to Responsible Utilities and/or RMR Owners on the Payment Date and shall give instructions to the ISO Bank to remit from the relevant Facility Trust Account to the relevant settlement account maintained by each Responsible Utility or RMR Owner the amounts determined by the ISO to be available for payment to each Responsible Utility or RMR Owner.

7.5 Payment Default by RMR Owner or Responsible Utility

If by 10.00 am on a Payment Date the ISO, in its reasonable opinion, believes that all or any part of any amount due to be remitted to the relevant Facility Trust Account by the RMR Owner or the Responsible Utility will not or has not been remitted ("the Default Amount") the ISO shall immediately notify the RMR

Owner and the Responsible Utility. Where the Default Amount was due from the Responsible Utility, the ISO and RMR Owner shall proceed as set forth in Section 30.6.1.1 of the ISO Tariff and the applicable provision of the RMR Contract. Where the Default Amount was due from the RMR Owner, the ISO and the

Responsible Utility shall proceed as set forth in the applicable provision of the RMR Contract.

7.5.1 Default relating to Market Payments

For the avoidance of doubt, non payment to RMR Owners, or their respective Scheduling Coordinators, of charges for Energy or Ancillary Services which are payable by the ISO to Scheduling Coordinators representing such RMR Owners shall be dealt with pursuant to Sections 11.3 to 11.24 (inclusive) of the ISO Tariff and the provisions of Appendix N.

7.6 Set-off

7.6.1 Set-off in the case of a defaulting Responsible Utility

The ISO is authorized to apply any amount to which any defaulting Responsible Utility is or will be entitled from the Responsible Utility Facility Trust Account in or towards the satisfaction of any amount owed by that Responsible Utility to the RMR Owner Facility Trust Account arising under the settlement and billing process set out in this Part J.

For the avoidance of doubt, neither the ISO nor any Responsible Utility will be authorized to set off any amounts owed by that Responsible Utility in respect of one Facility Trust Account against amounts owed to that Responsible Utility in respect of another Facility Trust Account or any amounts owed by that Responsible Utility under this Part J against amounts owed to that Responsible Utility except as provided by Section 30.6.1.1 of the ISO Tariff.

7.6.2 Set-off in the case of a defaulting RMR Owner

The ISO is authorized to apply any amount to which any defaulting RMR Owner is or will be entitled from the RMR Owner Facility Trust Account in or towards the satisfaction of any amount owed by that RMR Owner to the Responsible Utility Facility Trust Account in accordance with Article 9 of the RMR Contract and Sections 30.6.1.1 and 8.12 of the ISO Tariff.

For the avoidance of doubt, neither the ISO nor any RMR Owner will be authorized to set off any amounts owed by that RMR Owner in respect of one Facility Trust Account against amounts owed to that RMR Owner in respect of another Facility Trust Account or any amounts owed by that RMR Owner under this Part J against amounts owed to that RMR Owner under the RMR Contract.

7.7 Default Interest

Responsible Utilities shall pay interest on Default Amounts to the ISO at the interest rate specified in the RMR Contract for the period from the relevant Payment Date to the date on which the payment is received by the ISO.

RMR Owners shall pay interest to the ISO on Default Amounts at the interest rate specified in the RMR Contract for the period from the date on which payment was due to the date on which the payment is received by the ISO.

The ISO shall pay interest to RMR Owners at the interest rate specified in the RMR Contract for the period from the date on which payment is due under the RMR Contract to the date on which the payment is received by the RMR Owner.

The ISO shall pay interest to Responsible Utilities at the interest rate specified in the relevant RMR Contract for the period from the date following the date it received an RMR Refund from the relevant RMR Owner to the date in which the payment is received by the relevant Responsible Utility.

Where payment of a Default Amount is made by exercise of a right of set-off or deduction, payments shall be deemed received when payment of the sum which takes that set-off or deduction into account is made.

8 Overpayments

The provisions of Sections 11.18.2.a and 11.18.2.b shall apply to RMR Owners and Responsible Utilities which have been overpaid by the ISO and references to “ISO Creditors” in these sections and in the relevant Sections of the ISO Tariff shall be read, for the purposes of this Part J, to mean RMR Owners and Responsible Utilities as applicable. Disputed amounts shall not be considered to be overpayments until and unless the dispute is resolved.

9 Communications

9.1 Method of Communication

ISO Invoices will be issued by the ISO via Electronic Data Interchange (“EDI”). RMR Invoices and Prior Period Change Worksheets will be issued by the RMR Owner in an electronic form mutually agreed by the parties and maintained on the ISO’s Home Page. ISO shall also post prior period change examples and prior period change guidelines as specified in Article 9.1 of the RMR Contract.

9.2 Emergency Procedures

9.2.1 Emergency Affecting the ISO

In the event of an emergency or a failure of any of the ISO software or business systems, the ISO may deem any Estimated RMR Invoice or any Adjusted RMR Invoice to be correct without thorough verification and may implement any temporary variation of the timing requirements relating to the settlement and billing process contained in this Part J.

9.2.2 Emergency Affecting the RMR Owner

In the event of an emergency or a failure of any of the RMR Owner’s systems, the RMR Owner may use Estimated RMR Invoices as provided in the applicable section of the RMR Contract or may implement any temporary variation of the timing requirements relating to the settlement and billing process contained in this Part J and its RMR Contract. Details of the variation will be published on the ISO Home Page.

Communications of an emergency nature on a Due Date or a Payment Date relating to payments shall be made by the fastest practical means including by telephone.

10 Confidentiality

The provisions of Sections 11.9A, 20.5, and 11 shall apply to this Part J between and among the RMR Owners, the ISO and Responsible Utilities.

Except as may otherwise be required by applicable Law, all information and data provided by RMR Owner or the ISO to the Responsible Utility pursuant to the RMR Contract, Section 30.6.1.1 of the ISO Tariff or this Part J ("confidential information") shall be treated as confidential and proprietary to the providing party to the extent required by Section 12.5 and Schedule N of the RMR Contract and will be used by the receiving party only as permitted by such Section 12.5 and Schedule N.

11 Amendments to this Part J

If the ISO determines a need for an amendment to this Part J, the ISO shall follow the requirements as set forth in Section 22.11 of the ISO Tariff, provided that ISO may not modify Part J as it applies to any RMR contract without the consent of the relevant RMR Owner and Responsible Utility.

ISO TARIFF APPENDIX O

Metering

PART A

FAILURE OF ISO FACILITIES

A 1 WEnet Unavailable

A 1.1 Unavailable Functions of WEnet

During a total disruption of the WEnet the ISO will not be able to:

(a) communicate with ISO Metered Entities or Scheduling Coordinators to acquire or provide any Meter Data or Settlement Quality Meter Data; and

(b) communicate general information.

A 1.2 Communications during WEnet Unavailability

During any period of WEnet unavailability, the ISO shall:

(a) make all reasonable efforts to provide general information to ISO Metered Entities and Scheduling Coordinators using voice communications; and

(b) inform ISO Metered Entities and Scheduling Coordinators of the methods they must use to provide Meter Data and Settlement Quality Meter Data to the ISO during that period.

A 2 Primary MDAS Master Station Completely Unavailable

A 2.1 Notification of Loss of Primary MDAS Master Station

In the event that the primary MDAS master station becomes completely unavailable, the ISO will use alternate communications to notify the redundant MDAS master station that the primary MDAS master station is unavailable. The ISO will post information on the situation on the WEnet. Additional voice notifications will be made as time permits.

A 2.2 Notification of Restoration of Primary MDAS Master Station

The ISO will post confirmation on WEnet that all computer systems are functioning normally (if such be the case) and use the redundant MDAS master station to take complete control of the all MDAS functions. Once the primary MDAS master station is again available, all functions will be transferred back to the primary MDAS master station and the ISO will notify all ISO Metered Entities and Scheduling Coordinators via the WEnet.

PART B

CERTIFICATION PROCESS FOR METERING FACILITIES

Paragraphs B1 to B3 of this Part describe the steps that ISO Authorized Inspectors and the ISO will take to certify Metering Facilities of ISO Metered Entities.

The steps described here will also be applicable to Scheduling Coordinator Metered Entities where no certification requirements are imposed on a Scheduling Coordinator Metered Entity by its Local Regulatory Authority.

Paragraph B5 of this Part describes the manner in which requests must be made to the ISO to perform the certification of Metering Facilities.

B 1 Documentation to be Provided by ISO/Scheduling Coordinator Metered Entity

The ISO Metered Entity or Scheduling Coordinator Metered Entity shall provide the ISO and the ISO Authorized Inspector with schematic drawings (both detailed and one line) of the Metering Facilities being considered for ISO certification. Such drawings shall be dated, bear the current drawing revision number and show all wiring, connections and devices in the circuits. Drawings shall also be provided for instrument transformers to the meter and the meter to the WEnet POP.

In addition, the ISO Metered Entity or Scheduling Coordinator Metered Entity will provide the ISO and the ISO Authorized Inspector with a completed ISO Meter Certification Form (a copy of which forms part of this Part) in respect of each set of Metering Facilities being considered for ISO certification.

B 2 Documentation to be completed by the ISO Authorized Inspector

The ISO Authorized Inspector will complete an ISO approved site verification form (an internal ISO document) in relation to each set of Metering Facilities that it inspects. The site verification form and the ISO Meter Certification Form will be the official forms used to document whether Metering Facilities meet the ISO certification criteria.

If there are any discrepancies between the ISO certified drawings on file and the actual metering circuitry inspected by the ISO Authorized Inspector or the ISO, then the ISO Authorized Inspector or the ISO will document that discrepancy and revise the schematic drawings provided to the ISO. The ISO Authorized Inspector will notify the ISO of the discrepancy and give the ISO Metered Entity or Scheduling Coordinator Metered Entity a notice detailing the discrepancies within 24 hours of that notification.

B 3 Review by the ISO

The ISO will review all documentation provided to it by the ISO Metered Entity or Scheduling Coordinator Metered Entity (including the ISO Meter Certification Form) and the site verification form prepared by the ISO Authorized Inspector.

If the ISO finds that the data is incomplete or fails to meet the relevant standards referred to in the ISO Tariff and this Appendix, the ISO shall provide written notice of the deficiencies to the ISO Metered Entity or Scheduling Coordinator Metered Entity within seven days of receiving the documentation referred to above.

If the ISO finds that the data is complete, it shall, subject to any exemptions granted under 10.3.18.5.1 in relation to providing Meter Data directly to MDAS, initiate tests to certify the MDAS interface with the relevant Metering Facilities.

Upon successful completion of the MDAS interface tests the ISO will issue a Certificate of Compliance. The ISO shall return the original schematic drawings, stamped by the ISO as approved and certified, and the original ISO Meter Certification Form and site verification form. The ISO will retain copies of these documents. Once all conditions have been satisfied to the ISO's satisfaction, the ISO shall promptly issue an original Certificate of Compliance.

B 4 Provisional Certification

If the ISO finds that:

(a) the data provided to it by the ISO Metered Entity or Scheduling Coordinator Metered Entity is incomplete or fails to meet the relevant standards referred to in the ISO Tariff and this Appendix; or

(b) the Metering Facilities fail the MDAS interface test,

the ISO may, at its discretion, elect to issue a provisional Certificate of Compliance in respect of those Metering Facilities. The term of and conditions on which such a provisional Certificate of Compliance is issued shall be at the ISO's discretion. However, the ISO will not issue an original Certificate of Compliance to the ISO Metered Entity until such time as all of the conditions of the provisional Certificate of Compliance have been fulfilled to the satisfaction of the ISO.

B 5 Requests for the ISO to Perform Certification

If an ISO Metered Entity would like the ISO to perform the certification of its Metering Facilities in accordance with Section 10.2.4.1, that ISO Metered Entity shall submit a written request to the ISO. The written request must:

(a) specify the Metering Facilities to be certified;

(b) provide the documentation referred to in paragraph B1 of this Part; and

(c) detail the reasons why it would be impossible or impractical for the ISO Metered Entity to engage the services of an ISO Authorized Inspector to perform the certification.

The ISO will, within 14 days of receiving a request for it to certify Metering Facilities, inform the ISO Metered Entity whether it will undertake the certification or require the ISO Metered Entity to engage an ISO Authorized Inspector to perform the certification.

ISO Meter Certification Form

Facility Information

Name:	Unit Name:
Address:	Drawing Numbers: (see note 1)
ISO Metered Entity Contact :	Phone Number:
Scheduled ISO Inspection Date:	

Generator Information

Gross Output		Auxiliary Load	
Net Output		Voltage / Connections	

Revenue Billing Information

Meter Manufacturer		Register Constant	
Meter Serial Number		Program ID Number	
Meter Type		Device ID	
Meter Form		IP Address/Router Port #	

Does meter have external pulse inputs for totalization purposes? Yes □ (info. is attached) No □

Internal Mass Memory Constants

Function	Channel	K_e	PRI KWH Constant	Interval Size	Display Sequence
KWH DELIVERED					
KVARH DEL					
KVARH REC					
KWH RECEIVED					

Voltage Transformer Information				**Current Transformer Information**			
Name Plate	**A**□	**B**□	**C**□	Name Plate	**A**□	**B**□	**C**□
Manufacturer				Manufacturer			
Serial Number				Serial Number			
Type				Type			

Ratio				Ratio			
Voltage Class				Voltage Class			
BIL Rating				BIL Rating			
Accuracy Class				Accuracy Class			
Burden Rating				Rating Factor			
Connected Burden				Burden Rating			
				Connected Burden			
				Applied Test Burden			
				Burden Test	Pass □ Fail □	Pass □ Fail □	Pass □ Fail □

Instrument Transformer Correction Factors (FCF) (see note 2)		
Full Load	**Power Factor**	**Light Load**

Line Loss Compensation Values (at Full Load Meter Rating) (see note 2 and 3)	
% Watt Fe Loss	% Var Fe Loss
% Watt Cu Loss	% Var Cu Loss
Total Compensation Values (at Full Load Meter Rating)	
% Watt Total Loss	% Var Total Loss
Completed by:	Date:
Remarks:	
Reviewed by:	Date:

Notes:

1. ISO Metered Entities shall provide a copy of the one line diagram and schematics detailing the connections from the instrument transformer to the meter, communication circuit and local meter data server (if applicable)in accordance with this Part.
2. ISO Metered Entities shall attach a copy of the calculations used to determine these values.
3. For Power Transformer Loss Correction and Radial Line Loss Correction values the appropriate sign (+/-) should be utilized depending on the flow of Energy (delivered/received) and the location of the ISO Meter Point.

PART C

METER CONFIGURATION CRITERIA

C 1 Power Flow Conventions

Meters shall be installed and configured in such a manner so as to define the 4 Quadrants referred to in Exhibit 1 to Part D of this Appendix.

C 2 ISO Standard Meter Memory Channel Assignments

Metering Facilities shall be installed and configured in such a manner so as to comply with the following ISO requirements:

Channel 1 shall record active power delivered by the ISO Controlled Grid;

Channel 2 shall record reactive power delivered by the ISO Controlled Grid;

Channel 3 shall record reactive power received by the ISO Controlled Grid; and

Channel 4 shall record active power received by the ISO Controlled Grid.

For metering with bi-directional power flows, the ISO reserves the right to require metering which will measure 4 quadrant Vars. Situations like a generating plant that nets gross generator output and auxiliary loads on one meter which could swap from a supplying to a buying mode and vice versa may require this type of metering. To properly account for such cases, six channels of data will be required. This configuration is considered optional unless specified by ISO as required. Such Metering Facilities shall be installed and configured in such a manner so as to comply with the following ISO requirements:

Channel 1 shall record active power delivered by the ISO Controlled Grid;

Channel 2 shall record quadrant 1 reactive power delivered by the ISO Controlled Grid;

Channel 3 shall record quadrant 3 reactive power received by the ISO Controlled Grid;

Channel 4 shall record active power received by the ISO Controlled Grid;

Channel 5 shall record quadrant 2 reactive power delivered by the ISO Controlled Grid; and

Channel 6 shall record quadrant 4 reactive power received by the ISO Controlled Grid.

C 3 ISO Standard Meter Display Modes

The following display readings shall be displayed in the normal display mode to comply with ISO requirements.

Normal Display Mode (Standard Configuration, Uni-directional/Bi-directional kWh and kVarh)

For standard metering applications the display items should be utilized in the sequence listed below. When metering uni-directional power flows, the quantities listed below that do not apply (i.e. for generation only applications, the delivered quantities should have zero accumulation) may be omitted. The only exception to this would be where the display items correlate to the load profile channel assignments. The 4 display readings that correlate to the 4 load profile channels must also be displayed.

Date MM:DD:YY.

Time HH:MM:SS (Pacific Standard Time, military format).

Total kWh delivered by the ISO Controlled Grid.

Maximum kWd (5 minute or hourly demand interval) delivered by the ISO Controlled Grid.

Date and time of maximum kWd delivered by the ISO Controlled Grid.

Total kVarh delivered by the ISO Controlled Grid.

Total kVarh received by the ISO Controlled Grid.

Total kWh received by the ISO Controlled Grid.

Maximum kWd (5 minute or hourly demand interval) received by the ISO Controlled Grid.

Date and time of maximum kWd received by the ISO Controlled Grid.

Normal Display Mode (Optional Configuration, Bi-directional Kwh and Four Quadrant kVarh)

For metering bi-directional power flows in which ISO requires optional 4 quadrant Var measurement, the following display items should be displayed in the sequence listed below:

Date MM:DD:YY.

Time HH:MM:SS (Pacific Standard time, military format).

Total kWh delivered by the ISO Controlled Grid.

Maximum kWd (5 minute or hourly demand interval) delivered by the ISO Controlled Grid.

Date and time of maximum kWd delivered by the ISO Controlled Grid.

Total kVarh for Quadrant 1.

Total kVarh for Quadrant 2.

Total kVarh for Quadrant 3.

Total kVarh for Quadrant 4.

Total kWh received by the ISO Controlled Grid.

Maximum kWd (5 minute or hourly demand interval) received by the ISO Controlled Grid.

Date and time of maximum kWd received by the ISO Controlled Grid.

Consumption Values

The consumption values shall be in XXXXX.X format and demand in XXXX.XX format. The register scaling factor should be set such that the display does not roll over in less than 60 days.

Alternative Display Mode

The values listed below should be displayed in the alternate display mode to comply with ISO requirements:

Phase A voltage magnitude and phase angle.

Phase B voltage magnitude and phase angle.

Phase C voltage magnitude and phase angle.

Phase A current magnitude and phase angle.

Phase B current magnitude and phase angle.

Phase C current magnitude and phase angle.

Neutral current magnitude and phase angle (if available).

Instantaneous kW delivered by the ISO Controlled Grid (for bi-directional power flows and/or applications where the power flow is out of ISO Controlled Grid).

Instantaneous kW received by the ISO Controlled Grid (for bi-directional power flows and/or applications where the power flow is received by the ISO Controlled Grid).

When available, the alternative display mode may also be used by ISO Metered Entities to display other definable quantities in sequence after the values defined above.

C 4 Instantaneous Power Factor - Test Mode

The following values should be displayed in the test mode to comply with ISO requirements:

total pulse count for test; and

total consumption during test.

During the test mode the above values should be provided for each function being tested (Watts, Vars). The data displayed by the meter while in test mode shall not change the normal mode display registers nor shall it be recorded in the load profile channels. This requirement is imposed to prevent the test data from being recorded as actual load/generation data.

ISO Metered Entities may add additional display quantities in sequence in the test mode after the values defined above.

C 5 Transformer and Line Loss Correction

The ISO Metered Entity will be responsible for properly calculating and applying the transformer and line loss corrections to its meters in accordance with this Appendix to reflect the actual meter usage (on the low side) as opposed to the theoretical meter usage at the transmission point.

C 6 CT/VT and Cable Loss Correction Factors

Where the connected burden of a metering circuit exceeds the burden rating of a CT or VT or if an existing instrument transformer does not meet the minimum ISO accuracy requirements, then one of the actions listed below must to be taken:

(a) replace the instrument transformer(s) with higher burden rated revenue class units; or

(b) reduce the burden on the circuit to comply with the name plate of existing instrument transformer(s); or

(c) apply correction factors to the meter to adjust the meter's registration to compensate for inaccuracies.

The ISO preferred action is that referred to in paragraph (a) above.

The ISO Metered Entity will be responsible for properly calculating and applying the CT/VT and cable loss correction factors to its meters in accordance with this Appendix to adjust for inaccuracies in the metering circuit.

C 7 Special Applications, Configurations and Unique Situations

ISO Metered Entities are responsible for providing the ISO with the necessary Meter Data and other information to enable the ISO to prepare Settlement Quality Meter Data. For instance, where there is a generating plant with multiple generators and auxiliary loads, the ISO Metered Entity must provide appropriate information (i.e. documentation, descriptions, one line diagrams, etc.) to the ISO to ensure that the ISO can properly account for the net generator output of each unit under all combinations of generation and load (e.g. where only one generator is operating but all auxiliary loads are being supplied).

PART D

STANDARDS FOR METERING FACILITIES

The standards for Metering Facilities referred to in this Part provide additional details to the standards referred to in Appendix J to the ISO Tariff.

The standards referred to in Appendix J to the ISO Tariff and this Part apply to ISO Metered Entities and, where the relevant Local Regulatory Authority has not set any standards, to Scheduling Coordinator Metered Entities.

D 1 Standards for Existing Metering Facilities

Existing Metering Facilities are those facilities that are fully installed as of the ISO Operations Date. Existing Metering Facilities used by ISO Metered Entities shall meet the following general standards:

revenue quality instrument transformers at the generator output level (specifically at all main generators, banks and local distribution load supplied from the generator) must have an accuracy of 0.3% or better

generator auxiliary load metering must have an overall accuracy of 3%

revenue quality instrument transformers at transmission metering points must have an accuracy of 0.3% or better

D 2 General Standards for New Meters

New Meters are those meters that are installed after the ISO Operations Date. New Meters used by ISO Metered Entities shall meet the following general standards:

they must be revenue quality in an accuracy class of 0.25%

they must be remotely accessible, reliable, 60 Hz, three phase, bi-directional, programmable and multifunction electronic meters

they must be capable of measuring kWh and kVarh and providing calculated three phase values for kVah, kVa

they must have a demand function including cumulative, rolling, block interval demand calculation and maximum demand peaks

there must be battery back-up for maintaining RAM and a real-time clock during outages of up to thirty days

there must be AC potential indicators on each of the three phases

they must be capable of being powered either internally from the bus or externally from a standard 120 volt AC source.

they must be capable of providing MDAS (MV-90) addressable metering protocol

they must be capable of 60 days storage of kWh and KVarh interval data

If there is any inconsistency between these general standards and the detailed standards referred to in paragraphs D3 and D4 of this Part, the detailed standards shall prevail.

D 3 Detailed Standards for New Meters

Exhibit 1 to this Part provides the detailed specifications with which new meters must comply.

D 4 Detailed Standards for New Oil Filled, Wound Instrument Transformers

Exhibit 2 to this Part provides the detailed specifications with which new oil filled, wound instrument transformers must comply.

D 5 Standards for Compatible Meter Data Servers

In order for a meter data acquisition and processing system of a metered entity to be certified by the ISO as a Compatible Meter Data Server, that metered entity must satisfy the ISO that the server is capable of providing:

- Meter Data and/or Settlement Quality Meter Data to MDAS in the Meter Data Exchange Format via WEnet and/or REMnet via File Transfer Protocol (FTP);
- Meter Data to the ISO which is real data at least comparable to data obtained directly by MDAS from meters;
- Meter Data and/or Settlement Quality Meter Data to the ISO on demand within 10 minutes of receiving such a demand from the ISO;
- System Back Up procedures that permit submission of data within 41 days of a Trading Day to MDAS even in the event of a major facility or system problem. Back Up procedures must be documented and available for review by ISO.
- System Security procedures that limit the accessibility to meter data and the system parameters . The System Security procedures must be documented and available for review by ISO.
- If applicable, procedures that define methods of profiling consumption meter data into intervals. These procedures must be documented, they must follow any appropriate regulatory guidelines and they must be available for review by the ISO.
- System day-to-day operational procedures, these procedures should be available for ISO review and audit.

EXHIBIT 1 TO PART D

SPECIFICATION MTR1-96

ENGINEERING SPECIFICATION
FOR POLYPHASE SOLID-STATE
ELECTRICITY REVENUE QUALITY METERS
FOR USE ON THE ISO CONTROLLED GRID

TABLE OF CONTENTS

1 General Information

This Exhibit applies to all solid-state polyphase electricity meters used in revenue metering applications on the ISO Controlled Grid (Meters).

2 Scope

2.1 General

This Exhibit provides the minimum functional and performance requirements for Meters. All requirements in this Exhibit are intended to ensure the expected life cycles, security, accuracy, reliability and minimum maintenance requirement of Meters. Some requirements, however, are specified to maintain the compatibility and interchangeability of the Meter.

2.2 Applicability

Meters approved under this Exhibit may not be required to have all of the specified features. Meters shall meet the specified minimum requirements and the requirements of Section 13 (Meter Approval Testing) of this Exhibit.

3 Metering Functions

3.1 Measured Quantities

As used in this Exhibit, the term “delivered” applies to Energy flowing out of the ISO Controlled Grid and the term “received” applies to Energy flowing into the ISO Controlled Grid.

3.1.1 Consumption

The following consumption quantities are required for all Meters approved for use on the ISO Controlled Grid:

(a) Kilowatt-hours—delivered;

(b) Kilowatt-hours—received;

(c) Kilovar-hours—delivered, received, for each quadrant;

(d) Kilovoltamp-hours—delivered, received, for each quadrant;

(e) Ampere-squared-hours; and

(f) Volts-squared-hours.

3.1.2 Demand

The following demand quantities are required for all meters approved for use on the ISO Controlled Grid:

(a) Kilowatts—delivered;

(b) Kilowatts—received;

(c) Kilovars—delivered, received, for any quadrant; and

(d) Kilovoltamps—delivered, received, for any quadrant.

3.1.3 Power Factors

The ISO may specify average power factors for the previous demand sub-interval in any quadrant or any combination of two quadrants.

3.1.4 Reverse Consumption/Demand

The Meter shall be programmable to take one of the following actions for reverse consumption and demand quantities:

(a) ignore the reverse quantities; and

(b) add the reverse quantities to the appropriate consumption and demand quantities.

3.2 Basic Default Metering Function

When power is applied to the Meter, it shall immediately begin recording bi-directional total kilowatt-hours. Reverse power flow shall carry a negative sign. This function shall be performed regardless of whether the Meter is programmed or not and shall not require a battery. An unprogrammed Meter shall indicate that it is unprogrammed. The ISO may request a Meter to be programmed with a specific program.

3.3 Demand Metering Function

Meters shall have the following demand metering functions:

(a) as a minimum, the Meter shall be programmable for fixed and/or rolling interval demand calculations on bi-directional kilowatts and kilovars;

(b) a battery shall not be required to perform demand calculations, to save the results or to communicate the results to a handheld meter reader connected to the optical port;

(c) the Meter shall be programmable for one minute delivered kilowatt demand (as an approximation of “instantaneous” kilowatts delivered) in addition to the rolling interval demand calculation. The one minute demand is not required to be synchronous with the other demand quantities;

(d) the Meter shall be programmable for rolling interval demand calculations for any optional demand quantity (see Section 3.1.2) that ISO specifies.

(e) demand intervals shall be programmable for a duration of 5, 10, 15, 30 or 60 minutes;

(f) the demand interval shall be composed of an integral number of sub-intervals. Sub-interval duration shall be a programmable duration of 1, 5, 10, 15 or 30 minutes;

(g) demand functions shall be capable of temporary suspension for a programmable time interval after power is restored following a power outage. The length of time shall be programmable from zero to 60 minutes in one minute intervals;

(h) after a demand reset, further manual demand resets shall be prevented with a programmable lockout time. A demand reset from a Meter Programmer connected to the optical port is not subject to this delay and can be initiated as frequently as required; and

(i) if the Meter has been programmed for Time-of-Use (TOU) functions, the time at which maximum demand occurred shall be recorded at the end of that demand interval.

3.4 Time-of-Use (TOU) Metering Function

Meters shall have the following TOU metering functions:

(a) as a minimum, the Meter shall be programmable for TOU calculations for bi-directional kilowatt-hours and kilovarhours and bi-directional kilowatt and kilovar demand.;

(b) the Meter shall be programmable for TOU calculations for any optional consumption or demand quantity (see Section 3.1.1 or 3.1.2) that the ISO specifies;

(c) the calendar shall be programmable into one to four mutually exclusive seasons;

(d) each season shall be further programmable into one to four mutually exclusive daily TOU schedules;

(e) the Meter shall be capable of distinguishing weekdays, weekends, days of the week, and holidays.

(f) each consumption and demand quantity shall be metered independently for each TOU schedule;

(g) only one season and one TOU schedule shall be active at a given time. There shall always be one active season and one active TOU schedule;

(h) each daily TOU schedule shall be capable of a minimum of eight switch points with a minimum resolution of a quarter hour;

(i) the calendar shall be capable of accommodating leap years, daylight saving time changes and recurring holidays; and

(j) the Meter shall have capacity for a minimum calendar of 20 years, taking into account 12 holidays/year, 4 seasons/year, and 2 daylight savings time adjustments/year.

3.5 Self-Read TOU Metering Function

Meters shall have the following self-read TOU metering functions:

(a) as a minimum the Meter shall perform a self-read of all consumption and demand quantities on season changes. A self-read shall consist of reading the quantities, resetting the demand and storing the data;

(b) the change of season self-reads shall occur at midnight of the day before the season change;

(c) the ISO may specify that the Meter be programmable for up to three consecutive self-reads. The self-reads shall be programmable for:

i. a specific day of each month at midnight;

ii. a specific number of days from the last demand reset (read) at midnight; and

iii. self-read time of use metering; and

(d) self-read data, other than previous season data, need not be displayed but shall be retrievable with a Meter Programmer connected to the optical port.

3.6 Load Profile Function

Meters shall have the following load profile functions:

(a) the ISO may specify that the Meter provide load profile recording of interval data for 1 to 4 channels of consumption quantities;

(b) load recording of interval data shall operate independently of the TOU functions;

(c) date and time shall be stored with the load recording of interval data;

(d) load recording of interval data shall use a “wraparound” memory that stores new interval data by writing over the oldest interval data;

(e) the load recording of interval data function shall be capable of storing and communicating a minimum of 60 days of 4 channel, 5 minute interval data, in addition to allowances for event recording (power outages, resets, time sets, etc.);

(f) the load recording of interval data function shall have the capacity to count and store at least 16,000 counts in a 15 minute period of time; and

(g) load recording of interval data shall continue while the Meter is communicating with a Meter Programmer connected to the optical port.

3.7 Function during Power Disturbances

Meters shall have the following functions during power disturbances:

(a) during powerline disturbances such as brownout or outage conditions the Meter shall maintain all meter data as well as time keeping functions. Display and communication functions are not required during these conditions;

(b) the Meter shall withstand the following outages during a continuous ten year or longer service without the need to maintain its auxiliary power system, including replacing the battery:

i. 20 short outages per year of less than 30 seconds per outage; and

ii. 40 days of continuous/cumulative outage;

(c) during a power outage, critical program and billing data shall be written to non-volatile memory. When power is restored, data shall be returned to active memory and data collection resumed;

(d) following a power outage, register "catch-up" time shall be a maximum of 30 seconds. During the "catch-up" time the Meter shall still calculate consumption and demand quantities. Optional outputs shall also function during this time;

(e) during power outages, time shall be maintained with a cumulative error of no more than 2 minutes per week (0.02%);

(f) the Meter shall record the date and time of any power outage; and

(g) Meters may also record the duration of any power outage.

3.8 Meter Test Mode Function

Meters shall have the following meter test mode functions:

(a) the Meter shall have the capability of a Test Mode function that suspends normal metering operation during testing so that additional consumption and demand from the tests are not added to the Meter's totals;

(b) the Test Mode function shall be activated by a permanently mounted physical device that requires removal of the Meter cover to access or by a Meter Programmer connected to the optical port;

(c) activation of the Test Mode shall cause all present critical billing data to be stored in non-volatile memory and restored at the time of exit from the Test Mode;

(d) upon activation of the Test Mode, register displays shall accumulate beginning from zero;

(e) actuation of the billing period reset device during Test Mode shall reset the test mode registers;

(f) after a programmable time-out period, the Meter will automatically exit from Test Mode and return to normal metering; and

(g) the default Test Mode registers for an unprogrammed meter shall include as a minimum:

i. time remaining in the test interval;

ii. maximum kilowatt block demand; and

iii. total kilowatt-hours.

4 Display Requirements

4.1 LCD Display

The Meter shall have an electronic display for displaying the consumption and demand quantities. A liquid crystal display (LCD) is preferred.

4.2 Viewing Characteristics

Digits for displaying the consumption and demand quantities shall be a minimum of $^{7}/_{16}$" in height and be legible in normal daylight conditions from a distance of six feet by an observer. The viewing angle shall be a minimum of fifteen degrees from the front Meter face line of sight.

4.3 Display Components

The display shall provide the following:

(a) six digits for display of the consumption and demand quantities and constants with decimal points for the three least significant digits;

(b) three digits for numeric display identifiers (ID numbers);

(c) alternate and Test Mode indication;

(d) potential indication for each phase;

(e) current TOU rate indicator;

(f) end of interval indicator;

(g) visual representation of the magnitude and direction of kilowatt loading;

(h) visual representation of the magnitude and direction of kilovar loading if the Meter is capable of measuring kilovars; and

(i) Annunciators for most consumption and demand quantities.

4.4 Digits

Consumption and demand quantities shall be programmable for display with leading zeroes in four, five or six digits with a decimal point at any of the least significant three digits.

4.5 Time Format

Time shall be displayed in the 24 hour military format.

4.6 Date Format

Date shall be displayed programmable in either Day/Month/Year or Month/Day/Year format.

4.7 Operating Modes

The display shall have at least three of the following operating modes:

(a) Normal Mode – in this mode, the display shall scroll automatically through the programmed displays for normal meter reading;

(b) Alternate Mode – in this mode, the display shall scroll automatically, scroll manually or freeze for up to one minute for alternate programmed displays;

(c) Test Mode – in this mode, the display shall scroll automatically, scroll manually or freeze for up to one minute for test quantity displays; and

(d) Segment Check – in this mode, all segments or displays are activated to verify display integrity.

Display ID numbers and display sequence shall be independently programmable for each of the modes referred to above. Display times shall be programmable.

4.8 Normal Mode

Upon power-up, the Meter display shall operate in the Normal Mode. The Meter display shall operate in Normal Mode until power is disconnected or until either the Alternate Mode or the Test Mode is activated.

4.9 Alternate Mode

The Alternate Mode shall be initiated with a display control device that does not require Meter cover removal or with a Meter Programmer connected to the optical port.

Display Items

As a minimum, the Meter shall provide the display quantities and items for each of the modes referred to in Section 4.7 as detailed in Attachment 2.

4.10 Constants and Correction Factors.

The Meter shall have programmable multi-variable polynomial function multipliers and/or summers to account for instrument transformer ratios, instrument transformer correction factors, the Meter constant, radial line losses and power transformer loss correction.

4.11 Identifiers

The Meter shall have programmable identifiers for the Meter ID, the person who programmed the Meter (programmer ID) and the current program ID. The Meter ID shall be capable of eight alphanumeric characters.

5 Meter Diagnostics

5.1 Self-test

The Meter register shall be capable of performing a self-test of the register software. As a minimum, the self-test shall be performed at the following times:

(a) whenever communications are established to the register;

(b) after a power-up; and

(c) once per day.

5.2 Diagnostic Checks

As a minimum, the following diagnostic checks shall be performed during a self-test:

(a) check the backup battery capacity;

(b) verify the program integrity; and

(c) verify the memory integrity.

5.3 Pulse Overrun

The register shall be capable of detecting that the maximum number of pulses have been exceeded during a demand interval.

5.4 Error and Warning Displays

Meters shall be capable of the following displays:

(a) any detected error or warning shall be stored in memory and an error or warning code displayed on the display;

(b) error code displays shall freeze the display; and

(c) warning code displays shall be programmable to one of the following choices:

i. freeze the warning code on the display;

ii. ignore the warning code (not displayed); or

iii. warning code display at the end of the Normal, Alternate or Test Modes display sequences.

5.5 Error Reset

Error or warning conditions shall only be reset upon an explicit command invoked via the Meter Programmer or upon some other explicit action by the Meter technician.

6 Programming and Software

6.1 Optical Communications Interface.

The Meter shall be capable of communicating with a handheld reader (Itron DataCap or similar) through the optical port.

6.2 Meter Programmers

The ISO and ISO Authorized Inspectors will use PC DOS based laptop and handheld computers with LCD displays as meter reader/programming devices (Meter Programmers). Communications with the Meter shall be through the optical port.

6.3 Software

The ISO Metered Entity shall ensure that its supplier provides all software for maintenance, programming and operation of the Meter. The software shall include the following:

(a) Rate Development Program;

(b) Field Program;

(c) Field Disk Serialization Program; and

(d) Password protection to preclude 3rd party access for all levels of access except read-only.

6.4 Rate Development Program

The ISO Metered Entity shall ensure that its supplier provides a Rate Development Program software package which allows the ISO to customize the Meter's rate schedules and the Meter's operating parameters. The Rate Development Program shall be capable of utilizing all programmable functions of the Meter.

6.5 Rate Development Program Functions

The Rate Development Program as a minimum shall provide the following functions in a "user-friendly" manner:

(a) originate or modify Meter configuration records;

(b) validate user entries for format and range;

(c) translate user entry into code for configuring the Meter;

(d) send and receive configurations to and from the Meter;

(e) compare configuration files from the Meter with desired files and report discrepancies;

(f) read Meter billing data and load profile data;

(g) generate Meter data and diagnostic reports for printing; and

(h) generate configuration files for loading into the Meter via the Field Program.

6.6 Field Program

The ISO Metered Entity shall ensure its supplier provides a Field Program software package for use with ISO's Meter Programmer. The Field Program in conjunction with any such Meter Programmer shall be capable of loading the rate schedule and meter operating parameters as generated by the Rate Development Program into the Meter.

6.7 Field Program Functions

The Field Program as a minimum shall provide the following functions:

(a) set date and time on the Meter;

(b) preset the Meter consumption registers;

(c) send and receive configurations to and from the Meter;

(d) compare configuration files from the Meter with desired files and report discrepancies;

(e) read Meter billing data and load profile data;

(f) generate Meter data and diagnostic reports for printing;

(g) read, display and modify the present settings of field configurable items;

(h) execute a billing period reset;

(i) reset all consumption and demand quantities; and

(j) not have the capability to alter the configuration files as generated by the Rate Development Program.

6.8 Field Disk Serialization Program

The ISO Metered Entity shall ensure that its supplier provides a Field Disk Serialization Program software package that associates an unique password with each copy of the Field Program. The Field Disk Serialization Program shall use an ASCII text file in a specified format as input and place a different password on one or more copies of a field disk generated by the Rate Development Program.

6.9 DOS or Windows

All software programs shall be PC DOS or Windows based. The Rate Development Program shall be either a Microsoft Windows 9x application or a DOS application capable of running under Microsoft Windows 9x without any loss of function. The Field Program and the Field Disk Serialization Program shall be DOS applications capable of running under PC-DOS Version 7 or later.

6.10 Communication Protocol

The protocol used for communication with the Meter through either the optical port or the optional modem shall be an asynchronous, byte oriented protocol.

6.11 Optical Probe

The Rate Development Program and the Field Program shall support use of a compatible optical probe (ABB Unicomm or similar) connected to the standard PC serial port of the Meter Programmer.

7 Communication

7.1 Optical Port

The primary communication port to the Meter for reading and programming of the internal data shall be an optically isolated communication port per ANSI C12.13, Type 2 or other serial port.

7.2 Baud Rate

The optical port shall communicate at a minimum of 9600 baud.

7.3 Optical Port Location

The optical port shall be located in the front of the Meter and be accessible without removing the Meter's cover. The optical port shall also be functional with the Meter cover removed.

7.4 Optical Port Cable

There shall be no cable connection between the optical port on the Meter cover and the register.

7.5 RS232 or RS 485 or RSXXX.

One RSXXX port shall be provided at the Meter for bi-directional communications (with security provisions included) to computers and/or data acquisition devices. The Meter must have the capability for being polled every 15 minutes for data by MDAS or a Compatible Meter Data Server. An optional RSXXX port or ports with read-only access can be provided for others desiring the data. All RSXXX ports shall be optically isolated.

The Meter shall be capable of being polled simultaneously by more than one entity on one or more of it's ports without loss of data, interference, lockup or other such problems. In all cases, priority servicing shall be given to the ISO required RSXXX port (used by MDAS).

The Meter shall support and be implementable with ISO WEnet communication chains, including:

(a) Meter RSXXX port to ISDN line (or lease line) to ATM Cloud POP to MDAS; and

(b) Meter RSXXX port to Compatible Meter Data Server to Frame Relay or ISDN line to ATM Cloud POP to MDAS.

8 Optional Meter Functions

8.1 Pulse Outputs

The ISO may specify one to four channels of pulse outputs that are proportional to the consumption quantities. The pulse output values shall be programmable with pulse durations of at least 100 milliseconds. The outputs may be either 2-wire, Form A or 3-wire, Form C configuration.

8.2 Current Loop

The ISO may specify an additional serial communication port consisting of a 2-wire, 20 milliamp current loop that is optically isolated from the rest of the Meter. At a minimum, the baud rate shall be selectable as 300/ 1200/ 2400/ 9600 baud.

8.3 Internal Modem

The ISO may specify an internal modem having telephone communications at autobaud rates of up to 28800 baud. The modem shall include automatic baud select, configurable answer time window and configurable answer ringcounter. The ring detect circuitry shall not be affected by spurious voltage rises in the telephone line.

8.4 Demand Threshold Alarm

The ISO may specify a kilowatt threshold relay that closes at a programmable demand value and stays closed for the remainder of the interval and until at least one complete interval does not exceed the threshold value. The value shall be independently programmable for each TOU rate season and schedule.

9 Accuracy

9.1 ANSI C12.10

The Meter shall meet or exceed the accuracy specifications contained in ANSI C12.10 over its entire service life without the need for adjustment.

9.2 Factory Calibration

The Meter shall be calibrated to provide the following level of accuracy:

(a) ± 0.2% at full load at power factor of 100%;

(b) ± 0.25% at full load at power factor of 50% lag;

(c) ± 0.25% at full load power factor at 50% lead; and

(d) ± 0.25% at light load at power factor of 100%.

9.3 Test Equipment

Meter accuracy and calibration tests, both shop and field, shall require only standard test equipment. No special laboratory-type test equipment or test procedures shall be required to assure accuracy of the Meter.

9.4 Creep

The Meter shall not creep. No pulse generation or registration shall occur for any consumption or demand quantity which depends on current while the current circuit is open.

9.5 Starting Current

The Meter shall start to calculate consumption and demand quantities when the per phase current reaches Class 20 - 5 milliamps.

9.6 Start-up Delay

The Meter shall start to calculate consumption and demand quantities less than 3 seconds after power application.

9.7 Pulse Outputs

Pulse outputs shall have the same accuracy as the Meter displays.

10 Electrical Requirements

10.1 Meter Forms, Voltage Ratings and Classes

The following forms, voltage ratings and classes of Meters are approved for installation on the ISO Controlled Grid:

(a) A – Base Type, FORMS 5A and 9A, 120 Volts, Class 10 and Class 20;

(b) Socket – Type, FORMS 5S and 9S, 120 Volts, Class 10 and Class 20;

(c) Switchboard – Type, 2 Element and 3 Element, 120 Volts, Class 10 & Class 20; and

(d) Rack mounted meter assemblies – 2 element and 3 element, Class 10 & Class 20.

10.2 Circuit Boards

All circuit boards in the Meter shall be designed to meet ISO's environmental and electrical testing requirements and the service life and performance expectations detailed in this Exhibit.

10.3 LCD Display Connectors

Gold pins encased in an elastomer or carbonized contacts, or some other better construction, shall be used to connect the LCD display to the register circuit board.

10.4 Metering Application

The Meter shall be used to meter electrical service on a continuous duty.

10.5 Connections

The Meter's internal electrical connections shall be in accordance with ANSI C12.10.

10.6 Meter Register Power Supply

The Meter register shall be powered from the line side of the Meter and shall have provision for external backup power. Neither the normal power supply nor the backup power supply (when so equipped) shall be fused.

10.7 Clock

Clocks shall meet the following requirements:

(a) the clock internal to the Meter shall be accurate within 2 minutes per week (0.02%) when not synchronized to the ISO Controlled Grid operation line frequency and shall be resettable through the ISO communications interface. The ISO will transmit a periodic master synchronizing signal to the meter;

(b) the internal clock shall have two modes of operation as follows:

i. the clock shall synchronize with the ISO Controlled Grid operation line frequency until an outage occurs. During the outage, the clock will then synchronize with its own internal crystal. When power returns, the clock shall resynchronize with the ISO's master synchronizing signal and follow line frequency; and

ii. the clock shall always synchronize with its own internal crystal, as a default; and

(c) the choice of clock mode shall be programmable.

10.8 Batteries

Batteries shall meet the following requirements:

(a) when the Meter design requires a battery as auxiliary power supply, the requirements of Section 3.7 shall apply;

(b) the battery shall be secured with a holder securely attached to the Meter. The battery holder and electrical connections shall be designed to prevent the battery from being installed with reversed polarity;

(c) replaceable batteries shall be easily accessible by removing the Meter cover. Battery replacement while the Meter is in service shall not interfere with any of the specified functions;

(d) no fuse external to the battery shall be installed in the battery circuit;

(e) the Meter battery shall provide a minimum carryover capability at 23° C for the functions listed in Section 3.7 and have a 15 year shelf life; and

(f) the following information shall be clearly identified on the battery:

i. manufacturer;

ii. date of manufacture, including year and month (i.e. 9601) or year and week (i.e. 9644);

iii. polarity;

iv. voltage rating; and

v. type.

10.9 Electromagnetic Compatibility

The Meter shall be designed in such a way that conducted or radiated electromagnetic disturbances as well as electrostatic discharges do not damage nor substantially influence the Meter.

10.10 Radio Interference Suppression

The Meter shall:

(a) not generate conducted or radiated radio frequency noise which could interfere with other equipment; and

(b) meet FCC Part 15 Class B computing device radio frequency interference standards.

11 Mechanical Requirements

11.1 General

The Meter shall not pose any danger when operating under rated conditions in its normal working position. Particular attention should be paid to the following:

(a) personnel protection against electric shock;

(b) personnel protection against effects of excessive temperature;

(c) protection against the spread of fire; and

(d) protection against penetration of solid objects, dust or water.

11.2 Corrosion Protection

All parts of the Meter shall be effectively protected against corrosion under normal operating conditions. Protective coatings shall not be damaged by ordinary handling nor damaged due to exposure to air. The Meter shall be capable of operating in atmospheres of up to (and including) 95% relative humidity condensing.

11.3 Solar Radiation

The functions of the Meter shall not be impaired, the appearance of the Meter shall not be altered and the legibility of the Meter nameplate and other labels shall not be reduced due to exposure to solar radiation throughout the service life of the Meter.

11.4 Corrosive Atmospheres

ISO may specify additional requirements for Meters used in corrosive atmospheres.

11.5 Meter Package

The Meter Package shall meet the following requirements:

(a) the socket Meter's dimensions shall be in accordance with ANSI C12.10;

(b) the socket Meter shall be designed for mounting outdoors in a standard meter socket;

(c) Meters shall have a twist-on self locking cover in accordance with ANSI C12.10 requirements. The Meter cover shall:

- i. not contain a metal or conducting locking ring;
- ii. shall be resistant to ultraviolet radiation;
- iii. be sealed in such a way that the internal parts of the Meter are accessible only after breaking the seal(s);
- iv. for any non-permanent cover deformation, not prevent the satisfactory operation of the meter;
- v. for the "sprue" hole (mold fill hole), not affect the ability to read the Meter; and
- vi. have an optical port per ANSI C12.13, Type 2.

(d) the method of securing the socket Meter to the meter socket shall be with either a sealing ring or a high security sealing device;

(e) the billing period demand reset device shall accommodate a standard electric meter seal and shall remain in place with friction if not sealed; and

(f) filtered ventilation shall be provided in the base of the Meter to prevent condensation inside the Meter.

11.6 Nameplate

The Meter nameplate shall:

(a) comply with the minimum information requirements of ANSI C12.10;

(b) include the Meter's serial number and the date of manufacture. The manufacturing date shall include the year and month (i.e. 9601) or the year and week (i.e. 9644);

(c) have the following attributes:

i. it shall be mounted on the front of the Meter;

ii. it shall not be attached to the removable Meter cover;

iii. it shall be readable when the Meter is installed in the Meter socket or panel; and

iv. it shall not impair access for accuracy adjustment or field replacement of components (such as the battery).

(d) include ANSI standard bar coding; and

(e) include an easily erasable strip with minimum dimensions of 3/8 inch by 1½ inches for penciling in items such as meter multiplier or the Meter tester's initials.

12 Security

12.1 Billing Period Reset

Operation of the billing period demand reset mechanism shall require breaking of a mechanical sealing device. Use of common utility-type sealing devices shall be accommodated.

12.2 Meter Password

The Meter shall be programmable by the Meter Programmer with up to four unique passwords to prevent unauthorized tampering by use of the optical port or the optional modem. For meters procured after 1/1/98, passwords must be a minimum of four (4) alpha/numeric characters. Access rights and capabilities shall be individually programmable for each password. The Meter shall accept multiple requests from different sources without error, lockup or loss of data.

12.3 Test Mode

Removal of the Meter cover shall be required to activate the Test Mode.

12.4 Program Security

At least four levels of security shall be available for the Rate Development Program and the Field Program. These levels include:

(a) Read Register— the user can only read billing and load profile data;

(b) Read Register— the user can only read billing and load profile data, and perform a billing period reset;

(c) Read/Modify Register— the user can perform functions listed in 12.4(a) and 12.4(b), plus download Meter configuration files and operate other features of the Field Program; and

(d) Read/Modify/Program Register— the user can perform functions listed in 12.4(a), 12.4(b) and 12.4(c), plus develop Meter configuration files and operate additional features of the Rate Development Program.

12.5 Revenue Protection

Meters that help prevent Energy diversion are preferred.

13 Meter Approval Testing

13.1 General Requirement

This Section outlines the testing required by the ISO to assure the quality of Meters, the ISO will not approve Meters which have not undergone the testing referred to in this Section.

ISO Testing using Independent Laboratory

In addition to the required manufacturer testing specified in this Section, the ISO reserves the right to require independent laboratory test data resulting from the performance of tests as outlined in this Section.

In addition to the applicable testing requirements of the ANSI C12 standards, the qualification tests specified in this Section shall be conducted to confirm correct operation of the Meter. The qualification testing is required for new Meter designs and for Meter product changes.

The ISO Metered Entity shall ensure that its supplier provides a certified test report documenting the tests and their results. The test report will be signed by the supplier and shall include all charts, graphs and data recorded during testing.

13.2 Meter Failure Definition

A Meter shall be designated as failed if any of the following events occur:

(a) failure of the Meter to perform all of the specified functions;

(b) failure of the Meter to meet the technical performance specifications included in this Exhibit;

(c) signs of physical damage or performance degradation as a result of a test procedure, including effects which could shorten the service life of the Meter;

(d) the occurrence of an unexpected change of state, loss of data or other unacceptable mode of operation for the Meter as a consequence of a test procedure; and

(e) failures shall be classified as a hardware, firmware or software failure or a combination according to the following definitions:

i. firmware failures are errors made during the fabrication of programmable read only memory (PROM) chips such that the required program or instruction set that the microprocessor is to perform is incorrect;

ii. hardware failures are failures that are physical in nature and directly traceable to the component level. Visual observances such as discoloration, cracking, hardening of cables, poor solder joints, etc. are also included. Failures of DIP switches, jumpers, and links are also included; and

iii. software failures are failures such as the loss or unintended change of data, the inability to program the Meter, the loss of the Meter program or the erroneous output or display of false information.

13.3 Meter Design Rejection Criteria

A Meter design will be rejected if any of the following events occur:

(a) the failure of one Meter during one test procedure and the failure of a second Meter during another test procedure; and

the failure of two or more Meters during the same test procedure.

13.4 Test Setup

(a) the Meter shall be connected to its normal operating supply voltage with a fully charged Power Failure Backup System. The Meter shall be energized throughout the duration of the test procedures, unless otherwise stated;

(b) before testing commences, the Meter shall be energized for a minimum of two hours at room temperature;

(c) all tests shall be conducted at room temperature unless otherwise specified; and

(d) the Meter shall be loaded to the nameplate test amperes at 100% power factor for all tests unless otherwise indicated.

13.5 Functional Test (No Load Test)

This test confirms the operation of the Meter functions in accordance with this Exhibit:

(a) the Meter shall be energized with no load;

(b) the Meter shall be programmed with the ISO supplied parameters using a Meter Programmer;

(c) operation of the specified functions will be verified over 24 hours by observing the Meter display and by interrogating the contents of Meter registers via a Meter Programmer; and

(d) to pass this test, the Meter shall operate as specified with no observed anomalies.

13.6 Accuracy Test

This test confirms the accuracy of the Meter:

(a) the accuracy of the Meter shall be tested for all combinations of the following conditions:

i. at ambient temperature, 85°C and -20°C;

ii. at power factors of 100%, 50% lag and 50% lead; and

iii. at 0% to 120% of class current;

(b) accuracy curves shall be provided for all combinations of the conditions; and

(c) to pass this test, the Meter shall have the indicated accuracy at ambient temperature for the following load conditions:

i. ± 0.2% at Full load at power factor of 100%;

ii. ± 0.25% at Full load at power factor of 50% lag;

iii. ± 0.25% at Full load at power factor of 50% lead; and

iv. ± 0.25% at Light load at power factor of 100%.

13.7 Line Voltage Variation Test

This test confirms the Meter's correct operation under varying line voltage conditions:

(a) the Meter shall be tested at line voltages ranging from 80% to 120% of rated voltage under the following load conditions:

i. full load at power factor of 100%; and

ii. light load at power factor of 100%; and

(b) to pass this test the Meter shall meet the following criteria:

i. operate as specified;

ii. have an accuracy as specified in Section 13.6(c) throughout the 80% to 120% voltage range; and

iii. the Power Failure Backup System shall not take over when the voltage is above 80% and below 120% of rated.

13.8 Momentary Power Loss

This test confirms the Meter's ability to withstand momentary power outages:

(a) the test will be performed by opening the AC power supply input for the specified duration;

(b) twelve tests shall be conducted using the following sequence:

i. energize the Meter;

ii. simulate a power loss of 0.5 cycles at 60 hertz;

iii. lengthen each succeeding simulated power outage by 0.5 cycles until a duration of 6.0 cycles is attained; and

iv. the start of each successive test shall be delayed by one minute; and

(c) to pass this test, the Meter shall operate as specified with no observed anomalies.

13.9 Power Failure Backup System Test

This test confirms the carryover capability of the Power Failure Backup System:

(a) this test shall be conducted at ambient temperature using a new or fully charged battery;

(b) the test shall be conducted using the following sequence:

i. Energize the Meter at full load for two hours;

ii. De-energize the Meter for 24 hours; and

iii. Verify the integrity of programs and metering data stored in memory; and

(c) to pass this test, the Meter shall operate as specified with no observed anomalies.

13.10 Brownout and Extended Low Voltage Test

This test confirms the Meter's ability to withstand brownouts and extended low voltage conditions:

(a) the test shall be conducted using the following sequence:

i. Energize the Meter and verify correct operation;

ii. Slowly lower the line voltage to 80% of nominal;

iii. Operate the Meter at this voltage level for 6 hours;

iv. Verify correct Meter operation;

v. Lower the line voltage to 50% of nominal;

vi. Operate the Meter at this voltage level for 6 hours; and

vii. Verify correct operation of the Meter and the Power Failure Backup System; and

(b) to pass this test, the Meter shall operate as specified with no observed anomalies.

13.11 Effect of Power Failure Backup System Voltage Variation on Clock Accuracy

This test confirms the effects of the battery voltage on the Meter's clock accuracy:

(a) the Meter shall be tested with the battery disconnected and an auxiliary DC power supply connected to the battery carryover circuit. The DC power shall be varied from 95% to 105% of nominal battery voltage; and

(b) to pass this test, the accuracy of the Meter clock shall be within 0.02% (2 minutes per week) with a voltage variation of 5 % of nominal battery voltage at ambient temperature.

13.12 Effect of Temperature Variation on Clock Accuracy

This test confirms the effects of temperature on the Meter clock accuracy:

(a) this test shall be conducted with the register in the battery carryover mode;

(b) the temperature shall be varied from 85°C to –20°C;

(c) the Meter shall be exposed to each temperature for a least 2 hours prior to testing; and

(d) to pass this test, the accuracy of the Meter clock shall be within 0.02% (2 minutes per week) at ambient temperature, 85°C, and -20°C.

13.13 Temperature Cycle Test

This test confirms the effects of an accelerated temperature cycle on the Meter:

(a) the Meter cover shall be removed during this test;

(b) the test duration shall be 7 days (168 hours);

(c) the temperature shall be cycled once per 24 hour period;

(d) temperature shall be varied linearly during the tests at a constant rate not to exceed 20°C per hour;

(e) humidity shall not be controlled during the test;

(f) the Meter shall be de-energized during the fourth and fifth cycles of the test to verify the performance of the Power Failure Backup System during temperature fluctuations;

(g) each 24 hour cycle shall consist of the following:

i. begin test at +20°C (or room temperature if within 5°C);

ii. ramp up to +85°C in approximately 3.25 hours;

iii. hold at +85°C for approximately 10.75 hours;

iv. ramp down to -20 C in approximately 5.25 hours;

v. hold at -20°C for approximately 2.75 hours;

vi. ramp up to +20°C in approximately 2.00 hours; and

vii. begin next 24 hour cycle or end test after 7 cycles; and

(h) to pass this test, the Meter shall operate as specified with no observed anomalies for the entire test period.

13.14 Humidity Cycle Test

This test confirms the effects of an accelerated humidity cycle on the Meter:

(a) the Meter cover shall be removed during this test, or a meter cover with a large hole at the bottom may be substituted;

(b) the duration of the test shall be 24 hours;

(c) condensation may form on the Meter during the test;

(d) temperature shall be varied linearly during the tests at a constant rate not to exceed 20°C per hour;

(e) humidity shall not be controlled during temperature changes;

(f) the test shall consist of the following sequence:

i. begin at +20°C (or room temperature if within 5°C);

ii. ramp up to +85°C in approximately 3.25 hours;

iii. ramp up to a relative humidity of 95% in approximately 1 hour;

iv. hold at +85°C at a relative humidity of 95% ±1% for approximately 14.5 hours;

v. ramp down to +20°C in approximately 3.25 hours;

vi. concurrently with Section 13.14(f)v. ramp down to a relative humidity of 75% in approximately 15 minutes;

vii. hold relative humidity at 75% for remainder of temperature ramp down; and

viii. hold at 20°C at a relative humidity of 75% ±1% for approximately 2 hours; and

(g) to pass this test, the Meter shall operate as specified with no observed anomalies for the entire test period.

13.15 Insulation Withstand Test

This test confirms the insulation levels of the Meter:

(a) the Meter shall not be energized for this test;

(b) the insulation between power line voltage and current carrying parts and any other metallic or conductive part shall be tested by applying 2500 volts rms, 60 Hz for a period of one minute; and

(c) to pass this test the leakage current shall not exceed one milliamp for the duration of the test and the Meter shall operate after completion of the test.

13.16 Standard Waveform Surge Withstand Test

This test confirms the ability of the Meter to withstand voltage transients:

(a) the Meter shall be energized but not loaded during the test;

(b) the test shall be conducted in accordance with the latest recognized industry standards;

(c) the oscillatory test wave shall be applied at a repetition rate of 100 tests per second for 25 seconds;

(d) the test signal shall be applied in both the common and transverse modes;

(e) the test shall be conducted on all voltage, current, and optional equipment inputs and outputs;

(f) this test will be performed two times with a maximum period of 1 minute between tests; and

(g) to pass this test, the Meter shall operate as specified with no observed anomalies;

13.17 Fast Transient Waveform Surge Withstand Test

This test confirms the ability of the Meter to withstand fast voltage transients:

(a) the Meter shall be energized but not loaded during the test;

(b) this test shall be conducted in accordance with the latest industry recognized standard;

(c) the unipolar test wave shall be applied at a repetition rate of 100 tests per second for 25 seconds;

(d) the test signal shall be applied in both the common and transverse modes;

(e) the test shall be conducted on all voltage, current, and optional equipment inputs and outputs;

(f) this test will be performed two times with a maximum period of 1 minute between tests; and

(g) to pass this test, the Meter shall operate as specified with no observed anomalies.

13.18 Powerline Surge Voltage and Current Test

This test confirms the ability of the Meter to withstand power line voltage and current surges:

(a) the meter shall be energized but not loaded during the test;

(b) the test shall be performed using the unipolar and the ring waveform specified in the latest industry recognized standard;

(c) the test surges shall be applied to the power line in both the normal and common modes;

(d) the following number of surges shall be applied at the indicated voltages:

i. 12 surges at 6 kV;

ii. 12 surges at 5 kV; and

iii. 36 surges at 4 kV.

(e) the first test surges at 5 kV and 6 kV shall be injected at 0 degrees on the positive half-cycle of the waveform. Each successive test surge shall be shifted 15 degrees on the positive half-cycle of the waveform up to 180 degrees;

(f) the first test surge at 4 kV shall be injected at 0 degrees on the positive half-cycle of the waveform. Each successive test surge shall be shifted 15 degrees on both the positive and negative half-cycles of the waveform up to 360 degrees;

(g) sufficient time shall be allowed in between test surges for the electronic components to return to normal operating temperatures. A minimum of 5 minutes shall be allowed between each surge test;

(h) the applied test signals shall be monitored and recorded. The Meter under test shall be monitored to confirm that correct operation is maintained;

(i) after the tests each meter shall be inspected for visible damage, such as signs of arcing, etc.; and

(j) to pass this test, the Meter shall operate as specified with no visible damage observed.

13.19 Electrostatic Susceptibility Test

This test verifies the ability of the Meter to withstand electrostatic discharges:

(a) this test shall be tested in accordance with the latest revision of Military Handbook DOD-HDBK-263;

(b) the test generator shall simulate a human body with a capacitance of 100 picofarads and a series resistance of 1500 ohms;

(c) the test probe shall be a 3/8 inch rod with a rounded tip;

(d) the following procedures shall be followed:

i. test all surfaces, including switches and buttons and other components that will be contacted by personnel under normal handling, installation and use of the Meter. This shall include any safety grounded or neutral terminals on the exterior of the meter enclosure;

ii. with the test probe voltage set at 10 kV, contact each of the above surfaces with the probe;

iii. with the test probe voltage set to 15 kV, locate the probe to within approximately 0.5 inch (avoiding contact) with each of the above surfaces; and

iv. the functions of the Meter shall be periodically verified for correct operation; and

(e) to pass this test, the Meter shall operate as specified with no observed anomalies.

13.20 Visual Inspection

This test shall be performed after all of the other tests except the Shipping Test have been performed:

(a) visual inspection shall be performed for all electronic circuit boards in the Meter; and

(b) to pass this test, the Meter shall not have any defect which would result in rejection under the latest recognized industry standards on any electronic circuit board.

13.21 Shipping Test

This test confirms the ability of the Meter and its packaging to withstand the rigors of shipping and handling:

(a) the Meter shall not be energized during this test, but shall be programmed and operating in the power Backup mode;

(b) the packaged Meter shall be subjected to the following tests:

i. the National/International Safe Transit Association Pre-shipment Test Procedures, Project IA; and

ii. Method B, Single Container Resonance Test, of the latest revision of American Society for Testing and Materials (ASTM) Standard D-999. Test intensities, frequency ranges and test durations shall meet or exceed the recommended values of ASTM D-999; and

(c) to pass this test, the Meter shall be inspected and tested to verify that no damage had occurred and that the time and all stored data is correct.

14 Safety

14.1 Hazardous Voltage

Hazardous voltages shall not be easily accessible with the Meter cover removed.

14.2 Grounding

All accessible conductive parts on the exterior of the Meter and conductive parts that are accessible upon removal of the Meter cover shall be electrically connected to the Meter grounding tabs. All connections in the grounding circuit shall be made with an effective bonding technique.

14.3 Toxic Materials

No materials that are toxic to life or harmful to the environment shall be exposed in the Meter during normal use.

14.4 Fire Hazard

Materials used in the construction of the Meter shall not create a fire hazard.

15 Data Security And Performance

(a) Manual access for changing data or reprogramming shall require the physical removal or breaking of an ISO seal by the ISO or an ISO Authorized Inspector.

(b) No loss of data shall occur as a result of the following events within design specifications:

i. power outages, frequency changes, transients, harmonics, reprogramming, reading; and

ii. environmental factors—dampness, heat, cold, vibration, dust.

(c) 5-minute interval data for the most recent 60 day period shall always be available and accessible via the communications interface or the optical interface.

16 Documentation

16.1 Hardware Documentation To Be Provided For ISO Review

(a) Drawing(s) showing the external meter connections.

(b) Instruction booklets detailing the necessary procedures and precautions for installation of the Meter provided for use by field personnel during initial installation written in the style of a step by step outline.

(c) One (1) technical/maintenance manual and one (1) repair manual shall be provided for each Meter style. These manuals shall be sufficiently detailed so that circuit operation can be understood and equipment repair facilitated.

(d) The above documents shall be submitted for approval by ISO before equipment is installed. Approval of documents by the ISO shall not relieve any responsibility for complying with all the requirements of this Exhibit.

16.2 Software

A complete set of manuals detailing the operation of the Rate Development Program, the Field Program, and the Field Disk Serialization Program shall be provided to ISO for review. These manuals shall explain to a person with only basic computer knowledge how to generate and download Meter configuration files.

17 Applicable Standards

The standards referred to in Appendix J to the ISO Tariff shall apply to all Meters.

18 Definitions

The following terms and expressions used in this Exhibit are detailed as set forth below:

"Ambient Temperature" means temperature of 23°±2° Celsius.

"Average Power Factor" means the power factor calculated using the average active and reactive power flows over the latest demand interval.

"Delivered" means Energy (active, reactive, or apparent) that flows from the ISO Controlled Grid to an End-User.

"Failed Meter" means a Meter in which any part or component, except the removable battery, has failed.

"Failure" means any hardware, firmware or software failure, or any combination.

"Field Disk Serialization Program" means a software package that allows the user to assign a separate password to each disk copy of the Field Program.

"Field Program" means a software package that allows the user to download Meter configuration files into the Meter and perform other testing and maintenance activities.

"Hazardous Voltage" means any voltage exceeding 30 volts rms.

"Meter" means all single phase and three phase electricity meters with electronic registers, including hybrid and solid state meters, but excluding solid state recorders, and including any optional devices included under the Meter cover.

"Meter Programmer" means the PC DOS based laptop computers used for meter reading/programming.

"MSDS" means the Material Safety Data Sheet.

"Power Failure Backup System" means a sub-system in the Meter that provides power to the electronic circuitry when the normal power line voltage is below operating limits. The sub-system usually consists of a battery and may or may not include a super capacitor.

"Quadrant" means the term used to represent the direction of power flows (active and reactive) between the ISO Controlled Grid and an End-User. The 4 quadrants are defined as follows:

(a) Quadrant 1 – shall measure active power and reactive power delivered by the ISO Controlled Grid;

(b) Quadrant 2 – shall measure active power received by ISO Controlled Grid and reactive power delivered by the ISO Controlled Grid;

(c) Quadrant 3 – shall measure active power and reactive power received by the ISO Controlled Grid; and

(d) Quadrant 4 – shall measure active power delivered by ISO Controlled Grid and reactive power received by the ISO Controlled Grid.

"Rate Development Program" means a software package that allows the user to generate Meter configuration files including operating parameters and TOU schedules.

"Received" means Energy (active, reactive or apparent) that flows from a Generator to the ISO Controlled Grid.

"RFI" means the Radio Frequency Interference.

"Temperature tolerance" means ±2° Celsius.

Attachment 1
Physical and Electronic Attribute Criterion for Electricity Meters

	Test / Inspection Description	Pass	Fail
1.	**Bayonets**		
A.	Missing or loose parts, i.e., cotter pin, arc gap, etc.		
2.	**Meter Base**		
A.	Any cracked and/or missing/damaged gasket		
B.	Any broken leg		
C.	Missing or loose voltage link or screw		
D.	Any missing or loose arc gaps		
E.	Missing or damaged ventilation screen or filter on applicable meter		
F.	Sealing hole unusable for sealing		
G.	Any chips on upper half of meter (gasket ring area)		
H.	Any chips which may jeopardize meter integrity		
I.	Any sign of water damage in meter such as corrosion, oxidation, stain		
J.	Missing or loose rivets holding frame to base		
3.	**Meter Frame**		
A.	Nameplate data incorrect or flawed		
B.	Missing or loose hardware on frame		
4.	**Module**		
A.	Loose or defective power connectors		
B.	Improper routing of voltage leads		
C.	Improper fit (loose or crooked)		
D.	Crimped or pinched voltage leads		
E.	Incorrect module		
F.	Calibration screw access should not be significantly affected (or covered)		
5.	**Meter Cover**		
A.	Wiring to communication port is correct & solid		
B.	Proper meter cover is used for meter type and class		
C.	Mechanical reset mechanism works properly		
D.	Proper alignment, positioning, and operation of all cover mechanisms		

Attachment 1

Physical and Electronic Attribute Criterion for Electricity Meters (cont.)

6. Electronic Register		
A. Program register to verify acceptance of rate schedule		
B. Check display that all segments are operational		
C. Check battery carryover function, if appropriate		
D. Check register tracking by inputting disk revolutions		
E. Check for any visual defects in the register assembly		

Only scratches and/or chips that are cosmetically or functionally objectionable will be classified as defective and failing.

Attachment 2
Meter Display Items

Display Item	Normal Mode	Alternate Mode	Test Mode
Minimum Requirements for Delivered kWh			
Complete Display (Segment) Test	x	x	
Demand Reset Count		x	
Demand Reset Date		x	
Instantaneous kW	x	x	
Interval length		x	
Minutes of Battery Use		x	
Present time	x	x	
Previous Billing Rate A kWh		x	
Previous Billing Rate A Maximum kW		x	
Previous Billing Rate B kWh		x	
Previous Billing Rate B Maximum kW		x	
Previous Billing Rate C kWh		x	
Previous Billing Rate C Maximum kW		x	
Previous Billing Rate D kWh		x	
Previous Billing Rate D Maximum kW		x	
Previous Billing Total kWh		x	
Previous Season Rate A kWh	x	x	
Previous Season Rate A Maximum kW	x	x	
Previous Season Rate B kWh	x	x	
Previous Season Rate B Maximum kW	x	x	
Previous Season Rate C kWh	x	x	
Previous Season Rate C Maximum kW	x	x	
Previous Season Rate D kWh	x	x	
Previous Season Rate D Maximum kW	x	x	
Previous Season Total kWh		x	
Program ID		x	
Rate A kWh	x	x	
Rate A Maximum kW	x	x	
Rate B kWh	x	x	
Rate B Maximum kW	x	x	
Rate C kWh	x	x	
Rate C Maximum kW	x	x	
Rate D kWh	x	x	
Rate D Maximum kW	x	x	

Attachment 2
Meter Display Items (cont.)

Display Item	Normal Mode	Alternate Mode	Test Mode
Minimum Requirements for Delivered kWh (cont.)			
Total kWh	x	x	x
Wh per disk revolution (Kh)		x	
Wh per pulse (Ke)		x	
Minimum Requirements for Test Mode			
Present Interval Demand—kW			x
Pulse count			x
Time left in subinterval			x
Total kWh			x
Additional requirements for Received kWh (if specified)			
Previous Billing Total Received kWh		x	
Previous Season Total Received kWh		x	
Total Received kWh	x	x	
Additional requirements for kVARh (if specified)			
Maximum Delivered kVAR		x	
Maximum Received kVAR		x	
Previous Billing Maximum Delivered kVAR		x	
Previous Billing Maximum Received kVAR		x	
Previous Billing Total Delivered kVARh		x	
Previous Billing Total Received kVARh		x	
Previous Season Maximum Delivered kVAR		x	
Previous Season Maximum Received kVAR		x	
Previous Season Total Delivered kVARh		x	
Previous Season Total Received kVARh		x	
Total Delivered kVARh		x	
Total Received kVARh		x	
Previous Billing Maximum Delivered kVA		x	
Previous Billing Maximum Received kVA		x	
Previous Billing Total Delivered kVAh		x	
Previous Billing Total Received kVAh		x	
Previous Season Maximum Delivered kVA		x	
Previous Season Maximum Received kVA		x	

Attachment 2
Meter Display Items (cont.)

Additional requirements for kVAh (cont.)			
Previous Season Total Delivered kVAh		x	
Previous Season Total Received kVAh		x	
Total Delivered kVAh		x	
Total Received kVAh		x	
Additional requirements for Power Factor (if specified)			
Quadrant 1 Average Power Factor		x	
Quadrant 2 Average Power Factor		x	
Quadrant 3 Average Power Factor		x	
Quadrant 4 Average Power Factor		x	
Total Average Power Factor Delivered		x	
Total Average Power Factor Received		x	

EXHIBIT 2 TO PART D

ISO SPECIFICATION FOR CERTIFICATION OF OIL-FILLED, WOUND INSTRUMENT TRANSFORMERS FOR REVENUE METERING

1 Purpose

This Exhibit specifies the technical requirements for reliable high-accuracy Current Transformers (CT) and Voltage Transformers (VT) to be used for revenue quality metering on the ISO Controlled Grid.

2 Scope

2.1 This Exhibit applies only to the following:

- Oil-filled Single-Phase CTs - 35kV-230kV.
- Oil-filled Single-Phase VTs - 35kV-230kV.
- Oil-filled Single-Phase Combination Current/Voltage Transformers - 35kV-230kV.

2.2 This Exhibit applies only to the following Oil-filled Wound Devices, which are VTs < 35kv.

VTs > 230kv must be individually specified in accordance with the engineered installations.

3 Standards

All instrument transformers covered by this Exhibit shall be designed, manufactured, tested and supplied in accordance with the applicable standards referred to in Appendix J to the ISO Tariff.

4 Definitions

"Hermetically Sealed" means completely sealed by fusion, soldering, etc., so as to keep air or gas from getting in or out (i.e. airtight).

"Metering Unit" means one or more Voltage element(s) and one or more Current element(s) contained in one common housing.

"BIL Rating" means basic lightning impulse insulation level.

"Burden Rating" means the total impedance (in ohms) that can be connected to the secondary circuit(s) of an instrument transformer while still maintaining metering accuracy of plus-or-minus 0.3%

5 Specifications

5.1 General

All instrument transformers covered by this Exhibit shall be hermetically sealed, oil-filled type and have a minimum BIL Rating appropriate for the designated nominal System voltage:

- 60 - 69 kV – 350 kV BIL
- 115 kV – 550 kV BIL

- 230 kV – 900 kV BIL

5.2 Current Transformers

5.2.1 Current Transformer windings (typical configurations) shall be either:

(a) a single primary winding and single secondary winding with dual ratio tap;

(b) a dual primary winding and a single ratio tap;

(c) a single primary winding and one or more secondary windings with dual ratio tap(s); or

(d) other combinations as available and approved by the ISO.

5.2.2 Rated primary current

The rated primary current must be as specified by the ISO Metered Entity.

5.2.3 Rated secondary current

The rated secondary current must be 5 amperes @ rated primary current.

5.2.4 Accuracy and burden

All current transformers shall have an accuracy and burden of:

(a) standard – plus-or-minus 0.3% @ B0.1 - 1.8 ohms, 10% - 100% rated current; or

(b) optional – plus-or-minus 0.15 % @ B0.1 - 1.8 ohms, 5% - 100 % rated current.

5.2.5 Continuous current rating factor

All current transformers shall have a continuous current rating factor of:

(a) standard – 1.5 @ 30 degrees C Ambient; or

(b) optional – 1.0 @ 30 degrees C Ambient.

5.2.6 Short time thermal current rating

The short time thermal current rating varies with transformer rating as follows:

25/50: 5 ratio, 4 kA RMS to 1500/3000:5 ratio, 120 kA RMS.

5.2.7 Mechanical short time current rating

The mechanical short time current rating varies with transformer rating as follows:

25/50:5 ratio, 3 kA RMS to 1500/3000:5 ratio, 90 kA RMS.

5.3 Voltage Transformers

5.3.1 Transformer windings shall consist of a single primary winding and one or more tapped secondary windings.

5.3.2 Rated primary voltage, as specified by the ISO Metered Entity, must be 34,500 volts through 138,000 volts, L-N.

5.3.3 Rated secondary voltage must typically be 115/69 volts.

5.3.4 The ratio of primary to secondary windings must be 300/500:1 through 1200/2000:1.

5.3.5 Accuracy and burden

All voltage transformers shall have accuracy and burden of:

(a) standard – plus-or-minus 0.3% through B. ZZ @ 90% through 110% of nominal voltage; or

(b) optional – plus-or-minus 0.15% through B. Y 90% through 110% of nominal voltage.

5.3.6 Thermal burden rating

All voltage transformers shall have a thermal burden rating of:

(a) 34.5 kV – 2500 VA, 60 hertz;

(b) 60 kV & 69 kV – 4000 VA, 60 hertz; or

(c) 115 kV – 6000 VA, 60 hertz.

5.4 Combination Current/Voltage Transformers (Metering Units)

Combination Current/Voltage Transformers shall maintain the same electrical, accuracy and mechanical characteristics as individual CTs and VTs. Physical dimensions may vary according to design.

5.5 Grounding

The neutral terminal of the VT shall exit the tank via a 5kV insulated bushing and be grounded by means of a removable copper strap to a NEMA 2-hole pad.

5.6 Primary Terminals

The primary terminals shall be tin-plated NEMA 4-hole pads (4”x4”).

5.7 Paint

Exterior metal non current-carrying surfaces shall be painted with a weather-resistant paint system consisting of one primer and two industry recognized gray finish coats. As an option, for high-corrosion areas, special corrosion-resistant finishes (e.g. zinc-rich paint, stainless steel tank) shall be used.

5.8 Porcelain

Porcelain shall be of one-piece wet-process, glazed inside and outside. The outside color shall be in accordance with industry recognized gray glaze. The minimum creepage and strike-to-ground distances for various voltages shall be as follows:

Voltage (nominal kV)	Creepage (inches)	Strike (inches)
34.5	34	13
60 & 69	52	24
115	101	42
230	169	65
230 (1050 BIL)	214	84

5.9 Insulating Oil

The nameplate shall be of non-corroding material and shall indicate that the dielectric fluid is free of polychlorinated biphenyls by the inscription:

"CONTAINS NO PCB AT TIME OF MANUFACTURE".

5.10 Accessories

All units shall be equipped with the following standard accessories:

- 1/2" brass ball drain valve with plug
- 1" oil filling opening with nitrogen valve
- Magnetic oil level gauge, readable from ground level
- Primary bypass protector
- Sliding CT shorting link
- Four 7/8"x 2-3/8" mounting slots
- Four 1" eyebolts on base for four-point lifting sling
- 1/4" threaded stud secondary terminals

- Two conduit boxes, each with three 1-1/2” knockout

6 Testing

The ISO Metered Entity shall ensure that, before shipment, each transformer is subjected to testing as prescribed by recognized industry standards and other tests including:

(a) Applied voltage test for primary and secondary winding withstand to ground;

(b) Induced voltage test for proper turn-to-turn insulation;

(c) Accuracy test for ratio correction factor and phase-angle verification to confirm 0.3% metering accuracy per recognized industry standards;

(d) Ratio test;

(e) Insulation Power Factor test;

(f) Polarity test;

(g) Leak test to assure integrity of gaskets and seals; and

(h) Partial Discharge Test may be done in conjunction with applied voltage testing to assure proper line-to-ground withstand.

The tests shall be submitted to the ISO on a formal certified test report.

7 Required Information

The following drawings and information shall be required:

(a) 3 sets of drawings showing physical dimensions including mounting holes and primary CT terminal details, nameplate. The ISO Metered Entity shall ensure that it receives a schematic of connections from its supplier; and

(b) a copy of quality controls/quality assurance (QC/QA) manuals applicable to production of the transformer(s).

PART E

TRANSFORMER AND LINE LOSS CORRECTION FACTORS

E 1 Introduction

Transformer loss correction refers to the practice of metering electrical Energy delivered at a high-voltage billing point using metering equipment connected on the low-voltage side of the delivery point. The metering equipment is provided with a means of correction that adds to, or subtracts from, the actual active and reactive metered values in proportion to losses that are occurring in the transformer.

Transformer losses are divided into two parts:

the core or iron loss (referred to as the no-load loss); and

the copper loss (referred to as the load loss).

Both the no-load loss and the load loss are further divided into Watts and Var components.

The no-load (iron) loss is composed mostly of eddy current and hystersis losses in the core. No-load loss varies in proportion to applied voltage and is present with or without load applied. Dielectric losses and copper loss due to exciting current are also present, but are generally small enough to be neglected.

The load (copper) watt loss (I^2 + stray loss) is primarily due to the resistance of conductors and essentially varies as the square of the load current. The Var component of transformer load loss is caused by the leakage reactance between windings and varies as the square of the load current.

Line losses are considered to be resistive and have I^2R losses. The lengths, spacings and configurations of lines are usually such that inductive and capacitive effects can be ignored. If line losses are to be compensated, they are included as part of the transformer load losses (Watts copper).

The coefficients, which are calculated at the calibration point of the meter, are entered into the meter as Percent Loss Watts Copper %LWCU), Percent Loss Watts Iron (%LWFE), Percent Loss Vars Copper (%LVCU), and Percent Loss Vars Iron (%LVFE).

Percent losses are losses expressed as a percent of the full load on a meter.

The formulas used to determine the compensation values at a particular operating point are:

$$\text{WATTS Compensation Value} = \frac{\text{Measured Voltage}^2}{\text{Calibration Point Voltage}^2} * \%LWFE + \frac{\text{Measured Current}^2}{\text{Calibration Point Current}^2} * \%LWCU$$

$$\text{Vars Compensation Value} = \frac{\text{Measured Voltage}^4}{\text{Calibration Point Voltage}^4} * \%LVFE + \frac{\text{Measured Current}^2}{\text{Calibration Point Current}^2} * \%LVCU$$

E 2 Calculating Transformer Loss Constants

Transformer Loss correction calculations with electronic meters are accomplished internally with firmware. Various setting information and test data is required to calculate the four values which are to be programmed into the meter.

The following information is required about meter installations:

the transformer high voltage (HV) voltage rating

the transformer kVa rating

the transformer high voltage (HV) tap settings

the transformer low voltage (LV) tap settings

the transformer connection (wye or delta)

the transformer phases (1 or 3)

the voltage transformer (VT) ratio

the current transformer (CT) ratio

the number of meter elements

The following data from a transformer test report is required:

no-load (iron) loss

full-load (copper) loss

percent impedance

percent excitation current

The test data required may be obtained from the following sources:

the manufacturer’s test report

a test completed by a utility or independent electrical testing company

If the transformer bank is used to deliver power to more than one entity (that is, it is a joint use transformer bank) additional data is required, including the:

maximum available kVa from the transformer bank

contracted amount of load to be compensated in kW

contractual power factor amount to be used in calculations

E 3 Calculating Line Loss Constants

Line Loss correction calculations with electronic meters are accomplished internally with firmware. Various information about the radial line is required to calculate the value which is programmed into the meter. The resistance of the conductors are used to calculate a value which is added to the Watts copper loss value which is programmed into the meter. It is not practical to compensate for line losses in a network connected line, only radial lines.

The following information is required about the transmission line:

the transmission line type

the ohms per mile

the length in miles of each type of line

E 4 Applications

Joint Use Transformers

Where a transformer bank is used to deliver power to more than one entity (that is, a joint use transformer bank), no-load iron losses are adjusted by the transformer percent use. This percent use is determined by dividing a negotiated contract kW load (*Contract kW*) at a negotiated power factor (*% Power Factor*) by the maximum available kVa from the transformer bank (*Max. Available kVa*).

$$Percent\ Use = \frac{Contract\ kW \big/ \%\ Power\ Factor}{Max.Available\ kVa}$$

Switched Lines

Line Loss correction for radial lines which are switched, must be based on a negotiated average resistance based on the typical operating characteristics.

Transformer Load Tap Changer

Transformers equipped with a load tap changer (i.e., which has the capability to change transformer voltage tap positions or settings under Load) for regulating voltage, must have the corrections calculated at the median tap voltage. Differences in the corrections must be minimal and must even out over time as the bank operates above and below the median tap voltage.

E 5 Worksheets

A pro forma Transformer and Line Loss Correction Worksheet which can be used to perform the above calculation is attached to this Part. Instructions for completing the worksheet are as follows:

Complete the Name, Delivery, Location and Revision Date fields using the ISO Metered Entity's name, operating name, city, state, and the date of the calculation.

Enter Transformer High Voltage (HV) winding rated voltage, this is the voltage at which the transformer tests were performed.

Enter the HV and Low Voltage (LV) transformer tap settings.

Enter 'Y' or 'D' to indicate the secondary winding connection of either wye or delta.

Enter '1' to indicate that the transformer bank is comprised of single phase units or '3' to indicate the bank is comprised of three phase units.

Enter '2' or '3' to indicate the number of elements in the meter.

Enter the VT and CT ratios of the instrument transformers used in the metering.

Enter 'Y' or 'N' to indicate if the transformer bank is utilized by more than one entity.

Enter the negotiated contract and power factor for the joint use portion of the transformer (if any).

If compensation coefficients are required at a calibration point other than five amps, enter the new value.

Space is provided to make comments about the calculation or delivery configuration.

Enter the manufacturer and serial number of the transformer(s).

Enter the kVa rating of each bank. For multiple rated banks, the base kVa should be used. Enter the test data collected at base kVa.

Enter the no-load losses in Watts from the test data.

Enter the load losses in Watts from the test data.

Enter the impedance from the test data.

Enter the Exciting current from the test data.

If the maximum available kVa from the transformer bank is more than the rated kVa, this value can be entered manually. An example may be for a triple rated transformer that has fans with a rating which is more than the base kVa. This value only affects the percent use calculation.

Enter the line type for each type of line to be compensated.

Enter the resistance in ohms per mile of each type of line to be compensated.

Enter the total length in miles of each type of line to be compensated.

E 6 Reference Materials

The following additional references may be referred to for assistance when calculating the correction factors referred to in this Part.

Handbook For Electricity Metering, Ninth Edition. Edison Electric Institute. Washington, D.C.

Eastern Specialty Company Bulletin No. 63.

American National Standard Institute. Test Code for Distribution, Power and Regulating Transformers.

System Loss Compensation, Schlumberger Industries, Quantum Multifunction Meter Hardware Instruction Manual 1610, November 1993.

Transformer Loss Calculation Method, Process System Manual, Appendix E.

Transformer and Line Loss Correction Worksheet (Example)

TRANSFORMER AND LINE LOSS CORRECTION

Name: Acme Power Company
Delivery: Delivery Number 5
Location: Surf Beach, CA
Rev. Date: 5/6/97

HV Rated Voltage:	110000 V	VT Ratio:	60:1
HV Tap:	101200 V	CT Ratio:	600:5
LV Tap:	13090 V	Joint Use (Y/N):	N
Trf. Conn. (Y/D):	Y	Metering Trf. Use:	100 %
Trf. Phase (1 or 3)	3	Contract kW:	10,000 kW
# Meter Elem.:	3	Power Factor:	95 %

Compensation Values (@ 5A F.L.)		Compensation Values at:	10 A
Watt Fe Loss:	0.16 %	Watt Fe Loss:	.08 %
Watt Cu Loss:	0.53 %	Watt Cu Loss:	1.06 %
Watt Tot. Loss:	0.69 %	Watt Tot. Loss:	1.14 %
Var Fe Loss:	0.31 %	Var Fe Loss:	0.16 %
Var Cu Loss:	10.96 %	Var Cu Loss:	21.92 %
Var Tot. Loss:	11.27 %	Var Tot. Loss:	22.08 %

Comments:

TRANSFORMER DATA

Serial Number	KVa Rating	No Load (Fe) Loss	Load (Cu) Loss	(Z) Impedance	(IE) Exciting Current
ABB 1000001	12000	22200 w	51360 w	8.84 %	0.45 %

Total kVa rating:	12000		Max Available kVa:	12000

LINE DATA

	Resistance	Length
#1 Line Type:	Ohms/mile	miles
#2 Line Type:	Ohms/mile	miles
#3 Line Type:	Ohms/mile	miles
#4 Line Type:	Ohms/mile	miles
#5 Line Type:	Ohms/mile	miles
#6 Line Type:	Ohms/mile	miles

Transformer and Line Loss Correction Worksheet (Example, continued)

TRANSFORMER AND LINE LOSS CORRECTION

Name: ACME Power Company
Delivery: Delivery Number 5
Location: Surf Beach, CA
Rev. Date: 5/6/97

HV Rated Voltage:	110000 V	VT Ratio:	60:1
HV Tap:	101200 V	CT Ratio:	600:5
LV Tap:	13090 V	Joint Use (Y/N):	N
Trf. Conn. (Y/D):	Y	Metering Trf. Use:	100 %
Trf. Phase (1 or 3)	3	Contract kW:	10,000 kW
# Meter Elem.:	3	Power Factor:	95 %

TRANSFORMERS

Serial Number	kVa
ABB 1000001	12000

TRANSFORMER LOSS COMPENSATION TEST POINTS FOR WATTHOURS

SERIES TEST

Test Load	% Iron	% Copper	% Total
Light	1.60	0.05	1.65
Full	0.16	0.53	0.69
0.5 P.F.	0.32	1.06	1.38

TRANSFORMER LOSS COMPENSATION TEST POINTS FOR VARHOURS

SERIES TEST

Test Load	% Iron	% Copper	% Total
Light	3.10	1.10	4.20
Full	0.31	10.96	11.27
0.5 P.F.	0.62	21.92	22.54

Pro Forma Transformer and Line Loss Correction Worksheet

TRANSFORMER AND LINE LOSS CORRECTION

Name:
Delivery:
Location:
Rev. Date:

HV Rated Voltage:	V	VT Ratio:	:1
HV Tap:	V	CT Ratio:	:5
LV Tap:	V	Joint Use (Y/N):	
Trf. Conn. (Y/D):		Metering Trf. Use:	100 %
Trf. Phase (1 or 3)		Contract kW:	kW
# Meter Elem.:		Power Factor:	%

Compensation Values (@ 5A F.L.)		Compensation Values at:	10 A
Watt Fe Loss:	%	Watt Fe Loss:	%
Watt Cu Loss:	%	Watt Cu Loss:	%
Watt Tot. Loss:	%	Watt Tot. Loss:	%
Var Fe Loss:	%	Var Fe Loss:	%
Var Cu Loss:	%	Var Cu Loss:	%
Var Tot. Loss:	%	Var Tot. Loss:	%

Comments:

TRANSFORMER DATA

Serial Number	KVa Rating	No Load (Fe) Loss	Load (Cu) Loss	(Z) Impedance	(IE) Exciting Current

Total kVa rating:	Max Available kVa:

LINE DATA

	Resistance	Length
#1 Line Type:	Ohms/mile	miles
#2 Line Type:	Ohms/mile	miles
#3 Line Type:	Ohms/mile	miles
#4 Line Type:	Ohms/mile	miles
#5 Line Type:	Ohms/mile	miles
#6 Line Type:	Ohms/mile	miles

Pro Forma Transformer and Line Loss Correction Worksheet (continued)
TRANSFORMER AND LINE LOSS COMPENSATION

Name:
Delivery:
Location:
Rev. Date:

HV Rated Voltage:	V	VT Ratio:	:1
HV Tap:	V	CT Ratio:	:5
LV Tap:	V	Joint Use (Y/N):	
Trf. Conn. (Y/D):		Metering Trf. Use:	100 %
Trf. Phase (1 or 3)		Contract kW:	kW
# Meter Elem.:		Power Factor:	%

TRANSFORMERS

Serial Number	kVa

TRANSFORMER LOSS COMPENSATION TEST POINTS FOR WATTHOURS

SERIES TEST

Test Load	% Iron	% Copper	% Total
Full			
0.5 P.F.			
Light			

TRANSFORMER LOSS COMPENSATION TEST POINTS FOR VARHOURS

SERIES TEST

Test Load	% Iron	% Copper	% Total
Full			
0.5 P.F.			
Light			

PART F

INSTRUMENT TRANSFORMER RATIO AND CABLE LOSS CORRECTION FACTORS

Background

All current transformers (CTs) and voltage transformers (VTs) (collectively, instrument transformers) have inherent errors due to their design and the physical properties of the materials used in their construction. These errors are manifested as a magnitude and phase angle difference between the "ideal" nameplate ratio and the waveform actually present on the secondary of the transformer. The terms used to denote these errors are Ratio Correction Factor (RCF) and Phase Angle Correction Factor (PACF).

The burden (load) connected to instrument transformer secondaries has an effect on the RCF and PACF of the units. All wiring and instrumentation of any kind is part of the burden. On a CT, the burden is designated in ohms and is represented by a number ranging from B-0.1 through B-1.8. On a VT, burden is measured in volt-amps and indicated by an alpha character, such as W, X, M, Y, Z or ZZ. The magnitude of these burdens must be known and kept within specified limits or additional errors will occur in the metering.

Significant impedance in the leads between the VTs and the meter can be another source of error, where a voltage drop in the leads is caused by the load of the meter and any other connected devices between the VTs and the meter. Conductors which are too small or too long can cause metering error.

Correction when the Burden Rating is exceeded

Where the connected burden of a metering circuit exceeds the burden rating of a CT or VT or if an existing instrument transformer does not meet minimum ISO accuracy requirements, then one of the actions listed below must to be taken:

i. The preferred action is to correct the problem by either replacing the instrument transformer(s) with higher burden rated revenue class units or reducing the burden on the circuit to comply with the name plate of existing instrument transformer(s).

ii. An acceptable action is to apply ISO approved correction factors to the meter to adjust the meter's registration to compensate for inaccuracies.

The ISO Metered Entity will be responsible for properly calculating and applying the CT/VT and cable loss correction factors to its meter to adjust for inaccuracies in the metering circuit. ISO approved algorithms and spreadsheets for calculating correction factors are included in this Part.

CT Ratio Correction Factor

Current transformers are usually tested by the manufacturer for the value of RCF and phase angle at both 5 and 0.5 amp secondary currents. The values for each CT in an installation would be averaged together to determine the CT Ratio Correction Factor (RCFI) and CT Phase Angle (b). If the current transformers used are revenue metering with an accuracy class of 0.3 % and are operated at or below their rated burden, then the correction factors may be disregarded.

VT Ratio Correction Factor

Voltage transformers are usually tested by the manufacturer for the value of RCF and phase angle at rated voltage. The values for each VT in an installation would be averaged together to determine the VT Ratio Correction Factor (RCFE) and VT Phase Angle (g). If the voltage transformers used are revenue metering with an accuracy class of 0.3 % and are operated at or below their rated burden, then the correction factors may be disregarded.

Cable Loss Correction Factor

The secondary voltage cables at an installation can be tested to determine the losses and phase angle of each. These values would then be averaged together to get the Cable Loss Correction Factor (CLCF) and the Phase Angle (a) for the installation. If the calculated connected burden of each phase do not exceed the VT burden rating, then the correction factors may be disregarded.

Final Correction Factor

The PACF for an installation is determined by the following formula:

$$PACF = \frac{cos(Q + b - a - g)}{cos Q}$$

Where *cosQ* is the secondary apparent power factor.

The Final Correction Factor (FCF) can then be determined as follows:

FCF = RCFI * RCFE * CLCF * PACF

The Percent Error is the amount of error caused by the instrument transformers and cable loss, it is calculated as follows:

Percent Error = (1-FCF)*(100)

The Percent Meter Adjustment is the adjustment to the meter required to compensate for the Percent Error, it is calculated as follows:

Percent Adjustment Factor = (FCF-1)*(100)

The FCF is applied to the calibration of the meter, usually through adjustment of the calibration potentiometer or through a change in the programmed calibration values. After an adjustment to the meter is made, the meter should be tested at all test points to show that the meter is within calibration limits with the calibration values applied. A FCF which results in a correction of less than 0.6% can be disregarded since this is less than the required combined accuracy of the instrument transformers. However, if any correction factor (full load, light load or power factor) results in a correction of more than 0.6%, they should all be applied.

Applications

Typical Installation

The preferred meter installation would utilize revenue metering class instrument transformers (0.3 %) operated at or below rated burden. If this is not the case, one or more of the following actions may be used to correct the problem:

Replace instrument transformers with higher burden rated units.

Reduce the burden on the circuit to comply with the existing rated burden.

Apply correction factors to the meter to compensate for inaccuracies.

Paralleling CTs

In normal revenue metering, current transformers would not be paralleled, but there are some applications where paralleling is done because the cost of the installation is reduced and the possibility of reduced meter accuracy is acceptable. A typical installation of this type would be to meter the net output of a generating station on a single meter rather than metering gross generator output and auxiliary power separately. In these type of installations additional rules apply:

All of the transformers must have the same nominal ratio regardless of the ratings of the circuits in which they are connected.

All transformers which have their secondaries paralleled must be connected in the same phase of the primary circuits.

The secondaries must be paralleled at the meter and not at the current transformers.

There should only be one ground on the secondaries of all transformers. This should be at their common point at the meter. Each utility may use their established grounding procedures.

Modern current transformers with low exciting currents and, therefore, little shunting effect when one or more current transformers are “floating” at no load should be used. Three or more “floating” current transformers might have an effect that should be investigated.

The secondary circuits must be so designed that the maximum possible burden on any transformer will not exceed its rating. The burden should be kept as low as possible as its effects are increased in direct proportion to the square of the total secondary current.

A common voltage and frequency must be available for the meter.

If adjustments are made at the meter to compensate for ratio and phase angle errors, the ratio and phase angle error corrections used must represent the entire combination of transformers as a unit.

The watthour meter must be able to carry, without overload errors, the combined currents from all the transformers to which it is connected.

While servicing meters and equipment on parallel CT secondaries, all CTs must be by-passed (shorted). When work is completed all by-passes must be removed.

Worksheets

A worksheet which can be used to perform the above calculations is attached to this Part. Instructions for completing the worksheet follow:

Complete the Name, Delivery and Location fields using the ISO Metered Entity's name, the operating name of the delivery, and the city and state for the location.

Enter the values of RCF and phase angle as tested at full load and light load for each CT in the circuit. Record the manufacturer and serial number of each transformer.

Enter the values of RCF and phase angle as tested at rated voltage for each VT in the circuit. Record the manufacturer and serial number of each transformer.

Enter the values of the Cable Loss Correction Factor and Phase Angle for the secondary voltage cables.

The worksheet will calculate the Final Correction Factors, Percent Errors and Percent Adjustment Factors to be applied to the meter calibration.

Reference Materials

The following additional reference may be referred to for assistance when calculating the correction factors referred to in this Part.

Handbook For Electricity Metering, Ninth Edition. Edison Electric Institute. Washington, D.C.

CT/VT Ratio and Cable Loss Correction Worksheet (Example)

Name:

Delivery:

Location:

Full Load	Light Load

CT Test Data:

Phase ‘A’ CT Mfr. & Serial Number:

Ratio Correction Factor (RCF^I)	1.0003	1.0002
Phase Angle (β) (minutes)	-0.3	2.2

Phase ‘B’ CT Mfr. & Serial Number:

Ratio Correction Factor (RCF^I)	1.0004	1.0029
Phase Angle (β) (minutes)	-0.4	2.2

Phase ‘C’ CT Mfr. & Serial Number:

Ratio Correction Factor (RCF^I)	1.0019	1.0028
Phase Angle (β) (minutes)	-0.3	3.1

Average of CT’s Mfr. & Serial Number:

Ratio Correction Factor (RCF^I)	1.0009	1.0020
Phase Angle (β) (minutes)	-0.3	2.5

VT Test Data:

Phase ‘A’ VT Mfr. & Serial Number:

Ratio Correction Factor (RCF^E)	0.9997

Phase Angle (γ) (minutes)	1.5

Phase 'B' VT Mfr. & Serial Number:

Ratio Correction Factor (RCF^E)	0.9996
Phase Angle (γ) (minutes)	1.5

Phase 'C' VT Mfr. & Serial Number:

Ratio Correction Factor (RCF^E)	0.9997
Phase Angle (γ) (minutes)	1.7

Average of VT's Mfr. & Serial Number:

Ratio Correction Factor (RCF^E)	0.9997
Phase Angle (γ) (minutes)	1.6

Cable Loss Test Data:

Phase 'A'

Ratio Correction Factor (CLCF)	0.9969
Phase Angle (α) (minutes)	4.3

Phase 'B'

Ratio Correction Factor (CLCF)	0.9949
Phase Angle (α) (minutes)	4.2

Phase 'C'

Ratio Correction Factor (CLCF)	0.9959
Phase Angle (α) (minutes)	4.7

Average Cable Loss Data

Ratio Correction Factor (CLCF)	0.9959
Phase Angle (α) (minutes)	4.4

Correction Factors:	Full Load	Power Factor	Light Load
Avg. Combined Corr. Factor	0.9964	0.9964	0.9975
Phase Ang Corr Factor (PACF)	1.0003	1.0032	1.0001
Final Correction Factor (FCF)	0.9967	0.9996	0.9977
Percent Error	+ 0.33	+ 0.04	+ 0.23
Percent Meter Adjustment	- 0.33	- 0.04	- 0.23

CT/VT Ratio and Cable Loss Correction Worksheet

Name:

Delivery:

Location:

Full Load	Light Load

CT Test Data:

Phase 'A' CT Mfr. & Serial Number:

Ratio Correction Factor (RCF^I)		
Phase Angle (β) (minutes)		

Phase 'B' CT Mfr. & Serial Number:

Ratio Correction Factor (RCF^I)		
Phase Angle (β) (minutes)		

Phase 'C' CT Mfr. & Serial Number:

Ratio Correction Factor (RCF^I)		
Phase Angle (β) (minutes)		

Average of CT's Mfr. & Serial Number:

Ratio Correction Factor (RCF^I)		
Phase Angle (β) (minutes)		

VT Test Data:

Phase 'A' VT Mfr. & Serial Number:

Ratio Correction Factor (RCF^E)	

Phase Angle (γ) (minutes)	

Phase 'B' VT Mfr. & Serial Number:

Ratio Correction Factor (RCF^E)	
Phase Angle (γ) (minutes)	

Phase 'C' VT Mfr. & Serial Number:

Ratio Correction Factor (RCF^E)	
Phase Angle (γ) (minutes)	

Average of VT's Mfr. & Serial Number:

Ratio Correction Factor (RCF^E)	
Phase Angle (γ) (minutes)	

Cable Loss Test Data:

Phase 'A'

Ratio Correction Factor (CLCF)	
Phase Angle (α) (minutes)	

Phase 'B'

Ratio Correction Factor (CLCF)	
Phase Angle (α) (minutes)	

Phase ‘C’

Ratio Correction Factor (CLCF)	
Phase Angle (α) (minutes)	

Average Cable Loss Data

Ratio Correction Factor (CLCF)	
Phase Angle (α) (minutes)	

Correction Factors:	Full Load	Power Factor	Light Load
Avg. Combined Corr. Factor			
Phase Ang Corr Factor (PACF)			
Final Correction Factor (FCF)			
Percent Error			
Percent Meter Adjustment			

PART G

ISO DATA VALIDATION, ESTIMATION AND EDITING PROCEDURES

This Part is provided for information purposes only, it gives an overview of the procedures that the ISO will use to validate, edit and estimate Meter Data received from ISO Metered Entities and, where an exemption applies, Meter Data received from Scheduling Coordinator Metered Entities.

G 1 Validation

G 1.1 Timing of Data Validation

Meter Data will be remotely retrieved via WEnet from ISO Metered Entities by MDAS on a daily basis. Validation will be performed on the new Meter Data as it is retrieved from the meter or Compatible Meter Data Server in order to detect:

missing data;

data that could be invalid based upon status information returned from the meter; or

meter hardware or communication failure.

Additional validation will be performed on a daily basis to verify data against load patterns, check meters, schedules, MDAS load interval data and data obtained by SCADA.

G 1.2 Data Validation Conditions

MDAS will detect the following conditions so that erroneous data will not be used for Settlement or billing purposes:

G 1.2.1 Validation of metering/communications hardware:

meter hardware/firmware failures;

metering CT/VT failures (for example, losing one phase voltage input to the meter);

communication errors;

data which is recorded during meter tests;

mismatches between the meter configuration and host system master files;

meter changeouts (including changing CT/VT ratios);

gaps in data;

overflow of data within an interval;

ROM/RAM errors reported by the meter; and alarms/phase errors reported by the meter.

G 1.2.2 Validation of MDAS load Interval Data characteristics:

data which exceeds a defined tolerance between main and check meters;

data which exceeds a defined tolerance between metering and SCADA data;

load factor limits;

power factor limits; and

for End-Users, validation of load patterns against historical load shapes.

G 1.3 Validation Criteria

Validation criteria will be defined by the ISO for each channel of MDAS load interval data (kW/kVar/kVa/Volts, etc.) depending on the load characteristics for each meter location and the type of data being recorded.

For loads that do not change significantly over time or change in a predictable manner, percentage changes between intervals will be used.

For loads that switch from no-load to load and for reactive power where capacitors may be switched to control power factors, validation will be based upon historical data for that meter location. If no historical data is available, data such as the rating of transformers or the maximum output from a Generator will be used to set maximum limits on interval data.

Validation will be based upon reasonable criteria that can detect both hardware and operational problems with a high degree of confidence but will be set so as to avoid unnecessary rejection of data.

G 1.4 Validation for Stated Criteria

Data validation will be performed only for the validation criteria that has been entered for each meter channel of data. For example, the number of intervals of zero Energy recorded by the meter for the channel indicated will be validated only when a non-zero value is entered for this criteria.

Additional validation will be performed on a daily basis to verify data which is based upon load patterns, comparisons to check meters, schedules, MDAS load profiles or data obtained by SCADA.

G 1.5 Validation Failure

Data that fails validation will be flagged with the reason for the failure, where applicable. Data that fails checks such as load factor limits or comparisons of a MDAS load profile to the previous day, check meter or other load shape will be identified so that manual intervention can be used to estimate the correct values in order to edit the data or to manually accept the data.

G 1.6 Validation Criteria

G 1.6.1 Time of Application of Criteria

Validation Criteria	Hourly	Daily
Meter Readings vs. MDAS load profile (Energy Tolerance)		Yes
Intervals Found vs. Intervals Expected		Yes
Time Tolerance Between MDAS and Meter	Yes	Yes
Number of Power Outage Intervals		Yes
Missing Intervals (Gap In Data)		Yes
High/Low Limit Check On Interval Demand	Yes	Yes
High/Low Limit Check on Energy		Yes
CRC/ROM/RAM Checksum Error	Yes	Yes
Meter Clock Error	Yes	Yes
Hardware Reset Occurred	Yes	Yes
Watchdog Timeout	Yes	Yes
Time Reset Occurred	Yes	Yes
Data Overflow In Interval	Yes	Yes
Parity Error (Reported By Meter)	Yes	Yes
Alarms (From Meter)	Yes	Yes
Load Factor Limit		Yes
Power Factor Limit		Yes
Main vs. Check Meter Tolerance		Yes
Actual vs Scheduled Profile		Yes
Actual vs SCADA Data		Yes
Comparison Of Current Day To Previous Day		Yes
Percent Change Between Intervals		Yes

G 1.6.2 Validation Criteria

(a) Meter Reading vs. MDAS load Interval Data (Energy Tolerance)

Meter readings will be obtained from ISO approved meters on a daily basis in order to validate interval Energy measurements

obtained from the MDAS approved meters data and Energy from the meter readings. This Energy tolerance check will be used to detect meter changeouts or changes in metering CT/PT ratios that have not been reflected in the MDAS master files (meter configuration files). A "tolerance type" parameter will be set in the MDAS system parameter to define the type of check to be performed.

The types of check that will be used will include the following (the constant used to convert the meter readings to kWh):

ID	Term	Description
M	**Multiplier**	Allows a percentage of the meter multiplier difference between the meter reading the recorded interval total energy.
P	**Percent**	Allows a percentage of the metered total energy difference between the metered total energy and the recorded total energy. The percent of allowed difference will be defined by the ISO on an individual meter channel basis.
Q	**Same as Percent**	Based on 30 days of data. If the data relates to a period less than 30 days then the total usage will be projected to 30 days as follows: Projected Usage=Total Usage * (30/Total Days)
D	**Dual Check**	Percent Method (P) is the primary check. If it fails, then the Multiplier Method (M) is used.
E	**Dual Method**	Percent Method (Q) is the primary check. If it fails, then the Multiplier Method (M) is used.
N	**None**	No tolerance check

(b) Intervals Found vs Intervals Expected

MDAS will calculate the expected number of time intervals between the start and stop time of the MDAS load profile data file and compare that number against the actual number of time intervals found in the MDAS data file. The calculation used to determine the expected number of time intervals will take into account the size or duration of the actual time intervals for the particular meter/data file (e.g., 5 min, 15 min, 30 min and 60-min interval sizes).

(c) Time Tolerance Between MDAS and Meter

When MDAS retrieves data from a meter, the MDAS workstation clock will be compared against the meter's clock. MDAS will be configured to automatically update the meter clocks within certain tolerances, limits and rules including:

i. a time tolerance parameter (in seconds) which indicates the allowable difference between the MDAS workstation clock and the meter clock (if the meter clock is within that parameter, MDAS will not update the meter clock);

ii. an upper limit for auto timeset which is the maximum number of minutes a meter can be out of time tolerance before MDAS will perform an auto timeset;

iii. the MDAS will not perform auto timesets across interval boundaries; and

iv. the auto timeset feature will support DST changes and time zone differences. Since all ISO Metered Entity's meters that are polled by MDAS will be set to PST, this rule will not generally apply.

(d) Number of Power Outage Intervals

The ISO approved meter will record a time stamped event for each occurrence of a loss of AC power and a restoration of AC power. During the Meter Data retrieval process, MDAS will flag each MDAS interval between occurrences of AC power loss and AC power restoration with a power outage status bit. MDAS will sum the total number of power outages for a time frame of MDAS data and compare that value against an ISO defined Power Outage Interval Tolerance value stored in the MDAS validation parameters.

(e) Missing Intervals (Gap in Data)

The MDAS validation process will compare the stop and start times of two consecutive pulse data files for a meter and will report if a missing interval/gap exists. The MDAS automatic estimation process for "plugging" missing intervals/gaps in data is described in more detail in the Data Estimation section of this Part.

(f) High/Low Limit Check on Interval Demand

The MDAS validation process will compare the Demand High/Low Limits entered by the MDAS operator on a meter channel basis in the MDAS meter channel table against the actual Demand value collected from the meter. This comparison will be performed on an interval by interval basis. If the actual Demand value is less than the Low Limit or greater than the High Limit, the MDAS validation process fails.

(g) High/Low Limit Check on Energy

The MDAS validation process compares the Energy High/Low Limits entered by the MDAS operator on a meter channel basis in the MDAS meter channel table against the actual total Energy collected from the meter for the time period. If the actual total Energy is less than the Low Limit or greater than the High Limit, the MDAS validation process fails.

(h) CRC/ROM/RAM Checksum Error

This general meter hardware error condition can occur during an internal status check or an internal read/write function within the meter. This error code may not be standard on some meters (reference should be made to the meter's user manual). When available, this internal status information will be collected during the MDAS Meter Data retrieval process and stored for review/reporting purposes.

(i) Meter Clock Error

This meter hardware error condition can occur whenever an internal meter hardware clock error results in an invalid time, day, month, year, etc. This error code may not be standard on some meters (reference should be made to the meter's user manual). When available this interval status information is collected during the MDAS Meter Data retrieval process and stored for review/reporting purposes.

(j) Hardware Reset Occurred

This meter hardware error condition occurs whenever an internal meter hardware reset occurs. This error code may not be standard on some meters (reference should be made to the meter's user manual). When available this interval status information is collected during the MDAS Meter Data retrieval process and stored for review/reporting purposes.

(k) Watchdog Timeout

This error code may not be standard on some meters (reference should be made to the meter's user manual). When available, this feature watches for meter inactivity, indicating a possible meter failure.

(l) Time Reset Occurred

This is a meter error code that indicates that the meter time has been reset. See paragraph (c) above.

(m) Data Overflow In Interval

This error code occurs when the amount of data in an interval exceeds the memory capabilities of the meter to store the data. This alerts MDAS that there is corrupt data for the interval.

(n) Parity Error (Reported by Meter)

Parity error is another indicator of corrupted data.

(o) Alarms (From Meter)

ISO MDAS operator will evaluate all meter alarms to determine if the alarm condition creates data integrity problems that need to be investigated.

(p) Load Factor Limit

The MDAS validation process compares the daily Load Factor to the limit entered by the MDAS operator. MDAS will prompt the operator to investigate data integrity if the limit is out of tolerance.

(q) Power Factor Limit

The MDAS validation process compares the actual Power Factor to the limit entered by the MDAS operator. MDAS will prompt the operator to investigate if the limit is out of tolerance.

(r) Main vs Check Meter Tolerance

The main and check meters can be configured in MDAS to be compared on a channel by channel basis to the check meter ID, channel number, percent tolerance allowance and the type of check. Interval or daily Meter Data will be entered into the corresponding main meter MDAS meter channel table record. This information will remain constant unless:

i. a meter changeout occurs at the site;

ii. the percent tolerance allowance needs adjusting; and/or

iii. the type of check is switched.

If the percentage difference between the main channel interval Demand and the check channel interval Demand exceeds the Percent Tolerance allowed, the MDAS validation will fail. If, after applying this validation test, the percentage difference between the main channel total Energy and the check channel total Energy for each Trading Day exceeds the allowed percentage, the MDAS validation will fail. In both cases, if the percentage difference is less than the Percent Tolerance allowed, the MDAS validation will be accepted.

(s) Actual vs. Scheduled Profile

Data is compared on an interval by interval basis like Main vs Check.

(t) Actual vs. SCADA Data

Data is compared on an interval by interval basis like Main vs Check.

(u) Comparison Of Current Day To Previous Day

The MDAS validation process compares the last complete day's Demand and Energy in the validation time period to one of the following parameters configured by the MDAS operator:

i. previous day;

ii. same day last week; or

iii. same day last month.

Validation Failure

If the percentage difference between the Demand and Energy exceeds the tolerance setup in the MDAS validation parameters, the data subjected to the validation process fails.

(v) Percent Change Between Intervals

The MDAS validation process uses the Interval Percent Change Tolerance set by the MDAS operator on a meter channel basis in the MDAS meter channel table to compare the percentage change in the pulses for the channel between two consecutive intervals.

If the percent change exceeds the Interval Percent Change Tolerance set for that channel, the MDAS validation process fails.

G 2 Data Estimation Criteria

When interval data is missing due to there not being any response from the meter or the meter reports it as missing, MDAS will supply estimated data for the missing intervals based on the guidelines discussed below.

If a certified Check Meter is available and that data is valid, the data from the Check Meter will be used to replace the invalid or missing data from the main meter. When reading meters on a frequency basis, the point-to-point linear interpolation method will be used to estimate the current interval(s) of data. This method will only normally be used when estimating one hour or less of contiguous missing interval data when the previous and next intervals are actual values from the meter. If data is missing for an extended time period, historical data will be used as the reference date so that data can be matched to time of day and day of week.

G 2.1 Data Estimation Methods

The following data estimation methods are configurable by the MDAS operator on a meter-by-meter basis. The algorithms for each method are described below in order of precedence as implemented by the MDAS automatic estimation application software. The MDAS operators can alter this order by simply not activating a certain method. In addition, the MDAS operator can manually select each data estimation method at any time during the data analysis process.

G 2.2 Main vs Check Meter

The global primary and Check Meters can be configured in the MDAS meter channel table to be compared on a channel-by-channel basis. The Check Meter ID and channel number will be entered into the corresponding primary meter MDAS meter channel table record. This information remains constant unless a meter changeout at the site occurs. During the MDAS automatic estimation process, if missing data is encountered and actual values from a certified Check Meter are available, the values for the corresponding intervals from that Check Meter will be substituted into the data file for the primary meter. All copied intervals will be tagged as an edited interval. In order for actual values from the check meter to be deemed acceptable for use in the automatic estimation process, the values must reside in an accepted data file that passed the validation criteria referred to earlier in this Part and no error codes or alarms can be set on the interval values. Meter Data from Check Meters may only be used where Meter Data is not available from the primary meter.

G 2.3 Point-to-Point Linear Interpolation

When reading meters on a frequency basis, the Point-to-Point Linear Interpolation Algorithm described below can be used to estimate the missing intervals of data. This method will only normally be used to estimate a maximum of one hour of contiguous missing interval data when the previous and next intervals are actual values from the meter. Even though this method will not normally be used above that maximum of one hour, the MDAS allows this maximum threshold to be set by the MDAS operator on a meter-by-meter basis. The same rules for defining acceptable actual values apply as detailed in Main vs. Check Meter description above. All estimated intervals will be tagged as an edited interval.

Point to Point Linear Interpolation Algorithm

$$\text{Estimated Interval} = \frac{\text{Next Actual - Previous Actual Interval}}{\text{Number of Missing Intervals} + 1} + \text{Previous Actual Interval}$$

G 2.4 Historical Data Estimation

Historical data estimation is the process of replacing missing or corrupt interval data in the MDAS data files. The data is replacing using historical data as a reference. There are two basic requirements when estimating data to be inserted or replaced:

the amount of data to add or replace; and

the shape or contour of the data over the time span requested.

G 2.4.1 Estimation Parameters

The following estimation parameters are required on a per meter basis:

Auto Plug (Y/N)	Controls the option to perform automatic estimation
Auto Plug Option (W/C/P/L)	Indicates where to get the reference data used in the estimation process: W - use the previous week as the reference data (all data for the week must be present). C - use the current month as reference data. P - use the previous month as reference data. L - use the current month of last year as reference data.
Reference ID	ID from which the reference data is retrieved. The contour of the data is determined from this ID. The Reference ID can be the same as the meter ID (i.e. use historical data from the same meter) or a different Reference ID.
Auto Plug Missing Days Limit	Verifies that the number of missing days of data is less then the missing day limit in order to invoke automatic estimation.

Auto Plug Reference Data %	Identifies a percent adjustment for situations where there is a need to factor the reference data by a percent increase or decrease. If this value is set to “0”, the adjustment is not performed.
Auto Plug Power Outage	Indicates if intervals with a power outage status are to be estimated/replaced automatically.
Reference Time Span	Identifies the reference time span for the historical data.

G 2.4.2 Total Data

The estimation algorithm used depends on the total amount of data to be added or replaced and the shape of that data. The MDAS operator can give the total data or that can be calculated to balance the meter usage in the file. The shape of the data is defined with the use of the reference data.

G 2.4.3 Reference Data

The reference data is based on the day of the week. All reference data is averaged and stored into a 7-day table of values for each interval. The table includes a day’s worth of intervals for each day of the week (Sunday-Saturday). When the shape of a day’s data is needed, this weekly table is referenced. Two data tables are set up to use in the algorithm. One stores the number of times that an interval value is needed from the reference data. While the other table maps the interval value in the reference data to the correct data in the update file. The data from the reference must be scaled up or down to match the magnitude of the data needed for the update file. This is determined by comparing the data total from the reference file with the data needed for the update file. This ratio is used when getting reference data to use for the update file.

G 2.4.4 Iterations

Iterations will be used to get the best reproduction of data in the update file. This process will attempt to get the correct shape for the data and also to get as close to the requested total data as possible by using up to ten iterations. Since MDAS data will be integer data and cannot have decimal values, the total data used will not be exactly what is requested. Definition of some of the tables and variables are:

REFTOT	Total data from the reference file for the time requested.
REQTOT	Total requested data.
REFADJ	Adjusted total reference data.
IP( )	A table containing the total times that a value is used from the reference data.

NP ( )	A table containing the data in the update file for that value in the reference data. A table mapping the reference data to the update data according to the needed ratio.

G 2.4.5 Population of Tables

The first step is to populate the tables. All intervals for the requested time are read from the reference data. These values are stored into table NP( ). The number of times a value is used is stored into the table IP( ). For example:

If the value 54 is needed 3 times, then IP(54)=3 and NP(54)=54

The table IP( ) is used to quickly add up the totals. The table NP( ) is modified by the ratio REQROT/REFADJ. For example:

If: REQTOT=22000

REFTOT=44000

Then: REQTOT/REFTOT=0.50

and NP(54) = 0.50* NP(54) = 27

After modifying the complete NP( ) table, the total data is added to determine how close this total is to the requested total (REQTOT). The NP( ) values have to be rounded to whole numbers. This total is calculated by adding up all of the values in the NP ( ) table multiplied by the times the value is needed (IP( )). Each value used (IP(x) not zero) is multiplied by the value (NP(x)). Then each of the results is added up to a total. If the total is close enough to the requested total then the iteration process ends. After ten iterations the total will automatically be considered close enough to the requested total.

G 2.4.6 Update File

As the data is needed to insert into the update file, the reference data is read from the reference file. The mapping table (NP) modifies the value. This modified value is inserted into the update file. All intervals are inserted in this manner to complete the data estimation.

G 3 Editing

All estimated intervals will be tagged as an edited interval in MDAS. The ISO MDAS operator will notify the Metered Entity of the edited interval start and stop times, new value and technique used to estimate the data.

If estimation and editing is frequently required for the Meter Data received from a particularly metered entity, the ISO may require re-certification and or facility maintenance or repair to correct the continued provision of erroneous or missing data.

ISO TARIFF APPENDIX P

ISO Department of Market Analysis and Market Surveillance Committee

ISO TARIFF APPENDIX P

ISO Department of Market Analysis and Market Surveillance Committee

1 ISO DEPARTMENT OF MARKET ANALYSIS

1.1 Establishment

There shall be established on or before ISO Operations Date within the ISO a Department of Market Analysis that shall be responsible for the ongoing development, implementation, and execution of the ISO Market monitoring and information scheme described in this Tariff and the adherence to its objectives, as set forth in Section 38.1.

1.2 Composition

The Department of Market Analysis shall be adequately staffed by the ISO with full-time ISO staff with the experience and qualifications necessary to fulfill the functions referred to in this ISO Tariff. Such qualifications may include professional training pertinent to and experience in the operation of markets analogous to ISO Markets, in the electric power industry, and in the field of competition and antitrust law, economics and policy. The Department of Market Analysis shall be under the general management of the ISO CEO, provided that the CEO may designate another ISO officer (currently the General Counsel) for day-to-day oversight of the Department.

1.3 Accountability and Responsibilities

1.3.1 Department of Market Analysis

The Department of Market Analysis shall report to and be accountable to the ISO CEO and his or her designee on all matters pertaining to policy and other matters that may affect the effectiveness and integrity of the monitoring function, including matters pertaining to market monitoring, information development and dissemination and pertaining to generic or entity-specific investigations, corrective actions or enforcement.

1.3.2 CEO and MSC

The ISO CEO and the MSC shall each have the independent authority to refer any of the matters referred to in Section 37.3.3.1 to the ISO Governing Board for approval of recommended actions.

1.3.3 Chief Executive Officer (CEO)

1.3.3.1 The Department of Market Analysis shall report to and be accountable to the ISO CEO and his or her designee on all matters relating to administration of the Department and the internal resources and organization of the ISO in accordance with Appendix P, Section 1.3.3.2.

1.3.3.2 The ISO, through its CEO and Governing Board, shall determine that the Department of Market Analysis has adequate resources and full access to data and the full cooperation of all parts of the ISO organization in developing the database necessary for the effective functioning of the Department of Market Analysis and the fulfillment of its monitoring function.

1.3.4 Regulatory and Antitrust Enforcement Agencies

Where considered necessary and appropriate, or where so ordered by the regulatory or antitrust agency with jurisdiction over the matter in question, or by a court of competent jurisdiction, the ISO shall refer a matter to the regulatory or antitrust enforcement agency concerned, e.g., in cases of serious abuse requiring expeditious investigation or action by the agency. In all such cases of direct referral, the ISO CEO shall promptly inform the ISO Governing Board and the MSC of the fact of and the content of the referral.

1.3.5 Complaints

Any Market Participant, or any other interested entity, may at any time submit information to or make a complaint to the Department of Market Analysis concerning any matter that it believes may be relevant to the Department of Market Analysis's monitoring responsibilities. Such submissions or complaints may be made on a confidential basis in which case the Department of Market Analysis shall preserve the confidentiality thereof. The Department of Market Analysis, at its discretion, may request further information from such entity and carry out any investigation that it considers appropriate as to the concern raised. The Department of Market Analysis shall periodically make reports to the ISO CEO and ISO Governing Board on complaints received.

ISO TARIFF APPENDIX P1

ISO Department of Market Analysis

P1.1 ISO Department of Market Analysis

P1.1.1 Information Gathering and Market Monitoring Indices for Evaluation

P1.1.1.1 Information System

The Department of Market Analysis shall be responsible for developing an information system and criteria for evaluation that will permit it to effectively monitor the ISO Markets to identify and investigate abuses of that market, whether caused by exercises of market power or by other actions or inactions.

P1.1.1.2 Data Categories

To develop the information system set forth in Section P1.1.1.1, the Department of Market Analysis shall initially develop, and shall refine on the basis of experience, a detailed catalog of all the categories of data it will have the means of acquiring, and the procedures it will use (including procedures for protecting confidential data) to handle such data.

P1.1.1.3 Catalog of Market Monitoring Indices

The Department of Market Analysis shall initially develop, and shall refine on the basis of experience, a catalog of the ISO Market monitoring indices that it will use to evaluate the data so collected.

P1.1.2 Evaluation of Information

P1.1.2.1 Ongoing Evaluation

The Department of Market Analysis shall evaluate and reevaluate on an ongoing basis the data categories and market monitoring indices that it has developed under Appendix P1, Sections P1.1.1.2 and P1.1.1.3, and the information it collects and receives from various other sources, including and in particular the ISO's operation of the ISO Markets. Such ongoing evaluations shall provide the basis for its reporting and publication responsibilities as set forth in this ISO Tariff, for recommendations on proposed changes to the ISO Tariff and ISO Protocols and other potential rules affecting the ISO Markets, and for the development of criteria or standards for the initiation of proposed corrective or enforcement actions. In evaluating such information, the Department of Market Analysis may consult the MSC or such external bodies as may be appropriate.

P1.1.2.2 Submission of Evaluation Results

The final results of the Department of Market Analysis's ongoing evaluations under Appendix P1, Section P1.1.2.1 shall routinely and promptly be submitted to the ISO CEO and to the MSC for comment.

P1.1.3 Review of Rules of Conduct

The Department of Market Analysis shall review Rules of Conduct for their effectiveness and consistency with its market monitoring activities and standards. The Department of Market Analysis may at that time, and from time to time thereafter based on its experience in monitoring the ISO Markets, propose to the ISO CEO and/or the ISO Governing Board that changes be made in such Rules of Conduct.

P1.1.4 Reports and Recommendations

P1.1.4.1 ISO CEO and Governing Board

On the basis of the evaluation conducted under Appendix P1, Section P1.1.2 or the review conducted under Section 37.4.3, the Department of Market Analysis shall prepare periodic reports, as required by the ISO CEO, and specific ad hoc reports as appropriate, for the ISO CEO and ISO Governing Board on the state of competition in or the efficiency of the ISO Markets; and on its monitoring activities, the results of its evaluation and review activities, and its development and implementation of recommendations. Where appropriate, the ISO Department of Market Analysis may recommend to the ISO CEO and/or the ISO Governing Board actions to be taken, including the amendment of the ISO Tariff and ISO Protocols and corrective or enforcement action against specific entities. Such reports shall be made not less frequently than quarterly in the case of the ISO CEO and annually in the case of the ISO Governing Board and shall contain such information and be in such form as specified by such entities. Such reports shall be made public and publicized as specified by such entities except to the extent that they contain confidential or commercially sensitive information or to the extent such entities determine that effective enforcement of the monitoring function dictates otherwise.

P1.1.4.2 Regulatory Agencies

As required in the ISO Tariff or by the ISO CEO and ISO Governing Board, or as required by the regulatory agency with jurisdiction over the matters in question, the Department of Market Analysis shall prepare reports to the FERC and other regulatory agencies, which shall be reviewed and approved by the ISO CEO or his or her designee and then submitted as required. When publicly available reports are made to one regulatory agency with competent jurisdiction, such as the FERC, the Department of Market Analysis may simultaneously make such reports available to other regulatory agencies with legitimate interests in their contents, such as the Electricity Oversight Board, the California Public Utilities Commission, the California Energy Commission and/or the California Attorney General.

P1.1.4.3 ISO Market Surveillance Committee

All reports and recommendations to be made to regulatory agencies under Appendix P1, Section P1.1.4.2, unless urgency requires otherwise, shall first be submitted to the MSC for comments, which comments shall be reflected in any submittal to the ISO Governing Board seeking approval of any such reports or recommendations. All final reports made to external regulatory agencies shall be simultaneously submitted to the MSC.

P1.1.5 Market Participants

P1.1.5.1 Collection of Data

The Department of Market Analysis may request that Market Participants or other entities whose activities may affect the operation of the ISO markets submit any information or data determined by the Department of Market Analysis to be potentially relevant. This data will be subject to due safeguards to protect confidential and commercially sensitive data. Failures by Market Participants to provide such data shall be treated under Section 37. In the event of failures by other entities to provide such data, the ISO may take whatever action is available to it and appropriate for it to take, including reporting the failure to the pertinent regulatory agency, after providing such entity the opportunity to respond in writing as to the reason for the alleged failure and may include possible exclusion from the ISO Markets or termination of any relevant ISO agreements or certifications. Before any such action is taken, the ISO Participant shall be provided the opportunity to respond in writing as to the reason for the alleged failure.

P1.1.5.2 Dissemination of Data

Any Market Participant may request that the ISO provide data that the ISO has collected concerning that Market Participant; and, such data may, subject to constraints on the ISO's resources and at the ISO's sole discretion, be provided by the ISO subject to due safeguards to protect confidential and commercially sensitive data. Where such activity imposes a significant burden or expense on the ISO, the data may be provided on the condition that a reasonable contribution to the cost incurred by the ISO is made to the ISO by the requesting party.

P1.1.6 External Consulting Assistance and Expert Advice

In carrying out any of its responsibilities under this ISO Tariff, including the development of an information system, market monitoring indices and evaluation criteria, and the catalogs associated therewith, and in its analysis and ongoing evaluation of these catalogs and of the Rules of Conduct, the Department of Market Analysis may hire consulting assistance subject to the budgetary approval of the ISO CEO and may seek such expert external advice as it believes necessary.

P1.1.7 Liability for Damages

As provided in Section 14 of the ISO Tariff, the Department of Market Analysis, the MSC, the ISO CEO and other ISO staff, and the ISO Governing Board shall not be liable to any Market Participant under any circumstances whatsoever for any matter described in those sections, including but not limited to any financial loss or loss of economic advantage resulting from the performance or non-performance by such ISO entities of their functions under this ISO Tariff.

ISO TARIFF APPENDIX P2

Market Surveillance Committee

P2.2 Market Surveillance Committee

P2.2.1 Establishment

There shall be established on or before ISO Operations Date a Market Surveillance Committee (MSC), whose role it shall be to provide independent external expertise on the ISO market monitoring process and, in particular, to provide independent expert advice and recommendations to the ISO CEO and Governing Board. Members of the Committee shall not be, and shall not be understood to be, employees or agents of the ISO.

P2.2.2 Composition

P2.2.2.1 Qualifications

The MSC shall comprise a body of three or more independent and recognized experts whose combined professional expertise and experience shall encompass the following:

(a) economics, with emphasis on antitrust, competition, and market power issues in the electricity industry;

(b) experience in operational aspects of Generation and transmission in electricity markets;

(c) experience in antitrust or competition law in regulated industries; and

(d) financial expertise relevant to energy or other commodity trading.

P2.2.2.2 Criteria for Independence

Each member of the MSC must meet the following criteria for independence:

P2.2.2.2.1 no material affiliation, through employment, consulting or otherwise, with any Market Participant or Affiliate thereof consistent with the pertinent FERC Standards of Conduct; and

P2.2.2.2.2 no material financial interest in any Market Participant or Affiliate thereof consistent with the pertinent FERC Standards of Conduct.

P2.2.2.2.3 during their time on the Committee, members may not provide paid expert witness testimony or other commercial services to the ISO or to any other party in connection with any legal or regulatory proceeding relating to the ISO or any trade or other transaction involving the ISO markets (except that the Committee may consult with and make recommendations concerning the functioning of the markets to ISO Management or the ISO Governing Board in connection with legal or regulatory proceedings).

P2.2.3 Appointments to the MSC

For each position on the MSC, the ISO CEO shall conduct a thorough search and requisite due diligence to develop a nomination to the ISO Governing Board, which nomination shall be consistent with meeting the combined professional expertise and experience of the MSC set forth in Appendix P2, Section

P2.2.2.1 and with the criteria for independence set forth in Appendix P2, Section P2.2.2.2. The ISO Governing Board shall expeditiously consider such nominations. If the nomination is approved, the ISO

CEO shall appoint the candidate so nominated to the MSC. If the nomination is rejected, the ISO CEO shall expeditiously proceed to develop another nomination.

P2.2.4 Compensation and Reimbursements

Members of the MSC shall be compensated on such basis as the ISO Governing Board shall from time to time determine.

Members of the MSC shall receive prompt reimbursement for all expenses reasonably incurred in the execution of their responsibilities under this Appendix P2, Section P2.2.

P2.2.5 Liability for Damages

As provided in Section 14 of the ISO Tariff, the Department of Market Analysis, the MSC, the ISO CEO and other ISO staff, and the ISO Governing Board shall not be liable to any Market Participant under any circumstances whatsoever for any matter described in those sections, including but not limited to any financial loss or loss of economic advantage resulting from the performance or non-performance by such ISO entities of their functions under this ISO Tariff.

P2.2.6 SPECIFIC FUNCTIONS OF MARKET SURVEILLANCE COMMITTEE (MSC)

P2.2.6.1 Information Gathering and Evaluation Criteria

The MSC shall review the initial catalogs of information and data and of evaluation criteria developed by the Department of Market Analysis pursuant to Appendix P1, Section P1.1 and shall propose such changes, additions or deletions to such catalogs or items therein as it sees fit. In so doing, the MSC shall have full discretion to specify database items or evaluation criteria for inclusion in the pertinent catalog.

P2.2.6.2 Evaluation of Information

The MSC may, upon request of the Department of Market Analysis, the ISO Management or the ISO Governing Board, or on its own volition, evaluate such information or data, including as may be collected by the Department of Market Analysis on the basis of the evaluation criteria developed by the Department of Market Analysis or on such further articulated evaluation criteria developed by the MSC.

P2.2.6.3 Reports and Recommendations

P2.2.6.3.1 Required Reports

All evaluations carried out by the MSC pursuant to Appendix P2, Section P2.2.6.2, and any recommendations emanating from such evaluations, shall be embodied by the MSC in written reports to the ISO CEO and ISO Governing Board and shall be made publicly available subject to due restrictions on dissemination of confidential or commercially sensitive information. The MSC may submit any MSC report to FERC, subject to due restrictions on dissemination of confidential or commercially sensitive information.

P2.2.6.3.2 Additional Reports

The MSC may make such additional reports and recommendations as it sees fit relating to the monitoring program referred to in this ISO Tariff, the analysis of information, the evaluation criteria or any corrective or enforcement actions proposed by the Department of Market Analysis or proposed of its own volition.

P2.2.6.4 Publication of Reports and Recommendations

Upon request of the MSC, the ISO shall publish reports and recommendations of the MSC or incorporate them, if consistent, into the ISO's own reports or recommendations.

P2.2.7 IMPLEMENTATION OF RECOMMENDATIONS

P2.2.7.1 Plan and Rules of Conduct Changes

Following a recommendation of the MSC, the ISO Governing Board may make such changes as it believes are appropriate to the ISO Tariff, any ISO Protocol or Agreement, or any Rules of Conduct applicable in accordance with Sections 14.1.1 and 4.9 of this Tariff. .

P2.2.7.2 Tariff Changes

Upon recommendation of the MSC, the ISO Governing Board shall consider and may adopt proposed ISO Tariff changes in accordance with Section 14.1.1 of this Tariff.

P2.2.7.3 Sanctions and Penalties

Upon recommendation of the MSC, the ISO may impose such sanctions or penalties as it believes necessary and as are permitted under the ISO Tariff and related protocols approved by FERC; Section 37.9 or it may make any such referral to such regulatory or antitrust agency as it sees fit to recommend the imposition of sanctions and penalties.

P2.2.8 PUBLICATION OF INFORMATION

P2.2.8.1 Market Monitoring Data and Indices

The ISO Department of Market Analysis shall, pursuant to Appendix P1**,** Section P1.1.1, develop a catalog of data and indices. Upon approval of the ISO CEO, such catalogs shall be duly published on the ISO Home Page and disseminated to all Market Participants.

P2.2.8.2 Reports to Regulators

The ISO shall develop annual reports of market performance for delivery to FERC, and such other reports as may be required by FERC, which shall be submitted for review to the MSC. The Department of Market Analysis shall prepare and submit such reports to the ISO CEO, ISO Governing Board and to the regulatory agency concerned.

ISO TARIFF APPENDIX P

Attachment A

Conduct Warranting Mitigation

ISO Market Monitoring Plan

Market Mitigation Measures

1 PURPOSE AND OBJECTIVES

1.1 These ISO market power mitigation measures ("Mitigation Measures") are intended to provide the means for the ISO to mitigate the market effects of any conduct that would substantially distort competitive outcomes in the ISO Real Time Market while avoiding unnecessary interference with competitive price signals. These Mitigation Measures are intended to minimize interference with an open and competitive market, and thus to permit, to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the Mitigation Measures authorize the mitigation only of specific conduct that exceeds well-defined thresholds specified below.

1.2 In addition, the ISO shall monitor the markets it administers for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified below for the imposition of mitigation measures by the ISO. If the ISO identifies any such conduct, and in particular conduct exceeding the thresholds for presumptive market effects specified below, it shall make a filing under Section 205 of the Federal Power Act, 16 U.S.C. § 824d, with FERC requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the ISO believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the ISO's justification for imposing that mitigation measure.

2 CONDUCT WARRANTING MITIGATION

2.1 Definitions

The following definitions are applicable to this Attachment A:

“Economic Market Clearing Prices” are the Market Clearing Prices for a particular resource at the location of that particular resource at the time the resource was either Scheduled or was Dispatched by the ISO. Economic Market Clearing Prices may originate from the Day-Ahead Energy market, the Hour-Ahead Energy market (when these markets are in place), or ISO real-time Imbalance Energy market. The Economic Market Clearing Price for the ISO real-time Imbalance Energy market shall be the Dispatch Interval Ex Post Price, unless the resource cannot change output level within the hour (i.e., the resource is not amenable to intra-hour real-time Dispatch instructions), or it is a System Resource. Economic Market Clearing Prices for the ISO real-time Imbalance Energy market for resources that cannot change output level within one Dispatch Interval and System Resources shall be the simple average of the relevant Dispatch Interval Ex Post Prices for each hour.

"Electric Facility" shall mean an electric resource, including a Generating Unit, System Unit, or a Participating Load.

2.2 Conduct Subject to Mitigation

Mitigation Measures may be applied: (i) to the bidding, scheduling, or operation of an "Electric Facility"; or (ii) as specified in Section 2.4 below.

2.3 Conditions for the Imposition of Mitigation Measures

2.3.1 In general, the ISO shall consider a Market Participant's conduct to be inconsistent with competitive conduct if the conduct would not be in the economic interest of the Market Participant in the absence of market power. The categories of conduct that are inconsistent with competitive conduct include, but may not be limited to, the three categories of conduct specified in Section 2.4 below.

2.4 Categories of Conduct that May Warrant Mitigation

2.4.1 The following categories of conduct, whether by a single firm or by multiple firms acting in concert, may cause a material effect on prices or generally the outcome of the ISO Real Time Market if exercised from a position of market power. Accordingly, the ISO shall monitor the ISO Markets for the following categories of conduct, and shall impose appropriate Mitigation Measures if such conduct is detected and the other applicable conditions for the imposition of Mitigation Measures are met:

(1) Physical withholding of an Electric Facility, in whole or in part, that is, not offering to sell or schedule the output of or services provided by an Electric Facility capable of serving an ISO Market. Such withholding may include, but not be limited to: (i) falsely declaring that an Electric Facility has been forced out of service or otherwise become totally or partially unavailable, (ii) refusing to offer bids or schedules for an Electric Facility when it would be in the economic interest, absent market power, of the withholding entity to do so, (iii) declining real-time bids called upon by the ISO (unless the ISO is informed in accordance with established procedures that the relevant resource for which the bid is submitted has undergone a forced outage or derate), or (iv) operating a Generating Unit in real time to produce an output level that is less than the ISO's Dispatch instruction.

(2) Economic withholding of an Electric Facility, that is, submitting bids for an Electric Facility that are unjustifiably high (relative to known operational characteristics and/or the known operating cost of the resource) so that: (i) the Electric Facility is not or will not be dispatched or scheduled, or (ii) the bids will set a Market Clearing Price.

(3) Uneconomic production from an Electric Facility that is, increasing the output of an Electric Facility to levels that would otherwise be uneconomic in order to cause, and obtain benefits from, a transmission constraint.

2.4.2 Mitigation Measures may also be imposed to mitigate the market effects of a rule, standard, procedure, design feature, or known software imperfection of an ISO Market that allows a Market Participant to manipulate market prices or otherwise impair the efficient operation of that market, pending the revision of such rule, standard, procedure design feature, or software defect to preclude such manipulation of prices or impairment of efficiency.

2.4.3 Taking advantage of opportunities to sell at a higher price or buy at a lower price in a market other than an ISO Market shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

2.4.4 The ISO shall monitor ISO Markets for other categories of conduct, whether by a single firm or by multiple firms acting in concert, that have material effects on prices in an ISO Market or other payments. The ISO shall: (i) seek to amend the foregoing list as may be appropriate to include any such conduct that would substantially distort or impair the competitiveness of any of the ISO Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the FERC as may be appropriate.

3 CRITERIA FOR IMPOSING MITIGATION MEASURES

3.1 Identification of Conduct Inconsistent with Competition

Conduct that may potentially warrant the imposition of a mitigation measure includes the categories described in Section 2.4 above. The thresholds listed in Section 3.1.1 below shall be used to identify substantial departures from competitive conduct indicative of an absence of workable competition.

3.1.1 Conduct Thresholds for Identifying Economic Withholding

The following thresholds shall be employed by the ISO to identify economic withholding that may warrant the mitigation of the bid from a resource and shall be determined with respect to a reference level determined as specified in Section 3.1.1.1:

For Energy Bids to be Dispatched as Imbalance Energy through the RTD Software: the lower of a 200 percent increase or $100/MWh increase in the bid with respect to its Reference Level.

3.1.1.1 Reference Levels

(a) For purposes of establishing reference levels, bid segments shall be defined as follows:

1. the capacity of each generation resource shall be divided into 10 equal Energy bid segments between its minimum (Pmin) and maximum (Pmax) operating point.

    A reference level for each bid segment shall be calculated each day for peak and off-peak periods on the basis of the following methods, listed in the following order of preference subject to the existence of sufficient data, where sufficient data means at least one data point per time period (peak or off-peak) for the bid segment. Peak periods shall be the periods Monday through Saturday from Hour Ending 0700 through Hour Ending 2200, excluding holidays. Off-Peak periods are all other hours.

    1. Excluding non-positive proxy and mitigated bids, the accepted bid, or the lower of the mean or the median of a resource's accepted bids if such a resource has more than one accepted bid in competitive periods over the previous 90 days for peak and off-peak periods, adjusted for daily changes in fuel prices using gas price determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Edison Company, or Pacific Gas and Electric Company), or, if the resource is not served from one of those three Service Areas, from the nearest of those three Service Areas. Accepted and justified bids above the applicable soft cap, as set forth in Section 39.2 of this Tariff, will be included in the calculation of reference prices.

2. If the resource is a gas-fired unit that does not have significant energy limitations, the unit's default Energy Bid determined monthly as set forth in Section 5.11.5 (based on the incremental heat rate submitted to the ISO, adjusted for gas prices, and the variable O&M cost on file with the ISO, or the default O&M cost of $6/MWh).

3. For non gas-fired units and gas-fired units that have significant energy limitations, a level determined in consultation with the Market Participant submitting the bid or bids at issue, provided such consultation has occurred prior to the occurrence of the conduct being examined by the ISO, and provided the Market Participant has provided sufficient data on a unit's energy limitations and operating costs (opportunity cost for energy limited resources) in accordance with specifications provided by the ISO.

4. The mean of the Economic Market Clearing Prices for the units' relevant location (Zone or node commensurate with the pricing granularity in effect) during the lowest-priced 25 percent of the hours that the unit was dispatched or scheduled over the previous 90 days for peak and off-peak periods, adjusted for changes in fuel prices; or

5. If sufficient data do not exist to calculate a reference level on the basis of the first, second, or fourth methods and the third method is not applicable or an attempt to determine a reference level in consultation with a Market Participant has not been successful, the ISO shall determine a reference level on the basis of:

   i. the ISO's estimated costs of an Electric Facility, taking into account available operating costs data, opportunity cost, and appropriate input from the Market Participant, and the best information available to the ISO; or

   ii. an appropriate average of competitive bids of one or more similar Electric Facilities.

(b) The reference levels ($/MWh bid price) for the different bid segments of each resource (or import bid curve of a Scheduling Coordinator at a Scheduling Point) shall be made monotonically non-decreasing by the ISO by proceeding from the lowest MW bid segment moving through each higher MW bid segment. The reference level of each succeeding bid segment shall be the higher of the reference level of the preceding bid segment or the reference level determined according to paragraph (a) above.

3.2 Material Price Effects

3.2.1 Market Impact Thresholds

In order to avoid unnecessary intervention in the ISO Market, Mitigation Measures for economic withholding shall not be imposed unless conduct identified as specified above causes or contributes to a material change in one or more of the ISO Market Clearing Prices (MCPs). Initially, the thresholds to be used by the ISO to determine a material price effect shall be as follows:

For Energy Bids to be Dispatched as Imbalance Energy through the RTD Software: the lower of an increase of 200 percent or $50 per MWh in the projected Hourly Ex Post Price at any location (Zone or node) commensurate with the relevant pricing structure in effect in accordance with the ISO Tariff.

For Energy Bids to be Dispatched out of economic merit order to manage Intra-Zonal Congestion: if the price of the bid is $50/MWh or 200 percent greater than the Dispatch Interval Ex Post Price at that location (Zone or node) commensurate with the relevant pricing structure in effect in accordance with the ISO Tariff.

Accepted and justified bids above the applicable soft cap, as set forth in Section 28.1.2 of this Tariff, will not be eligible to set the Market Clearing Price. Such bids shall be included in the Market Impact test, however, and, for purposes of this test only, shall be assumed to be eligible to set the Market Clearing Price.

3.2.2 Price Impact Analysis

3.2.2.1 Bids to be Dispatched as Imbalance Energy.

The ISO shall determine the effect on prices of questioned conduct through automated computer modeling and analytical methods. An Automatic Mitigation Procedure (AMP) shall identify bids that have exceeded the conduct thresholds and shall compute the change in projected Hourly Ex Post Prices as a result of simultaneously setting all such bids to their Reference Levels. If a change in the projected Hourly Ex Post Price exceeds the Impact threshold stated in Section 3.2.1, those bids would be kept mitigated at their default bid levels as specified in Section 4.2.2 below.

3.2.2.2 Bids to be Dispatched out of economic merit order to manage Intra-Zonal Congestion. If the price of the bid is $50/MWh or 200 percent greater than the Dispatch Interval Ex Post Price at that location (Zone or node) commensurate with the relevant pricing structure in effect in accordance with the ISO Tariff, the bid price shall be mitigated to the reference price and the Scheduling Coordinator for that

resource shall be paid the greater of the reference price or the relevant Dispatch Interval Ex Post Price. Bids mitigated in accordance with this Section 3.2.2.2 shall not set the Dispatch Interval Ex Post Price.

3.2.3 Section 205 Filings

In addition, the ISO shall make a filing under Section 205 of the Federal Power Act with FERC seeking authorization to apply an appropriate mitigation measure to conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Section 3.1.1 above, unless the ISO determines, from information provided by the Market Participant or Parties that would be subject to mitigation or other information available to the ISO that the conduct is attributable to legitimate competitive market forces or incentives. The following are examples of conduct that are deemed to depart significantly from the conduct that would be expected under competitive market conditions:

(1) bids that vary with unit output in a way that is unrelated to the known performance characteristics of the unit, or

(2) bids that vary over time in a manner that appears unrelated to the change in the unit's performance or to changes in the supply environment that would induce additional risk or other adverse shifts in the cost basis.

The conducts listed above are intended to be examples rather than a comprehensive list.

3.3 Consultation with a Market Participant

If a Market Participant anticipates submitting bids in an ISO Market administered by the ISO that will exceed the thresholds specified in Section 3.1 above for identifying conduct inconsistent with competition, the Market Participant may contact the ISO to provide an explanation of any legitimate basis for any such changes in the Market Participant's bids. If a Market Participant's explanation of the reasons for its bidding indicates to the satisfaction of the ISO, that the questioned conduct is consistent with competitive behavior, no further action will be taken. Upon request, the ISO shall also consult with a Market Participant with respect to the information and analysis used to determine reference levels under Section 3.1.1 above for that Market Participant.

4 MITIGATION MEASURES

4.1 Purpose

If conduct is detected that meets the criteria specified in Section 3, the appropriate mitigation measures described in this Section 4 shall be applied by the ISO. The conduct specified in Section 3.1.1 shall be remedied by the prospective application of a default bid measure as described in Section 4.2 for the specific hour that they violate the price and market impact thresholds.

4.2 Sanctions for Economic Withholding

4.2.1 Default Bid

A default bid shall be designed to cause a Market Participant to bid as if it faced workable competition during a period when: (i) the Market Participant does not face workable competition and (ii) has responded to such condition by engaging in the economic withholding of an Electric Facility. In designing and implementing default bids, the ISO shall seek to avoid causing an Electric Facility to bid below its marginal cost.

4.2.2 Implementation

(a) If the criteria contained in Section 3 are met, the ISO may substitute a default bid for a bid submitted for an Electric Facility. The default bid shall establish a maximum value for each component of the submitted bid, equal to a reference level for that component determined as specified in Section 3.1.1 above.

(b) The Mitigation Measures will be applied to 1) all incremental bids submitted to the real-time Imbalance Energy market during the pre-dispatch process prior to the real-time Imbalance Energy market based on the projected real-time MCPs that are computed during this process; and 2) to the Day-Ahead and the Hour-Ahead Energy markets when these markets are made operational.

(c) An Electric Facility subject to a default bid shall be paid the MCP applicable to the output from the facility. Accordingly, a default bid shall not limit the price that a facility may receive unless the default bid determines the MCP applicable to that facility.

(d) The ISO shall not use a default bid to determine revised MCPs for periods prior to the imposition of the default bid, except as may be specifically authorized by FERC.

(e) The Mitigation Measures shall not be applied to Energy Bids projected to be Dispatched as Imbalance Energy through the RTD Software in the hours in which all Zonal Ex Post Prices are projected to be below $91.87/MWh. If the Zonal Dispatch Interval Ex Post Price is projected to be above $91.87/MWh in any ISO Zone, the Mitigation Measures shall be applied to all bids, except those from System Resources, in all ISO Zones. The ISO will apply Mitigation Measures to all bids taken out of merit order to address Intra-Zonal Congestion.

(f) The Mitigation Measures shall not be applied to bids below $25/MWh.

(g) The posting of the MCP may be delayed if necessary for the completion of automated mitigation procedures.

(h) Bids not mitigated under these Mitigation Measures shall remain subject to mitigation by other procedures specified in the ISO Tariff as may be appropriate.

4.3 Sanctions for Physical Withholding

The ISO may report a Market Participant the ISO determines to have engaged in physical withholding, including providing the ISO false information regarding the derating or outage of an Electric Facility, to the Federal Energy Regulatory Commission in accordance with Section 9.3.10.5 of the ISO Tariff. In addition, a Market Participant that fails to operate a Generating Unit in conformance with ISO Dispatch Instructions shall be subject to the penalties set forth in Section 11.2.4.1.2 of the ISO Tariff.

4.4 Duration of Mitigation Measures

Bids will be mitigated only in the specific hour that they violate the price and market impact thresholds.

5 FERC-ORDERED MEASURES

In addition to any mitigation measures specified above, the ISO shall administer, and apply when appropriate in accordance with their terms, such other mitigation measures as it may be directed to implement by order of the FERC.

6 DISPUTE RESOLUTION

If a Market Participant has reasonable grounds to believe that it has been adversely affected because a Mitigation Measure has been improperly applied or withheld, it may seek a determination in accordance with the dispute resolution provisions of the ISO Tariff. In no event, however, shall the ISO be liable to a Market Participant or any other person or entity for money damages or any other remedy or relief except and to the extent specified in the ISO Tariff.

7 EFFECTIVE DATE

These Mitigation Measures shall be effective as of the date they are approved by the FERC.

ISO TARIFF APPENDIX Q

Eligible Intermittent Resources Protocol

APPENDIX Q

Eligible Intermittent Resources Protocol

EIRP 1.3 Scope

EIRP 1.3.1 Scope of Application to Parties

This Protocol applies to the ISO and to:

(a) Scheduling Coordinators (SCs);

(b) Eligible Intermittent Resources; and

(c) Participating Intermittent Resources.

EIRP 1.3.2 Liability of the ISO

Any liability of the ISO arising out of or in relation to this Protocol shall be subject to Section 14 of the ISO Tariff as if references to the ISO Tariff were references to this Protocol.

EIRP 2 PARTICIPATING INTERMITTENT RESOURCE CERTIFICATION

EIRP 2.1 No Mandatory Participation

Eligible Intermittent Resources may elect to be scheduled and settled as the ISO Tariff provides for Generating Units, and are not required to seek certification as Participating Intermittent Resources.

EIRP 2.2 Minimum Certification Requirements

Those Eligible Intermittent Resources that intend to become Participating Intermittent Resources must meet the following requirements.

EIRP 2.2.1 Agreements

The following agreements must be executed:

(a) A Participating Generator Agreement that, among other things, binds the Participating Intermittent Resource to comply with the ISO Tariff;

(b) A Meter Service Agreement for ISO Metered Entities; and

(c) A letter of intent to become a Participating Intermittent Resource, which when executed and delivered to the ISO shall initiate the process of certifying the Participating Intermittent Resource. The form of the letter of intent shall be specified by the ISO and published on the ISO Home Page.

EIRP 2.2.2 Composition

The ISO shall develop criteria to determine whether one or more Eligible Intermittent Resources may be included within a Participating Intermittent Resource. Such criteria shall include:

(a) A Participating Intermittent Resource must be at least 1 MW rated capacity.

(b) A Participating Intermittent Resource may include one or more Eligible Intermittent Resources that have similar response to weather conditions or other variables relevant to forecasting Energy, as determined by the ISO.

(c) Each Participating Intermittent Resource shall be electrically connected at a single point on the ISO Controlled Grid, except as otherwise permitted by the ISO on a case-by-case basis as may be allowed under the ISO Tariff.

(d) The same Scheduling Coordinator must schedule all Eligible Intermittent Resources aggregated into a single Participating Intermittent Resource.

EIRP 2.2.3 Equipment Installation

A Participating Intermittent Resource must install and maintain the communication equipment required pursuant to EIRP 3, and the equipment supporting forecast data required pursuant to EIRP 6.

EIRP 2.2.4 Forecast Model Validation

The ISO must determine that sufficient historic and real-time telemetered data are available to support an accurate and unbiased forecast of Energy generation by the Participating Intermittent Resource, according to the forecasting process validation criteria described in EIRP 4.

EIRP 2.2.5 Information Requirements For Participating Intermittent Resource Export Fee

In order for the ISO to administer, implement and calculate the Participating Intermittent Resource Export Fee, each Participating Intermittent Resource jointly with, and through, its Scheduling Coordinator must provide the ISO with the following information and documents under the schedule and conditions set forth in this section. The ISO will maintain the confidentiality of all information and documents received under this section in accordance with ISO Tariff section 20 et seq.

(a) A certification, in the form posted on the ISO Homepage, signed by an officer of the Participating Intermittent Resource and its Scheduling Coordinator, identifying (1) the Export Percentage under EIRP 5.3.2, if any, and basis thereof, and (2) each contract to sell Energy or capacity from the Participating Intermittent Resource, including for each such contract, the counterparty, start and end dates, delivery point(s), quantity in MW, other temporal terms, i.e., seasonal or hourly limitations.

The certification must be updated by resubmission to the ISO (1) upon a request to modify the composition of the Participating Intermittent Resource under EIRP 2.4.2; or (2) within ten (10) calendar days of final execution of a new contract or any change in counterparty, start and end dates, delivery point(s), quantity in MW, or other temporal terms, as described above, for any prior certified contract. All other contractual changes will not trigger the obligation for recertification;

(b) Copies of all contracts, including changes, identified in the above-referenced certification; however, price information may be redacted from the contracts provided.

Each Participating Intermittent Resource, as of November 1, 2006, must initially provide the information requested by EIRP 2.2.5 in accordance with a market notice provided by the ISO to Participating Intermittent Resources. All other Eligible Intermittent Resources must satisfy EIRP 2.2.5 in order to become a Participating Intermittent Resource after November 1, 2006.

EIRP 2.3 Notice of Certification

When all requirements described in EIRP 2.2 have been fulfilled, the ISO shall notify the Scheduling Coordinator and the representatives of the Eligible Intermittent Resources comprising the Participating Intermittent Resource that the Participating Intermittent Resource has been certified, and is eligible for the settlement terms provided under Section 11.2.4.5 of the ISO Tariff, as conditioned by the terms of this EIRP.

EIRP 2.4 Requirements After Certification

EIRP 2.4.1 Forecast Fee

Beginning on the date first certified, a Participating Intermittent Resource must pay the Forecast Fee for all metered Energy generated by the Participating Intermitted Resource over the duration of the commitment indicated in the letter of intent described in EIRP 2.2.1(c).

The amount of the Forecast Fee shall be determined so as to recover the projected annual costs related to developing Energy forecasting systems, generating forecasts, validating forecasts, and monitoring forecast performance, that are incurred by the ISO as a direct result of participation by Participating Intermittent Resources in ISO Markets, divided by the projected annual Energy production by all Participating Intermittent Resources.

The initial rate for the Forecast Fee, and all subsequent rate changes as may be necessary from time to time to recover costs incurred by the ISO for the forecasting conducted on the behalf of Participating Intermittent Resources, shall be posted on the

ISO Home Page. In no event shall the level of the Forecast Fee exceed the amount specified in ISO Tariff Appendix F, Schedule 4.

EIRP 2.4.2 Modification of Participating Intermittent Resource Composition

A Participating Intermittent Resource may seek to modify the composition of the Participating Intermittent Resource (e.g., by adding or eliminating an Eligible Intermittent Resource from the Participating Intermittent Resource). Such changes shall not be implemented without prior compliance with the written approval by the ISO. The ISO will apply consistent criteria and expeditiously review any proposed changes in the composition of a Participating Intermittent Resource.

EIRP 2.4.3 Changes in Scheduling Coordinator

This EIRP does not impose any additional requirement for ISO approval to change the Scheduling Coordinator for an approved Participating Intermittent Resource than would otherwise apply under the ISO Tariff to changes in the Scheduling Coordinator representing a Generating Unit.

EIRP 2.4.4 Continuing Obligation

A Participating Intermittent Resource must meet all obligations established for Participating Intermittent Resources under the ISO Tariff and this EIRP, and must fully cooperate in providing all data, other information, and authorizations the ISO reasonably requests to fulfill its obligation to validate forecast models, explain deviations, and implement the Participating Intermittent Resource Export Fees.

EIRP 2.4.5 Failure to Perform

If the ISO determines that a material deficiency has arisen in the Participating Intermittent Resource's fulfillment of its obligations under the ISO Tariff and this EIRP, and such Participating Intermittent Resource fails to promptly correct such deficiencies when notified by the ISO, then the eligibility of the Participating Intermittent Resource for the settlement accommodations provided in Section 11.2.4.5 of the ISO Tariff shall be suspended until such time that the unavailable data is provided or other material deficiency is corrected to the ISO's reasonable satisfaction. Such suspension shall not relieve the Scheduling Coordinator for the deficient Participating Intermittent Resource from paying the Forecast Fee over the duration of the period covered by the letter of intent described in EIRP 2.2.1(c).

EIRP 3 COMMUNICATIONS

EIRP 3.1 Forecast Data

The ISO may require various data relevant to forecasting Energy from the Participating Intermittent Resource to be telemetered to the ISO, including appropriate operational data, meteorological data or other data reasonably necessary to forecast Energy.

EIRP 3.2 Standards

The standards for communications shall be the monitoring and communications requirements for Generating Units providing only Energy and Supplemental Energy; as such standards may be amended from time to time, and published on the ISO Home Page.

EIRP 3.3 Cost Responsibility

An applicant for certification as a Participating Intermittent Resource is responsible for expenses associated with engineering, installation, operation and maintenance of required communication equipment.

EIRP 4 FORECASTING

The ISO is responsible for overseeing the development of tools or services to forecast Energy for Participating Intermittent Resources. The ISO will use its best efforts to develop accurate and unbiased forecasts, as limited by the availability of relevant explanatory data. Objective criteria and thresholds for unbiased, accurate forecasts shall be published on the ISO Home Page, and shall be used to certify Participating Intermittent Resources in accordance with EIRP 2.2.4.

EIRP 4.1 Hour-Ahead Forecast

The ISO shall develop expert, independent hourly forecasts of Energy generation on each Participating Intermittent Resource. A forecast shall be published each hour on the half hour for each of the next seven operating hours. Other forecasts, including a day-ahead forecast, may be developed at the ISO's discretion. The Scheduling Coordinator representing the Participating Intermittent Resource must use the Hour-Ahead Forecast that is available 30 minutes prior to the deadline for submitting the Preferred Hour-Ahead Schedule. The ISO shall use best efforts to provide reliable and timely forecasts. However, if the ISO fails to deliver the Hour-Ahead Forecast to the Scheduling Coordinator prior to 15 minutes before the deadline for submitting Preferred Hour-Ahead Schedules, then the Hour-Ahead Forecast shall be the most recent Energy forecast provided by the ISO to the Scheduling Coordinator for the operating hour for which Preferred Schedules are next due.

EIRP 4.2 Forecast Calibration

The ISO shall calibrate the forecast to eliminate bias as measured by net MWh deviations across any and all relevant time periods to minimize the expected cumulative net charges or payments that are recovered or allocated through Section 11.2.4.5 of the ISO Tariff.

EIRP 4.3 Confidentiality

The ISO shall maintain the confidentiality of proprietary data for each Participating Intermittent Resource in accordance with Section 20 of the ISO Tariff.

EIRP 5 SCHEDULING AND SETTLEMENT

EIRP 5.1 Schedules

Scheduling Coordinators shall be required to submit Preferred Hour-Ahead Energy Schedules (MWh) for the Generating Units that comprise each Participating Intermittent Resource that are identical, in the aggregate, to the Hour-Ahead Forecast published for that Participating Intermittent Resource (MWh).

EIRP 5.2 Settlement

After a Participating Intermittent Resource is certified, settlement shall be determined for each Settlement Period based on consistency of Schedules and bids submitted on behalf of such Participating Intermittent Resources with the rules specified in the ISO Tariff and this Protocol.

No Supplemental Energy bids or Adjustment Bids may be submitted on behalf of a Participating Intermittent Resource. Submitting such bids shall render the Participating Intermittent Resource ineligible for settlement according to Section 11.2.4.5 of the ISO Tariff for that Settlement Period. Such activity will be monitored in accordance with EIRP 7.

EIRP 5.3 Participating Intermittent Resource Export Fee

EIRP 5.3.1 Exemptions

After November 1, 2006, Participating Intermittent Resources shall be subject to the Participating Intermittent Resource Export Fee, as set forth in Schedule 4 of Appendix F, for Energy generated, except to the extent the Participating Intermittent Resource is exempt under one or more of the following conditions:

(a) The owner of a Participating Intermittent Resource, as of November 1, 2006, utilizes the Energy generated from the Participating Intermittent Resource to meet its own Native Load outside the ISO Control Area. Should any Participating Intermittent Resource subject to this exemption increase its Pmax set forth in the ISO's Master File by modification under EIRP 2.4.2, the exemption will not apply to the added capacity unless exempt under another subsection of EIRP 5.3.1.

If the Participating Intermittent Resource subject to this exemption changes ownership, the Participating Intermittent Resource Export Fee will apply, except where the prior exempt owner demonstrates that the entire output of the Participating Intermittent Resource continues to be delivered to the exempt owner under a power purchase agreement for the purpose of serving the prior exempt owner's Native Load. The exemption will then continue only for the period of the power purchase agreement as provided in accordance with EIRP 2.2.5 and cannot exceed the MW quantity originally exempted.

(b) A Participating Intermittent Resource demonstrates in its certification under EIRP 2.2.5(a) an export contract with a starting term prior to November 1, 2006. An export contract is any power purchase agreement to sell Energy to any entity other than a load serving entity with an obligation under law or franchise to serve Demand within the ISO Control Area.

The exemption will apply to any extension of the current export contract through an evergreen or other existing extension provision. The exemption terminates upon termination of the export contract. Should any Participating Intermittent Resource subject to this exemption increase its Pmax set forth in the ISO's Master File by modification under EIRP 2.4.2, the exemption will apply only to Energy generated up to the contract quantity, unless the Participating Intermittent Resource demonstrates a basis for exemption under subsection (c) for the expanded capacity.

(c) A Participating Intermittent Resource demonstrates in its certification under EIRP 2.2.5(a) a contract to sell Energy to a load serving entity with Native Load within the ISO Control Area. Energy Service Providers with contractual obligations with customers within the ISO Control Area would be deemed a load serving entity with an obligation to serve Native Load within the ISO Control Area.

The exemption will apply to any extension of the current contract through an evergreen or other existing extension provision. The exemption terminates upon termination of the contract. Should any Participating Intermittent Resource subject to this exemption increase its Pmax set forth in the ISO's Master File by modification under EIRP 2.4.2, the exemption will continue to apply only to Energy generated up to the contract quantity unless the Participating Intermittent Resource demonstrates a basis for exemption under this subsection (c) for the expanded capacity.

EIRP 5.3.2 Participating Intermittent Resource Export Percentage

Based on the information required in EIRP 2.2.5 and application of the exemptions to the Participating Intermittent Resource Export Fee in EIRP 5.3.2, the ISO will determine an "Export Percentage" for each Participating Intermittent Resource that will be calculated as the ratio of the Participating Intermittent Resource's Pmax in the ISO Master File minus the MW, subject to an exemption under EIRP 5.3.2 on a MW basis to the Participating Intermittent Resource's Pmax in the ISO Master File. For example, a Participating Intermittent Resource with a Pmax of 100 MW and a contract with an ISO Control Area load serving entity for 40 MW would have an export percentage of (100-40)/100 = 60%. A Participating Intermittent Resource with Export Percentage greater than zero (0) will be deemed an Exporting Participant Intermittent Resource. The ISO will notify the Participating Intermittent Resource and its Scheduling Coordinator of the facility's Export Percentage. Any dispute regarding the ISO's determination of Export Percentage shall be subject to the dispute resolution procedures under Section 13 of the ISO Tariff.

EIRP 5.3.3 Quarterly Application of Participating Intermittent Resource Export Fee

Each quarter the ISO will charge Exporting Participating Intermittent Resources the Participating Intermittent Resource Export Fee, as set forth in Schedule 4 of Appendix F.

EIRP 5.3.4 Allocation of Credit for Participating Intermittent Resource Export Fees Received

Payments received by the ISO from application of the Participating Intermittent Export Fee in accordance with EIRP 5.3 shall be allocated as a credit on a quarterly basis to Scheduling Coordinators with Net Negative Uninstructed Deviations in proportion to the to the amount of Net Negative Uninstructed Deviations that each Scheduling Coordinator was assessed for Participating Intermittent Resources settlement charges for ISO Charge Type 721 during the prior quarter.

EIRP 5.3.5 Recording of Exemptions and Notice of Termination

The ISO will record any exemption period ending date, if applicable, for each Participating Intermittent Resource. At the conclusion of the exemption period, the ISO will notify the Scheduling Coordinator for the Participating Intermittent Resource that the facility is no longer exempt from the Participating Intermittent Resource Export Fee.

EIRP 5.3.6 Annual Confirmation

On December 31 of each calendar year, each Participating Intermittent Resource shall confirm in the form posted on the ISO Homepage, signed by an officer of the Participating Intermittent Resource, that the operations of the Participating Intermittent Resource are consistent with any certification(s) provided to the ISO under EIRP 2.2.5.

EIRP 5.3.7 Audit Rights

In addition to the rights set forth in ISO Tariff Section 4.6.9, the ISO shall have the right to contact any counterparty to a contract relied upon under EIRP 5.3.1 for purposes of determining compliance with this EIRP.

EIRP 6 DATA COLLECTION FACILITIES

The Participating Intermittent Resource must install and maintain equipment to collect, record and transmit data that the ISO reasonably determines is necessary to develop and support a forecast model that meets the requirements of EIRP 4.

EIRP 6.1 Wind Resources

A Participating Intermittent Resource powered by wind must install at least one meteorological tower at a project location that is representative of the microclimate within the project boundary.

The meteorological tower must rely on equipment typically used in the wind industry to continuously monitor weather conditions at a wind resource site. Data collected shall be consistent with requirements published on the ISO Home Page. Such data must be gathered and telemetered to the ISO in accordance with EIRP 3.

If objective standards developed by the ISO indicate that the meteorological data may not be sufficiently representative of conditions affecting Energy output or changes in Energy output by that Participating Intermittent Resource, then the ISO may require that additional meteorological equipment be temporarily installed at another location within the project boundary. The cost of such equipment, which may be temporarily installed by the Participating Intermittent Resource or the ISO, shall be the responsibility of the Participating Intermittent Resource.

If objective standards indicate that the data collected from such a temporary site contribute significantly to the development of an accurate and unbiased forecast, then the Participating Intermittent Resource shall be responsible for installing and arranging for the telemetry of data from an additional permanent meteorological tower at such site, and for the reasonable cost, if any, that the ISO may have incurred to install and remove the temporary equipment. Relocation of the original meteorological tower to the new site will be allowed if the ISO determines that a sufficiently accurate and unbiased forecast can be generated from a single relocated meteorological tower.

EIRP 6.2 Other Eligible Intermittent Resources

Eligible Intermittent Resources other than wind projects that wish to become Participating Intermittent Resources will be required to provide data of comparable relevance to estimating Energy generation. Standards will be developed as such projects are identified and will be posted on the ISO Home Page.

EIRP 7 PROGRAM MONITORING

The ISO shall monitor the operation of these rules, and will in particular seek to eliminate any gaming opportunities provided by the flexibility provided Participating Intermittent Resources to self-select participation on an hourly basis.

Participating Intermittent Resources are expected to schedule and otherwise perform in good faith, and not seek to act strategically in a manner that causes financial gain through systematic behavior, where such gain results solely from the settlement accommodations provided under ISO Tariff Section 11.2.4.5.

If requirements specified in this technical standard are not met, then Participating Intermittent Resource certification may be revoked pursuant to EIRP 2.4.5. Any patterns of strategic behavior by Participating Intermittent Resources will be tracked, and the statistical significance of such deviations will be used by the ISO to evaluate whether changes in the rules defined in this EIRP are appropriate.

The ISO will monitor the impact of rules for Participating Intermittent Resources on Imbalance Energy and Regulation costs to the ISO.

EIRP 8 AMENDMENTS

If the ISO determines a need for an amendment to this Protocol, the ISO will follow the requirements as set forth in Section 22.10 of the ISO Tariff.

ISO TARIFF APPENDIX R

UDP Aggregation Protocol (UDPAP)

ISO TARIFF APPENDIX R

UDP Aggregation Protocol (UDPAP)

UAP 1.3 Scope

There are two types of UDP Aggregation Classifications:

(1) Basic UDP Aggregations: composed of Generating Units connected at the same substation and stepping up to the same voltage level bus bar, or

(2) Custom UDP Aggregations: composed of Generating Units connected at different substations and/or different voltage levels, particularly where the Generating Units to be aggregated are separated by ISO Controlled Grid facilities. Examples of a proposed Custom UDP Aggregation include hydroelectric units operating on a common watershed (but having multiple different interconnection points), or geothermal units fed from a common geothermal steam supply.

UAP 2 SUBMITTAL OF A REQUEST FOR UDP AGGREGATION

Requests for UDP Aggregation are submitted to the ISO and must include the following documentation:

(1) A completed UDP Aggregation Request form, which is available for downloading on the ISO website;

(2) A simplified electrical one-line diagram, which illustrates each resource, the connection of the resources to each other and to the ISO Control Area Grid;

(3) For Custom UDP Aggregations, a detailed description that explains physical operating interrelationships between the units, or, if there are no interrelationships, how the units are compatible and why an aggregation of these units for the purpose of calculating Uninstructed Deviation Penalties is reasonable.

UAP 3 ISO REVIEW OF A UDP AGGREGATION REQUEST

Upon receipt of a completed request form and accompanying attachments, the ISO shall review the request according to the criteria outlined herein. For Basic UDP Aggregations, the ISO shall review and approve or reject it within one week of receipt. The ISO shall review and approve or reject a request for a Custom UDP Aggregation within thirty (30) days of receipt.

UAP 3.1 Criteria for Reviewing a Request

UAP 3.1.1 Scheduling Coordinator and Interconnection Point

Uninstructed Deviations may be aggregated for resources that are:

(1) Represented by the same Scheduling Coordinator and

(2) Connected to the same ISO Controlled Grid bus and voltage level.

The ISO will consider, on a case-by-case basis, requests to aggregate Uninstructed Deviations among resources represented by the same Scheduling Coordinator but not sharing a common ISO Controlled Grid bus and voltage level based on an ISO review of impact on the ISO Controlled Grid. In particular, the ISO will consider whether the request concerns resources related by a common flow of fuel which cannot be interrupted without a substantial loss of efficiency of the combined output of all components; whether the Energy production from one resource necessarily causes Energy production from other resource(s); and whether the operational arrangement of resources determines the overall physical efficiency of the combined output of all of the resources.

UAP 3.1.2 Additional Criteria

Additional eligibility criteria for a UDP Aggregation are as follows:

(1) Only Generating Units shall be eligible for UDP Aggregation. As a general rule, pump-generating Units (or a Physical Scheduling Plant [PSP] containing a pump-generating Unit) cannot be part of a UDP Aggregation. However, it is possible that generating Units could form a UDP Aggregation comprised entirely of pump-generating Units whose operation is uniform, that is, Units all operating in either Generation mode or all in pump mode, but never mixed.

(2) UDP Aggregations cannot include any of the following:

(a) Load;

(b) Condition 2 Reliability Must Run (RMR) Units;

(c) Participating Intermittent Resources;

(d) Generating Units less than 5 MW; or

(e) Generating Units that span active or inactive Congestion Zones.

(3) The resources must have ISO direct telemetry and must be fully compliant with the ISO's direct telemetry standards.

(4) The Generating Units must have the same relative effect on all network elements for which the Generating Units have at least a five (5) percent effectiveness factor, that is, for those network elements for which a 1 MW change in the output of the Generating Unit changes the flow across that element by at least 0.05 MW. For the purposes of this item (4), the "same relative effect" means that the effectiveness factors of any Generating Unit relative to a network element cannot differ by more than 10% from the midpoint effectiveness factor of all the units. The midpoint effectiveness is the arithmetic mean of the two most different effectiveness factors to be aggregated.

(5) Custom UDP Aggregations involving units not directly connecting to the ISO Controlled Grid must recognize the transfer limits and status of the intermediate local facilities.

(6) The applicable Pmax of aggregated groups of resources will exclude units that are not operating.

UAP 3.1.3 Approval of a Request

If a UDP Aggregation request is approved, the ISO shall create a new unique Resource ID, which reflects the identity or location of the units and stipulates the UDP Aggregation, but which cannot be used for scheduling purposes. The ISO shall inform the Scheduling Coordinator of the approval and ask the Scheduling Coordinator to confirm the desired start date of the UDP Aggregation. When that confirmation has been received, the new aggregation will be entered into the ISO systems. Unless otherwise agreed to by the Scheduling Coordinator and the ISO, the UDP Aggregation will become effective on the first day of the month following approval. The Units in an approved UDP Aggregation are obligated to follow their individual schedules and instructions at all times.

UAP 3.1.4 Rejection of a Request

If the ISO determines that the proposed UDP Aggregation is likely to impact grid reliability or the reliability of transmission systems or equipment of intermediate entities between the relevant resources and the ISO grid, the request will be rejected. If the ISO rejects a request, the ISO shall inform the Scheduling Coordinator, and forward to it the reason for the rejection. The ISO may suggest alternative solutions if it has adequate time and data. The Scheduling Coordinator may choose to resubmit based on the ISO's recommendations, or to close the request.

UAP 4 MODIFICATIONS TO AN EXISTING UDP AGGREGATION

UAP.4.1 Status of UDP Aggregation

An approved UDP Aggregation shall be considered active until otherwise requested by the Scheduling Coordinator.

UAP 4.2 Suspension by the ISO

The ISO may temporarily suspend any aggregation as needed to ensure reliability. The ISO may also suspend previously approved UDP Aggregations if, due to changes to the grid, to the aggregated Generating Units, or to the facilities connecting aggregated Generating Units to the grid, the UDP Aggregation no longer meets the criteria set forth in Sections 3.1.1 and 3.1.2 of this ISO Protocol.

If the ISO must suspend the UDP Aggregation due to a forced outage or other unanticipated event, the ISO shall provide notice that the UDP Aggregation has been suspended as soon as practical after the affecting event, but in no case longer than 72 hours after that event. If the ISO must suspend the UDP Aggregation due to future changes, the ISO shall notify the affected Scheduling Coordinator (1) that the UDP Aggregation will be suspended and (2) when the UDP Aggregation will be suspended as soon as practical after the ISO determines the UDP Aggregation must be suspended.

The ISO shall write a report that explains the reason for the suspension and that specifies the effective date and time. The ISO will forward the report to the Scheduling Coordinator and take steps to have the aggregation removed from the ISO systems.

In the event that a resource in a UDP Aggregation changes from one Scheduling Coordinator to another, the UDP Aggregation will be suspended. In order to reinstate the aggregation, the new Scheduling Coordinator must submit a new request reflecting the change.

UAP 4.3 Request for Modification by a Scheduling Coordinator

A Scheduling Coordinator may request a modification to an existing aggregation up to once per calendar month. A request for modification will follow the same procedures as a new request.

ISO TARIFF APPENDIX S

Station Power Protocol

STATION POWER PROTOCOL

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STATION POWER PROTOCOL (SPP)

SPP 1 General Conditions

SPP 1.1 Procurement

Station Power may be voluntarily self-supplied through a) permitted netting as provided in Section 10.1.3 of this ISO Tariff using Energy generated contemporaneously at the same location, b) On-Site Self Supply or c) Remote Self Supply. Third Party Supply may serve Station Power only to the extent permissible under the rules and regulations of the applicable Local Regulatory Authority.

SPP 1.2 Eligibility

SPP 1.2.1 Only Station Power loads associated with Generating Units in the ISO Control Area that are part of an approved Station Power Portfolio may be self-supplied in accordance with this SPP. Each Generating Unit must be subject to a PGA, QF PGA, or MSS Agreement. Any generating facility outside the ISO Control Area owned by the same entity is eligible to provide Remote Self-Supply to Station Power loads, subject to the terms of this SPP. Generating Units wishing to self-supply Station Power shall complete the application process specified in SPP 2.

SPP 1.2.2 Station Power may be self-supplied by a single corporate entity, government agency, or joint powers agency or other legal entity organized under the laws of the State of California. A Station Power Portfolio may not include any facilities that are owned by the owner's corporate affiliates. In the case of a joint powers agency, a Station Power Portfolio may not include facilities independently owned by one or more members or other legally distinct entities. If an entity owns a portion of a jointly owned Generating Unit, such ownership share may be included in a Station Power Portfolio up to the amount of the associated entitlement to Energy from the jointly-owned Generating Unit provided that: (i) the entity has the right to call upon that Energy for its own use; and (ii) the Energy entitlement is not characterized as a sale from the jointly owned Generating Unit to any of its joint owners.

SPP 1.2.3 Net Output from generating facilities outside the ISO Control Area may be included in a Station Power Portfolio and used as a source of Remote Self-Supply to serve Station Power of Generating Units in the ISO Control Area and part of the Station Power Portfolio, so long as the following conditions are fulfilled:

(a) Imports of Net Output must be scheduled using an interchange ID specified by the ISO;

(b) Import Schedules using such interchange ID do not exceed the available Net Output of such generating facilities in any hour;

(c) Firm transmission service to a Scheduling Point that assures delivery into the ISO Control Area is secured; and

(d) Meter data for generating facilities located outside the ISO Control Area shall be subject to ISO audit to verify performance in accordance with these requirements.

SPP 1.3 Limitations

SPP 1.3.1 Station Power supplied by contemporaneous on-site Generation is treated as permitted netting under Section 10.1.3 of this ISO Tariff. This SPP neither expands opportunities for nor imposes additional conditions on permitted netting. In accordance with this ISO Tariff such contemporaneous self-supplied Station Power need not be scheduled with the ISO.

SPP 1.3.2 Self-supply of Station Power shall be strictly voluntary. Nothing in this SPP is intended to: 1) preclude a Generating Unit from purchasing Station Power pursuant to an applicable retail rate or tariff; or 2) supersede otherwise applicable jurisdiction of a Local Regulatory Authority, except in the event of a conflict between federal and state tariff provisions, in which case the federal tariff provisions will control.

SPP 2 Station Power Requirements and Review

SPP 2.1 Applications to Self-Supply Station Power

SPP 2.1.1 An application to establish a Station Power Portfolio or to modify the configuration of Station Power meters or the Generating facilities included in a Station Power portfolio must be submitted according to the process specified by the ISO and posted on the ISO Home Page, and shall include the following information:

(a) One-line diagrams clearly showing the location and ownership of all Generating Units and Station Power meters, their connection to the ISO Controlled Grid or distribution system, and the status of breakers and switchgear for normal system operation.

(b) Identification of any generating facilities outside the ISO Control Area, to be used to provide Remote Self Supply of Station Power within the proposed Station Power Portfolio. No loads associated with generating facilities outside the ISO Control Area may be supplied under this SPP.

(c) Certification that the applicant is the sole owner of all generating facilities proposed to be included in the Station Power Portfolio, and that the applicant has the right to call on Energy for its own use from its ownership share of any jointly owned facilities that are proposed to be used to self supply Station Power.

(d) Demonstration that each Station Power meter is certified in accordance with the ISO Tariff.

(e) Verification that each Station Power meter is subject to a Meter Service Agreement for ISO Metered Entities, and that each Generating Unit is bound to the ISO Tariff by a PGA, QF PGA, or MSS Agreement.

(f) Verification that the applicant has arranged for terms of service with the responsible UDC or MSS Operator for the use of any distribution facilities required to self-supply Station Power.

SPP 2.1.2 On the ISO's written request, the applicant will provide additional information that the ISO reasonably determines is necessary to verify the planned operation of the Station Power Portfolio and meet the requirements of SPP 2.1.1.

SPP 2.2 ISO Monitoring and Review

SPP 2.2.1 The ISO will take the following actions with respect to each application to establish a Station Power Portfolio:

(a) The ISO shall post on the ISO Home Page a listing of the specific Station Power meters and Generating Units located in the ISO Control Area, and any generating facilities outside the ISO Control Area, that compose each Station Power Portfolio, and which are eligible to participate in the self-supply of Station Power in accordance with this SPP.

(b) The ISO will provide the appropriate UDC or MSS Operator and the Local Regulatory Authority with one-line diagrams and other information regarding each application.

(c) The ISO will make a determination in consultation with the UDC or MSS Operator and the Local Regulatory Authority on the factual question of whether distribution facilities are involved in the requested self-supply of Station Power. Any disputes regarding such determinations shall be subject to the dispute resolution procedures of this ISO Tariff.

(d) The ISO will verify metering schemes and assign unique load identifiers consistent with the ISO Data Templates and Validation Rules that the Scheduling Coordinator responsible for each meter will be required to use for scheduling and settlement.

SPP 2.2.2 The ISO shall promptly review each application to establish or modify a Station Power Portfolio. Within ten (10) Business Days after the submittal of the application, the ISO shall notify the applicant in writing that the application is complete, or shall list any specific deficiencies or additional information that the ISO reasonably requires to complete the application. The ISO shall use all reasonable efforts to make the changes necessary for the new or modified configurations to take effect and the Station Power Portfolio to begin self-supplying Station Power within twenty (20) Business Days after a complete application is submitted. In no event shall a Station Power Portfolio begin self-supplying Station Power until any and all required changes to the configuration of metering or other equipment are completed as required under SPP 6. The ISO will have an ongoing right to request additional information reasonably necessary to verify that conditions on the self-supply of Station Power as specified in this SPP are met.

SPP 3 Self-Supply Verification and ISO Charges

SPP 3.1 Self-Supply Verification

At the end of each Netting Period, the ISO will calculate the Net Output for each Generating Unit in the Station Power Portfolio. If the Net Output is positive, then all Station Power associated with that Generating Unit, other than load netted in accordance with this ISO Tariff, will have been served by On-Site Self Supply. Any positive Net Output from facilities in the Station Power Portfolio will be available to provide Remote Self Supply to any Generating Unit with negative Net Output. If the available Remote Self Supply is less than the aggregate negative Net Output in the Station Power Portfolio, then such shortfall will be deemed to have been served by Third Party Supply. The ISO will incorporate these determinations in its accounting and billing for the Netting Period by reassigning Station Power to unique load identifiers for Remote Self Supply and Third Party Supply, as required.

SPP 3.2 Charges on Metered Demand

Station Power that is not eligible for permitted netting in accordance with Section 10.1.3 of this ISO Tariff must be scheduled in accordance with the ISO Tariff, and will be assessed all charges applicable to metered Demand under the ISO Tariff, except as provided in SPP 4.1.

SPP 3.3 Administrative Charge

Scheduling Coordinators of Generating Units that have Station Power meters shall be assessed an administrative charge in accordance with Schedule 5 of Appendix F to the ISO Tariff.

SPP 4 Transmission Service

SPP 4.1 Station Power Load that is directly connected to the transmission facilities or directly connected to the Distribution System of a UDC or MSS Operator located in a PTO Service Territory and that is determined to have been served by On-Site Self Supply shall be deemed not to have used the ISO Controlled Grid and shall not be included in the Gross Load of the applicable UDC or MSS Operator. Station Power that is served by Wheeling service and that is determined to have been served by On-Site Self Supply shall be deemed not to have used the ISO Controlled Grid and shall not be included in the hourly schedules (in kWh) of the applicable Scheduling Coordinator that are subject to the Wheeling Access Charge.

SPP 4.2 Station Power Load that is directly connected to the transmission facilities or directly connected to the Distribution System of a UDC or MSS Operator located in a PTO Service Territory and that is determined to have been served by Remote Self-Supply or Third Party Supply shall be included in the Gross Load of the applicable UDC or MSS Operator. Station Power that is served by Wheeling service and that is determined to have been served by Remote Self-Supply or Third Party Supply shall be included in the hourly schedules (in kWh) of the applicable Scheduling Coordinator that are subject to the Wheeling Access Charge.

SPP 4.3 If the Generating Unit requires the use of distribution facilities or other facilities that are not part of the ISO Controlled Grid, then the Generating Unit will be subject to the appropriate charges of the applicable UDC, MSS Operator or owner of such non-ISO Controlled Grid Facilities.

SPP 5 ENERGY PRICING

All deviations between scheduled and metered Generation or Station Power will be settled at the applicable zonal price. The determination of Net Output and attribution of On-Site Self Supply, Remote Self Supply and Third Party Supply to serving Station Power under this SPP shall apply only to determine whether Station Power was self-supplied during the Netting Period and will have no effect on the price of Energy sold or consumed by any facility in the Station Power Portfolio.

SPP 6 METERING

SPP 6.1 In order to self-supply Station Power under this SPP, a Generating Unit must be subject to a Meter Service Agreement for ISO Metered Entities pursuant to ISO Tariff Section 10.3.1. A meter certified in accordance with the ISO Tariff is required for Station Power Load taken under the SPP. Separate metering is required for any on-site Load that does not meet the definition of Station Power. Under no circumstances may ineligible Loads be included in the meter data collected by the ISO from a Station Power meter.

SPP 6.2 Any costs associated with owning or operating metering or related facilities necessary to self-supply Station Power according to the terms of this SPP are the responsibility of the owner-applicant.

SPP 6.3 A single Scheduling Coordinator must represent the unique load identifiers assigned by the ISO for On-Site Self-Supply and Remote Self-Supply associated with each Station Power meter.

SPP 7 PROVISION OF DATA TO UDC OR MSS OPERATOR

The ISO will provide the applicable UDC or MSS Operator with the amount of On-Site Self Supply, Remote Self-Supply, and Third Party Supply serving Station Power at the granularity required to allow the UDC or MSS Operator to assess charges, if any, under the applicable retail tariff(s).

ISO TARIFF APPENDIX T

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ISO TARIFF APPENDIX U

Standard Large Generator Interconnection Procedures (LGIP)

Standard Large Generator Interconnection Procedures (LGIP)

Table of Contents

SECTION 1. OBJECTIVES, DEFINITIONS, AND INTERPRETATION.

1.1 Objectives.

The objective of this LGIP is to implement FERC's Order No. 2003 setting forth the requirements for Large Generating Facility interconnections to the ISO Controlled Grid.

1.2 Definitions.

1.2.1 Master Definitions Supplement.

Unless the context otherwise requires, any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this LGIP. A reference to a Section or an Appendix is a reference to a Section or an Appendix of the ISO Tariff. References to LGIP are to this Protocol or to the stated paragraph of this Protocol.

1.2.2 Special Definitions for this LGIP.

In this LGIP, the following words and expressions shall have the meanings set opposite them:

"Confidential Information" shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise, subject to Section 13.1 of the LGIP.

"Dispute Resolution" shall mean the procedure set forth in this LGIP for resolution of a dispute between the Parties.

"Force Majeure" shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

"Governmental Authority" shall mean any federal, state, local or other governmental, regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the Interconnection Customer, ISO, or Participating TO, or any Affiliate thereof.

"Party" or "Parties" shall mean the ISO, Participating TO(s), Interconnection Customer or the applicable combination of the above.

"Reasonable Efforts" shall mean, with respect to an action required to be attempted or taken by a Party under the Standard Large Generator Interconnection Procedures, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

1.2.3 Rules of Interpretation.

(a) Unless the context otherwise requires, if the provisions of this LGIP and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency.

(b) A reference in this LGIP to a given agreement, ISO Protocol or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made.

(c) The captions and headings in this LGIP are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this LGIP.

(d) This LGIP shall be effective as of the date specified by FERC.

Section 2. Scope and Application.

2.1 Application of Standard Large Generator Interconnection Procedures.

Sections 2 through 13 of this LGIP apply to processing an Interconnection Request pertaining to a Large Generating Facility.

2.2 Comparability.

The ISO shall receive, process and analyze Interconnection Requests in a timely manner as set forth in this LGIP. The ISO will use the same Reasonable Efforts in processing and analyzing Interconnection Requests from all Interconnection Customers, whether the Generating Facilities are owned by a Participating TO, its subsidiaries, or Affiliates or others.

2.3 Base Case Data.

The ISO and/or the applicable Participating TO(s) shall provide base power flow, short circuit and stability databases, including all underlying assumptions, and contingency list upon request subject to applicable confidentiality provisions in LGIP Section 13.1. The applicable Participating TO(s) and the ISO are permitted to require that the Interconnection Customer sign a confidentiality agreement before the release of commercially sensitive information or Critical Energy Infrastructure Information (as that term is defined by FERC) in the Base Case data. Such Base Cases shall include (i) generation projects and (ii) transmission projects, including merchant transmission projects that are proposed for the transmission system for which a transmission expansion plan has been submitted and approved by the applicable authority.

2.4 No Applicability to Transmission Service.

Nothing in this LGIP shall constitute a request for transmission service or confer upon an Interconnection Customer any right to receive transmission service.

Section 3. Interconnection Requests.

3.1 General.

Pursuant to ISO Tariff Section 5.7.1, an Interconnection Customer shall submit to the ISO an Interconnection Request in the form of Appendix 1 to this LGIP and a refundable deposit of $10,000. The ISO will forward a copy of the Interconnection Request to the applicable Participating TO within one (1) Business Day of receipt. The ISO shall apply the deposit toward the cost of an Interconnection Feasibility Study. The Interconnection Customer shall submit a separate Interconnection Request for each site and may submit multiple Interconnection Requests for a single site. The Interconnection Customer must submit a deposit with each Interconnection Request even when more than one request is submitted for a single site. An Interconnection Request to evaluate one site at two different voltage levels shall be treated as two Interconnection Requests.

At the Interconnection Customer's option, the applicable Participating TO(s), the ISO and Interconnection Customer will identify alternative Point(s) of Interconnection and configurations at the Scoping Meeting to evaluate in this process and attempt to eliminate alternatives in a reasonable fashion given resources and information available. Interconnection Customer will select the definitive Point of Interconnection to be studied and one alternative Point of Interconnection no later than the execution of the first Interconnection Feasibility Study Agreement.

3.2 Roles and Responsibilities.

(a) Each Interconnection Request will be subject to the direction and oversight of the ISO. The ISO will conduct or cause to be performed the required Interconnection Studies and any additional studies the ISO determines to be reasonably necessary, and will direct the applicable Participating TO to perform portions of studies where the Participating TO has specific and non-transferable expertise or data and can conduct the studies more efficiently and cost effectively than the ISO. The ISO will coordinate with Affected System Operators in accordance with LGIP Section 3.7.

(b) The ISO will complete or cause to be completed all studies as required within the timelines provided in this LGIP. Any portion of the studies performed at the direction of the ISO by the Participating TOs or by a third party shall also be completed within timelines provided in this LGIP.

(c) The ISO has established a pro forma Roles and Responsibilities Agreement, attached hereto and incorporated herein by reference, for execution by the ISO and the applicable Participating TOs.

(d) Each Interconnection Customer shall pay the actual costs of all Interconnection Studies, and any additional studies the ISO determines to be reasonably necessary in response to the Interconnection Request. The ISO shall reimburse the Participating TO for the actual cost of any portion of all Interconnection Studies that such Participating TO performs at the direction of the ISO.

3.3 Interconnection Service.

3.3.1 The Product. Interconnection Service allows the Interconnection Customer to connect the Large Generating Facility to the ISO Controlled Grid and be eligible to deliver the Large Generating Facility’s output using the available capacity of the ISO Controlled Grid. Interconnection Service does not in and of itself convey any right to deliver electricity to any specific customer or point of delivery.

3.3.2 The Interconnection Studies. The Interconnection Studies consist of, but are not limited to, short circuit/fault duty, steady state (thermal and voltage) and stability analyses. The Interconnection Studies will identify direct Interconnection Facilities and required Reliability Network Upgrades necessary to mitigate thermal overloads and voltage violations, and address short circuit, stability, and reliability issues associated with the requested Interconnection Service.

The Interconnection Studies will also identify necessary Delivery Network Upgrades to allow full output of the proposed Large Generating Facility under a variety of potential system conditions, and the maximum allowed output, under a variety of potential system conditions, of the interconnecting Large Generating Facility without the Delivery Network Upgrades.

3.3.3 Deliverability Assessment.

3.3.3.1 The Product. A Deliverability Assessment will be performed which shall determine the Interconnection Customer’s Large Generating Facility’s ability to deliver its energy to the ISO Controlled Grid under peak load conditions. The Deliverability Assessment will provide the Interconnection Customer with information as to the level of deliverability without Network Upgrades, and the Deliverability Assessment will provide the Interconnection Customer with information as to the required Network Upgrades to enable the Interconnection Customer's Large Generating Facility the ability to deliver the full output of the proposed Large Generating Facility to the ISO Controlled Grid based on specified study assumptions.

Thus, the Deliverability Assessment results will provide the Interconnection Customer two (2) data points on the scale of deliverability: 1) a deliverability level with no Network Upgrades, and 2) the required Network Upgrades to support 100% deliverability.

Deliverability of a new Large Generating Facility will be assessed on the same basis as all other existing resources interconnected to the ISO Controlled Grid.

3.3.3.2 The Assessment. The Deliverability Assessment will identify the facilities that are required to enable the Interconnection Customer's Large Generating Facility to meet the requirements for deliverability and as a general matter, that such Large Generating Facility's interconnection is also studied with the ISO Controlled Grid at peak load, under a variety of severely stressed conditions, to determine whether, with the Large Generating Facility at full output, the aggregate of generation in the local area can be delivered to the aggregate of load on the ISO Controlled Grid, consistent with the ISO’s reliability criteria and procedures. This approach assumes that some portion of existing resources that are designated as deliverable is displaced by the output of the Interconnection Customer's Large Generating Facility. This Deliverability Assessment in and of itself does not convey any right to deliver electricity to any specific customer or point of delivery. The ISO Controlled Grid may also be studied under non-peak load conditions. However, upon request by the Interconnection Customer, the Deliverability Assessment must explain in writing to the Interconnection Customer why the study of non-peak load conditions is required for reliability purposes.

3.4 Network Upgrades.

3.4.1 Initial Funding

Unless the Participating TO elects to fund the capital for Reliability and Delivery Network Upgrades, they shall be solely funded by the Interconnection Customer.

3.4.2 [Section Intentionally Omitted]

3.4.3 Repayment of Amounts Advanced for Network Upgrades.

Upon the Commercial Operation Date, the Interconnection Customer shall be entitled to a repayment for the cost of Network Upgrades. Such amount shall be paid to the Interconnection Customer by the applicable Participating TO(s) on a dollar-for-dollar basis either through (1) direct payments made on a levelized basis over the five-year period commencing on the Commercial Operation Date; or (2) any alternative payment schedule that is mutually agreeable to the Interconnection Customer and Participating TO, provided that such amount is paid within five (5) years of the Commercial Operation Date. Any repayment shall include interest calculated in accordance with the methodology set forth in FERC's regulations at 18 C.F.R. §35.19a(a)(2)(iii) from the date of any payment for Network Upgrades through the date on which the Interconnection Customer receives a repayment of such payment. The Interconnection Customer may assign such repayment rights to any person.

Instead of direct payments, the Interconnection Customer may elect to receive Firm Transmission Rights (FTRs) in accordance with the ISO Tariff associated with the Network Upgrades that were funded by the Interconnection Customer, to the extent such FTRs or alternative rights are available under the ISO Tariff at the time of the election. Such FTRs would take effect upon the Commercial Operation Date of the Large Generating Facility in accordance with the LGIA.

3.4.4 Special Provisions for Affected Systems and Other Affected Participating TOs.

The Interconnection Customer shall enter into an agreement with the owner of the Affected System and/or other affected Participating TO(s), as applicable. The agreement shall specify the terms governing payments to be made by the Interconnection Customer to the owner of the Affected System and/or other affected Participating TO(s) as well as the repayment by the owner of the Affected System and/or other affected Participating TO(s). If the affected entity is another Participating TO, the initial form of agreement will be the LGIA, as appropriately modified.

Any repayment by the owner of the Affected System shall be in accordance with FERC Order No. 2003-B (109 FERC ¶ 61,287).

3.5 Valid Interconnection Request.

3.5.1 Initiating an Interconnection Request.

To initiate an Interconnection Request, the Interconnection Customer must submit all of the following: (i) a $10,000 deposit, (ii) a completed application in the form of LGIP Part 1, and (iii) demonstration of Site Control or a posting of an additional deposit of $10,000. Such deposits may be applied toward any Interconnection Studies pursuant to the Interconnection Request. If the Interconnection Customer demonstrates Site Control within the cure period specified in LGIP Section 3.5.3 after submitting its Interconnection

Request, the additional deposit shall be refundable; otherwise, all such deposit(s), additional and initial, become non-refundable.

The expected In-Service Date of the new Large Generating Facility or increase in capacity of the existing Generating Facility shall be no more than the process window for the regional expansion planning period (or in the absence of a regional planning process, the process window for the ISO's expansion planning period) not to exceed seven years from the date the Interconnection Request is received by the ISO, unless the Interconnection Customer demonstrates that engineering, permitting and construction of the new Large Generating Facility or increase in capacity of the existing Generating Facility will take longer than the regional expansion planning period. The In-Service Date may succeed the date the Interconnection Request is received by the ISO by a period up to ten years, or longer where the Interconnection Customer, the applicable Participating TO and the ISO agree, such agreement not to be unreasonably withheld.

3.5.2 Acknowledgment of Interconnection Request.

The ISO shall acknowledge receipt of the Interconnection Request within six (6) Business Days of receipt of the request and attach a copy of the received Interconnection Request to the acknowledgement.

3.5.3 Deficiencies in Interconnection Request.

An Interconnection Request will not be considered to be a valid request until all items in LGIP Section 3.5.1 have been received and deemed valid by the ISO. If an Interconnection Request fails to meet the requirements set forth in LGIP Section 3.5.1, the ISO shall notify the Interconnection Customer within six (6) Business Days of receipt of the initial Interconnection Request of the reasons for such failure and that the Interconnection Request does not constitute a valid request. The Interconnection Customer shall provide the ISO the additional requested information needed to constitute a valid request within ten (10) Business Days after receipt of such notice. Failure by the Interconnection Customer to comply with this LGIP Section 3.5.3 shall be treated in accordance with LGIP Section 3.8.

3.5.4 Scoping Meeting.

Within ten (10) Business Days after the ISO notifies the Interconnection Customer of a valid Interconnection Request, the ISO shall establish a date agreeable to the Interconnection Customer and the applicable Participating TO(s) for the Scoping Meeting, and such date shall be no later than thirty (30) Calendar Days from notification of the valid Interconnection Request, unless otherwise mutually agreed upon by the Parties. The ISO shall determine whether the Interconnection Request is at or near the boundary of an affected Participating TO(s) service territory or of any other Affected System(s) so as to potentially affect such third parties. If such a determination is made, the ISO shall invite the affected Participating TO(s), and/or Affected System Operator(s) in accordance with Section 3.7, to the Scoping Meeting by informing such third parties of the time and place of the scheduled Scoping Meeting as soon as practicable.

The purpose of the Scoping Meeting shall be to discuss alternative interconnection options, to exchange information including any transmission data that would reasonably be expected to impact such interconnection options, to analyze such information and to determine the potential feasible Points of Interconnection. The applicable Participating TO(s) and the ISO will bring to the meeting such already available technical data, including, but not limited to: (i) general facility loadings, (ii) general instability issues, (iii) general short circuit issues, (iv) general voltage issues, and (v) general reliability issues, as may be reasonably required to accomplish the purpose of the meeting.

The Interconnection Customer will bring to the Scoping Meeting as much large generator technical data in Attachment A to Appendix 1, and system studies previously performed, as available. The applicable Participating TO(s), the ISO, and the Interconnection Customer will also bring to the meeting personnel and other resources as may be reasonably required to accomplish the purpose of the meeting in the time allocated for the meeting. On the basis of the meeting, the Interconnection Customer shall designate its Point of Interconnection, pursuant to LGIP Section 6.1, and one alternative Point of Interconnection. The duration of the meeting shall be sufficient to accomplish its purpose.

The ISO shall prepare minutes from the meeting, verified by the Interconnection Customer and the other attendees, that will include, at a minimum, discussions among the applicable Participating TO(s) and the ISO of what the expected results may be for the Interconnection Feasibility Study.

3.6 Internet Posting.

The ISO will maintain on the ISO Home Page a list of all Interconnection Requests. The list will identify, for each Interconnection Request: (i) the maximum summer and winter megawatt electrical output; (ii) the location by county and state; (iii) the station or transmission line or lines where the interconnection will be made; (iv) the projected In-Service Date; (v) the status of the Interconnection Request, including Queue Position; (vi) the availability of any studies related to the Interconnection Request; (vii) the date of the Interconnection Request; (viii) the type of Generating Facility to be constructed (combined cycle, base load or combustion turbine and fuel type); and (ix) for Interconnection Requests that have not resulted in a completed interconnection, an explanation as to why it was not completed.

Except in the case of an Affiliate, the list will not disclose the identity of the Interconnection Customer until the Interconnection Customer executes an LGIA or requests that the applicable Participating TO(s) and the ISO file an unexecuted LGIA with FERC. The ISO shall post on the ISO Home Page an advance notice whenever a Scoping Meeting will be held with an Affiliate of a Participating TO.

The ISO shall post to the ISO Home Page any deviations from the study timelines set forth herein. Interconnection Study reports and Optional Interconnection Study reports shall be posted to the ISO Home Page subsequent to the meeting among the Interconnection Customer, the applicable Participating TO(s) and the ISO to discuss the applicable study results. The ISO shall also post any known deviations in the Large Generating Facility's In-Service Date.

3.7 Coordination with Affected Systems.

The ISO will notify the Affected System Operators that are potentially affected by the project proposed by the Interconnection Customer. The ISO will coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System Operators, to the extent possible, and, if possible, the (ISO) will include those results (if available) in its applicable Interconnection Study within the time frame specified in this LGIP. The ISO will include such Affected System Operators in all meetings held with the Interconnection Customer as required by this LGIP. The Interconnection Customer will cooperate with the ISO in all matters related to the conduct of studies and the determination of modifications to Affected Systems, including signing separate study agreements with Affected System owners and paying for necessary studies. An entity which may be an Affected System shall cooperate with the ISO in all matters related to the conduct of studies and the determination of modifications to Affected Systems.

3.8 Withdrawal.

The Interconnection Customer may withdraw its Interconnection Request at any time by written notice of such withdrawal to the ISO, and the ISO will notify the applicable Participating TO(s), within three (3) Business Days of receipt of such a notice. In addition, if the Interconnection Customer fails to adhere to all requirements of this LGIP, except as provided in LGIP Section 13.5 (Disputes), the ISO shall deem the Interconnection Request to be withdrawn and shall provide written notice to the Interconnection Customer within five (5) Business Days of the deemed withdrawal and an explanation of the reasons for such deemed withdrawal. Upon receipt of such written notice, the Interconnection Customer shall have fifteen (15) Business Days in which to either respond with information or actions that cures the deficiency or to notify the ISO of its intent to pursue Dispute Resolution.

Withdrawal shall result in the loss of the Interconnection Customer's Queue Position, if any. If an Interconnection Customer disputes the withdrawal and loss of its Queue Position, then during Dispute Resolution, the Interconnection Customer's Interconnection Request is eliminated from the queue until such time that the outcome of Dispute Resolution would restore its Queue Position. An Interconnection Customer that withdraws or is deemed to have withdrawn its Interconnection Request shall pay to the ISO all costs that have been prudently incurred or irrevocably have committed to be incurred with respect to that Interconnection Request prior to the ISO's receipt of notice described above. The Interconnection Customer must pay all monies due to the Participating TO before it is allowed to obtain any Interconnection Study data or results. The ISO will reimburse the applicable Participating TO(s) for all work performed associated with the Interconnection Request at the ISO's direction.

The ISO shall update the ISO Home Page Queue Position posting. The ISO shall refund to the Interconnection Customer any portion of the Interconnection Customer's deposit or study payments that exceed the costs that the ISO has incurred or Participating TO(s) have incurred, including interest calculated in accordance with section 35.19a(a)(2) of FERC's regulations. In the event of such withdrawal, the ISO, subject to the confidentiality provisions of LGIP Section 13.1, shall provide, at the Interconnection Customer's request, all information that the ISO developed for any completed study conducted up to the date of withdrawal of the Interconnection Request.

Section 4. Queue Position.

4.1 General.

The ISO shall assign a Queue Position based upon the date and time of receipt of the valid Interconnection Request; provided that, if the sole reason an Interconnection Request is not valid is the lack of required information on the application form, and the Interconnection Customer provides such information in accordance with LGIP Section 3.5.3, then the ISO shall assign the Interconnection Customer a Queue Position based on the date the application form was originally filed. Moving a Point of Interconnection shall result in a lowering of Queue Position if it is deemed a Material Modification under LGIP Section 4.4.3.

The queue position of each Interconnection Request will be used to determine the order of performing the Interconnection Studies and determination of cost responsibility for the facilities necessary to accommodate the Interconnection Request. A higher Queue Position Interconnection Request is one that has been placed "earlier" in the ISO's queue in relation to another Interconnection Request that is lower queued. The cost of the common upgrades for clustered Interconnection Requests may be allocated without regard to queue position.

4.2 Clustering.

At the ISO's option, and in coordination with the applicable Participating TO(s), Interconnection Requests may be studied serially or in clusters for the purpose of the Interconnection System Impact Study.

Clustering shall be implemented on the basis of Queue Position. If the ISO elects, in coordination with applicable Participating TO(s), to study Interconnection Requests using Clustering, all Interconnection Requests received within a period not to exceed one hundred and eighty (180) Calendar Days, hereinafter referred to as the "Queue Cluster Window" shall be studied together without regard to the nature of the underlying Interconnection Service. The deadline for completing all Interconnection System Impact Studies for which an Interconnection System Impact Study Agreement has been executed during a Queue Cluster Window shall be in accordance with LGIP Section 7.4, for all Interconnection Requests assigned to the same Queue Cluster Window. The ISO may agree to conduct the study of an Interconnection Request separately to the extent warranted by Good Utility Practice based upon the electrical remoteness of the proposed Large Generating Facility.

Clustering Interconnection System Impact Studies shall be conducted in such a manner to ensure the efficient implementation of the applicable regional transmission expansion plan in light of the transmission system's capabilities at the time of each study.

The Queue Cluster Window shall have a fixed time interval based on fixed annual opening and closing dates. Any changes to the established Queue Cluster Window interval and opening or closing dates shall be announced with a posting on the ISO Home Page beginning at least one hundred and eighty (180) Calendar Days in advance of the change and continuing thereafter through the end date of the first Queue Cluster Window that is to be modified.

4.3 Transferability of Queue Position.

An Interconnection Customer may transfer its Queue Position to another entity only if such entity acquires the specific Generating Facility identified in the Interconnection Request and the Point of Interconnection does not change.

4.4 Modifications.

The Interconnection Customer shall submit to the ISO, in writing, modifications to any information provided in the Interconnection Request. The ISO will forward the Interconnection Customer's modification to the applicable Participating TO(s) within one (1) Business Day of receipt. The Interconnection Customer shall retain its Queue Position if the modifications are in accordance with LGIP Sections 4.4.1, 4.4.2 or 4.4.5, or are determined not to be Material Modifications pursuant to LGIP Section 4.4.3.

Notwithstanding the above, during the course of the Interconnection Studies, the Interconnection Customer, the applicable Participating TO(s), or the ISO may identify changes to the planned interconnection that may improve the costs and benefits (including reliability) of the interconnection, and the ability of the proposed change to accommodate the Interconnection Request. To the extent the identified changes are acceptable to the applicable Participating TO(s), the ISO, and Interconnection Customer, such acceptance not to be unreasonably withheld, the ISO shall modify the Point of Interconnection and/or configuration in accordance with such changes and proceed with any re-studies necessary to do so in accordance with LGIP Section 6.4, LGIP Section 7.6 and LGIP Section 8.5 as applicable and the Interconnection Customer shall retain its Queue Position.

4.4.1 Prior to the return of the executed Interconnection System Impact Study Agreement to the ISO, modifications permitted under this Section shall include specifically: (a) a decrease of up to 60 percent of electrical output (MW) of the proposed project; (b) modifying the technical parameters associated with the Large Generating Facility technology or the Large Generating Facility step-up transformer impedance characteristics; and (c) modifying the interconnection configuration. For plant increases, the incremental increase in plant output will go to the end of the queue for the purposes of cost allocation and study analysis.

4.4.2 Prior to the return of the executed Interconnection Facility Study Agreement to the ISO, the modifications permitted under this Section shall include specifically: (a) additional 15 percent decrease of electrical output (MW), and (b) Large Generating Facility technical parameters associated with modifications to Large Generating Facility technology and transformer impedances; provided, however, the incremental costs associated with those modifications are the responsibility of the requesting Interconnection Customer.

4.4.3 Prior to making any modification other than those specifically permitted by LGIP Sections 4.4.1, 4.4.2, and 4.4.5, the Interconnection Customer may first request that the ISO evaluate whether such modification is a Material Modification. In response to the Interconnection Customer's request, the ISO, in coordination with the affected Participating TO, shall evaluate the proposed modifications prior to making them and the ISO shall inform the Interconnection Customer in writing of whether the modifications would constitute a Material Modification. Any change to the Point of Interconnection, except those deemed acceptable under Sections 4.4.1, 6.1, 7.2 or so allowed elsewhere, shall constitute a Material Modification. The Interconnection Customer may then withdraw the proposed modification or proceed with a new Interconnection Request for such modification.

4.4.4 Upon receipt of the Interconnection Customer's request for modification permitted under this LGIP Section 4.4, the ISO shall commence and conduct or have conducted any necessary additional studies as soon as practicable, but in no event shall such studies commence later than thirty (30) Calendar Days after receiving notice of the Interconnection Customer's request. Any additional studies resulting from such modification shall be done at the Interconnection Customer's cost.

4.4.5 Extensions of less than three (3) cumulative years in the Commercial Operation Date of the Large Generating Facility to which the Interconnection Request relates are not material and should be handled through construction sequencing.

Section 5. Procedures for Interconnection Requests Submitted Prior to Effective Date of Standard Large Generator Interconnection Procedures.

5.1 Queue Position for Pending Requests.

5.1.1 Any Interconnection Customer assigned a queue position prior to the effective date of this LGIP shall retain that relative queue position.

5.1.1.1 If an Interconnection Study agreement has not been executed as of the effective date of this LGIP, then such Interconnection Study, and any subsequent Interconnection Studies, shall be processed in accordance with this LGIP.

5.1.1.2 If an Interconnection Study agreement has been executed prior to the effective date of this LGIP, such Interconnection Study shall be completed in accordance with the terms of such agreement. With respect to any remaining studies for which an Interconnection Customer has not signed an Interconnection Study agreement prior to the effective date of the LGIP, the Participating TO must offer the Interconnection Customer the option of either continuing under the Participating TO's existing interconnection study process pursuant to ISO Tariff Appendix W or going forward with the completion of the necessary Interconnection Studies (for which it does not have a signed Interconnection Studies agreement) in accordance with this LGIP.

5.1.1.3 If an agreement to interconnect a Generating Unit has been submitted to FERC for approval before the effective date of the LGIP, then the agreement would be grandfathered.

5.1.2 Transition Period.

To the extent necessary, the Participating TO and/or the ISO and Interconnection Customers with an outstanding request (i.e., an interconnection request or application for which an agreement to interconnect a Generating Unit has not been submitted to FERC for approval as of the effective date of this LGIP) shall transition to this LGIP within a reasonable period of time not to exceed sixty (60) Calendar Days. The use of the term "outstanding request" herein shall mean any interconnection request or application, on the effective date of this LGIP: (i) that has been submitted but not yet accepted by the ISO or the Participating TO; (ii) where the related interconnection agreement has not yet been submitted to FERC for approval in executed or unexecuted form, (iii) where the relevant interconnection study agreements have not yet been executed, or (iv) where any of the relevant interconnection studies are in process but not yet completed. Any Interconnection Customer with an outstanding request as of the effective date of this LGIP may request a reasonable extension of any deadline, otherwise applicable, if necessary to avoid undue hardship or prejudice to its Interconnection Request. A reasonable extension shall be granted by the ISO, as applicable, to the extent consistent with the intent and process provided for under this LGIP.

5.2 Change in ISO Operational Control.

If the ISO no longer has control of the portion of the ISO Controlled Grid at the Point of Interconnection during the period when an Interconnection Request is pending, the ISO shall transfer to applicable Participating TO which has ownership of the Point of Interconnection any amount of the deposit or payment with interest thereon that exceeds the cost that it incurred to evaluate the request for interconnection. Any difference between such net deposit amount and the costs that the successor Participating TO incurs to evaluate the request for interconnection shall be paid by or refunded to the Interconnection Customer, as appropriate. The ISO shall coordinate with the applicable Participating TO which has ownership of the Point of Interconnection to complete any Interconnection Study, as appropriate, that the ISO has begun but has not completed. If the ISO has tendered a draft LGIA to the Interconnection Customer but the Interconnection Customer has neither executed the LGIA or requested the filing of an unexecuted LGIA with FERC, unless otherwise provided, the Interconnection Customer must complete negotiations with the applicable Participating TO which has the ownership of the Point of Interconnection.

Section 6. Interconnection Feasibility Study.

6.1 Interconnection Feasibility Study Agreement.

Simultaneously with the acknowledgement of a valid Interconnection Request, the ISO shall provide to the Interconnection Customer a pro forma Interconnection Feasibility Study Agreement. The pro forma Interconnection Feasibility Study Agreement shall specify that the Interconnection Customer is responsible for the actual cost of the Interconnection Feasibility Study. Within five (5) Business Days following the Scoping Meeting, the Interconnection Customer shall specify for inclusion in the attachment to the Interconnection Feasibility Study Agreement the Point of Interconnection and one alternative Point of Interconnection. Within fifteen (15) Business Days following the ISO's receipt of such designation, the ISO, in coordination with the Participating TO shall provide to the Interconnection Customer a signed Interconnection Feasibility Study Agreement, which shall include a good faith estimate of the cost for completing the Interconnection Feasibility Study. The Interconnection Customer shall execute and deliver to the ISO the Interconnection Feasibility Study Agreement along with an additional $10,000 deposit no later than thirty (30) Calendar Days after its receipt.

On or before the return of the executed Interconnection Feasibility Study Agreement to the ISO, the Interconnection Customer shall provide to the ISO valid technical data called for in LGIP Appendix 1, Attachment A.

If the Interconnection Feasibility Study uncovers any unexpected result(s) not contemplated during the Scoping Meeting, a substitute Point of Interconnection identified by the Interconnection Customer, the applicable Participating TO(s)and ISO, and acceptable to the others, such acceptance not to be unreasonably withheld, will be substituted for the designated Point of Interconnection specified above without loss of Queue Position, and re-studies shall be completed pursuant to LGIP Section 6.4 as applicable. For the purpose of this LGIP Section 6.1, if the ISO, applicable Participating TO(s) and Interconnection Customer cannot agree on the substituted Point of Interconnection, then the Interconnection Customer may direct that the alternative as specified in the Interconnection Feasibility Study Agreement, as specified pursuant to LGIP Section 3.5.4, shall be the substitute.

If the Interconnection Customer, the applicable Participating TO, and the ISO agree to forgo the Interconnection Feasibility Study, the ISO will tender an Interconnection System Impact Study Agreement within fifteen (15) Business Days from receipt of the Interconnection Customer's designated Point of Interconnection and alternative, pursuant to the procedures specified in Section 7 of this LGIP and apply the deposits made in accordance with LGIP Section 3.5.1, in addition to the deposit made in accordance with LGIP Section 7, towards the Interconnection System Impact Study.

6.2 Scope of Interconnection Feasibility Study.

The Interconnection Feasibility Study shall preliminarily evaluate the feasibility of the proposed interconnection to the ISO Controlled Grid.

The Interconnection Feasibility Study will consider Base Cases as well as all generating facilities (and with respect to (iv), any identified Network Upgrades) that, on the date the Interconnection Feasibility Study is commenced: (i) are directly interconnected to the ISO Controlled Grid; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending request to interconnect to an Affected System; (iv) have a pending higher queued Interconnection Request to interconnect to the ISO Controlled Grid; and (v) have no Queue Position but have executed an LGIA or requested that an unexecuted LGIA be filed with FERC. The Interconnection Feasibility Study will consist of a power flow and short circuit analysis. The Interconnection Feasibility Study will provide a list of facilities on the applicable Participating TOs' portion of the ISO Controlled Grid and a non-binding good faith estimate of cost and cost responsibility and a non-binding good faith estimated time to construct. In addition, the Interconnection Feasibility Study will describe what results are expected in the Interconnection System Impact Study and any other financial impacts (i.e., on Local Furnishing Bonds).

6.3 Interconnection Feasibility Study Procedures.

Existing studies shall be used to the extent practicable when conducting the Interconnection Feasibility Study. The ISO shall use Reasonable Efforts to complete a draft Interconnection Feasibility Study no later than forty-five (45) Calendar Days after the ISO receives the fully executed Interconnection Feasibility Study Agreement. The ISO shall share applicable study results for review and comment, provide the study results to any other potentially-impacted Participating TO(s), and incorporate comments and issue a final Interconnection Feasibility Study to the Interconnection Customer within sixty (60) Calendar Days following receipt of the fully executed Interconnection Feasibility Study Agreement. At the request of the Interconnection Customer or at any time the ISO determines that the study cannot be completed within the required time frame for completing the Interconnection Feasibility Study, the ISO shall notify the Interconnection Customer as to the schedule status of the Interconnection Feasibility Study. If the Interconnection Feasibility Study cannot be completed within that time period, the ISO shall notify the Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required.

Upon request, the ISO shall provide the Interconnection Customer supporting documentation, workpapers and relevant power flow and short circuit databases for the Interconnection Feasibility Study, subject to confidentiality arrangements consistent with LGIP Sections 2.3 and 13.1.

6.3.1 Meeting with the Participating TO(s) and ISO.

Within ten (10) Business Days of providing an Interconnection Feasibility Study report to the Interconnection Customer, the ISO, the applicable Participating TO(s), and the Interconnection Customer shall meet to discuss the results of the Interconnection Feasibility Study.

6.4 Re-Study.

If re-study of the Interconnection Feasibility Study is required due to a higher queued project dropping out of the queue, or a modification of a higher queued project subject to LGIP Section 4.4, or re-designation of the Point of Interconnection pursuant to LGIP Section 6.1, or any other effective change in information which necessitates a re-study, the ISO shall notify the Interconnection Customer and the applicable Participating TO(s) in writing along with providing a description of the expected results of the re-study. Upon receipt of such notice, the Interconnection Customer shall provide the ISO within ten (10) Business Days either a written request that the ISO (i) terminate the study and withdraw the Interconnection Request; or (ii) continue the study. If the Interconnection Customer requests the ISO to continue the study, the Interconnection Customer shall pay the ISO an additional $10,000 deposit for the re-study along with providing written notice for the ISO to continue.

Such re-study shall take not longer than forty-five (45) Calendar Days from the date the ISO receives the Interconnection Customer's written notice to continue the study and payment of the additional $10,000 deposit. The ISO shall share applicable study results for review, provide the study results for review and comment to any other potentially-impacted Participating TO(s), incorporate comments, and issue a final study to the Interconnection Customer within sixty (60) Calendar Days from the date the ISO receives the Interconnection Customer's written notice to continue the study and payment of the additional $10,000 deposit. If the Interconnection Feasibility Study cannot be completed within that time period, the ISO shall notify the Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required. Any and all costs of the re-study shall be borne by the Interconnection Customer being re-studied.

Section 7. Interconnection System Impact Study.

7.1 Interconnection System Impact Study Agreement.

Simultaneously with the delivery of the Interconnection Feasibility Study to the Interconnection Customer, the ISO shall provide to the Interconnection Customer an Interconnection System Impact Study Agreement. The Interconnection System Impact Study Agreement shall provide that the Interconnection Customer shall compensate the ISO for the actual cost of the Interconnection System Impact Study. Within three (3) Business Days following the Interconnection Feasibility Study results meeting, the ISO in coordination with the applicable Participating TO(s) shall provide to the Interconnection Customer a signed System Impact Study Agreement which shall include a non-binding good faith estimate of the cost and timeframe for completing the Interconnection System Impact Study.

7.2 Execution of Interconnection System Impact Study Agreement.

The Interconnection Customer shall execute the Interconnection System Impact Study Agreement and deliver the executed Interconnection System Impact Study Agreement to the ISO no later than thirty (30) Calendar Days after its receipt along with a $50,000 deposit.

If the Interconnection Customer does not provide all such valid technical data, such as Attachment A to Part 1, when it delivers the Interconnection System Impact Study Agreement, the ISO shall notify the Interconnection Customer of the deficiency within five (5) Business Days of the receipt of the executed Interconnection System Impact Study Agreement and the Interconnection Customer shall cure the deficiency within ten (10) Business Days of receipt of the notice, provided, however, such deficiency does not include failure to deliver the executed Interconnection System Impact Study Agreement or deposit.

If the Interconnection System Impact Study uncovers any unexpected result(s) not contemplated during the Scoping Meeting and the Interconnection Feasibility Study, a substitute Point of Interconnection identified by either the Interconnection Customer, the

ISO, or the applicable Participating TO(s), and acceptable to the others, such acceptance not to be unreasonably withheld, will be substituted for the designated Point of Interconnection specified above without loss of Queue Position, and re-studies shall be completed pursuant to LGIP Section 7.6 as applicable. If the ISO, applicable Participating TO(s)and the Interconnection Customer cannot agree that the results were unexpected, then the ISO will make a determination that the results were either expected or unexpected. For the purpose of this LGIP Section 7.2, if the applicable Participating TO(s), ISO and Interconnection Customer cannot agree on the substituted Point of Interconnection, then the Interconnection Customer may direct that the alternative as specified in the Interconnection Feasibility Study Agreement, as specified pursuant to LGIP Section 3.5.4, shall be the substitute.

7.3 Scope of Interconnection System Impact Study.

The Interconnection System Impact Study shall evaluate the impact of the proposed interconnection on the reliability of the ISO Controlled Grid. The Interconnection System Impact Study will consider Base Cases as well as all generating facilities (and with respect to (iv) below, any identified Network Upgrades associated with such higher queued Interconnection Request) that, on the date the Interconnection System Impact Study is commenced: (i) are directly interconnected to the ISO Controlled Grid; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending request to interconnect to an Affected System; (iv) have a pending higher queued Interconnection Request to interconnect to the ISO Controlled Grid; and (v) have no Queue Position but have executed an LGIA or requested that an unexecuted LGIA be filed with FERC.

The Interconnection System Impact Study will consist of a short circuit analysis, a stability analysis, a power flow analysis and a Deliverability Assessment as described in LGIP Sections 3.3.2 and 3.3.3. The Interconnection System Impact Study will state the assumptions upon which it is based; state the results of the analyses; and provide the requirements or potential impediments to providing the requested Interconnection Service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The Interconnection System Impact Study will provide a list of facilities the ISO Controlled Grid that are required as a result of the Interconnection Request and a non-binding good faith estimate of cost and cost responsibility and a non-binding good faith estimated time to construct and estimate of any other financial impacts (i.e., on Local Furnishing Bonds).

7.4 Interconnection System Impact Study Procedures.

The ISO shall coordinate the Interconnection System Impact Study with applicable Participating TO(s) and any Affected System that is affected by the Interconnection Request pursuant to LGIP Section 3.7 above. Existing studies shall be used to the extent practicable when conducting the Interconnection System Impact Study. The ISO will coordinate Base Case development with the applicable Participating TOs to ensure the Base Cases are accurately developed. The SO shall use Reasonable Efforts to complete a draft Interconnection System Impact Study within ninety (90) Calendar Days after the receipt of the executed Interconnection System Impact Study Agreement, study payment, and valid technical data. The ISO will share applicable sturdy results with the applicable Participating TO(s), for review and comment, and will incorporate comments into the study report. The ISO will issue a final Interconnection System Impact Study report to the Interconnection Customer within one hundred twenty (120) Calendar Days after the receipt of the executed Interconnection System Impact Study Agreement, study payment, and valid technical data. If the ISO uses Clustering, the ISO shall use Reasonable Efforts to deliver a completed Interconnection System Impact Study within one hundred twenty (120) Calendar Days after the close of the Queue Cluster Window.

At the request of the Interconnection Customer or at any time the ISO determines that it will not meet the required time frame for completing the Interconnection System Impact Study, the ISO shall notify the Interconnection Customer as to the schedule status of the Interconnection System Impact Study. If the Interconnection System Impact Study cannot be completed within the time period, the ISO shall notify the Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required.

Upon request, the ISO shall provide the Interconnection Customer all supporting documentation, workpapers and relevant pre-Interconnection Request and post-Interconnection Request power flow, short circuit and stability databases for the Interconnection System Impact Study, subject to confidentiality arrangements consistent with LGIP Section 13.1.

7.5 Meeting with the ISO and Participating TO(s).

Within ten (10) Business Days of providing an Interconnection System Impact Study report to the Interconnection Customer, the applicable Participating TO(s), the ISO and the Interconnection Customer shall meet to discuss the results of the Interconnection System Impact Study.

7.6 Re-Study.

If re-study of the Interconnection System Impact Study is required due to a higher queued project dropping out of the queue, a modification of a higher queued project subject to LGIP Section 4.4, or re-designation of the Point of Interconnection pursuant to LGIP Section 7.2, or any other effective change in information which necessitates a re-study, the ISO shall notify the Interconnection Customer in writing along with providing a description of the expected results of the re-study. Upon receipt of such notice, the Interconnection Customer shall provide the ISO within ten (10) Business Days either a written request that the ISO (i) terminate the study and withdraw the Interconnection Request; or (ii) continue the study. If the Interconnection Customer requests the ISO to continue the study, the Interconnection Customer shall pay the ISO an additional $10,000 deposit for the re-study along with providing written notice for the ISO to continue.

Such re-study shall take no longer than sixty (60) Calendar Days from the date the ISO receives the Interconnection Customer's written notice to continue the study and payment of the additional $10,000 deposit. The ISO will share applicable study results within the applicable Participating TO(s) for review and comment, and will incorporate comments into the study report. The ISO will issue a final study report to the Interconnection Customer within eighty (80) Calendar Days following receipt of the Interconnection Customer's written notice to continue the study and payment of the additional $10,000 deposit. If the Interconnection System Impact Study cannot be completed within that time period, the ISO shall notify the Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required. Any and all costs of re-study shall be borne by the Interconnection Customer being re-studied.

Section 8. Interconnection Facilities Study.

8.1 Interconnection Facilities Study Agreement.

Simultaneously with the delivery of the Interconnection System Impact Study report to the Interconnection Customer, the ISO shall provide to the Interconnection Customer a pro forma Interconnection Facilities Study Agreement. The pro forma Interconnection Facilities Study Agreement shall provide that the Interconnection Customer shall compensate the ISO for the actual cost of the Interconnection Facilities Study. Within ten (10) Business Days following the Interconnection System Impact Study results meeting, the ISO shall provide to the Interconnection Customer a signed Interconnection Facilities Study Agreement which shall include a non-binding good faith estimate of the cost and timeframe for completing the Interconnection Facilities Study. The Interconnection Customer shall execute the Interconnection Facilities Study Agreement and deliver the executed Interconnection Facilities Study Agreement to the ISO within thirty (30) Calendar Days after its receipt, together with the required technical data and the greater of $100,000 or the Interconnection Customer's portion of the estimated monthly cost of conducting the Interconnection Facilities Study.

8.1.1 For studies where the estimated cost exceeds $100,000, the ISO may invoice the Interconnection Customer on a monthly basis for the work to be conducted on the Interconnection Facilities Study for the remaining balance of the estimated Interconnection Facilities Study cost. The Interconnection Customer shall pay invoiced amounts within thirty (30) Calendar Days of receipt of invoice. The ISO shall continue to hold the amounts on deposit until settlement of the final invoice.

8.2 Scope of Interconnection Facilities Study.

The Interconnection Facilities Study shall specify and estimate the cost of the equipment, engineering, procurement and construction work, including the financial impacts (i.e., on Local Furnishing Bonds), if any, and schedule for effecting remedial measures that address such financial impacts, needed on the ISO Controlled Grid to implement the conclusions of the Interconnection System Impact Study in accordance with Good Utility Practice to physically and electrically connect the Interconnection Customer's Interconnection Facilities to the ISO Controlled Grid. The Interconnection Facilities Study shall also identify the electrical switching configuration of the connection equipment, including, without limitation: the transformer, switchgear, meters, and other station equipment; the nature and estimated cost of any Participating TO's Interconnection Facilities and Network Upgrades necessary to accomplish the interconnection; and an estimate of the time required to complete the construction and installation of such facilities.

8.3 Interconnection Facilities Study Procedures.

The ISO shall coordinate the Interconnection Facilities Study with the Participating TO(s) and any Affected System pursuant to LGIP Section 3.7 above. Existing studies shall be used to the extent practicable in conducting the Interconnection Facilities Study. The ISO, in collaboration with the Participating TO(s), shall use Reasonable Efforts to complete the study and issue a draft Interconnection Facilities Study report to the Interconnection Customer. Prior to issuing draft study results to the Interconnection Customer, the ISO shall share study resultswi the Participating TO(s) for review and incorporate comments as necessary. Within the following number of days after receipt of an executed Interconnection Facilities Study Agreement, the ISO shall provide a draft Interconnection Facilities Study report to the Interconnection Customer: one hundred twenty (120) Calendar Days, with no more than a +/- 20 percent cost estimate contained in the report; or two hundred ten (210) Calendar Days, if the Interconnection Customer requests a +/- 10 percent cost estimate. At the request of the Interconnection Customer or at any time the ISO determines that the required time frame for completing the Interconnection Facilities Study will not be met, the ISO shall notify the Interconnection Customer as to the schedule status of the Interconnection Facilities Study. If the Interconnection Facilities Study cannot be conducted and a draft Interconnection Facilities Study report cannot be issued within the time required, the ISO shall notify the Interconnection Customer and provide an estimated completion date and an explanation of the reasons why additional time is required.

The Interconnection Customer shall, within thirty (30) Calendar Days after receipt of the draft report, either (i) provide written comments to the ISO, which the ISO, to the extent the comments are applicable, shall include in the final report, or (ii) provide a statement to the Participating TO and ISO that it will not provide comments. The ISO shall issue the final Interconnection Facilities Study report within fifteen (15) Business Days of receiving the Interconnection Customer's comments or promptly upon receiving the Interconnection Customer's statement that it will not provide comments. The ISO may reasonably extend such fifteen (15) Business Day period upon notice to the Interconnection Customer if the Interconnection Customer's comments require the applicable Participating TO(s) and/or ISO to perform additional analyses or make other significant modifications prior to the issuance of the final Interconnection Facilities Study report. Upon request, the ISO shall provide the Interconnection Customer supporting documentation, workpapers, and databases or data developed in the preparation of the Interconnection Facilities Study, subject to confidentiality arrangements consistent with LGIP Section 13.1.

8.4 Meeting with the ISO and Applicalbe Participating TO(s).

Within ten (10) Business Days of providing a draft Interconnection Facilities Study report to the Interconnection Customer, the applicable Participating TO(s), the ISO and the Interconnection Customer shall meet to discuss the results of the Interconnection Facilities Study. Within ten (10) Business Days of this meeting the Interconnection Customer shall make the election of which Delivery Network Upgrades identified in the Interconnection Facilities Study are to be installed. Any operating constraints on the Interconnection Customer's Generating Facility arising out of the Interconnection Customer's election not to install the Delivery Network Upgrades shall be as set forth in Article 9 and Part C of the LGIA.

8.5 Re-Study.

If re-study of the Interconnection Facilities Study is required due to a higher queued project dropping out of the queue or a modification of a higher queued project pursuant to LGIP Section 4.4, or any other effective change in information which necessitates a re-study, the ISO shall so notify the Interconnection Customer in writing. Upon receipt of such notice, the Interconnection Customer shall provide the ISO within ten (10) Business Days a written request that the ISO either (i) terminate the study and withdraw the Interconnection Request; or (ii) continue the study. If the Interconnection Customer requests the ISO to continue the study, the Interconnection Customer shall pay the ISO an additional $10,000 deposit for the re-study along with providing written notice for the ISO to continue.

Such re-study shall take no longer than sixty (60) Calendar Days from the date the ISO receives the Interconnection Customer's written notice to continue the study and payment of the additional $10,000 deposit. The ISO shall share applicable study results with the applicable Participating TO(s) for review and comment and incorporate comments, as appropriate. The ISO will issue a final Interconnection Facilities Study report to the Interconnection Customer within eighty (80) Calendar Days following receipt of the Interconnection Customer's written notice to continue the study and payment of the additional $10,000 deposit. If the Interconnection Facilities Study cannot be completed within that time period, the ISO shall notify the Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required. Any and all costs of re-study shall be borne by the Interconnection Customer being re-studied.

Section 9. Engineering & Procurement ("E&P") Agreement.

Prior to executing an LGIA, an Interconnection Customer may, in order to advance the implementation of its interconnection, request and the applicable Participating TO(s) shall offer the Interconnection Customer, an E&P Agreement that authorizes the applicable Participating TO(s) to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection. However, the applicable Participating TO(s) shall not be obligated to offer an E&P Agreement if the Interconnection Customer is in Dispute Resolution as a result of an allegation that the Interconnection Customer has failed to meet any milestones or comply with any prerequisites specified in other parts of the LGIP. The E&P Agreement is an optional procedure and it will not alter the Interconnection Customer's Queue Position or In-Service Date. The E&P Agreement shall provide for the Interconnection Customer to pay the cost of all activities authorized by the Interconnection Customer and to make advance payments or provide other satisfactory security for such costs.

The Interconnection Customer shall pay the cost of such authorized activities and any cancellation costs for equipment that is already ordered for its interconnection, which cannot be mitigated as hereafter described, whether or not such items or equipment later become unnecessary. If the Interconnection Customer withdraws its application for interconnection or either Party terminates the E&P Agreement, to the extent the equipment ordered can be canceled under reasonable terms, the Interconnection Customer shall be obligated to pay the associated cancellation costs. To the extent that the equipment cannot be reasonably canceled, the applicable Participating TO(s) may elect: (i) to take title to the equipment, in which event the applicable Participating TO(s) shall refund the Interconnection Customer any amounts paid by Interconnection Customer for such equipment and shall pay the cost of delivery of such equipment, or (ii) to transfer title to and deliver such equipment to the Interconnection Customer, in which event the Interconnection Customer shall pay any unpaid balance and cost of delivery of such equipment.

Section 10. Optional Interconnection Study.

10.1 Optional Interconnection Study Agreement.

On or after the date when the Interconnection Customer receives Interconnection System Impact Study results, the Interconnection Customer may request, and the ISO shall conduct or cause to be conducted, a reasonable number of Optional Interconnection Studies. The request shall describe the assumptions that the Interconnection Customer wishes to be studied within the scope described in LGIP Section 10.2. Within five (5) Business Days after receipt of a request for an Optional Interconnection Study, the ISO shall provide to the Interconnection Customer an Optional Interconnection Study Agreement.

The Optional Interconnection Study Agreement shall: (i) specify the technical data that the Interconnection Customer must provide for each phase of the Optional Interconnection Study, (ii) specify the Interconnection Customer's assumptions as to which Interconnection Requests with higher Queue Positions will be excluded from the Optional Interconnection Study case and assumptions as to the type of interconnection service for Interconnection Requests remaining in the Optional Interconnection Study case, and (iii) the ISO's estimate of the cost of the Optional Interconnection Study. To the extent known by the ISO, such estimate shall include any costs expected to be incurred by any Affected System whose participation is necessary to complete the Optional Interconnection Study. Notwithstanding the above, the ISO shall not be required as a result of an Optional Interconnection Study request to conduct any additional Interconnection Studies with respect to any other Interconnection Request.

The Interconnection Customer shall execute the Optional Interconnection Study Agreement within ten (10) Business Days of receipt and deliver the Optional Interconnection Study Agreement, the technical data and a $10,000 deposit to the ISO as applicable.

10.2 Scope of Optional Interconnection Study.

The Optional Interconnection Study will consist of a sensitivity analysis based on the assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement. The Optional Interconnection Study will also identify the Participating TOs' Interconnection Facilities and the Network Upgrades, and the estimated cost thereof, that may be required to provide transmission service or Interconnection Service based upon the results of the Optional Interconnection Study. The Optional Interconnection Study shall be performed solely for informational purposes. The ISO shall use Reasonable Efforts to coordinate the study with any Affected Systems that may be affected by the types of Interconnection Services that are being studied. The ISO shall utilize existing studies to the extent practicable in conducting the Optional Interconnection Study.

10.3 Optional Interconnection Study Procedures.

The ISO shall use Reasonable Efforts to have the Optional Interconnection Study completed within a mutually agreed upon time period specified within the Optional Interconnection Study Agreement. If the Optional Interconnection Study cannot be completed within such time period, the ISO shall notify the Interconnection Customer and provide an estimated completion date and an explanation of the reasons why additional time is required. Any difference between the study payment and the actual cost of the study shall be paid to the ISO, as applicable, or refunded to the Interconnection Customer, as appropriate. Upon request, the ISO with support and cooperation of the applicable Participating TO(s) shall provide the Interconnection Customer supporting documentation and workpapers, and databases or data developed in the preparation of the Optional Interconnection Study, subject to confidentiality arrangements consistent with LGIP Sections 2.3 and 13.1.

Section 11. Standard Large Generator Interconnection Agreement (LGIA).

11.1 Tender.

11.1.1 Within thirty (30) Calendar Days after the ISO receives the Interconnection Customer's written comments, or notification of no comments, to the draft Interconnection Facilities Study report, the applicable Participating TO(s) and the ISO shall tender a draft LGIA, together with draft appendices. The draft LGIA shall be in the form of the FERC-approved standard form LGIA. The Interconnection Customer shall provide written comments, or notification of no comments, to the draft appendices to the applicable Participating TO(s) and the ISO within (30) Calendar Days of receipt.

11.1.2 Consistent with Section 3.4.4 and 11.1.1 of this LGIP, when the transmission system of a Participating TO, in which the Interconnection Point is not located, is affected, such Participating TO shall tender a separate agreement, in the form of the LGIA, as appropriately modified.

11.2 Negotiation.

Notwithstanding LGIP Section 11.1, at the request of the Interconnection Customer, the applicable Participating TO(s), and ISO shall begin negotiations with the Interconnection Customer concerning the appendices to the LGIA at any time after the Interconnection Customer executes the Interconnection Facilities Study Agreement. The applicable Participating TO(s) and ISO and the Interconnection Customer shall negotiate concerning any disputed provisions of the appendices to the draft LGIA for not more than sixty (60) Calendar Days after tender of the final Interconnection Facilities Study report. If the Interconnection Customer determines that negotiations are at an impasse, it may request termination of the negotiations at any time after tender of the draft LGIA pursuant to LGIP Section 11.1 and request submission of the unexecuted LGIA with FERC or initiate Dispute Resolution procedures pursuant to LGIP Section 13.5. If the Interconnection Customer requests termination of the negotiations, but within ninety (90) Calendar Days after issuance of the final Interconnection Facilities Study report fails to request either the filing of the unexecuted LGIA or initiate Dispute Resolution, it shall be deemed to have withdrawn its Interconnection Request. Unless otherwise agreed by the Parties, if the Interconnection Customer has not executed and returned the LGIA, requested filing of an unexecuted LGIA, or initiated Dispute Resolution procedures pursuant to LGIP Section 13.5 within ninety (90) Calendar Days after issuance of the final Interconnection Facilities Study report, it shall be deemed to have withdrawn its Interconnection Request. The applicable Participating TO(s) and ISO shall provide to the Interconnection Customer a final LGIA within fifteen (15) Business Days after the completion of the negotiation process.

11.3 Execution and Filing.

At the time that the Interconnection Customer either returns the executed LGIA or requests the filing of an unexecuted LGIA as specified below, the Interconnection Customer shall provide the applicable Participating TO(s) and ISO (A) reasonable evidence of continued Site Control or (B) posting to the applicable Participating TO(s) of $250,000, non-refundable additional security, which shall be applied toward future construction costs. At the same time, the Interconnection Customer also shall provide reasonable evidence that one or more of the following milestones in the development of the Large Generating Facility, at the Interconnection Customer election, has been achieved: (i) the execution of a contract for the supply or transportation of fuel to the Large Generating Facility; (ii) the execution of a contract for the supply of cooling water to the Large Generating Facility; (iii) execution of a contract for the engineering for, procurement of major equipment for, or construction of, the Large Generating Facility; (iv) execution of a contract for the sale of electric energy or capacity from the Large Generating Facility; or (v) application for an air, water, or land use permit.

The Interconnection Customer shall either: (i) execute four originals of the tendered LGIA and return one to the applicable Participating TO(s) and two to the ISO; or (ii) request in writing that the applicable Participating TO(s) and ISO file with FERC an LGIA in unexecuted form. As soon as practicable, but not later than ten (10) Business Days after receiving either the executed originals of the tendered LGIA (if it does not conform with a FERC-approved standard form of interconnection agreement) or the request to file an unexecuted LGIA, the applicable Participating TO(s) and ISO shall file the LGIA with FERC, as necessary, together with an explanation of any matters as to which the Interconnection Customer and the applicable Participating TO(s) or ISO disagree and support for the costs that the applicable Participating TO(s) propose to charge to the Interconnection Customer under the LGIA. An unexecuted LGIA should contain terms and conditions deemed appropriate by the applicable Participating TO(s) and ISO for the Interconnection Request. If the Parties agree to proceed with design, procurement, and construction of facilities and upgrades under the agreed-upon terms of the unexecuted LGIA, they may proceed pending FERC action.

11.4 Commencement of Interconnection Activities.

If the Interconnection Customer executes the final LGIA, the applicable Participating TO(s), ISO and the Interconnection Customer shall perform their respective obligations in accordance with the terms of the LGIA, subject to modification by FERC. Upon submission of an unexecuted LGIA, the Interconnection Customer, applicable Participating TO(s) and ISO may proceed to comply with the unexecuted LGIA, pending FERC action.

11.5 Interconnection Customer to Meet Requirements of the Participating TO's Interconnection Handbook.

The Interconnection Customer's Interconnection Facilities shall be designed, constructed, operated and maintained in accordance with the applicable Participating TO's Interconnection Handbook.

Section 12. Construction of Participating TO's Interconnection Facilities and Network Upgrades.

12.1 Schedule.

The applicable Participating TO(s) and the Interconnection Customer shall negotiate in good faith concerning a schedule for the construction of the applicable Participating TO's Interconnection Facilities and the Network Upgrades.

12.2 Construction Sequencing.

12.2.1 General.

In general, the in-service date in the LGIA of an Interconnection Customer seeking interconnection to the ISO Controlled Grid will determine the sequence of construction of Network Upgrades.

12.2.2 Advance Construction of Network Upgrades that are an Obligation of an Entity other than the Interconnection Customer.

An Interconnection Customer with an LGIA, in order to maintain its In-Service Date, may request that the applicable Participating TO(s) advance to the extent necessary the completion of Network Upgrades that: (i) were assumed in the Interconnection Studies for such Interconnection Customer, (ii) are necessary to support such In-Service Date, and (iii) would otherwise not be completed, pursuant to a contractual obligation of an entity other than the Interconnection Customer that is seeking interconnection to the ISO Controlled Grid, in time to support such In-Service Date. Upon such request, the applicable Participating TO(s) will use Reasonable Efforts to advance the construction of such Network Upgrades to accommodate such request; provided that the Interconnection Customer commits to pay the applicable Participating TO(s): (i) any associated expediting costs and (ii) the cost of such Network Upgrades.

The applicable Participating TO(s) will refund to the Interconnection Customer both the expediting costs and the cost of Network Upgrades, in accordance with Article 11.4 of the LGIA. Consequently, the entity with a contractual obligation to construct such Network Upgrades shall be obligated to pay only that portion of the costs of the Network Upgrades that the applicable Participating TO(s) have not refunded to the Interconnection Customer. Payment by that entity shall be due on the date that it would have been due had there been no request for advance construction. The applicable Participating TO(s) shall forward to the Interconnection Customer the amount paid by the entity with a contractual obligation to construct the Network Upgrades as payment in full for the outstanding balance owed to the Interconnection Customer. The applicable Participating TO(s) then shall refund to that entity the amount that it paid for the Network Upgrades, in accordance with Article 11.4 of the LGIA.

12.2.3 Advancing Construction of Network Upgrades that are Part of an Expansion Plan of the Participating TO.

An Interconnection Customer with an LGIA, in order to maintain its in-service date as specified in the LGIA, may request that the applicable Participating TO(s) advance to the extent necessary the completion of Network Upgrades that: (i) are necessary to support such in-service date and (ii) would otherwise not be completed, pursuant to an expansion plan of the applicable Participating TO(s), in time to support such in-service date. Upon such request, the applicable Participating TO(s) will use Reasonable Efforts to advance the construction of such Network Upgrades to accommodate such request; provided that the Interconnection Customer commits to pay the applicable Participating TO(s) any associated expediting costs. The Interconnection Customer shall be entitled to refunds, if any, in accordance with this LGIP and the LGIA, for any expediting costs paid.

12.2.4 Amended Interconnection Study.

An Interconnection Study will be amended, as needed, to determine the facilities necessary to support the requested in-service date as specified in the LGIA. This amended study will include those transmission facilities, Large Generating Facilities and any other generating facilities that are expected to be in service on or before the requested in-service date. If an amendment to an Interconnection Study is required, the ISO shall notify the Interconnection Customer in writing. Upon receipt of such notice, the Interconnection Customer shall provide the ISO within ten (10) Business Days a written request that the ISO either (i) terminate the amended study and withdraw the Interconnection Customer's Interconnection Request or (ii) continue with the amended study. If the Interconnection Customer requests the ISO to continue with the amended study, the Interconnection Customer shall pay the ISO an additional $10,000 deposit for the amended study along with providing written notice for the ISO to continue. Such amended study shall take no longer than sixty (60) Calendar Days from the date the ISO receives the Interconnection Customer's written notice to continue the study and payment of the additional $10,000 deposit. The ISO shall share applicable study results with the applicable Participating TO(s) for review and comment, and incorporate comments and issue a final study to the Interconnection Customer within eighty (80) Calendar Days from the date of the Interconnection Customer's written notice to continue the study and payment of the additional $10,000 deposit. If the amended Interconnection Study cannot be completed within that time period, the ISO shall notify the Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required. Any and all costs of the amended study shall be borne by the Interconnection Customer being re-studied.

Section 13. Miscellaneous.

13.1 Confidentiality.

Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by any of the Parties to the other Parties prior to the execution of an LGIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Parties receiving the information that the information is confidential.

If requested by any Party, the other Parties shall provide in writing, the basis for asserting that the information referred to in this Section warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

The confidentiality provisions of this LGIP are limited to information provided pursuant to this LGIP.

13.1.1 Scope.

Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or breach of the LGIA; or (6) is required, in accordance with LGIP Section 13.1.6, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under the LGIP. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Parties that it no longer is confidential.

13.1.2 Release of Confidential Information.

No Party shall release or disclose Confidential Information to any other person, except to its employees, consultants, Affiliates (limited by FERC's Standards of Conduct requirements set forth in Part 358 of FERC's Regulations, 18 C.F.R. 358), or to parties who may be or considering providing financing to or equity participation with the Interconnection Customer, or to potential purchasers or assignees of the Interconnection Customer, on a need-to-know basis in connection with these procedures, unless such person has first been advised of the confidentiality provisions of this LGIP Section 13.1 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this LGIP Section 13.1.

13.1.3 Rights.

Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Parties. The disclosure by each Party to the other Parties of Confidential Information shall not be deemed a waiver by a Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

13.1.4 No Warranties.

By providing Confidential Information, no Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, no Party obligates itself to provide any particular information or Confidential Information to the other Parties nor to enter into any further agreements or proceed with any other relationship or joint venture.

13.1.5 Standard of Care.

Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Parties under these procedures or its regulatory requirements.

13.1.6 Order of Disclosure.

If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires any Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Parties with prompt notice of such request(s) or requirement(s) so that the other Parties may seek an appropriate protective order or waive compliance with the terms of the LGIP. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

13.1.7 Remedies.

Monetary damages are inadequate to compensate a Party for another Party’s breach of its obligations under this LGIP Section 13.1. Each Party accordingly agrees that the other Parties shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party breaches or threatens to breach its obligations under this LGIP Section 13.1, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the breach of this LGIP Section 13.1, but shall be in addition to all other remedies available at law or in equity. Further, the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this LGIP Section 13.1.

13.1.8 Disclosure to FERC, its Staff, or a State.

Notwithstanding anything in this Section 13.1 to the contrary, and pursuant to 18 C.F.R. section 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to the LGIP, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 C.F.R. section 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Parties prior to the release of the Confidential

Information to FERC or its staff. The Party shall notify the other applicable Parties when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time any of the Parties may respond before such information would be made public, pursuant to 18 C.F.R. section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner, consistent with applicable state rules and regulations.

13.1.9 Subject to the exception in LGIP Section 13.1.8, any Confidential Information shall not be disclosed by the other Parties to any person not employed or retained by the other Parties, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Parties, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this LGIP or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or ISO or to a subregional, regional or national reliability organization or planning group. The Party asserting confidentiality shall notify the other Parties in writing of the information it claims is confidential. Prior to any disclosures of another Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

13.1.10 This provision shall not apply to any information that was or is hereafter in the public domain (except as a result of a breach of this provision).

13.1.11 The Participating TO or ISO shall, at the Interconnection Customer's election, destroy, in a confidential manner, or return the Confidential Information provided at the time of Confidential Information is no longer needed.

13.2 Delegation of Responsibility.

The ISO and the participating TOs may use the services of subcontractors as deemed appropriate to perform their obligations under this LGIP. The applicable Participating TO or ISO shall remain primarily liable to the Interconnection Customer for the performance of its respective subcontractors and compliance with its obligations of this LGIP. The subcontractor shall keep all information provided confidential and shall use such information solely for the performance of such obligation for which it was provided and no other purpose.

13.3 Obligation for Study Costs.

The ISO shall charge and the Interconnection Customer shall pay the actual costs of the Interconnection Studies. Any difference between the study deposit and the actual cost of the applicable Interconnection Study shall be paid by or refunded to the Interconnection Customer. Any invoices for Interconnection Studies shall include a detailed and itemized accounting of the cost of each Interconnection Study. The Interconnection Customer shall pay any such undisputed costs within thirty (30) Calendar Days of receipt of an invoice therefor. The ISO shall not be obligated to continue to have any studies conducted unless the Interconnection Customer has paid all undisputed amounts in compliance herewith. In the event an Interconnection Study is performed by the ISO, or is performed by a third party consultant pursuant to LGIP Section 13.4, the Interconnection Customer shall pay only the costs of those activities performed by the Participating TO to adequately review or validate that Interconnection Study.

13.4 Third Parties Performing Studies.

If (i) at the time of the signing of an Interconnection Study agreement there is disagreement as to the estimated time to complete an Interconnection Study, (ii) the Interconnection Customer receives notice pursuant to LGIP Sections 6.3, 7.4 or 8.3 that an Interconnection Study cannot be completed within the applicable timeframe for such Interconnection Study, or (iii) the Interconnection Customer receives neither the Interconnection Study nor a notice under LGIP Sections 6.3, 7.4 or 8.3 within the applicable timeframe for such Interconnection Study, then the Interconnection Customer may request that the ISO: (1) utilize a third party consultant reasonably acceptable to the Interconnection Customer, the ISO, and the Participating TO or (2) utilize the applicable Participating TO(s) to perform such Interconnection Study under the direction of the ISO. At other times, the Participating TO or ISO may also utilize a third party consultant to perform such Interconnection Study, either in response to a general request of the Interconnection Customer, or on its own volition.

In all cases, use of a third party consultant shall be in accord with Article 26 of the LGIA (Subcontractors) and limited to situations where the ISO determines that doing so will help maintain or accelerate the study process for the Interconnection Customer's pending Interconnection Request and not interfere with the ISO's or Participating TO's progress on Interconnection Studies for other pending Interconnection Requests. In cases where the Interconnection Customer requests use of a third party consultant to perform such Interconnection Study, the Interconnection Customer and the Participating TO or ISO shall negotiate all of the pertinent terms and conditions, including reimbursement arrangements and the estimated study completion date and study review deadline. The applicable Participating TO(s) and the ISO shall convey all workpapers, data bases, study results and all other supporting documentation prepared to date with respect to the Interconnection Request as soon as practicable upon the Interconnection Customer's request subject to the confidentiality provision in LGIP Section 13.1. In any case, such third party contract may be entered into with the Interconnection Customer, the applicable Participating TO(s), or the ISO at the Participating TO's or ISO's discretion. If the Interconnection Customer enters into a third party Interconnection Study agreement, the Interconnection Customer shall provide the Interconnection Study to the ISO and the Participating TO for review, and such third party Interconnection Study agreement shall provide for reimbursement by the Interconnection Customer of the ISO's and Participating TO's actual cost of participating in and reviewing the Interconnection Study. In the case of (iii) the Interconnection Customer maintains its right to submit a claim to Dispute Resolution to recover the costs of such third party study. Such third party consultant shall be required to comply with this LGIP, Article 26 of the LGIA (Subcontractors), the ISO Tariff, and the relevant Participating TO's TO Tariff as would apply if the Participating TO or ISO were to conduct the Interconnection Study and shall use the information provided to it solely for purposes of performing such services and for no other purposes. The applicable Participating TO(s) and the ISO shall cooperate with such third party consultant and the Interconnection Customer to complete and issue the Interconnection Study in the shortest reasonable time.

13.5 Disputes.

All disputes arising out of or in connection with this LGIP whereby relief is sought by or from the ISO shall be settled in accordance with the ISO ADR Procedures. Disputes arising out of or in connection with this LGIP not subject to the ISO ADR Procedures shall be resolved as follows:

13.5.1 Submission.

In the event either Party has a dispute, or asserts a claim, that arises out of or in connection with the LGIA, the LGIP, or their performance, such Party (the "disputing Party") shall provide the other Party with written notice of the dispute or claim ("Notice of Dispute"). Such dispute or claim shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the other Party. In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within thirty (30) Calendar Days of the other Party's receipt of the Notice of Dispute, such claim or dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. In the event the Parties do not agree to submit such claim or dispute to arbitration, each Party may exercise whatever rights and remedies it may have in equity or at law consistent with the terms of the LGIA and LGIP.

13.5.2 External Arbitration Procedures.

Any arbitration initiated under these procedures shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) Calendar Days of the submission of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) Calendar Days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("Arbitration Rules") and any applicable FERC regulations or RTO rules; provided, however, in the event of a conflict between the Arbitration Rules and the terms of this LGIP Section 13, the terms of this LGIP Section 13 shall prevail.

13.5.3 Arbitration Decisions.

Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within ninety (90) Calendar Days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the LGIA and LGIP and shall have no power to modify or change any provision of the LGIA and LGIP in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with FERC if it affects jurisdictional rates, terms and conditions of service, Interconnection Facilities, or Network Upgrades.

13.5.4 Costs.

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (1) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or (2) one half the cost of the single arbitrator jointly chosen by the Parties.

13.6 Local Furnishing Bonds.

13.6.1 Participating TOs That Own Facilities Financed by Local Furnishing Bonds.

This provision is applicable only to a Participating TO that has financed facilities for the local furnishing of electric energy with Local Furnishing Bonds. Notwithstanding any other provisions of this LGIP, the Participating TO and the ISO shall not be required to provide Interconnection Service to the Interconnection Customer pursuant to this LGIP and the LGIA if the provision of such Interconnection Service would jeopardize the tax-exempt status of any Local Furnishing Bond(s) issued for the benefit of the Participating TO.

13.6.2 Alternative Procedures for Requesting Interconnection Service.

If a Participating TO determines that the provision of Interconnection Service requested by the Interconnection Customer would jeopardize the tax-exempt status of any Local Furnishing Bond(s) issued for the benefit of the Participating TO, it shall advise the Interconnection Customer and the ISO within (30) Calendar Days of receipt of the Interconnection Request.

The Interconnection Customer thereafter may renew its request for the same interconnection Service by tendering an application under Section 211 of the Federal Power Act, in which case the Participating TO, within ten (10) Calendar Days of receiving a copy of the Section 211 application, will waive its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act, and the ISO and Participating TO shall provide the requested Interconnection Service pursuant to the terms and conditions set forth in this LGIP and the LGIA.

PART 1 to LGIP
INTERCONNECTION REQUEST

Provide three copies of this completed form pursuant to Section 7 below.

1. The undersigned Interconnection Customer submits this request to interconnect its Large Generating Facility with the ISO Controlled Grid pursuant to the ISO Tariff.

2. This Interconnection Request is for (check one):
   _____ A proposed new Large Generating Facility.
   _____ An increase in the generating capacity or a Material Modification of an existing Generating Facility.

4. The Interconnection Customer provides the following information:

   a. Address or location, including the county, of the proposed new Large Generating Facility site or, in the case of an existing Generating Facility, the name and specific location, including the county, of the existing Generating Facility;

   b. Maximum megawatt electrical output of the proposed new Large Generating Facility or the amount of megawatt increase in the generating capacity of an existing Generating Facility;

   c. Type of project (i.e., gas turbine, hydro, wind, etc.) and general description of the equipment configuration;

   d. Proposed In-Service Date, Trial Operation date and Commercial Operation Date by day, month, and year and term of service;

   e. Name, address, telephone number, and e-mail address of the Interconnection Customer's contact person;

   f. Approximate location of the proposed Point of Interconnection; and

   g. Interconnection Customer Data (set forth in Attachment A)

5. Applicable deposit amount as specified in the LGIP.

6. Evidence of Site Control as specified in the LGIP and name(s), address(es) and contact information of site owner(s) (check one):

   ____ Is attached to this Interconnection Request
   ____ Will be provided at a later date in accordance with this LGIP

7. This Interconnection Request shall be submitted to the representative indicated below:

   New Resource Interconnection
   California ISO
   P.O. Box 639014
   Folsom, CA 95763-9014

   Overnight address: 151 Blue Ravine Road, Folsom, CA 95630

8. Representative of the Interconnection Customer to contact:

[To be completed by the Interconnection Customer]

9. This Interconnection Request is submitted by:

Name of the Interconnection Customer:

By (signature):

Name (type or print):

Title:

Date

Attachment A
To Part 1
Interconnection Request

LARGE GENERATING FACILITY DATA

Provide three copies of this completed form pursuant to Section 7 of Part 1.

1. Provide two original prints and one reproducible copy (no larger than 36" x 24") of the following:

A. Site drawing to scale, showing generator location and point of interconnection with the ISO Controlled Grid.

B. Single-line diagram showing applicable equipment such as generating units, step-up transformers, auxiliary transformers, switches/disconnects of the proposed interconnection, including the required protection devices and circuit breakers. For wind generator farms, the one line diagram should include the distribution lines connecting the various groups of generating units, the generator capacitor banks, the step up transformers, the distribution lines, and the substation transformers and capacitor banks at the point of interconnection with the utility.

2. Generating Facility Information

A) Total Generating Facility rated output (kW): _______________
B) Generating Facility auxiliary load (kW): _______________
C) Project net capacity (kW): _______________
D) Standby load when Generating Facility is off-line (kW): _______________

E) Number of Generating Units: ___________________
(Please repeat the following items for each generator)
F) Individual generator rated output (kW for each unit): ___________________________
G) Manufacturer: _____________________________________
H) Year Manufactured: ___________________
I) Nominal Terminal Voltage: ___________________
J) Rated Power Factor (%): _______
K) Type (Induction, Synchronous, D.C. with Inverter): _____________
L) Phase (3 phase or single phase): _______
M) Connection (Delta, Grounded WYE, Ungrounded WYE, impedance grounded): _________
N) Generator Voltage Regulation Range: _____________
O) Generator Power Factor Regulation Range: _____________
P) For combined cycle plants, specify the plant output for an outage of the steam turbine or an outage of a single combustion turbine:

3. Synchronous Generator – General Information:
(Please repeat the following for each generator)

A. Rated Generator speed (rpm): ____________
B. Rated MVA: _______________
C. Rated Generator Power Factor: ____________
D. Generator Efficiency at Rated Load (%): ____________
E. Moment of Inertia (including prime mover): ____________
F. Inertia Time Constant (on machine base) H: ____________ sec or MJ/MVA
G. SCR (Short-Circuit Ratio - the ratio of the field current required for rated open-circuit

voltage to the field current required for rated short-circuit current): ____________

H. Please attach generator reactive capability curves.
I. Rated Hydrogen Cooling Pressure in psig (Steam Units only): ____________
J. Please attach a plot of generator terminal voltage versus field current that shows the air gap line, the open-circuit saturation curve, and the saturation curve at full load and rated power factor.

4. Excitation System Information
(Please repeat the following for each generator)

A. Indicate the Manufacturer ____________________ and Type _____________of excitation system used for the generator. For exciter type, please choose from 1 to 8 below or describe the specific excitation system.

1) Rotating DC commutator exciter with continuously acting regulator. The regulator power source is independent of the generator terminal voltage and current.

2) Rotating DC commentator exciter with continuously acting regulator. The regulator power source is bus fed from the generator terminal voltage.

3) Rotating DC commutator exciter with non-continuously acting regulator (i.e., regulator adjustments are made in discrete increments).

4) Rotating AC Alternator Exciter with non-controlled (diode) rectifiers. The regulator power source is independent of the generator terminal voltage and current (not bus-fed).

5) Rotating AC Alternator Exciter with controlled (thyristor) rectifiers. The regulator power source is fed from the exciter output voltage.

6) Rotating AC Alternator Exciter with controlled (thyristor) rectifiers.

7) Static Exciter with controlled (thyristor) rectifiers. The regulator power source is bus-fed from the generator terminal voltage.

8) Static Exciter with controlled (thyristor) rectifiers. The regulator power source is bus-fed from a combination of generator terminal voltage and current (compound-source controlled rectifiers system.

B. Attach a copy of the block diagram of the excitation system from its instruction manual. The diagram should show the input, output, and all feedback loops of the excitation system.
C. Excitation system response ratio (ASA): _______________
D. Full load rated exciter output voltage: ____________
E. Maximum exciter output voltage (ceiling voltage): ____________
F. Other comments regarding the excitation system?
____
____
____

5. Power System Stabilizer Information.
(Please repeat the following for each generator. All new generators are required to install PSS unless an exemption has been obtained from WECC. Such an exemption can be obtained for units that do not have suitable excitation systems.)

A. Manufacturer: ____
B. Is the PSS digital or analog? _________________
C. Note the input signal source for the PSS?
_____ Bus frequency _____ Shaft speed _____ Bus Voltage
_____________________ Other (specify source)
D. Please attach a copy of a block diagram of the PSS from the PSS Instruction Manual and the correspondence between dial settings and the time constants or PSS gain.
E: Other comments regarding the PSS?
____
____
____

6. Turbine-Governor Information
(Please repeat the following for each generator)

Please complete Part A for steam, gas or combined-cycle turbines, Part B for hydro turbines, and Part C for both.

A. Steam, gas or combined-cycle turbines:

1.) List type of unit (Steam, Gas, or Combined-cycle):__________
2.) If steam or combined-cycle, does the turbine system have a reheat process (i.e., both high and low pressure turbines)? _______
3.) If steam with reheat process, or if combined-cycle, indicate in the space provided, the percent of full load power produced by each turbine:
Low pressure turbine or gas turbine: ______%
High pressure turbine or steam turbine: ______%

B. Hydro turbines:

1.) Turbine efficiency at rated load: _______%
2.) Length of penstock: ______ft
3.) Average cross-sectional area of the penstock: _______ft2
4.) Typical maximum head (vertical distance from the bottom of the penstock, at the gate, to the water level): ______ft
5.) Is the water supply run-of-the-river or reservoir: ___________
6.) Water flow rate at the typical maximum head: _________ft3/sec
7.) Average energy rate: _________kW-hrs/acre-ft
8.) Estimated yearly energy production: ________kW-hrs

C. Complete this section for each machine, independent of the turbine type.

1.) Turbine manufacturer: _______________
2.) Maximum turbine power output: ________________MW
3.) Minimum turbine power output (while on line): _________MW
4.) Governor information:
a: Droop setting (speed regulation): _____________
b: Is the governor mechanical-hydraulic or electro-hydraulic (Electro-hydraulic governors have an electronic speed sensor and transducer.)? _________________

c: Other comments regarding the turbine governor system?
____
____
____
____

7. Synchronous Generator and Associated Equipment – Dynamic Models:

For each generator, governor, exciter and power system stabilizer, select the appropriate dynamic model from the General Electric PSLF Program Manual and provide the required input data. The manual is available on the GE website at www.gepower.com. Select the following links within the website: 1) Our Businesses, 2) GE Power Systems, 3) Energy Consulting, 4) GE PSLF Software, 5) GE PSLF User's Manual.

There are links within the GE PSLF User's Manual to detailed descriptions of specific models, a definition of each parameter, a list of the output channels, explanatory notes, and a control system block diagram. The block diagrams are also available on the Ca-ISO website.

If you require assistance in developing the models, we suggest you contact General Electric. Accurate models are important to obtain accurate study results. Costs associated with any changes in facility requirements that are due to differences between model data provided by the generation developer and the actual generator test data, may be the responsibility of the generation developer.

8. Induction Generator Data:

A. Rated Generator Power Factor at rated load: ____________
B. Moment of Inertia (including prime mover): ____________
C. Do you wish reclose blocking? Yes ___, No ___
Note: Sufficient capacitance may be on the line now, or in the future, and the generator may self-excite unexpectedly.

9. Generator Short Circuit Data

For each generator, provide the following reactances expressed in p.u. on the generator base:

- X"1 – positive sequence subtransient reactance: _____
- X"2 – negative sequence subtransient reactance: _____
- X"0 – zero sequence subtransient reactance: _____

Generator Grounding:

A. _____ Solidly grounded
B. _____ Grounded through an impedance

Impedance value in p.u on generator base. R:_____________p.u.
X:_____________p.u.

C. _____ Ungrounded

10. Step-Up Transformer Data

For each step-up transformer, fill out the data form provided in Table 1.

11. Line Data

There is no need to provide data for new lines that are to be planned by the Participating TO. However, for transmission lines that are to be planned by the generation developer, please provide the following information:

Nominal Voltage: _______________
Line Length (miles): ____________________
Line termination Points: ____________________
Conductor Type: ______ Size: _________
If bundled. Number per phase: ______, Bundle spacing: _____in.
Phase Configuration. Vertical: _______, Horizontal: _______
Phase Spacing (ft): A-B: ______, B-C: _______, C-A: ________
Distance of lowest conductor to Ground: _________ft
Ground Wire Type: ________ Size: _______ Distance to Ground: ______ft
Attach Tower Configuration Diagram
Summer line ratings in amperes (normal and emergency) _________________
Resistance (R): __________ p.u.**
Reactance: (X): __________ p.u**
Line Charging (B/2): __________ p.u**
** On 100-MVA and nominal line voltage (kV) Base

12. Wind Generators

Number of generators to be interconnected pursuant to this Interconnection Request: ____

Elevation: ______ _____ Single Phase _____ Three Phase

Inverter manufacturer, model name, number, and version:
____

List of adjustable setpoints for the protective equipment or software:
____

Field Volts: _________________
Field Amperes: ______________
Motoring Power (kW): _______
Neutral Grounding Resistor (If Applicable): ____________
I_2^2t or K (Heating Time Constant): ____________
Rotor Resistance: ____________
Stator Resistance: ____________
Stator Reactance: ____________
Rotor Reactance: ____________
Magnetizing Reactance: ___________
Short Circuit Reactance: ___________
Exciting Current: ________________
Temperature Rise: ________________
Frame Size: _______________
Design Letter: ______________
Reactive Power Required In Vars (No Load): ________
Reactive Power Required In Vars (Full Load): ________
Total Rotating Inertia, H: ________ Per Unit on KVA Base

Note: A completed General Electric Company Power Systems Load Flow (PSLF) data sheet must be supplied with the Interconnection Request. If other data sheets are more appropriate to the proposed device then they shall be provided and discussed at Scoping Meeting.

TABLE 1

TRANSFORMER DATA

UNIT______________________________________

NUMBER OF TRANSFORMERS__________ PHASE ________

RATED KVA	H Winding	X Winding	Y Winding
Connection (Delta, Wye, Gnd.)	___________	___________	___________
55 C Rise	___________	___________	___________
65 C Rise	___________	___________	___________
RATED VOLTAGE	___________	___________	___________
BIL	___________	___________	___________
AVAILABLE TAPS (planned or existing)	___________	___________	___________
LOAD TAP CHANGER?	___________	___________	___________
TAP SETTINGS	___________	___________	___________

COOLING TYPE : OA_____ OA/FA_____ OA/FA/FA______ OA/FOA______

IMPEDANCE	H-X	H-Y	X-Y
Percent	___________	___________	___________
MVA Base	___________	___________	___________
Tested Taps	___________	___________	___________

WINDING RESISTANCE	H	X	Y
Ohms	___________	___________	___________

CURRENT TRANSFORMER RATIOS

H______________ X_______________ Y_______________ N______________

PERCENT EXCITING CURRENT 100 % Voltage; __________ 110% Voltage_________

Supply copy of nameplate and manufacture's test report when available

Part 2 TO LGIP

PART 2 INTERCONNECTION PROCEDURES FOR A WIND GENERATING PLANT

PART 2 to LGIP
INTERCONNECTION PROCEDURES FOR A WIND GENERATING PLANT

Part 2 sets forth procedures specific to a wind generating plant. All other requirements of this LGIP continue to apply to wind generating plant interconnections.

A. Special Procedures Applicable to Wind Generators

The wind plant Interconnection Customer, in completing the Interconnection Request required by section 3.1 of this LGIP, may provide to the ISO a set of preliminary electrical design specifications depicting the wind plant as a single equivalent generator. Upon satisfying these and other applicable Interconnection Request conditions, the wind plant may enter the queue and receive the Base Case data as provided for in this LGIP.

No later than six months after submitting an Interconnection Request completed in this manner, the wind plant Interconnection Customer must submit completed detailed electrical design specifications and other data (including collector system layout data) needed to allow the ISO to complete the Interconnection Study.

INTERCONNECTION FEASIBILITY STUDY AGREEMENT

THIS AGREEMENT is made and entered into this___day of ______, 20___by and between _______, a ____________ organized and existing under the laws of the State of _____, ("Interconnection Customer,") and the California Independent System Operator Corporation, a California nonprofit public benefit corporation existing under the laws of the State of California, ("ISO"). The Interconnection Customer and the ISO each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by the Interconnection Customer dated ______ ; and

WHEREAS, the Interconnection Customer desires to interconnect the Large Generating Facility with the ISO Controlled Grid; and

WHEREAS, the Interconnection Customer has requested the ISO to conduct or cause to be performed an Interconnection Feasibility Study to assess the feasibility of interconnecting the proposed Large Generating Facility.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in the ISO's FERC-approved Standard Large Generation Interconnection Procedures ("LGIP") or the Master Definitions Supplement, Appendix A to the ISO Tariff, as applicable.

2.0 The Interconnection Customer elects and the ISO shall conduct or cause to be performed an Interconnection Feasibility Study consistent with the LGIP in accordance with the ISO Tariff.

3.0 The scope of the Interconnection Feasibility Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Interconnection Feasibility Study shall be based on the technical information provided by the Interconnection Customer in the Interconnection Request, as may be modified as the result of the Scoping Meeting. The ISO reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interconnection Feasibility Study and as designated in accordance with Section 3.5.4 of the LGIP. If, after the designation of the Point of Interconnection pursuant to Section 3.5.4 of the LGIP, the Interconnection Customer modifies its Interconnection Request pursuant to Section 4.4, the time to complete the Interconnection Feasibility Study may be extended.

5.0 The Interconnection Feasibility Study report shall provide the following information:

- preliminary identification of any circuit breaker short circuit capability limits exceeded on the Participating TO's electric system or the ISO Controlled Grid as a result of the interconnection;

- preliminary identification of any thermal overload or voltage limit violations on the Participating TO's electric system or the ISO Controlled Grid resulting from the interconnection;

- preliminary description and non-binding good faith estimate of cost and cost responsibility for and time for construction of the Participating TO's facilities required to interconnect the Large Generating Facility to the Participating TO's electric system or the ISO Controlled Grid and to address the identified short circuit and power flow issues;

- preliminary identification of financial impacts, if any, on Local Furnishing Bonds; and

- expected results in the Interconnection System Impact Study.

6.0 In addition to the deposit(s) paid by the Interconnection Customer pursuant to Section 3.5.1 of the LGIP, the Interconnection Customer shall provide a deposit of $10,000 for the performance of the Interconnection Feasibility Study.

Following the issuance of the Interconnection Feasibility Study to the Interconnection Customer the ISO shall charge and the Interconnection Customer shall pay the actual costs of the Interconnection Feasibility Study, inclusive of any re-studies and amendments to the Interconnection Feasibility Study, pursuant to Section 9 of this Agreement.

Any difference between the deposits made toward the Interconnection Feasibility Study, amendments and re-studies to the Interconnection Feasibility Study, and the actual cost of the study shall be paid by or refunded to the Interconnection Customer, as appropriate in accordance with Section 13.3 of the LGIP.

7.0 Pursuant to Section 3.7 of the LGIP, the ISO will coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems. The ISO may provide a copy of the Interconnection Feasibility Study results to an Affected System Operator and the Western Electricity Coordinating Council. Requests for review and input from Affected System Operators or the Western Electricity Coordinating Council may arrive at any time prior to interconnection, and a revision of the Interconnection Feasibility Study or re-study may be required in such event.

8.0 Substantial portions of technical data and assumptions used to perform the Interconnection Feasibility Study, such as system conditions, existing and planned generation, and unit modeling, may change after the ISO provides the Interconnection Feasibility Study results to the Interconnection Customer.

Study results will reflect available data at the time the ISO provides the Interconnection Feasibility Study to the Interconnection Customer. The ISO shall not be responsible for any additional costs, including, without limitation, costs of new or additional facilities, system upgrades, or schedule changes, that may be incurred by the Interconnection Customer as a result of changes in such data and assumptions.

9.0 In the event that a re-study or amendment of the Interconnection Feasibility Study is required, the ISO shall provide notification of the need for such re-study or amendment, and the Interconnection Customer shall provide direction as to whether to proceed with the re-study or amendment and any associated deposit payment pursuant to Section 6.4 or Section 12.2.4 of the LGIP, as applicable.

10.0 The ISO shall maintain records and accounts of all costs incurred in performing the Interconnection Feasibility Study, inclusive of any re-studies or amendments thereto, in sufficient detail to allow verification of all costs incurred, including associated overheads. The Interconnection Customer shall have the right, upon reasonable notice, within a reasonable time following receipt of the final cost report associated with this Interconnection Feasibility Study at the ISO's offices and at its own expense, to audit the ISO's records as necessary and as appropriate in order to verify costs incurred by the ISO. Any audit requested by the Interconnection Customer shall be completed, and written notice of any audit dispute provided to the ISO, within one hundred eighty (180) Calendar Days following receipt by the Interconnection Customer of the ISO's notification of the final costs of the Interconnection Feasibility Study, inclusive of any re-study or amendment thereto.

11.0 In accordance with Section 3.8 of the LGIP, the Interconnection Customer may withdraw its Interconnection Request at any time by written notice to the ISO. Upon receipt of such notice, this Agreement shall terminate.

12.0 Pursuant to Section 6.1 of the LGIP, this Agreement shall become effective upon the date the fully executed Agreement and deposit specified in Section 6 of this Agreement are received by the ISO. If the ISO does not receive the fully executed Agreement and payment pursuant to Section 6.1 of the LGIP, then the Interconnection Request will be deemed withdrawn upon the Interconnection Customer's receipt of written notice by the ISO pursuant to Section 3.8 of the LGIP.

13.0 Miscellaneous.

13.1 Dispute Resolution. Any dispute, or assertion of a claim, arising out of or in connection with this Interconnection Feasibility Study Agreement, shall be resolved in accordance with Section 13.5 of the LGIP

13.2 Confidentiality. Confidential Information shall be treated in accordance with Section 13.1 of the LGIP.

13.3 Binding Effect. This Interconnection Feasibility Study Agreement and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

13.4 Conflicts. In the event of a conflict between the body of this Interconnection Feasibility Study Agreement and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Interconnection Feasibility Study Agreement shall prevail and be deemed the final intent of the Parties.

13.5 Rules of Interpretation. This Interconnection Feasibility Study Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Interconnection Feasibility Study Agreement, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this Section, or other provision hereof or thereof); (4) reference to any applicable laws and regulations means such applicable laws and regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article or Section of this Interconnection Feasibility Study Agreement or such Appendix to this Interconnection Feasibility Study Agreement, or such Section to the LGIP or such Appendix to the LGIP, as the case may be; (6) “hereunder”, “hereof”, “herein”, “hereto” and words of similar import shall be deemed references to this Interconnection Feasibility Study Agreement as a whole and not to any particular Article; (7) “including” (and with correlative meaning “include”) means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, “from” means “from and including”, “to” means “to but excluding” and “through” means “through and including”.

13.6 Entire Agreement. This Interconnection Feasibility Study Agreement, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Interconnection Feasibility Study Agreement. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, any Party’s compliance with its obligations under this Interconnection Feasibility Study Agreement.

13.7 No Third Party Beneficiaries. This Interconnection Feasibility Study Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

13.8 Waiver. The failure of a Party to this Interconnection Feasibility Study Agreement to insist, on any occasion, upon strict performance of any provision of this Interconnection Feasibility Study Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this Interconnection Feasibility Study Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Interconnection Feasibility Study Agreement. Termination or default of this Interconnection Feasibility Study Agreement for any reason by the Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Participating TO or ISO. Any waiver of this Interconnection Feasibility Study Agreement shall, if requested, be provided in writing.

Any waivers at any time by any Party of its rights with respect to any default under this Interconnection Feasibility Study Agreement, or with respect to any other matter arising in connection with this Interconnection Feasibility Study Agreement, shall not constitute or be deemed a waiver with respect to any subsequent default or other matter arising in connection with this Interconnection Feasibility Study Agreement. Any delay, short of the statutory period of limitations, in asserting or enforcing any right under this Interconnection Feasibility Study Agreement shall not constitute or be deemed a waiver of such right.

13.9 Headings. The descriptive headings of the various Articles and Sections of this Interconnection Feasibility Study Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Interconnection Feasibility Study Agreement.

13.10 Multiple Counterparts. This Interconnection Feasibility Study Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

13.11 Amendment. The Parties may by mutual agreement amend this Interconnection Feasibility Study Agreement by a written instrument duly executed by both of the Parties.

13.12 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this Interconnection Feasibility Study Agreement by a written instrument duly executed by both of the Parties. Such amendment shall become effective and a part of this Interconnection Feasibility Study Agreement upon satisfaction of all applicable laws and regulations.

13.13 Reservation of Rights. The ISO shall have the right to make a unilateral filing with FERC to modify this Interconnection Feasibility Study Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Interconnection Feasibility Study Agreement pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Interconnection Feasibility Study Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

13.14 No Partnership. This Interconnection Feasibility Study Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, another Party.

13.15 Assignment. This Interconnection Feasibility Study Agreement may be assigned by a Party only with the written consent of the other Party; provided that a Party may assign this Interconnection Feasibility Study Agreement without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Interconnection Feasibility Study Agreement; and provided further that the Interconnection Customer shall have the right to assign this Interconnection Feasibility Study Agreement, without the consent of the other Party, for collateral security purposes to aid in providing financing for the Large Generating Unit, provided that the Interconnection Customer will require any secured party, trustee or mortgagee to notify the other Party of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the other Party of the date and particulars of any such exercise of assignment right(s). Any attempted assignment that violates this Article is void and ineffective. Any assignment under this Interconnection Feasibility Study Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

California Independent System Operator Corporation

By: ______________________

Title: ______________________

Date: ___________________

[Insert name of the Interconnection Customer]

By: ______________________

Title:______________________

Date:___________________

Attachment A to
Interconnection Feasibility
Study Agreement

ASSUMPTIONS USED IN CONDUCTING THE
INTERCONNECTION FEASIBILITY STUDY

The Interconnection Feasibility Study will be based upon the information set forth in the Interconnection Request and agreed upon in the Scoping Meeting held on____________:

Designation of Point of Interconnection and configuration to be studied.

Designation of alternative Point(s) of Interconnection and configuration.

[Above assumptions to be completed by the Interconnection Customer and other assumptions to be provided by the Interconnection Customer and the ISO]

INTERCONNECTION SYSTEM IMPACT STUDY AGREEMENT

THIS AGREEMENT is made and entered into this___day of ______, 20___by and between _______, a ____________ organized and existing under the laws of the State of _____, ("Interconnection Customer,") and the California Independent System Operator Corporation, a California nonprofit public benefit corporation existing under the laws of the State of California, ("ISO"). The Interconnection Customer and the ISO each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by the Interconnection Customer dated _________; and

WHEREAS, the Interconnection Customer desires to interconnect the Large Generating Facility with the ISO Controlled Grid; and

WHEREAS, the ISO has completed an Interconnection Feasibility Study (the "Feasibility Study") and provided the results of said study to the Interconnection Customer[1]; and

WHEREAS, the Interconnection Customer has requested the ISO to conduct or cause to be performed an Interconnection System Impact Study to assess the impact of interconnecting the Large Generating Facility;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in the ISO's FERC-approved Standard Large Generation Interconnection Procedures ("LGIP") or the Master Definitions Supplement, Appendix A to the ISO Tariff, as applicable.

2.0 The Interconnection Customer elects and the ISO shall conduct or cause to be performed an Interconnection System Impact Study consistent with the LGIP in accordance with the ISO Tariff.

3.0 The scope of the Interconnection System Impact Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Interconnection System Impact Study will be based upon the results of the Interconnection Feasibility Study and the technical information provided by the Interconnection Customer in the Interconnection Request, subject to any modifications in accordance with Section 4.4 of the LGIP. The ISO reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interconnection System Impact Study. If the

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[1] This recital to be omitted if the Interconnection Customer has elected to forego the Interconnection Feasibility Study.

Interconnection Customer modifies its designated Point of Interconnection, Interconnection Request, or the technical information provided therein is modified, the time to complete the Interconnection System Impact Study may be extended.

5.0 The Interconnection System Impact Study report shall provide the following information:

- identification of any circuit breaker short circuit capability limits exceeded on the Participating TO's electric system or the ISO Controlled Grid as a result of the interconnection;

- identification of any thermal overload or voltage limit violations on the Participating TO's electric system or the ISO Controlled Grid resulting from the interconnection;

- identification of any instability or inadequately damped response to system disturbances on the Participating TO's electric system or the ISO Controlled Grid resulting from the interconnection;

- a description and non-binding, good faith estimate of cost and cost responsibility for and time for construction of facilities on the Participating TO's electric system required to interconnect the Large Generating Facility to the ISO Controlled Grid and to address the identified short circuit, instability, and power flow issues on the ISO Controlled Grid; and

- a Deliverability Assessment on the ISO Controlled Grid pursuant to Section 3.3 of the LGIP; and

- assessment of the potential magnitude of financial impacts, if any, on Local Furnishing Bonds and a proposed resolution.

6.0 The Interconnection Customer shall provide a deposit of $50,000 for the performance of the Interconnection System Impact Study. The good faith estimate for the time of completion of the Interconnection System Impact Study is ______________[insert date].

Following the issuance of the Interconnection System Impact Study, the ISO shall charge and the Interconnection Customer shall pay the actual costs of the Interconnection System Impact Study, inclusive of any re-studies and amendments to the Interconnection System Impact Study, pursuant to Section 9 of this Agreement.

Any difference between the deposit made toward the Interconnection System Impact Study, amendments and re-studies to the Interconnection System Impact Study, and the actual cost of the study shall be paid by or refunded to the Interconnection Customer, as appropriate in accordance with Section 13.3 of the LGIP.

7.0 Pursuant to Section 3.7 of the LGIP, the ISO will coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems. The ISO may provide a copy of the Interconnection System Impact Study results to an Affected System Operator and the Western Electricity Coordinating Council. Requests for review and input from Affected System Operators or the Western Electricity Coordinating Council may arrive at any time prior to interconnection, and a revision of the Interconnection System Impact Study or re-study may be required in such event.

8.0 Substantial portions of technical data and assumptions used to perform the Interconnection System Impact Study, such as system conditions, existing and planned generation, and unit modeling, may change after the ISO provides the Interconnection System Impact Study results to the Interconnection Customer. Study results will reflect available data at the time the ISO provides the Interconnection System Impact Study to the Interconnection Customer. The ISO shall not be responsible for any additional costs, including, without limitation, costs of new or additional facilities, system upgrades, or schedule changes, that may be incurred by the Interconnection Customer as a result of changes in such data and assumptions.

9.0 In the event that a re-study or amendment of the Interconnection System Impact Study is required, the ISO shall provide notification of the need for such re-study or amendment, and the Interconnection Customer shall provide direction as to whether to proceed with the re-study or amendment and any associated deposit payment pursuant to Section 7.6 or Section 12.2.4 of the LGIP, as applicable.

10.0 The ISO shall maintain records and accounts of all costs incurred in performing the Interconnection System Impact Study, inclusive of any re-studies or amendments thereto, in sufficient detail to allow verification of all costs incurred, including associated overheads. The Interconnection Customer shall have the right, upon reasonable notice, within a reasonable time at the Participating TO's offices and at its own expense, to audit the ISO's records as necessary and as appropriate in order to verify costs incurred by the ISO. Any audit requested by the Interconnection Customer shall be completed, and written notice of any audit dispute provided to the ISO representative, within one hundred eighty (180) Calendar Days following receipt by the Interconnection Customer of the ISO's notification of the final costs of the Interconnection System Impact Study, inclusive of any re-study or amendment thereto.

11.0 In accordance with Section 3.8 of the LGIP, the Interconnection Customer may withdraw its Interconnection Request at any time by written notice to the ISO. Upon receipt of such notice, this Agreement shall terminate.

12.0 Pursuant to Section 7.2 of the LGIP, this Agreement shall become effective upon the date the fully executed Agreement and deposit specified in Section 6 of this Agreement are received by the ISO. If ISO does not receive the fully executed Agreement and payment pursuant to Section 7.2 of the LGIP, then the Interconnection Request will be deemed withdrawn upon the Interconnection Customer's receipt of written notice by the ISO pursuant to Section 3.8 of the LGIP.

13.0 Miscellaneous.

13.1 Dispute Resolution. Any dispute, or assertion of a claim, arising out of or in connection with this Interconnection System Impact Study Agreement, shall be resolved in accordance with Section 13.5 of the LGIP.

13.2 Confidentiality. Confidential Information shall be treated in accordance with Section 13.1 of the LGIP.

13.3 Binding Effect. This Interconnection System Impact Study Agreement and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

13.4 Conflicts. In the event of a conflict between the body of this Interconnection System Impact Study Agreement and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Interconnection System Impact Study Agreement shall prevail and be deemed the final intent of the Parties.

13.5 Rules of Interpretation. This Interconnection System Impact Study Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Interconnection System Impact Study Agreement, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this Interconnection System Impact Study Agreement), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any applicable laws and regulations means such applicable laws and regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article or Section of this Interconnection System Impact Study Agreement or such Appendix to this Interconnection System Impact Study Agreement, or such Section to the LGIP or such Appendix to the LGIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this Interconnection System Impact Study Agreement as a whole and not to any particular Article, Section, or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

13.6 Entire Agreement. This Interconnection System Impact Study Agreement, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Interconnection System Impact Study Agreement. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, any Party's compliance with its obligations under this Interconnection System Impact Study Agreement.

13.7 No Third Party Beneficiaries. This Interconnection System Impact Study Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

13.8 Waiver. The failure of a Party to this Interconnection System Impact Study Agreement to insist, on any occasion, upon strict performance of any provision of this Interconnection System Impact Study Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this Interconnection System Impact Study Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Interconnection System Impact Study Agreement. Termination or default of this

Interconnection System Impact Study Agreement for any reason by the Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Participating TO or ISO. Any waiver of this Interconnection System Impact Study Agreement shall, if requested, be provided in writing.

Any waivers at any time by any Party of its rights with respect to any default under this Interconnection System Impact Study Agreement, or with respect to any other matter arising in connection with this Interconnection System Impact Study Agreement, shall not constitute or be deemed a waiver with respect to any subsequent default or other matter arising in connection with this Interconnection System Impact Study Agreement. Any delay, short of the statutory period of limitations, in asserting or enforcing any right under this Interconnection System Impact Study Agreement shall not constitute or be deemed a waiver of such right.

13.9 Headings. The descriptive headings of the various Articles and Sections of this Interconnection System Impact Study Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Interconnection System Impact Study Agreement.

13.10 Multiple Counterparts. This Interconnection System Impact Study Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

13.11 Amendment. The Parties may by mutual agreement amend this Interconnection System Impact Study Agreement by a written instrument duly executed by both of the Parties.

13.12 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this Interconnection System Impact Study Agreement by a written instrument duly executed by both of the Parties. Such amendment shall become effective and a part of this Interconnection System Impact Study Agreement upon satisfaction of all applicable laws and regulations.

13.13 Reservation of Rights. The ISO shall have the right to make a unilateral filing with FERC to modify this Interconnection System Impact Study Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC’s rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Interconnection System Impact Study Agreement pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC’s rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Interconnection System Impact Study Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC’s rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

13.14 No Partnership. This Interconnection System Impact Study Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, another Party.

13.15 Assignment. This Interconnection System Impact Study Agreement may be assigned by a Party only with the written consent of the other Party; provided that a Party may assign this Interconnection System Impact Study Agreement without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Interconnection System Impact Study Agreement; and provided further that the Interconnection Customer shall have the right to assign this Interconnection System Impact Study Agreement, without the consent of the other Party, for collateral security purposes to aid in providing financing for the Large Generating Unit, provided that the Interconnection Customer will require any secured party, trustee or mortgagee to notify the other Party of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the other Party of the date and particulars of any such exercise of assignment right(s). Any attempted assignment that violates this Article is void and ineffective. Any assignment under this Interconnection System Impact Study Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

California Independent System Operator Corporation

By: ______________________

Title: ______________________

Date: ____________________

[Insert name of the Interconnection Customer]

By: ______________________

Title: ______________________

Date: _____________________

Attachment A

**Interconnection System Impact
Study Agreement**

**ASSUMPTIONS USED IN CONDUCTING THE
INTERCONNECTION SYSTEM IMPACT STUDY**

The Interconnection System Impact Study will be based upon the results of the Interconnection Feasibility Study, subject to any modifications in accordance with Section 4.4 of the LGIP, and the following assumptions:

Designation of Point of Interconnection and configuration to be studied.

Designation of alternative Point(s) of Interconnection and configuration.

[Above assumptions to be completed by the Interconnection Customer and other assumptions to be provided by the Interconnection Customer and the ISO]

INTERCONNECTION FACILITIES STUDY AGREEMENT

THIS AGREEMENT is made and entered into this___day of ______, 20___by and between _______, a ____________ organized and existing under the laws of the State of _____, ("Interconnection Customer,") and the California Independent System Operator Corporation, a California nonprofit public benefit corporation existing under the laws of the State of California, ("ISO"). The Interconnection Customer and the ISO each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by the Interconnection Customer dated _______; and

WHEREAS, the Interconnection Customer desires to interconnect the Large Generating Facility with the ISO Controlled Grid;

WHEREAS, the ISO has completed an Interconnection System Impact Study (the "System Impact Study") and provided the results of said study to the Interconnection Customer; and

WHEREAS, the Interconnection Customer has requested the ISO to conduct or cause to be performed an Interconnection Facilities Study to specify and estimate the cost of the equipment, engineering, procurement and construction work needed on the Participating TO's electric system to implement the conclusions of the Interconnection System Impact Study in accordance with Good Utility Practice to physically and electrically connect the Large Generating Facility to the ISO Controlled Grid.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in the ISO's FERC-approved Standard Large Generation Interconnection Procedures ("LGIP") or the Master Definitions Supplement, Appendix A to the ISO Tariff, as applicable.

2.0 The Interconnection Customer elects and the ISO shall conduct or cause to be performed an Interconnection Facilities Study consistent with the LGIP in accordance with the ISO Tariff.

3.0 The scope of the Interconnection Facilities Study shall be subject to the assumptions set forth in Attachment A and the data provided in Attachment B to this Agreement.

4.0 The Interconnection Facilities Study report (i) shall provide a description, estimated cost, including, if applicable, the cost of remedial measures that address the financial impacts, if any, on Local Furnishing Bonds, of (consistent with Attachment A), and schedule for required facilities or for effecting remedial measures that address the financial impacts, if any, on Local Furnishing Bonds within each Participating TO's electric system to interconnect the Large Generating Facility to the ISO Controlled Grid and (ii) shall address the short circuit, instability, and power flow issues identified in the Interconnection System Impact Study.

5.0 The Interconnection Customer shall provide a deposit of the greater of $100,000 or the Interconnection Customer's portion of the estimated monthly cost for the performance of the Interconnection Facilities Study. The time for completion of the Interconnection Facilities Study is specified in Attachment A.

For studies where the estimated cost exceed $100,000, the ISO may invoice Interconnection Customer on a monthly basis for the work to be conducted on the Interconnection Facilities Study for the remaining balance of the estimated Interconnection Facilities Study cost. The Interconnection Customer shall pay invoiced amounts within thirty (30) Calendar Days of receipt of invoice. The ISO shall continue to hold the amounts on deposit until settlement of the final invoice.

Following the issuance of the Interconnection Facilities Study, the ISO shall charge and the Interconnection Customer shall pay the actual costs of the Interconnection Facilities Study, inclusive of any re-studies and amendments to the Interconnection Facilities Study, pursuant to Section 9 of this Agreement.

Any difference between the deposit made toward the Interconnection Facilities Study and the actual cost of the study, inclusive of any re-studies and amendments thereto, shall be paid by or refunded to the Interconnection Customer, as appropriate in accordance with Section 13.3 of the LGIP.

6.0 The Interconnection Facilities Study will be based upon the results of the Interconnection System Impact Study and the technical information provided by the Interconnection Customer in the Interconnection Request, subject to any modifications in accordance with Section 4.4 of the LGIP. The ISO reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interconnection Facilities Study.

If the Interconnection Customer modifies its Interconnection Request or the technical information provided therein is modified, the time to complete the Interconnection Facilities Study may be extended.

7.0 Pursuant to Section 3.7 of the LGIP, the ISO will coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems. The ISO may provide a copy of the Interconnection Facilities Study results to an Affected System Operator and the Western Electricity Coordinating Council. Requests for review and input from Affected System Operators or the Western Electricity Coordinating Council may arrive at any time prior to interconnection, and a revision of the Interconnection Facilities Study or re-study may be required in such event.

8.0 Substantial portions of technical data and assumptions used to perform the Interconnection Facilities Study, such as system conditions, existing and planned generation, and unit modeling, may change after the ISO provides the Interconnection Facilities Study results to the Interconnection Customer. Study results will reflect available data at the time the ISO provides the Interconnection Facilities Study to the Interconnection Customer. The ISO shall not be responsible for any additional costs, including, without limitation, costs of new or additional facilities, system upgrades, or schedule changes, that may be incurred by the Interconnection Customer as a result of changes in such data and assumptions.

9.0 In the event that a re-study or amendment of the Interconnection Facilities Study is required, the ISO shall provide notification of the need for such re-study or amendment, and the Interconnection

Customer shall provide direction as to whether to proceed with the re-study or amendment and any associated deposit payment pursuant to Section 8.5 or Section 12.2.4 of the LGIP, as applicable.

10.0 The ISO shall maintain records and accounts of all costs incurred in performing the Interconnection Facilities Study, inclusive of any re-studies or amendments thereto, in sufficient detail to allow verification of all costs incurred, including associated overhead. The Interconnection Customer shall have the right, upon reasonable notice, within a reasonable time at the ISO offices and at its own expense, to audit the ISO's records as necessary and as appropriate in order to verify costs incurred by the ISO. Any audit requested by the Interconnection Customer shall be completed, and written notice of any audit dispute provided to the ISO within one hundred eighty (180) Calendar Days following receipt by the Interconnection Customer of the ISO's notification of the final costs of the Interconnection Facilities Study, inclusive of any re-study or amendment thereto.

11.0 In accordance with Section 3.8 of the LGIP, the Interconnection Customer may withdraw its Interconnection Request at any time by written notice to the ISO. Upon receipt of such notice, this Agreement shall terminate.

12.0 Pursuant to Section 8.1 of the LGIP, this Agreement shall become effective upon the date the fully executed Agreement and deposit specified in Section 6 of this Agreement are received by the ISO. If the ISO does not receive the fully executed Agreement and payment pursuant to Section 8.1 of the LGIP, then the Interconnection Request will be deemed withdrawn upon the Interconnection Customer's receipt of written notice by the ISO pursuant to Section 3.8 of the LGIP.

13.0 Miscellaneous.

13.1 Dispute Resolution. Any dispute, or assertion of a claim, arising out of or in connection with this Interconnection Facilities Study Agreement, shall be resolved in accordance with Section 13.5 of the LGIP.

13.2 Confidentiality. Confidential Information shall be treated in accordance with Section 13.1 of the LGIP.

13.3 Binding Effect. This Interconnection Facilities Study Agreement and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

13.4 Conflicts. In the event of a conflict between the body of this Interconnection Facilities Study Agreement and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Interconnection Facilities Study Agreement shall prevail and be deemed the final intent of the Parties.

13.5 Rules of Interpretation. This Interconnection Facilities Study Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Interconnection Facilities Study Agreement, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this Interconnection Facilities Study Agreement), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any applicable laws and regulations means such applicable laws and regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article or Section of this Interconnection Facilities Study Agreement or such Appendix to this Interconnection Facilities Study Agreement, or such Section to the LGIP or such Appendix to the LGIP, as the case may be; (6) “hereunder”, “hereof”, “herein”, “hereto” and words of similar import shall be deemed references to this Interconnection Facilities Study Agreement as a whole and not to any particular Article, Section, or other provision hereof or thereof; (7) “including” (and with correlative meaning “include”) means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, “from” means “from and including”, “to” means “to but excluding” and “through” means “through and including”.

13.6 Entire Agreement. This Interconnection Facilities Study Agreement, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Interconnection Facilities Study Agreement. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, any Party’s compliance with its obligations under this Interconnection Facilities Study Agreement.

13.7 No Third Party Beneficiaries. This Interconnection Facilities Study Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

13.8 Waiver. The failure of a Party to this Interconnection Facilities Study Agreement to insist, on any occasion, upon strict performance of any provision of this Interconnection Facilities Study Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this Interconnection Facilities Study Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Interconnection Facilities Study Agreement. Termination or default of this Interconnection Facilities Study Agreement for any reason by the Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Participating TO or ISO. Any waiver of this Interconnection Facilities Study Agreement shall, if requested, be provided in writing.

Any waivers at any time by any Party of its rights with respect to any default under this Interconnection Facilities Study Agreement, or with respect to any other matter arising in connection with this Interconnection Facilities Study Agreement, shall not constitute or be deemed a waiver with respect to any subsequent default or other matter arising in connection with this Interconnection Facilities Study Agreement. Any delay, short of the statutory period of limitations, in asserting or enforcing any right under this Interconnection Facilities Study Agreement shall not constitute or be deemed a waiver of such right.

13.9 Headings. The descriptive headings of the various Articles and Sections of this Interconnection Facilities Study Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Interconnection Facilities Study Agreement.

13.10 Multiple Counterparts. This Interconnection Facilities Study Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

13.11 Amendment. The Parties may by mutual agreement amend this Interconnection Facilities Study Agreement by a written instrument duly executed by both of the Parties.

13.12 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this Interconnection Facilities Study Agreement by a written instrument duly executed by both of the Parties. Such amendment shall become effective and a part of this Interconnection Facilities Study Agreement upon satisfaction of all applicable laws and regulations.

13.13 Reservation of Rights. The ISO shall have the right to make a unilateral filing with FERC to modify this Interconnection Facilities Study Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Interconnection Facilities Study Agreement pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Interconnection Facilities Study Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

13.14 No Partnership. This Interconnection Facilities Study Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, another Party.

13.15 Assignment. This Interconnection Facilities Study Agreement may be assigned by a Party only with the written consent of the other Party; provided that a Party may assign this Interconnection Facilities Study Agreement without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Interconnection Facilities Study Agreement; and provided further that the Interconnection Customer shall have the right to assign this Interconnection Facilities Study Agreement, without the consent of the other Party, for collateral security purposes to aid in providing financing for the Large Generating Unit, provided that the Interconnection Customer will require any secured party, trustee or mortgagee to notify the other Party of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the other Party of the date and particulars of any such exercise of assignment right(s). Any attempted assignment that violates this Article is void and ineffective. Any assignment under this Interconnection Facilities Study Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

California Independent System Operator Corporation

By: ______________________

Title: ______________________

Date: ____________________

[Insert name of the Interconnection Customer]

By: ______________________

Title: ______________________

Date: ____________________

Attachment A

Interconnection Facilities
Study Agreement

INTERCONNECTION CUSTOMER SCHEDULE ELECTION FOR CONDUCTING THE INTERCONNECTION FACILITIES STUDY

The ISO shall use Reasonable Efforts to complete the study and issue a draft Interconnection Facilities Study report to the Interconnection Customer. Prior to issuing draft study results to the Interconnection Customer, the Participating TO and ISO shall share results for review and incorporate comments within the following number of days after of receipt of an executed copy of this Interconnection Facilities Study Agreement:

- one hundred twenty (120) Calendar Days with no more than a +/- 20 percent cost estimate contained in the report, or
- two hundred ten (210) Calendar Days with no more than a +/- 10 percent cost estimate contained in the report.

Attachment B

Interconnection Facilities
Study Agreement

DATA FORM TO BE PROVIDED BY THE INTERCONNECTION CUSTOMER WITH THE INTERCONNECTION FACILITIES STUDY AGREEMENT

Provide two copies of this completed form and other required plans and diagrams in accordance with Section 8.1 of the LGIP.

Provide location plan and one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, transmission circuits, etc.

One set of metering is required for each generation connection to the new bus or existing ISO Controlled Grid station. Number of generation connections: _________

On the one line indicate the generation capacity attached at each metering location. (Maximum load on CT/PT)

On the one line indicate the location of auxiliary power. (Minimum load on CT/PT)

Will an alternate source of auxiliary power be available during CT/PT maintenance? _____Yes ________No

Will a transfer bus on the generation side of the metering require that each meter set be designed for the total plant generation? _____Yes _____No
(Please indicate on one line).

What type of control system or PLC will be located at the Interconnection Customer's Large Generating Facility?
____
____

What protocol does the control system or PLC use?
____
____

Please provide a 7.5-minute quadrangle of the site. Sketch the plant, station, transmission line, and property line.

Physical dimensions of the proposed interconnection station:

Bus length from generation to interconnection station:

Line length from interconnection station to the Participating TO's transmission line.

Tower number observed in the field. (Painted on tower leg)*

Number of third party easements required for transmission lines*:

* To be completed in coordination with the Participating TO or ISO.

Is the Large Generating Facility in the Participating TO's service area?

_____Yes _____No

Local service provider for auziliary and other power:

Please provide proposed schedule dates:

Begin Construction	Date:
Generator step-up transformer receives back feed power	Date:
Generation Testing	Date:
Commercial Operation	Date:

Level of Deliverability: Choose one of the following:

_______ Deliverability with no Network Upgrades

________100% Deliverability

OPTIONAL INTERCONNECTION STUDY AGREEMENT

THIS AGREEMENT is made and entered into this___day of ______, 20___by and between _______, a ____________ organized and existing under the laws of the State of _____, ("Interconnection Customer,") and the California Independent System Operator Corporation, a California nonprofit public benefit corporation existing under the laws of the State of California, ("ISO"). The Interconnection Customer and the ISO each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by the Interconnection Customer dated ________________;

WHEREAS, the Interconnection Customer is proposing to establish an interconnection with the ISO Controlled Grid; and

WHEREAS, the Interconnection Customer has submitted to the ISO an Interconnection Request; and

WHEREAS, on or after the date when the Interconnection Customer receives the Interconnection System Impact Study results, the Interconnection Customer has further requested that the ISO conduct or cause to be performed an Optional Interconnection Study;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in the ISO's FERC-approved Standard Large Generation Interconnection Procedures (“LGIP”) or the Master Definitions Supplement, Appendix A to the ISO Tariff, as applicable.

2.0 The Interconnection Customer elects and the ISO shall conduct or cause to be performed an Optional Interconnection Study consistent with the LGIP in accordance with the ISO Tariff.

3.0 The scope of the Optional Interconnection Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Optional Interconnection Study shall be performed solely for informational purposes.

5.0 The Optional Interconnection Study report shall provide a sensitivity analysis based on the assumptions specified by the Interconnection Customer in Attachment A to this Agreement. The Optional Interconnection Study will identify the Participating TO’s Interconnection Facilities and the Network Upgrades, and the estimated cost thereof, including, if applicable, the cost of remedial measures that address the financial impacts, if any, on Local Furnishing Bonds, that may be required to provide transmission service or interconnection service based upon the assumptions specified by the Interconnection Customer in Attachment A.

6.0 The Interconnection Customer shall provide a deposit of $10,000 for the performance of the Optional Interconnection Study. The ISO’s good faith estimate for the time of completion of the Optional Interconnection Study is ____________ [insert date].

Following the issuance of the Optional Interconnection Study, the ISO shall charge and the Interconnection Customer shall pay the actual costs of the Optional Interconnection Study.

Any difference between the initial payment and the actual cost of the study shall be paid by or refunded to the Interconnection Customer, as appropriate.

7.0 Substantial portions of technical data and assumptions used to perform the Optional Interconnection Study, such as system conditions, existing and planned generation, and unit modeling, may change after the ISO provides the Optional Interconnection Study results to the Interconnection Customer. Study results will reflect available data at the time the ISO provides the Optional Interconnection Study to the Interconnection Customer. The ISO shall not be responsible for any additional costs, including without limitation, costs of new or additional facilities, system upgrades, or schedule changes, that may be incurred by the Interconnection Customer as a result of changes in such data and assumptions.

8.0 The ISO shall maintain records and accounts of all costs incurred in performing the Optional Interconnection Study in sufficient detail to allow verification of all costs incurred, including associated overheads. The Interconnection Customer shall have the right, upon reasonable notice, within a reasonable time at the ISO offices and at its own expense, to audit the ISO's records as necessary and as appropriate in order to verify costs incurred by the ISO. Any audit requested by the Interconnection Customer shall be completed, and written notice of any audit dispute provided to the ISO representative, within one hundred eighty (180) Calendar Days following receipt by the Interconnection Customer of the ISO's notification of the final costs of the Optional Interconnection Study.

9.0 Pursuant to Section 10.1 of the LGIP, this Agreement shall become effective upon the date the fully executed Agreement and deposit specified in Section 6 of this Agreement are received by the ISO. If the ISO does not receive the fully executed Agreement and payment pursuant to Section 10.1 of the LGIP, then the offer reflected in this Agreement will expire and this Agreement will be of no effect.

10.0 Miscellaneous.

10.1 Dispute Resolution. Any dispute, or assertion of a claim, arising out of or in connection with this Optional Interconnection Study Agreement, shall be resolved in accordance with Section 13.5 of the LGIP

10.2 Confidentiality. Confidential Information shall be treated in accordance with Section 13.1 of the LGIP.

10.3 Binding Effect. This Optional Interconnection Study Agreement and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

10.4 Conflicts. In the event of a conflict between the body of this Optional Interconnection Study Agreement and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Optional Interconnection Study Agreement shall prevail and be deemed the final intent of the Parties.

10.5 Rules of Interpretation. This Optional Interconnection Study Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Optional Interconnection Study Agreement, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this Optional Interconnection Study Agreement), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any applicable laws and regulations means such applicable laws and regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article or Section of this Optional Interconnection Study Agreement or such Appendix to this Optional Interconnection Study Agreement, or such Section to the LGIP or such Appendix to the LGIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this Optional Interconnection Study Agreement as a whole and not to any particular Article, Section, or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

10.6 Entire Agreement. This Optional Interconnection Study Agreement, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Optional Interconnection Study Agreement. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, any Party's compliance with its obligations under this Optional Interconnection Study Agreement.

10.7 No Third Party Beneficiaries. This Optional Interconnection Study Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

10.8 Waiver. The failure of a Party to this Optional Interconnection Study Agreement to insist, on any occasion, upon strict performance of any provision of this Optional Interconnection Study Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this Optional Interconnection Study Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Optional Interconnection Study Agreement. Termination or default of this Optional Interconnection Study Agreement for any reason by the Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the other Party. Any waiver of this Optional Interconnection Study Agreement shall, if requested, be provided in writing.

Any waivers at any time by any Party of its rights with respect to any default under this Optional Interconnection Study Agreement, or with respect to any other matter arising in connection with this Optional Interconnection Study Agreement, shall not constitute or be deemed a waiver with respect to any subsequent default or other matter arising in connection with this Optional Interconnection Study Agreement. Any delay, short of the statutory period of limitations, in asserting or enforcing any right under this Optional Interconnection Study Agreement shall not constitute or be deemed a waiver of such right.

10.9 Headings. The descriptive headings of the various Articles and Sections of this Optional Interconnection Study Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Optional Interconnection Study Agreement.

10.10 Multiple Counterparts. This Optional Interconnection Study Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

10.11 Amendment. The Parties may by mutual agreement amend this Optional Interconnection Study Agreement by a written instrument duly executed by both of the Parties.

10.12 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this Optional Interconnection Study Agreement by a written instrument duly executed by both of the Parties. Such amendment shall become effective and a part of this Optional Interconnection Study Agreement upon satisfaction of all applicable laws and regulations.

10.13 Reservation of Rights. The ISO shall have the right to make a unilateral filing with FERC to modify this Optional Interconnection Study Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC’s rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Optional Interconnection Study Agreement pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC’s rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Optional Interconnection Study Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC’s rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

10.14 No Partnership. This Optional Interconnection Study Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, another Party.

10.15 Assignment. This Optional Interconnection Study Agreement may be assigned by a Party only with the written consent of the other Party; provided that a Party may assign this Optional Interconnection Study Agreement without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Optional Interconnection Study Agreement; and provided further that the Interconnection

Customer shall have the right to assign this Optional Interconnection Study Agreement, without the consent of the other Party, for collateral security purposes to aid in providing financing for the Large Generating Unit, provided that the Interconnection Customer will require any secured party, trustee or mortgagee to notify the other Party of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the other Party of the date and particulars of any such exercise of assignment right(s). Any attempted assignment that violates this Article is void and ineffective. Any assignment under this Optional Interconnection Study Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

California Independent System Operator Corporation

By: ______________________

Title:______________________

Date:____________________

[Insert name of the Interconnection Customer]

By: ______________________

Title:______________________

Date:____________________

Attachment A
Optional Interconnection
Study Agreement

ASSUMPTIONS USED IN CONDUCTING
THE OPTIONAL INTERCONNECTION STUDY

[To be completed by the Interconnection Customer consistent with Section 10 of the LGIP.]

AGREEMENT FOR THE ALLOCATION OF RESPONSIBILITIES WITH REGARD TO LARGE GENERATOR INTERCONNECTION PROCEDURES AND INTERCONNECTION STUDY AGREEMENTS

This Agreement for the Allocation of Responsibilities With Regard to Large Generator Interconnection Procedures and Interconnection Study Agreements ("Agreement"), dated November 1, 2005, is entered into between the California Independent System Operator Corporation ("ISO") and **[NAME OF PTO]**________________________________("PTO"). The ISO and PTO are jointly referred to as the "Parties" and individually, as a "Party."

WHEREAS, this Agreement will ensure an independent assessment of new Large Generating Facility impacts on the ISO Controlled Grid and take advantage of the respective expertise of the Parties to facilitate efficient and cost effective Interconnection Study procedures in a manner consistent with the Federal Energy Regulatory Commission's ("FERC") July 1, 2005 Order (112 FERC ¶ 61,009), FERC's August 26, 2005 Order (112 FERC ¶ 61,231), and prior FERC Orders recognizing that Order No. 2003 did not allocate responsibilities between transmission owners and transmission providers for the provision of Interconnection Service and suggesting those parties enter into an agreement to allocate those responsibilities. Southwest Power Pool, Inc., 106 FERC ¶ 61,254 (2004).

NOW THEREFORE, in view of the respective responsibilities assigned to the Parties and the foregoing FERC orders, the ISO and PTO agree to the following allocation of responsibilities for a centralized Interconnection Study process under the direction and oversight of the ISO:

1. DEFINITIONS.

Unless otherwise defined herein, all capitalized terms shall have the meaning set forth in the ISO Tariff.

2. TERM OF AGREEMENT.

This Agreement shall become effective upon the date the provisions of the ISO Tariff implementing the centralized Interconnection Study process required by the July 1 Order and the August 26 Order are accepted and made effective by FERC, and shall remain in effect until (1) terminated by all Parties in writing, or (2) with respect to the PTO, upon the termination of that entity's status as a PTO pursuant to the Transmission Control Agreement, as amended from time to time.

3. PROVISIONS FOR ALLOCATION OF RESPONSIBILITIES BETWEEN ISO AND PTO.

3.1 Interconnection Service: The Parties acknowledge that, as the transmission provider, the ISO is responsible for reliably operating the transmission grid. The Parties also recognize that while the ISO is a transmission provider under the ISO Tariff, the ISO does not own any transmission facilities, and the PTO owns, constructs, and maintains the facilities to which Large Generating Facilities are to be interconnected, and that the PTO may construct or modify facilities to allow the interconnection. While the Parties recognize that the ISO will be responsible for conducting or causing to be performed Interconnection Studies and similar studies, the PTO will participate in these studies and conduct certain portions of studies, under the direction and oversight of, and approval by, the ISO, as provided in this Agreement. The ISO shall not enter into any Interconnection Study agreement with an Interconnection Customer that is contrary to these rights.

3.2 [INTENTIONALLY LEFT BLANK]

3.3 Transmission Owners' Right to Participation in Studies, Committees and Meetings:

3.3.1 In the event that an Interconnection Customer proposes to interconnect a Large Generating Facility with the PTO's facilities, or the PTO is an owner of an affected system, the PTO shall have the right to participate in any Interconnection Feasibility Study, Interconnection System Impact Study, Interconnection Facilities Study, or any other study conducted in connection with such request for Interconnection Service. "Participate" in this Section 3.3.1 means physically perform any study or portion thereof in connection with an Interconnection Request, under the direction and oversight of, and approval by, the ISO pursuant to Section 3.4 of this Agreement; provide or receive input, data or other information regarding any study or portion thereof consistent with Section 3.4 of this Agreement; and, when any study or portion thereof in connection with an Interconnection Request is physically performed by an entity other than the PTO, perform activities necessary to adequately review or validate, as appropriate, any results of the study or portions thereof and provide recommendations.

3.3.2 In the event that an Interconnection Customer proposes to interconnect a Large Generating Facility with the PTO's facilities, or the PTO is an owner of an affected system, the PTO shall have the right to participate in all meetings expressly established pursuant to the ISO LGIP. As appropriate, the PTO may participate in all other material or substantive communications in connection with an Interconnection Request.

3.4 Interconnection Study Responsibility Allocation: In complying with its responsibility for conducting or causing to be performed Interconnection Studies, the ISO will assign responsibility for performance of portions of the Interconnection Studies to the PTO, under the direction and oversight of, and approval by, the ISO, as set forth in Attachment A, except as specifically qualified as follows:

3.4.1 Unless an Interconnection Customer specifically requests that a third party perform an Interconnection Study pursuant to LGIP Section 13.4, for any tasks specifically assigned to the PTO pursuant to Attachment A or otherwise mutually agreed upon by the ISO and the PTO, the ISO reserves the right, on a case-by-case basis, to perform or reassign to a mutually agreed upon and pre-qualified contractor such task only where: (a) the quality and accuracy of prior PTO Interconnection Study work product resulting from assigned tasks has been deemed deficient by the ISO, the ISO has notified the PTO pursuant to notice provision Section 4.16 in writing of the deficiency, and the deficiency has not been cured pursuant to Section 3.4.2; (b) the timeliness of PTO Interconnection Study work product has been deemed deficient, and either (i) the ISO has not been notified of the reasons and actions taken to address the timeliness of the work, or (ii) if notified, the stated reasons and actions taken are insufficient or unjustifiable and the PTO has not cured the deficiency pursuant to Section 3.4.2; (c) the PTO has failed, in a mutually agreed upon timeframe, to provide the ISO with information or data related to an Interconnection Request despite a written request by the ISO, pursuant to Section 3.5 hereof, to do so, and such data is the responsibility of the PTO to provide to the ISO, subject to Section 4.3 of this Agreement; (d) the PTO advises the ISO in writing that it does not have the resources to adequately or timely perform the task according to the applicable timelines set forth in Attachment A; or (e) the estimated cost of the PTO performing the task has been determined in writing by the ISO to significantly exceed the cost of the ISO or mutually agreed upon contractor performing the task, inclusive of the costs that will be incurred by the PTO in exercising its review rights of the results of any such tasks performed by such third party(ies). If the ISO deviates from the assignments set forth in Attachment A based on the foregoing factors, the ISO will provide the PTO with a written explanation for the deviation and any associated reassignments of work. The PTO may contest the deviation pursuant to the Dispute Resolution procedures set forth in Section 4.1 of this Agreement.

Task(s) may only be reassigned in accordance with this Section 3.4.1 where the PTO has been deemed to be deficient in relation to that (those) particular task(s).

3.4.2 Cure for re-assigned Interconnection Study work
The ISO shall not reassign task(s) without the opportunity to cure, as specified in Section 3.4.1. The following actions will serve to cure the deficiencies and result in restoring the assignment(s) as provided in Attachment A:

a) The ISO and PTO shall negotiate in good faith and agree to a corrective action plan proposed by the PTO, including a reasonably adequate cure period, and the corrective action plan is satisfactorily implemented.

b) The ISO determines the deficiency is cured without an action plan.

3.4.3 Assessment of prior PTO Interconnection Study work shall only be based on work conducted under the process that becomes effective concurrent with the effective date of this Agreement. Further, assessment of prior PTO Interconnection Study work shall be based on work conducted no earlier than the eighteen (18) month period prior to the date of the ISO notice of deviation from assignments set forth in Attachment A to this Agreement.

3.5 Information Exchange: The PTO shall provide the ISO, subject to confidentiality requirements in Section 4.3, with any documentation or data requested by the ISO reasonably necessary to permit the ISO to perform, review, validate and approve any Interconnection Study, or portion thereof, performed by the PTO. The ISO shall provide the PTO with any documentation or data requested by the PTO, subject to confidentiality requirements in Section 4.3, reasonably necessary to perform, review, and validate any Interconnection Study, or portion thereof.

3.6 Consistency with Provisions for Centralized Interconnection Study Process: The ISO and PTO have determined that the processes and allocation of responsibilities in Section 3.4 of this Agreement ensure that impacts to the ISO Controlled Grid are independently assessed and that the assignment of responsibilities minimizes handoffs, takes advantage of non-transferable skills, and promotes the efficiency and cost-effectiveness of the centralized Interconnection Study processes, consistent with LGIP Section 3.2.

3.7 Re-Studies: If any re-studies are required, the ISO will confer with the PTO as to the need for a re-study. The ISO will make the final determination regarding the need for a re-study, subject to dispute resolution procedures.

3.8 Use of Contractors: Nothing in this Agreement shall prevent either the ISO or the PTO from using qualified, mutually agreed upon third party contractors to meet that Party's rights or obligations under this Agreement or the LGIP. To promote the efficiency of the process, the ISO and PTO will collaborate to identify a list of the mutually agreed to qualified contractors available to the Parties.

3.9 Performance Standards: Each Party shall perform all of its obligations under the LGIP, this Agreement, and any FERC approved Interconnection Study procedures that may be adopted by the ISO to implement the LGIP or this Agreement in accordance with Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice.

3.10 Recovery of Costs: In accordance with Section 13.3 of the LGIP, the PTOs shall recover all actual costs from the ISO incurred in performing Interconnection Studies or portions thereof assigned to it by the ISO, including all costs incurred in exercising its right to review, and make recommendations on, Interconnection Studies or portions thereof performed by the ISO and/or contractors under Section 3.8 of this Agreement.

4 GENERAL TERMS AND CONDITIONS.

4.1 Dispute Resolution: In the event any dispute regarding the terms, conditions, and performance of this Agreement is not settled informally, the Parties shall follow the ISO ADR Procedures set forth in Section 13 of the ISO Tariff.

4.2 Liability: No Party to this Agreement shall be liable to any other Party for any direct, indirect, special, incidental or consequential losses, damages, claims, liabilities, costs or expenses (including attorneys fees and court costs) arising from the performance or non-performance of its obligations under this Agreement regardless of the cause (including intentional action, willful action, gross or ordinary negligence, or force majeure); provided, however, that a Party may seek equitable or other non-monetary relief as may be necessary to enforce this Agreement and that damages for which a Party may be liable to another Party under another agreement will not be considered damages under this Agreement.

4.3 Confidentiality: Confidential Information shall be treated in accordance with Section 13.1 of the LGIP.

4.4 Binding Effect: This Agreement and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

4.5 Conflicts: In the event of a conflict between the body of this Agreement and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Agreement shall prevail and be deemed the final intent of the Parties.

4.6 Rules of Interpretation: This Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Agreement, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this Section, or other provision hereof or thereof); (4) reference to any applicable laws and regulations means such applicable laws and regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article or Section of this Agreement or such Appendix to this Agreement, or such Section to the LGIP or such Appendix to the LGIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this Agreement as a whole and not to any particular Article; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

4.7 Entire Agreement: This Agreement, including all Attachments hereto, constitutes the entire agreement among the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, among the Parties with respect to the subject matter of this Agreement. Thereare no other agreements, representations, warranties, or covenants, which constitute any part of the consideration for, or any condition to, any Party's compliance with its obligations under this Agreement.

4.8 No Third Party Beneficiaries: This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

4.9 Waiver: The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party. Any waiver at any time by a Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Any waiver of this Agreement shall, if requested, be provided in writing. Any waivers at any time by any Party of its rights with respect to any default under this Agreement, or with respect to any other matter arising in connection with this Agreement, shall not constitute or be deemed a waiver with respect to any subsequent default or other matter arising in connection with this Agreement. Any delay, short of the statutory period of limitations, in asserting or enforcing any right under this Agreement shall not constitute or be deemed a waiver of such right.

4.10 Headings: The descriptive headings of the various Articles and Sections of this Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Agreement.

4.11 Multiple Counterparts: This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

4.12 Modification by the Parties: The Parties may amend this Agreement and any Appendices to this Agreement only (1) by mutual agreement of the Parties by a written instrument duly executed by the Parties, subject to FERC approval or (2) upon the issuance of a FERC order, pursuant to Section 206 of the Federal Power Act. It is the Parties' intent that FERC's right to change any provision of this Agreement shall be limited to the maximum extent permissible by law and that any such change, if permissible, shall be in accordance with the Mobile-Sierra public interest standard applicable to fixed rate agreements. *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956). Such amendment shall become effective and a part of this Agreement upon satisfaction of all applicable laws and regulations. Notwithstanding the foregoing, Attachment B (Notices) may be modified as set forth in Section 4.15, and the ISO and the PTO may from time to time mutually agree to deviate from Attachment A in accordance with the provisions of this Agreement, however, such deviation shall be subject to Section 4.9 and not considered a course of dealing.

4.13 No Partnership: This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, another Party.

4.14 Assignment: This Agreement may be assigned by a Party only with the written consent of the other Parties; provided that a Party may assign this Agreement without the consent of the other Parties to any Affiliate of the assigning Party with an equal or greater creditrating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement. Any attempted assignment that violates this Article is void and ineffective. Any assignment under this Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

4.15 Notices: Any notice, demand, or request provided in this Agreement, or served, given, or made in connection with it, will be in writing and deemed properly served, given, or made if delivered in person, transmitted by facsimile, or sent by United States mail, postage prepaid, to the persons specified in Attachment B hereto unless otherwise provided in this Agreement. Any Party may at any time, by notice to all other Parties, change the designation or address of the person specified in Attachment B as the person who receives notices pursuant to this Agreement.

IN WITNESS WHEREOF, the Parties have executed this Agreement in multiple originals, each of which shall constitute and be an original effective agreement among the Parties.

California Independent System Operator Corporation

By: ______________________

Title: ______________________

Date: ___________________________

[NAME OF PTO]

By:_______________________________

Title:_____________________________

Date:_____________________________

ATTACHMENT A

INTERCONNECTION STUDY RESPONSIBILITY ALLOCATION

Description of Large Generator Interconnection Process: Roles and Responsibilities of ISO and PTOs.

Purpose: This Attachment A to the "AGREEMENT FOR THE ALLOCATION OF RESPONSIBILITIES WITH REGARD TO LARGE GENERATOR INTERCONNECTION PROCEDURES AND INTERCONNECTION STUDY AGREEMENTS" serves as further clarification of the roles and responsibilities of the parties to this Agreement. The ISO will assign responsibility for performance of portions of the Interconnection Studies to the relevant PTOs, under the direction and oversight of, and approval by, the ISO, as set forth in this Attachment A. This document serves as a general overview of only the roles and responsibilities as between the ISO and PTOs. This Agreement does not include the process steps, involvement or obligations of the Interconnection Customer (IC). This Agreement is not inclusive of all procedures necessary to comply with all provisions of the LGIA, LGIP and Interconnection Study agreements.

Interconnection Request (IR) Process

1. ISO forwards the IR to the PTO within 1 Business Day (BD) of receipt of IR from Interconnection Customer (IC)
2. PTO(s) provides any feed back regarding IR to ISO within 3 BD
3. PTO(s) provides draft study plan at Scoping Meeting.
4. ISO distributes draft Scoping Meeting Minutes for review within 3 BD of Scoping Meeting.
5. PTO(s) provide any comments to the Scoping Meeting Minutes within 2 BD of receipt of draft Scoping Meeting Minutes.
6. ISO issues the final Scoping Meeting Minutes within 3 BD of receipt of comments.

Interconnection Feasibility Study Process:

1. ISO forwards IC Point of Interconnection and any Appendix 1, Attachment A data to the PTO(s) within 1 BD of ISO receipt.
2. PTO(s) develop updated draft study plan based on technical data collected by ISO from IC within 7 BD.
3. ISO and PTO(s) coordinate to finalize study plan within 2 BD. ISO approves the study plan.
4. ISO tenders a signed IFSA to IC, with final study plan included in Attachment A, within 5 BD (for a total of 15 BD from ISO receipt of Point of Interconnection from IC in accordance with LGIP Section 6.1).
5. After ISO receives executed study agreement, ISO forwards any additional Appendix 1, Attachment A data to PTO(s) within 1 BD.
6. If during the course of the assigned portions of the study the PTO(s) determines the data is not sufficient to complete the study, PTO(s) informs ISO and ISO notices IC in accordance with LGIP Section 3.8**.**
7. PTO(s) must participate in study review meeting; date to be agreeable to PTO(s) and within 10 BD of ISO providing study report to IC (LGIP Section 6.3.1).
8. ISO and PTO collaborate on any re-study issues. ISO will direct any necessary re-studies.

Interconnection Feasibility Study Timeline

Load Flow	**Typical Calendar Days**	**Typical Cumulative Days**
ISO directs PTO(s) to Develop draft Base Cases **(Milestone)**	0	0
PTO(s) develop draft Base Cases and deliver to ISO	7	7
ISO reviews Base Cases and provides direction to PTO(s) At the direction of the ISO, PTO(s) develops contingency lists and provide to ISO.	7	14
PTO incorporates ISO directions into Base Cases; ISO approves Base Cases; ISO reviews and approves contingency lists. If there is disagreement on the contingency list, the ISO and PTO(s) must coordinate to revise the contingency list. ISO approves the contingency list.	7	21
ISO performs Load Flow & prepares summary results of impacted systems (other PTO(s) or Affected Systems) and submits results to impacted systems. Such results may include ISO proposed solutions for mitigation to any violations uncovered in the Load Flow study.	7	28
Impacted PTO(s) review ISO results and recommend mitigation solutions as appropriate.	5	33
Short Circuit Duty (concurrent with Load Flow Activity)		
At the ISO's direction, PTO(s) Develop Base Case, and run short circuit analyses.	10	10
PTO(s) to perform facilities review	18	28
PTO(s) prepare draft study results and submit to the ISO for review, recommendations and direction.	5	33
Facility cost estimates		
At the ISO's direction, PTO(s) to prepare non-binding cost estimates and schedule for the direct assignment facilities and network upgrades identified in the power flow and short circuit duty analyses.	7	40
Finalizing Report		
At the ISO's direction, PTO(s) to prepare draft report for impacts in their service territory.	5	45
ISO compiles all results into a draft report that covers grid impacts.	5	50
PTO(s) reviews ISO integrated report and provides comments to ISO.	4	54
ISO incorporates PTO(s) comments. If PTO(s') comments conflict with ISO conclusions, then ISO and PTO must coordinate to resolve conflicts. Any remaining conflicts must be noted in final report.	6	60
ISO provides final ISO approved report to IC, impacted PTOs, and any applicable Affected Systems. **(Milestone)**	0	0

Interconnection System Impact Study Process

1. Prior to beginning the ISIS process as outlined in this Attachment A, the ISO will notify the PTOs of potential seams issues and discuss the nature of the concerns with the PTOs. Where the ISO determines that there is a reasonable expectation that the new Large Generating Facility to be interconnected in one PTO area may impact system performance in other PTO areas within the ISO Controlled Grid that does not comply with the applicable planning standards, the ISO will conduct or cause to be performed the ISIS Load Flow, Post Transient and Stability analyses, as appropriate, to assess the extent of the impact on the grid and evaluate mitigation solutions. Applicable planning standards include FERC approved ISO Planning Standards, as may be amended from time to time, and the NERC/WECC Planning Standards, as may be amended from time to time. Further, there may be circumstances where information, including available studies, is not sufficient for the ISO to make a reasonable engineering determination whether the new Large Generating Facility to be interconnected in one PTO area could cause system performance in other PTO areas (i.e. within the ISO Controlled Grid) that does not comply with the applicable planning standards and, in such circumstances, the ISO may nonetheless conduct or cause to be performed the ISIS Load Flow, Post Transient and Stability analyses to make such a determination.
2. At the ISO's direction, the PTO develops a draft ISIS study plan and determines if available technical data is sufficient to complete ISIS.
3. PTO submits draft study plan to ISO for review, direction and approval within 7 BD of ISO tendering Interconnection Feasibility Study report to IC.
4. ISO and PTO coordinate to finalize study plan within 3 BD. ISO approves the study plan.
5. ISO tenders a signed ISISA to IC with final study plan included in Attachment A, within 3 BD.
6. Upon receipt of executed study agreement, ISO forwards any additional Attachment A, Appendix 1 data to PTO(s) within 1 BD.
7. If the data provided by IC is insufficient to perform the study, PTO notifies ISO within 2 BD of ISO receipt of the executed study agreement, and the ISO notifies the IC within 2 BD (total of 5 BD per LGIP Section 7.2) to correct any deficiencies within 10 BD or the IR will be deemed withdrawn, triggering LGIP Section 3.8.
8. PTO must participate in study review meeting; date to be agreeable to PTO and within 10 BD of ISO providing study report to IC (LGIP Section 7.5).
9. ISO to confer with PTO as to the need for a Re-study. ISO makes the final determination subject to dispute resolution procedures.

Interconnection System Impact Study Timeline

Standard System Impact Study Load Flow/Post Transient/Stability Process	**Typical Calendar Days**	**Typical Cumulative Days**
At the ISO's direction, PTO(s) develop draft Base Case(s)	0	0
PTO(s) develop(s) draft base case(s) and deliver(s) to ISO	14	14
ISO reviews Base Case(s) and provides direction to PTO At the ISO's direction, PTO develops contingency lists	7	21
PTO incorporates ISO directions into Base Cases ISO approves Base Case(s) ISO reviews and approves contingency lists	7	28
At the ISO's direction, the PTO may perform the ISIS Load Flow, Post Transient and Stability analyses & prepare mitigation solutions, as appropriate and submits draft study results to ISO for review and direction*.	21	49
***Pursuant to the terms of item 1 above: where the ISO performs the ISIS Load Flow, Post Transient and Stability analyses to determine grid impacts and evaluate mitigation solutions, the potentially impacted PTOs may, as part of the review process, perform activities to adequately review or validate Load Flow, Post Transient and Stability Analysis to assess ISO results and recommend alternative solutions. (In the case of this election, "PTOs" should be substituted for "PTO" for remainder of ISIS process.)**		
PTO develops or supplements ISO proposed mitigation plans and/or develops alternative mitigation plans for consideration, as appropriate, and submits to ISO for review and direction	14	63
Short Circuit Duty (concurrent with the LF/PT/S)		
ISO to coordinate with other potentially affected facility owners[2]	n/a	n/a
ISO directs PTO to develop Base Case and run short circuit analysis	21	21
PTO to perform facilities review	35	56
PTO to prepare draft study results and submits to the ISO for review and direction	7	63
Facility cost estimates and schedules		
At the ISO direction, PTO(s) to prepare cost estimates and schedules for the direct assignment facilities and network upgrades identified in the ISIS power flow, short circuit duty, post transient, and stability studies.	20	83
Final Report		
At the ISO's direction, PTO(s) prepares draft report for impacts in their service territory.	7	90

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[2] In accordance with the WECC Short Circuit Duty Procedure

ISO compiles all results into a draft report that covers grid impacts, as appropriate. ISO reviews integrated draft report and submits comments, recommendations and direction to the PTO	9	99
PTO incorporates ISO directions, conclusions and recommendations. If ISO conclusions and recommendations conflict with PTO conclusions then ISO and PTO must coordinate to resolve conflicts. Any remaining conflicts must be noted in the final report.	14	113
PTO submits final draft report less the deliverability results to the ISO. The ISO will finalize the report and tender the ISO approved report to the IC after incorporating Deliverability results.		
ISO Deliverability Assessment (concurrent with other studies) As part of the Deliverability Assessment process pursuant to LGIP Section 3.3.3, the ISO may also perform studies pursuant to LGIP Section 3.3.2 to determine potential operating limitations on the generator due to constraints under a variety of system conditions.		
PTO provides GE PSLF compatible change files for all project changes since last Deliverability Assessment, including subject LGIP project.	14	14
ISO incorporates project changes into Deliverability Base Case.	7	21
ISO provides Deliverability Study & prepares results summary.	14	35
ISO provides Initial Deliverability results with no upgrades and upgrades necessary for full Deliverability	14	49
ISO reviews Load Flow, post transient, and stability analysis mitigation options. (The timing of this action should be in sync with completion of Load Flow study results)	11	60
ISO has the opportunity to revise Deliverability Upgrades necessary for full Deliverability, based on optimization with LF results.	7	67
At the ISO's direction, PTO to provide Deliverability related upgrade costs and schedules, as appropriate. (This action should occur when PTO is performing cost analysis for Load Flow and Short Circuit Duty upgrades)	16	83
ISO drafts Deliverability study results.	7	90
PTO reviews/comments on Deliverability results.	12	102
ISO incorporates PTO comments on the Deliverability results, as appropriate. Any remaining conflicts must be noted in final report.	11	113
Final Study Report		
ISO provides final approved report to IC, PTO, and any applicable affected systems.	7	120

Interconnection Facilities Study Process**

****All Interconnection Facilities Studies will be under the direction and oversight of, and approval by, the ISO and may involve more than one PTO.**

1. Within 5 BD of the ISIS Study Review Meeting, the PTO develops draft Interconnection Facilities Study plan and submits to ISO for review and approval.
2. ISO submits executed Interconnection Facilities Study Agreement to IC within 5 BD.
3. Upon receipt of executed Interconnection Facilities Study Agreement from IC, ISO submits to PTO technical data provided by IC within 1 BD.
4. If the data provided by IC is insufficient to perform the study, PTO notifies ISO within 3 BD and the ISO notifies the IC within 2 BD (total of 5 BD per LGIP) that IR is deemed withdrawn and the reason for the withdrawal. IC has 15 BD to cure withdrawal notice (LGIP goes directly to withdrawal pursuant to Section 3.8).
5. PTO conducts Interconnection Facilities Study and submits draft report to ISO.
6. ISO forwards draft report to IC for comments.
7. ISO forwards IC comments or notice of no comments to PTO within 1 BD of receipt.
8. PTO incorporates IC Comments within 5 BDs and submits updated draft to ISO for review and comment.
9. ISO reviews and comments, provides recommendations and direction on PTO draft Interconnection Facilities Study report within 2 BD.
10. PTO reviews/incorporates ISO directions within 5 BD and sends revised report to ISO.
11. ISO issues final report to IC within 2 BD (total of 15 BD). If PTO comments conflict with ISO recommendations and conclusions, ISO and PTO must coordinate to resolve conflicts. Any remaining conflicts must be noted in the final report.
12. ISO, PTO(s), and IC meet within 10 BDs from issuance of draft report.
13. ISO and PTO collaborate on any re-study issues. ISO will direct any necessary re-studies and/or progress to LGIA process.

ATTACHMENT B

CONTACTS FOR NOTICES

[Section 4.15]

California ISO

Manager, Transmission Engineering
151 Blue Ravine Road
Folsom, CA 95630
Phone: 916.351.2104
Fax: 916.351.2264

[NAME OF PTO]

[Address of PTO]

ISO TARIFF APPENDIX V

Standard Large Generator Interconnection Agreement

STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT (LGIA)

[INTERCONNECTION CUSTOMER]

[PARTICIPATING TO]

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

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STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT

[INTERCONNECTION CUSTOMER]

[PARTICIPATING TO]

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

THIS STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT ("LGIA") is made and entered into this ____ day of ________________ 20___, by and among ________________, a ________________ organized and existing under the laws of the State/Commonwealth of _________ ("Interconnection Customer" with a Large Generating Facility), ________________, a corporation organized and existing under the laws of the State of California ("**Participating TO**"), and **California Independent System Operator Corporation**, a California nonprofit public benefit corporation organized and existing under the laws of the State of California ("ISO"). Interconnection Customer, Participating TO, and ISO each may be referred to as a "Party" or collectively as the "Parties."

RECITALS

WHEREAS, ISO exercises Operational Control over the ISO Controlled Grid; and

WHEREAS, the Participating TO owns, operates, and maintains the Participating TO's Transmission System; and

WHEREAS, Interconnection Customer intends to own, lease and/or control and operate the Generating Facility identified as a Large Generating Facility in Part C to this LGIA; and

WHEREAS, Interconnection Customer, Participating TO, and ISO have agreed to enter into this LGIA for the purpose of interconnecting the Large Generating Facility with the Participating TO's Transmission System;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

When used in this LGIA, terms with initial capitalization that are not defined in Article 1 shall have the meanings specified in the Article in which they are used.

ARTICLE 1. DEFINITIONS

Adverse System Impact shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

Affected System shall mean an electric system other than the ISO Controlled Grid that may be affected by the proposed interconnection, including the Participating TO's electric system that is not part of the ISO Controlled Grid.

Affiliate shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Applicable Reliability Council shall mean the Western Electricity Coordinating Council or its successor.

Applicable Reliability Standards shall mean the requirements and guidelines of NERC, the Applicable Reliability Council, and the Control Area of the Participating TO's Transmission System to which the Generating Facility is directly interconnected.

Base Case shall mean the base case power flow, short circuit, and stability data bases used for the Interconnection Studies.

Breach shall mean the failure of a Party to perform or observe any material term or condition of this LGIA.

Breaching Party shall mean a Party that is in Breach of this LGIA.

Business Day shall mean Monday through Friday, excluding federal holidays and the day after Thanksgiving Day.

Calendar Day shall mean any day including Saturday, Sunday or a federal holiday.

Commercial Operation shall mean the status of an Electric Generating Unit at a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date of an Electric Generating Unit shall mean the date on which the Electric Generating Unit at the Generating Facility commences Commercial Operation as agreed to by the applicable Participating TO and the Interconnection Customer pursuant to Part E to this LGIA.

Confidential Information shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise, subject to Article 22.1.2.

Control Area shall mean an electrical system or systems bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection. A Control Area must be certified by the Applicable Reliability Council.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of this LGIA.

Distribution System shall mean those non-ISO-controlled transmission and distribution facilities owned by the Participating TO.

Distribution Upgrades shall mean the additions, modifications, and upgrades to the Participating TO's Distribution System. Distribution Upgrades do not include Interconnection Facilities.

Effective Date shall mean the date on which this LGIA becomes effective upon execution by the Parties subject to acceptance by FERC, or if filed unexecuted, upon the date specified by FERC.

Electric Generating Unit shall mean an individual electric generator and its associated plant and apparatus whose electrical output is capable of being separately identified and metered.

Emergency Condition shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of the ISO, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the ISO Controlled Grid or the electric systems of others to which the ISO Controlled Grid is directly connected; (3) that, in the case of the Participating TO, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Participating TO's Transmission System, Participating TO's Interconnection Facilities, Distribution System, or the electric systems of others to which the Participating TO's electric system is directly connected; or (4) that, in the case of the Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by this LGIA to possess black start capability.

Environmental Law shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

Federal Power Act shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a *et seq*.

FERC shall mean the Federal Energy Regulatory Commission or its successor.

Force Majeure shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

Generating Facility shall mean the Interconnection Customer's Electric Generating Unit(s) used for the production of electricity identified in the Interconnection Customer's Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Generating Facility Capacity shall mean the net capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy production devices.

Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be any one of a number of the optimum practices, methods, or acts to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority shall mean any federal, state, local or other governmental, regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the Interconnection Customer, ISO, Participating TO, or any Affiliate thereof.

Hazardous Substances shall mean any chemicals, materials or substances defined as or included in the definition of “hazardous substances,” “hazardous wastes,” “hazardous materials,” “hazardous constituents,” “restricted hazardous materials,” “extremely hazardous substances,” “toxic substances,” “radioactive substances,” “contaminants,” “pollutants,” “toxic pollutants” or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

Initial Synchronization Date shall mean the date upon which an Electric Generating Unit is initially synchronized and upon which Trial Operation begins.

In-Service Date shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Participating TO’s Interconnection Facilities to obtain back feed power.

Interconnection Customer's Interconnection Facilities shall mean all facilities and equipment, as identified in Part A of this LGIA, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Participating TO’s Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

Interconnection Facilities shall mean the Participating TO’s Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Participating TO’s Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Facilities Study shall mean the study conducted or caused to be performed by the ISO, in coordination with the applicable Participating TO(s), or a third party consultant for the Interconnection Customer to determine a list of facilities (including the Participating TO’s Interconnection Facilities, Network Upgrades, and Distribution Upgrades), the cost of those facilities, and the time required to interconnect the Generating Facility with the Participating TO’s Transmission System.

Interconnection Facilities Study Agreement shall mean the agreement between the Interconnection Customer and the ISO for conducting the Interconnection Facilities Study.

Interconnection Feasibility Study shall mean the preliminary evaluation conducted or caused to be performed by the ISO, in coordination with the applicable Participating TO(s), or a third party consultant for the Interconnection Customer of the system impact and cost of interconnecting the Generating Facility to the Participating TO's Transmission System.

Interconnection Handbook shall mean a handbook, developed by the Participating TO and posted on the Participating TO's web site or otherwise made available by the Participating TO, describing technical and operational requirements for wholesale generators and loads connected to the Participating TO's portion of the ISO Controlled Grid, as such handbook may be modified or superseded from time to time. Participating TO's standards contained in the Interconnection Handbook shall be deemed consistent with Good Utility Practice and Applicable Reliability Standards. In the event of a conflict between the terms of this LGIA and the terms of the Participating TO's Interconnection Handbook, the terms in this LGIA shall apply.

Interconnection Request shall mean a request, in the form of Part 1 to the Standard Large Generator Interconnection Procedures, in accordance with the ISO Tariff.

Interconnection Service shall mean the service provided by the Participating TO and ISO associated with interconnecting the Interconnection Customer's Generating Facility to the Participating TO's Transmission System and enabling the ISO Controlled Grid to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of this LGIA, the Participating TO's Transmission Owner Tariff, and the ISO Tariff.

Interconnection Study shall mean any of the following studies: the Interconnection Feasibility Study, the Interconnection System Impact Study, and the Interconnection Facilities Study conducted or caused to be performed by the ISO, in coordination with the applicable Participating TO(s), or a third party consultant for the Interconnection Customer pursuant to the Standard Large Generator Interconnection Procedures.

Interconnection System Impact Study shall mean the engineering study conducted or caused to be performed by the ISO, in coordination with the applicable Participating TO(s), or a third party consultant for the Interconnection Customer that evaluates the impact of the proposed interconnection on the safety and reliability of the Participating TO's Transmission System and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on the Adverse System Impacts identified in the Interconnection Feasibility Study, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Standard Large Generator Interconnection Procedures.

IRS shall mean the Internal Revenue Service.

ISO Controlled Grid shall mean the system of transmission lines and associated facilities of the parties to the Transmission Control Agreement that have been placed under the ISO's Operational Control.

ISO Tariff shall mean the ISO's tariff, as filed with FERC, and as amended or supplemented from time to time, or any successor tariff.

Large Generating Facility shall mean a Generating Facility having a Generating Facility Capacity of more than 20 MW.

Loss shall mean any and all damages, losses, and claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties.

Material Modification shall mean those modifications that have a material impact on the cost or timing of any Interconnection Request or any other valid interconnection request with a later queue priority date.

Metering Equipment shall mean all metering equipment installed or to be installed for measuring the output of the Generating Facility pursuant to this LGIA at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

NERC shall mean the North American Electric Reliability Council or its successor organization.

Network Upgrades shall be Participating TO's Delivery Network Upgrades and Participating TO's Reliability Network Upgrades.

Operational Control shall mean the rights of the ISO under the Transmission Control Agreement and the ISO Tariff to direct the parties to the Transmission Control Agreement how to operate their transmission lines and facilities and other electric plant affecting the reliability of those lines and facilities for the purpose of affording comparable non-discriminatory transmission access and meeting applicable reliability criteria.

Participating TO's Delivery Network Upgrades shall mean the additions, modifications, and upgrades to the Participating TO's Transmission System at or beyond the Point of Interconnection, other than Reliability Network Upgrades, identified in the Interconnection Studies, as identified in Part A, to relieve constraints on the ISO Controlled Grid.

Participating TO's Interconnection Facilities shall mean all facilities and equipment owned, controlled or operated by the Participating TO from the Point of Change of Ownership to the Point of Interconnection as identified in Part A to this LGIA, including any modifications, additions or upgrades to such facilities and equipment. Participating TO's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Participating TO's Reliability Network Upgrades shall mean the additions, modifications, and upgrades to the Participating TO's Transmission System at or beyond the Point of Interconnection, identified in the Interconnection Studies, as identified in Part A, necessary to interconnect the Large Generating Facility safely and reliably to the Participating TO's Transmission System, which would not have been necessary but for the interconnection of the Large Generating Facility, including additions, modifications, and upgrades necessary to remedy short circuit or stability problems resulting from the interconnection of the Large Generating Facility to the Participating TO's Transmission System. Participating TO's Reliability Network Upgrades also include, consistent with Applicable Reliability Council practice, the Participating TO's facilities necessary to mitigate any adverse impact the Large Generating Facility's interconnection may have on a path's Applicable Reliability Council rating.

Participating TO's Transmission System shall mean the facilities owned and operated by the Participating TO and that have been placed under the ISO's Operational Control, which facilities form part of the ISO Controlled Grid.

Party or Parties shall mean the Participating TO, ISO, Interconnection Customer or the applicable combination of the above.

Point of Change of Ownership shall mean the point, as set forth in Part A to this LGIA, where the Interconnection Customer's Interconnection Facilities connect to the Participating TO's Interconnection Facilities.

Point of Interconnection shall mean the point, as set forth in Part A to this LGIA, where the Interconnection Facilities connect to the Participating TO's Transmission System.

Qualifying Facility shall mean a qualifying cogeneration facility or qualifying small power production facility, as defined in the Code of Federal Regulations, Title 18, Part 292 (18 C.F.R. §292).

QF PGA shall mean a Qualifying Facility Participating Generator Agreement specifying the special provisions for the operating relationship between a Qualifying Facility and the ISO, a pro forma version of which is set forth in Appendix B.3 of the ISO Tariff.

Reasonable Efforts shall mean, with respect to an action required to be attempted or taken by a Party under this LGIA, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Scoping Meeting shall mean the meeting among representatives of the Interconnection Customer, the Participating TO(s), other Affected Systems, and the ISO conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

Stand Alone Network Upgrades shall mean Network Upgrades that the Interconnection Customer may construct without affecting day-to-day operations of the ISO Controlled Grid or Affected Systems during their construction. The Participating TO, the ISO, and the Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Part A to this LGIA.

Standard Large Generator Interconnection Procedures (LGIP) shall mean the ISO protocol that sets forth the interconnection procedures applicable to an Interconnection Request pertaining to a Large Generating Facility that is included in the ISO Tariff.

System Protection Facilities shall mean the equipment, including necessary protection signal communications equipment, that protects (1) the Participating TO's Transmission System, Participating TO's Interconnection Facilities, ISO Controlled Grid, and Affected Systems from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the ISO Controlled Grid, Participating TO's Interconnection Facilities, and Affected Systems or on other delivery systems or other generating systems to which the ISO Controlled Grid is directly connected.

Transmission Control Agreement shall mean ISO FERC Electric Tariff No. 7.

Trial Operation shall mean the period during which the Interconnection Customer is engaged in on-site test operations and commissioning of an Electric Generating Unit prior to Commercial Operation.

ARTICLE 2. EFFECTIVE DATE, TERM AND TERMINATION

2.1 **Effective Date**. This LGIA shall become effective upon execution by the Parties subject to acceptance by FERC (if applicable), or if filed unexecuted, upon the date specified by FERC. The ISO and Participating TO shall promptly file this LGIA with FERC upon execution in accordance with Article 3.1, if required.

2.2 **Term of Agreement**. Subject to the provisions of Article 2.3, this LGIA shall remain in effect for a period of ____ years from the Effective Date (***Term Specified in Individual Agreements to be ten (10) years or such other longer period as the Interconnection Customer may request***) and shall be automatically renewed for each successive one-year period thereafter.

2.3 Termination Procedures.

2.3.1 Written Notice. This LGIA may be terminated by the Interconnection Customer after giving the ISO and the Participating TO ninety (90) Calendar Days advance written notice, or by the ISO and the Participating TO notifying FERC after the Generating Facility permanently ceases Commercial Operation.

2.3.2 Default. A Party may terminate this LGIA in accordance with Article 17.

2.3.3 Suspension of Work. This LGIA may be deemed terminated in accordance with Article 5.16.

2.3.4 Notwithstanding Articles 2.3.1, 2.3.2, and 2.3.3, no termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing with FERC of a notice of termination of this LGIA, which notice has been accepted for filing by FERC.

2.4 Termination Costs. If this LGIA terminates pursuant to Article 2.3 above, the Interconnection Customer shall pay all costs incurred or irrevocably committed to be incurred in association with the Interconnection Customer's interconnection (including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment) and other expenses, including any Network Upgrades and Distribution Upgrades for which the Participating TO or ISO has incurred expenses or has irrevocably committed to incur expenses and has not been reimbursed by the Interconnection Customer, as of the date of the other Parties' receipt of the notice of termination, subject to the limitations set forth in this Article 2.4. Nothing in this Article 2.4 shall limit the Parties' rights under Article 17.

2.4.1 Notwithstanding the foregoing, in the event of termination by a Party, all Parties shall use commercially Reasonable Efforts to mitigate the costs, damages and charges arising as a consequence of termination. With respect to any portion of the Participating TO's Interconnection Facilities that have not yet been constructed or installed, the Participating TO shall to the extent possible and with the Interconnection Customer's authorization cancel any pending orders of, or return, any materials or equipment for, or contracts for construction of, such facilities; provided that in the event the Interconnection Customer elects not to authorize such cancellation, the Interconnection Customer shall assume all payment obligations with respect to such materials, equipment, and contracts, and the Participating TO shall deliver such material and equipment, and, if necessary, assign such contracts, to the Interconnection Customer as soon as practicable, at the Interconnection Customer's expense. To the extent that the Interconnection Customer has already paid the Participating TO for any or all such costs of materials or equipment not taken by the Interconnection Customer, the Participating TO shall promptly refund such amounts to the Interconnection Customer, less any costs, including penalties, incurred by the Participating TO to cancel any pending orders of or return such materials, equipment, or contracts.

2.4.2 The Participating TO may, at its option, retain any portion of such materials, equipment, or facilities that the Interconnection Customer chooses not to accept delivery of, in which case the Participating TO shall be responsible for all costs associated with procuring such materials, equipment, or facilities.

2.4.3 With respect to any portion of the Interconnection Facilities, and any other facilities already installed or constructed pursuant to the terms of this LGIA, Interconnection Customer shall be responsible for all costs associated with the removal, relocation or other disposition or retirement of such materials, equipment, or facilities.

2.5 **Disconnection**. Upon termination of this LGIA, the Parties will take all appropriate steps to disconnect the Large Generating Facility from the Participating TO's Transmission System. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this LGIA or such non-terminating Party otherwise is responsible for these costs under this LGIA.

2.6 **Survival**. This LGIA shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, including billings and payments pursuant to this LGIA; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this LGIA was in effect; and to permit each Party to have access to the lands of the other Parties pursuant to this LGIA or other applicable agreements, to disconnect, remove or salvage its own facilities and equipment.

ARTICLE 3. REGULATORY FILINGS AND ISO TARIFF COMPLIANCE

3.1 **Filing**. The Participating TO and the ISO shall file this LGIA (and any amendment hereto) with the appropriate Governmental Authority(ies), if required. The Interconnection Customer may request that any information so provided be subject to the confidentiality provisions of Article 22. If the Interconnection Customer has executed this LGIA, or any amendment thereto, the Interconnection Customer shall reasonably cooperate with the Participating TO and ISO with respect to such filing and to provide any information reasonably requested by the Participating TO or ISO needed to comply with applicable regulatory requirements.

3.2 **Agreement Subject to ISO Tariff**. The Interconnection Customer will comply with all applicable provisions of the ISO Tariff, including the LGIP.

3.3 **Relationship Between this LGIA and the ISO Tariff.** With regard to rights and obligations between the Participating TO and the Interconnection Customer, if and to the extent a matter is specifically addressed by a provision of this LGIA (including any appendices, schedules or other attachments to this LGIA), the provisions of this LGIA shall govern. If and to the extent a provision of this LGIA is inconsistent with the ISO Tariff and dictates rights and obligations between the ISO and the Participating TO or the ISO and the Interconnection Customer, the ISO Tariff shall govern.

3.4 **Relationship Between this LGIA and the QF PGA.** With regard to the rights and obligations of a Qualifying Facility that has entered into a QF PGA with the ISO and has entered into this LGIA, if and to the extent a matter is specifically addressed by a provision of the QF PGA that is inconsistent with this LGIA, the terms of the QF PGA shall govern.

ARTICLE 4. SCOPE OF SERVICE

4.1 **Interconnection Service.** Interconnection Service allows the Interconnection Customer to connect the Large Generating Facility to the Participating TO's Transmission System and be eligible to deliver the Large Generating Facility's output using the available capacity of the ISO Controlled Grid. To the extent the Interconnection Customer wants to receive Interconnection Service, the Participating TO shall construct facilities identified in Appendices A and C that the Participating TO is responsible to construct.

Interconnection Service does not necessarily provide the Interconnection Customer with the capability to physically deliver the output of its Large Generating Facility to any particular load on the ISO Controlled Grid without incurring congestion costs. In the event of transmission constraints on the ISO Controlled Grid, the Interconnection Customer's Large Generating Facility shall be subject to the applicable congestion management procedures in the ISO Tariff in the same manner as all other resources.

4.2 **Provision of Service**. The Participating TO and the ISO shall provide Interconnection Service for the Large Generating Facility.

4.3 **Performance Standards**. Each Party shall perform all of its obligations under this LGIA in accordance with Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice, and to the extent a Party is required or prevented or limited in taking any action by such regulations and standards, such Party shall not be deemed to be in Breach of this LGIA for its compliance therewith. If such Party is the ISO or Participating TO, then that Party shall amend the LGIA and submit the amendment to FERC for approval.

4.4 **No Transmission Service**. The execution of this LGIA does not constitute a request for, nor the provision of, any transmission service under the ISO Tariff, and does not convey any right to deliver electricity to any specific customer or point of delivery.

4.5 **Interconnection Customer Provided Services**. The services provided by Interconnection Customer under this LGIA are set forth in Article 9.6 and Article 13.5.1. Interconnection Customer shall be paid for such services in accordance with Article 11.6.

ARTICLE 5. INTERCONNECTION FACILITIES ENGINEERING, PROCUREMENT, AND CONSTRUCTION

Interconnection Facilities, Network Upgrades, and Distribution Upgrades shall be studied, designed, and constructed pursuant to Good Utility Practice. Such studies, design and construction shall be based on the assumed accuracy and completeness of all technical information received by the Participating TO and the ISO from the Interconnection Customer associated with interconnecting the Large Generating Facility.

5.1 **Options**. Unless otherwise mutually agreed among the Parties, the Interconnection Customer shall select the In-Service Date, Initial Synchronization Date, and Commercial Operation Date; and either Standard Option or Alternate Option set forth below for completion of the Participating TO's Interconnection Facilities and Network Upgrades as set forth in Part A, Interconnection Facilities, Network Upgrades, and Distribution Upgrades, and such dates and selected option shall be set forth in Part B, Milestones.

5.1.1 **Standard Option**. The Participating TO shall design, procure, and construct the Participating TO's Interconnection Facilities, Network Upgrades, and Distribution Upgrades, using Reasonable Efforts to complete the Participating TO's Interconnection Facilities, Network Upgrades, and Distribution Upgrades by the dates set forth in Part B, Milestones. The Participating TO shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, and Applicable Laws and Regulations. In the event the Participating TO reasonably expects that it will not be able to complete the Participating TO's Interconnection Facilities, Network Upgrades, and Distribution Upgrades by the specified dates, the Participating TO shall promptly provide written notice to the Interconnection Customer and the ISO and shall undertake Reasonable Efforts to meet the earliest dates thereafter.

5.1.2 **Alternate Option**. If the dates designated by the Interconnection Customer are acceptable to the Participating TO, the Participating TO shall so notify the Interconnection Customer within thirty (30) Calendar Days, and shall assume responsibility for the design, procurement and construction of the Participating TO's Interconnection Facilities by the designated dates.

If the Participating TO subsequently fails to complete the Participating TO's Interconnection Facilities by the In-Service Date, to the extent necessary to provide back feed power; or fails to complete Network Upgrades by the Initial Synchronization Date to the extent necessary to allow for Trial Operation at full power output, unless other arrangements are made by the Parties for such Trial Operation; or fails to complete the Network Upgrades by the Commercial Operation Date, as such dates are reflected in Part B, Milestones; the Participating TO shall pay the Interconnection Customer liquidated damages in accordance with Article 5.3, Liquidated Damages, provided, however, the dates designated by the Interconnection Customer shall be extended day for day for each day that the ISO refuses to grant clearances to install equipment.

5.1.3 **Option to Build**. If the dates designated by the Interconnection Customer are not acceptable to the Participating TO, the Participating TO shall so notify the Interconnection Customer within thirty (30) Calendar Days, and unless the Parties agree otherwise, the Interconnection Customer shall have the option to assume responsibility for the design, procurement and construction of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades. If the Interconnection Customer elects to exercise its option to assume responsibility for the design, procurement and construction of the Participating TO’s Interconnection Facilities and Stand Alone Network Upgrades, it shall so notify the Participating TO within thirty (30) Calendar Days of receipt of the Participating TO’s notification that the designated dates are not acceptable to the Participating TO. The Participating TO, ISO, and Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify such Stand Alone Network Upgrades in Part A to this LGIA. Except for Stand Alone Network Upgrades, the Interconnection Customer shall have no right to construct Network Upgrades under this option.

5.1.4 **Negotiated Option**. If the Interconnection Customer elects not to exercise its option under Article 5.1.3, Option to Build, the Interconnection Customer shall so notify the Participating TO within thirty (30) Calendar Days of receipt of the Participating TO’s notification that the designated dates are not acceptable to the Participating TO, and the Parties shall in good faith attempt to negotiate terms and conditions (including revision of the specified dates and liquidated damages, the provision of incentives or the procurement and construction of a portion of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades by the Interconnection Customer) pursuant to which the Participating TO is responsible for the design, procurement and construction of the Participating TO's Interconnection Facilities and Network Upgrades. If the Parties are unable to reach agreement on such terms and conditions, the Participating TO shall assume responsibility for the design, procurement and construction of the Participating TO's Interconnection Facilities and Network Upgrades pursuant to Article 5.1.1, Standard Option.

5.2 General Conditions Applicable to Option to Build. If the Interconnection Customer assumes responsibility for the design, procurement and construction of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades,

(1) the Interconnection Customer shall engineer, procure equipment, and construct the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades (or portions thereof) using Good Utility Practice and using standards and specifications provided in advance by the Participating TO;

(2) The Interconnection Customer's engineering, procurement and construction of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades shall comply with all requirements of law to which the Participating TO would be subject in the engineering, procurement or construction of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades;

(3) the Participating TO shall review, and the Interconnection Customer shall obtain the Participating TO's approval of, the engineering design, equipment acceptance tests, and the construction of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades, which approval shall not be unreasonably withheld, and the ISO may, at its option, review the engineering design, equipment acceptance tests, and the construction of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades;

(4) prior to commencement of construction, the Interconnection Customer shall provide to the Participating TO, with a copy to the ISO for informational purposes, a schedule for construction of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades, and shall promptly respond to requests for information from the Participating TO;

(5) at any time during construction, the Participating TO shall have the right to gain unrestricted access to the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades and to conduct inspections of the same;

(6) at any time during construction, should any phase of the engineering, equipment procurement, or construction of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades not meet the standards and specifications provided by the Participating TO, the Interconnection Customer shall be obligated to remedy deficiencies in that portion of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades;

(7) the Interconnection Customer shall indemnify the ISO and Participating TO for claims arising from the Interconnection Customer's construction of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades under the terms and procedures applicable to Article 18.1 Indemnity;

(8) The Interconnection Customer shall transfer control of the Participating TO's Interconnection Facilities to the Participating TO and shall transfer Operational Control of Stand Alone Network Upgrades to the ISO;

(9) Unless the Parties otherwise agree, the Interconnection Customer shall transfer ownership of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades to the Participating TO. As soon as reasonably practicable, but within twelve months after completion of the construction of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades, the Interconnection Customer shall provide an invoice of the final cost of the construction of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades to the Participating TO, which invoice shall set forth such costs in sufficient detail to enable the Participating TO to reflect the proper costs of such facilities in its transmission rate base and to identify the investment upon which refunds will be provided;

(10) the Participating TO shall accept for operation and maintenance the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades to the extent engineered, procured, and constructed in accordance with this Article 5.2; and

(11) The Interconnection Customer's engineering, procurement and construction of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades shall comply with all requirements of the "Option to Build" conditions set forth in Part C. Interconnection Customer shall deliver to the Participating TO "as-built" drawings, information, and any other documents that are reasonably required by the Participating TO to assure that the Interconnection Facilities and Stand-Alone Network Upgrades are built to the standards and specifications required by the Participating TO.

5.3 Liquidated Damages. The actual damages to the Interconnection Customer, in the event the Participating TO's Interconnection Facilities or Network Upgrades are not completed by the dates designated by the Interconnection Customer and accepted by the Participating TO pursuant to subparagraphs 5.1.2 or 5.1.4, above, may include Interconnection Customer's fixed operation and maintenance costs and lost opportunity costs. Such actual damages are uncertain and impossible to determine at this time. Because of such uncertainty, any liquidated damages paid by the Participating TO to the Interconnection Customer in the event that the Participating TO does not complete any portion of the Participating TO's Interconnection Facilities or Network Upgrades by the applicable dates, shall be an amount equal to ½ of 1 percent per day of the actual cost of the Participating TO's Interconnection Facilities and Network Upgrades, in the aggregate, for which the Participating TO has assumed responsibility to design, procure and construct.

However, in no event shall the total liquidated damages exceed 20 percent of the actual cost of the Participating TO's Interconnection Facilities and Network Upgrades for which the Participating TO has assumed responsibility to design, procure, and construct. The foregoing payments will be made by the Participating TO to the Interconnection Customer as just compensation for the damages caused to the Interconnection Customer, which actual damages are uncertain and impossible to determine at this time, and as reasonable liquidated damages, but not as a penalty or a method to secure performance of this LGIA. Liquidated damages, when the Parties agree to them, are the exclusive remedy for the Participating TO's failure to meet its schedule.

No liquidated damages shall be paid to the Interconnection Customer if: (1) the Interconnection Customer is not ready to commence use of the Participating TO's Interconnection Facilities or Network Upgrades to take the delivery of power for the Electric Generating Unit's Trial Operation or to export power from the Electric Generating Unit on the specified dates, unless the Interconnection Customer would have been able to commence use of the Participating TO's Interconnection Facilities or Network Upgrades to take the delivery of power for Electric Generating Unit's Trial Operation or to export power from the Electric Generating Unit, but for the Participating TO's delay; (2) the Participating TO's failure to meet the specified dates is the result of the action or inaction of the Interconnection Customer or any other interconnection customer who has entered into an interconnection agreement with the ISO and/or Participating TO, action or inaction by the ISO, or any cause beyond the Participating TO's reasonable control or reasonable ability to cure; (3) the Interconnection Customer has assumed responsibility for the design, procurement and construction of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades; or (4) the Parties have otherwise agreed.

In no event shall the ISO have any responsibility or liability to the Interconnection Customer for liquidated damages pursuant to the provisions of this Article 5.3.

5.4 **Power System Stabilizers**. The Interconnection Customer shall procure, install, maintain and operate Power System Stabilizers in accordance with the guidelines and procedures established by the Applicable Reliability Council and in accordance with the provisions of Section 5.4.1 of the ISO Tariff. The ISO reserves the right to establish reasonable minimum acceptable settings for any installed Power System Stabilizers, subject to the design and operating limitations of the Large Generating Facility. If the Large Generating Facility's Power System Stabilizers are removed from service or not capable of automatic operation, the Interconnection Customer shall immediately notify the ISO and the Participating TO and restore the Power System Stabilizers to operation as soon as possible and in accordance with the Reliability Management System Agreement in Part G. The ISO shall have the right to order the reduction in output or disconnection of the Large Generating Facility if the reliability of the ISO Controlled Grid would be adversely affected as a result of improperly tuned Power System Stabilizers. The requirements of this Article 5.4 shall not apply to wind generators of the induction type.

5.5 **Equipment Procurement**. If responsibility for construction of the Participating TO's Interconnection Facilities or Network Upgrades is to be borne by the Participating TO, then the Participating TO shall commence design of the Participating TO's Interconnection Facilities or Network Upgrades and procure necessary equipment as soon as practicable after all of the following conditions are satisfied, unless the Parties otherwise agree in writing:

5.5.1 The ISO, in coordination with the applicable Participating TO(s), has completed the Interconnection Facilities Study pursuant to the Interconnection Facilities Study Agreement;

5.5.2 The Participating TO has received written authorization to proceed with design and procurement from the Interconnection Customer by the date specified in Part B, Milestones; and

5.5.3 The Interconnection Customer has provided security to the Participating TO in accordance with Article 11.5 by the dates specified in Part B, Milestones.

5.6 **Construction Commencement**. The Participating TO shall commence construction of the Participating TO's Interconnection Facilities and Network Upgrades for which it is responsible as soon as practicable after the following additional conditions are satisfied:

5.6.1 Approval of the appropriate Governmental Authority has been obtained for any facilities requiring regulatory approval;

5.6.2 Necessary real property rights and rights-of-way have been obtained, to the extent required for the construction of a discrete aspect of the Participating TO's Interconnection Facilities and Network Upgrades;

5.6.3 The Participating TO has received written authorization to proceed with construction from the Interconnection Customer by the date specified in Part B, Milestones; and

5.6.4 The Interconnection Customer has provided payment and security to the Participating TO in accordance with Article 11.5 by the dates specified in Part B, Milestones.

5.7 **Work Progress**. The Parties will keep each other advised periodically as to the progress of their respective design, procurement and construction efforts. Any Party may, at any time, request a progress report from another Party. If, at any time, the Interconnection Customer determines that the completion of the Participating TO's Interconnection Facilities will not be required until after the specified in-service date, the Interconnection Customer will provide written notice to the Participating TO and ISO of such later date upon which the completion of the Participating TO's Interconnection Facilities will be required.

5.8 **Information Exchange**. As soon as reasonably practicable after the Effective Date, the Parties shall exchange information regarding the design and compatibility of the Interconnection Customer's Interconnection Facilities and Participating TO's Interconnection Facilities and compatibility of the Interconnection Facilities with the Participating TO's Transmission System, and shall work diligently and in good faith to make any necessary design changes.

5.9 **Limited Operation**. If any of the Participating TO's Interconnection Facilities or Network Upgrades are not reasonably expected to be completed prior to the Commercial Operation Date of the Electric Generating Unit, the Participating TO and/or ISO, as applicable, shall, upon the request and at the expense of the Interconnection Customer, perform operating studies on a timely basis to determine the extent to which the Electric Generating Unit and the Interconnection Customer's Interconnection Facilities may operate prior to the completion of the Participating TO's Interconnection Facilities or Network Upgrades consistent with Applicable Laws and Regulations, Applicable Reliability Standards, Good Utility Practice, and this LGIA. The Participating TO and ISO shall permit Interconnection Customer to operate the Electric Generating Unit and the Interconnection Customer's Interconnection Facilities in accordance with the results of such studies.

5.10 **Interconnection Customer's Interconnection Facilities**. The Interconnection Customer shall, at its expense, design, procure, construct, own and install the Interconnection Customer's Interconnection Facilities, as set forth in Part A.

5.10.1 **Large Generating Facility and Interconnection Customer's Interconnection Facilities Specifications**. The Interconnection Customer shall submit initial specifications for the Interconnection Customer's Interconnection Facilities and Large Generating Facility, including System Protection Facilities, to the Participating TO and the ISO at least one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date; and final specifications for review and comment at least ninety (90) Calendar Days prior to the Initial Synchronization Date. The Participating TO and the ISO shall review such specifications pursuant to this LGIA and the LGIP to ensure that the Interconnection Customer's Interconnection Facilities and Large Generating Facility are compatible with the technical specifications, operational control, safety requirements, and any other applicable requirements of the Participating TO and the ISO and comment on such specifications within thirty (30) Calendar Days of the Interconnection Customer's submission. All specifications provided hereunder shall be deemed confidential.

5.10.2 Participating TO's and ISO's Review. The Participating TO's and the ISO's review of the Interconnection Customer's final specifications shall not be construed as confirming, endorsing, or providing a warranty as to the design, fitness, safety, durability or reliability of the Large Generating Facility, or the Interconnection Customer's Interconnection Facilities. Interconnection Customer shall make such changes to the Interconnection Customer's Interconnection Facilities as may reasonably be required by the Participating TO or the ISO, in accordance with Good Utility Practice, to ensure that the Interconnection Customer's Interconnection Facilities are compatible with the technical specifications, Operational Control, and safety requirements of the Participating TO or the ISO.

5.10.3 Interconnection Customer's Interconnection Facilities Construction. The Interconnection Customer's Interconnection Facilities shall be designed and constructed in accordance with Good Utility Practice. Within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Participating TO and Interconnection Customer agree on another mutually acceptable deadline, the Interconnection Customer shall deliver to the Participating TO and ISO "as-built" drawings, information and documents for the Interconnection Customer's Interconnection Facilities and the Electric Generating Unit(s), such as: a one-line diagram, a site plan showing the Large Generating Facility and the Interconnection Customer's Interconnection Facilities, plan and elevation drawings showing the layout of the Interconnection Customer's Interconnection Facilities, a relay functional diagram, relaying AC and DC schematic wiring diagrams and relay settings for all facilities associated with the Interconnection Customer's step-up transformers, the facilities connecting the Large Generating Facility to the step-up transformers and the Interconnection Customer's Interconnection Facilities, and the impedances (determined by factory tests) for the associated step-up transformers and the Electric Generating Units. The Interconnection Customer shall provide the Participating TO and the ISO specifications for the excitation system, automatic voltage regulator, Large Generating Facility control and protection settings, transformer tap settings, and communications, if applicable. Any deviations from the relay settings, machine specifications, and other specifications originally submitted by the Interconnection Customer shall be assessed by the Participating TO and the ISO pursuant to the appropriate provisions of this LGIA and the LGIP.

5.10.4 Interconnection Customer to Meet Requirements of the Participating TO's Interconnection Handbook. The Interconnection Customer shall comply with the Participating TO's Interconnection Handbook.

5.11 Participating TO's Interconnection Facilities Construction. The Participating TO's Interconnection Facilities shall be designed and constructed in accordance with Good Utility Practice. Upon request, within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Participating TO and Interconnection Customer agree on another mutually acceptable deadline, the Participating TO shall deliver to the Interconnection Customer and the ISO the following "as-built" drawings, information and documents for the Participating TO's Interconnection Facilities.

The Participating TO will obtain control for operating and maintenance purposes of the Participating TO's Interconnection Facilities and Stand Alone Network Upgrades upon completion of such facilities. Pursuant to Article 5.2, the ISO will obtain Operational Control of the Stand Alone Network Upgrades prior to the Commercial Operation Date.

5.12 Access Rights. Upon reasonable notice and supervision by a Party, and subject to any required or necessary regulatory approvals, a Party ("Granting Party") shall furnish *at no cost* to the other Party ("Access Party") any rights of use, licenses, rights of way and easements with respect to lands owned or controlled by the Granting Party, its agents (if allowed under the applicable agency agreement), or any Affiliate, that are necessary to enable the Access Party to obtain ingress and egress to construct, operate, maintain, repair, test (or witness testing), inspect, replace or remove facilities and equipment to: (i) interconnect the Large Generating Facility with the Participating TO's Transmission System; (ii) operate and maintain the Large Generating Facility, the Interconnection Facilities and the Participating TO's Transmission System; and (iii) disconnect or remove the Access Party's facilities and equipment upon termination of this LGIA. In exercising such licenses, rights of way and easements, the Access Party shall not unreasonably disrupt or interfere with normal operation of the Granting Party's business and shall adhere to the safety rules and procedures established in advance, as may be changed from time to time, by the Granting Party and provided to the Access Party.

5.13 Lands of Other Property Owners. If any part of the Participating TO's Interconnection Facilities and/or Network Upgrades are to be installed on property owned by persons other than the Interconnection Customer or Participating TO, the Participating TO shall at the Interconnection Customer's expense use efforts, similar in nature and extent to those that it typically undertakes on its own behalf or on behalf of its Affiliates, including use of its eminent domain authority, and to the extent consistent with state law, to procure from such persons any rights of use, licenses, rights of way and easements that are necessary to construct, operate, maintain, test, inspect, replace or remove the Participating TO's Interconnection Facilities and/or Network Upgrades upon such property.

5.14 Permits. Participating TO and Interconnection Customer shall cooperate with each other in good faith in obtaining all permits, licenses and authorization that are necessary to accomplish the interconnection in compliance with Applicable Laws and Regulations. With respect to this paragraph, the Participating TO shall provide permitting assistance to the Interconnection Customer comparable to that provided to the Participating TO's own, or an Affiliate's generation.

5.15 Early Construction of Base Case Facilities. The Interconnection Customer may request the Participating TO to construct, and the Participating TO shall construct, using Reasonable Efforts to accommodate Interconnection Customer's In-Service Date, all or any portion of any Network Upgrades required for Interconnection Customer to be interconnected to the Participating TO's Transmission System which are included in the Base Case of the Interconnection Studies for the Interconnection Customer, and which also are required to be constructed for another interconnection customer, but where such construction is not scheduled to be completed in time to achieve Interconnection Customer's In-Service Date.

5.16 Suspension. The Interconnection Customer reserves the right, upon written notice to the Participating TO and the ISO, to suspend at any time all work associated with the construction and installation of the Participating TO's Interconnection Facilities, Network Upgrades, and/or Distribution Upgrades required under this LGIA with the condition that the Participating TO's electrical system and the ISO Controlled Grid shall be left in a safe and reliable condition in accordance with Good Utility Practice and the Participating TO's safety and reliability criteria and the ISO's Applicable Reliability Standards. In such event, the Interconnection Customer shall be responsible for all reasonable and necessary costs which the Participating TO (i) has incurred pursuant to this LGIA prior to the suspension and (ii) incurs in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the Participating TO's electric system during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which the Participating TO cannot reasonably avoid; provided, however, that prior to canceling or suspending any such material, equipment or labor contract, the Participating TO shall obtain Interconnection Customer's authorization to do so.

The Participating TO shall invoice the Interconnection Customer for such costs pursuant to Article 12 and shall use due diligence to minimize its costs. In the event Interconnection Customer suspends work required under this LGIA pursuant to this Article 5.16, and has not requested the Participating TO to recommence the work or has not itself recommenced work required under this LGIA on or before the expiration of three (3) years following commencement of such suspension, this LGIA shall be deemed terminated. The three-year period shall begin on the date the suspension is requested, or the date of the written notice to the Participating TO and the ISO, if no effective date is specified.

5.17 Taxes.

5.17.1 Interconnection Customer Payments Not Taxable. The Parties intend that all payments or property transfers made by the Interconnection Customer to the Participating TO for the installation of the Participating TO's Interconnection Facilities and the Network Upgrades shall be non-taxable, either as contributions to capital, or as a refundable advance, in accordance with the Internal Revenue Code and any applicable state income tax laws and shall not be taxable as contributions in aid of construction or otherwise under the Internal Revenue Code and any applicable state income tax laws.

5.17.2 Representations And Covenants. In accordance with IRS Notice 2001-82 and IRS Notice 88-129, the Interconnection Customer represents and covenants that (i) ownership of the electricity generated at the Large Generating Facility will pass to another party prior to the transmission of the electricity on the ISO Controlled Grid, (ii) for income tax purposes, the amount of any payments and the cost of any property transferred to the Participating TO for the Participating TO's Interconnection Facilities will be capitalized by the Interconnection Customer as an intangible asset and recovered using the straight-line method over a useful life of twenty (20) years, and (iii) any portion of the Participating TO's Interconnection Facilities that is a “dual-use intertie,” within the meaning of IRS Notice 88-129, is reasonably expected to carry only a de minimis amount of electricity in the direction of the Large Generating Facility. For this purpose, “de minimis amount” means no more than 5 percent of the total power flows in both directions, calculated in accordance with the “5 percent test” set forth in IRS Notice 88-129. This is not intended to be an exclusive list of the relevant conditions that must be met to conform to IRS requirements for non-taxable treatment.

At the Participating TO’s request, the Interconnection Customer shall provide the Participating TO with a report from an independent engineer confirming its representation in clause (iii), above. The Participating TO represents and covenants that the cost of the Participating TO's Interconnection Facilities paid for by the Interconnection Customer without the possibility of refund or credit will have no net effect on the base upon which rates are determined.

5.17.3 Indemnification for the Cost Consequence of Current Tax Liability Imposed Upon the Participating TO. Notwithstanding Article 5.17.1, the Interconnection Customer shall protect, indemnify and hold harmless the Participating TO from the cost consequences of any current tax liability imposed against the Participating TO as the result of payments or property transfers made by the Interconnection Customer to the Participating TO under this LGIA for Interconnection Facilities, as well as any interest and penalties, other than interest and penalties attributable to any delay caused by the Participating TO.

The Participating TO shall not include a gross-up for the cost consequences of any current tax liability in the amounts it charges the Interconnection Customer under this LGIA unless (i) the Participating TO has determined, in good faith, that the payments or property transfers made by the Interconnection Customer to the Participating TO should be reported as income subject to taxation or (ii) any Governmental Authority directs the Participating TO to report payments or property as income subject to taxation; provided, however, that the Participating TO may require the Interconnection Customer to provide security for Interconnection Facilities, in a form reasonably acceptable to the Participating TO (such as a parental guarantee or a letter of credit), in an amount equal to the cost consequences of any current tax liability under this Article 5.17. The Interconnection Customer shall reimburse the Participating TO for such costs on a fully grossed-up basis, in accordance with Article 5.17.4, within thirty (30) Calendar Days of receiving written notification from the Participating TO of the amount due, including detail about how the amount was calculated.

The indemnification obligation shall terminate at the earlier of (1) the expiration of the ten year testing period and the applicable statute of limitation, as it may be extended by the Participating TO upon request of the IRS, to keep these years open for audit or adjustment, or (2) the occurrence of a subsequent taxable event and the payment of any related indemnification obligations as contemplated by this Article 5.17.

5.17.4 Tax Gross-Up Amount. The Interconnection Customer's liability for the cost consequences of any current tax liability under this Article 5.17 shall be calculated on a fully grossed-up basis. Except as may otherwise be agreed to by the parties, this means that the Interconnection Customer will pay the Participating TO, in addition to the amount paid for the Interconnection Facilities and Network Upgrades, an amount equal to (1) the current taxes imposed on the Participating TO ("Current Taxes") on the excess of (a) the gross income realized by the Participating TO as a result of payments or property transfers made by the Interconnection Customer to the Participating TO under this LGIA (without regard to any payments under this Article 5.17) (the "Gross Income Amount") over (b) the present value of future tax deductions for depreciation that will be available as a result of such payments or property transfers (the "Present Value Depreciation Amount"), plus (2) an additional amount sufficient to permit the Participating TO to receive and retain, after the payment of all Current Taxes, an amount equal to the net amount described in clause (1).

For this purpose, (i) Current Taxes shall be computed based on the Participating TO's composite federal and state tax rates at the time the payments or property transfers are received and the Participating TO will be treated as being subject to tax at the highest marginal rates in effect at that time (the "Current Tax Rate"), and (ii) the Present Value Depreciation Amount shall be computed by discounting the Participating TO's anticipated tax depreciation deductions as a result of such payments or property transfers by the Participating TO's current weighted average cost of capital. Thus, the formula for calculating the Interconnection Customer's liability to the Participating TO pursuant to this Article 5.17.4 can be expressed as follows: (Current Tax Rate x (Gross Income Amount – Present Value of Tax Depreciation))/(1-Current Tax Rate). Interconnection Customer's estimated tax liability in the event taxes are imposed shall be stated in Part A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

5.17.5 Private Letter Ruling or Change or Clarification of Law. At the Interconnection Customer's request and expense, the Participating TO shall file with the IRS a request for a private letter ruling as to whether any property transferred or sums paid, or to be paid, by the Interconnection Customer to the Participating TO under this LGIA are subject to federal income taxation. The Interconnection Customer will prepare the initial draft of the request for a private letter ruling, and will certify under penalties of perjury that all facts represented in such request are true and accurate to the best of the Interconnection Customer's knowledge. The Participating TO and Interconnection Customer shall cooperate in good faith with respect to the submission of such request, provided, however, the Interconnection Customer and the Participating TO explicitly acknowledge (and nothing herein is intended to alter) Participating TO's obligation under law to certify that the facts presented in the ruling request are true, correct and complete.

The Participating TO shall keep the Interconnection Customer fully informed of the status of such request for a private letter ruling and shall execute either a privacy act waiver or a limited power of attorney, in a form acceptable to the IRS, that authorizes the Interconnection Customer to participate in all discussions with the IRS regarding such request for a private letter ruling. The Participating TO shall allow the Interconnection Customer to attend all meetings with IRS officials about the request and shall permit the Interconnection Customer to prepare the initial drafts of any follow-up letters in connection with the request.

5.17.6 Subsequent Taxable Events. If, within 10 years from the date on which the relevant Participating TO's Interconnection Facilities are placed in service, (i) the Interconnection Customer Breaches the covenants contained in Article 5.17.2, (ii) a "disqualification event" occurs within the meaning of IRS Notice 88-129, or (iii) this LGIA terminates and the Participating TO retains ownership of the Interconnection Facilities and Network Upgrades, the Interconnection Customer shall pay a tax gross-up for the cost consequences of any current tax liability imposed on the Participating TO, calculated using the methodology described in Article 5.17.4 and in accordance with IRS Notice 90-60.

5.17.7 Contests. In the event any Governmental Authority determines that the Participating TO's receipt of payments or property constitutes income that is subject to taxation, the Participating TO shall notify the Interconnection Customer, in writing, within thirty (30) Calendar Days of receiving notification of such determination by a Governmental Authority. Upon the timely written request by the Interconnection Customer and at the Interconnection Customer's sole expense, the Participating TO may appeal, protest, seek abatement of, or otherwise oppose such determination. Upon the Interconnection Customer's written request and sole expense, the Participating TO may file a claim for refund with respect to any taxes paid under this Article 5.17, whether or not it has received such a determination. The Participating TO reserve the right to make all decisions with regard to the prosecution of such appeal, protest, abatement or other contest, including the selection of counsel and compromise or settlement of the claim, but the Participating TO shall keep the Interconnection Customer informed, shall consider in good faith suggestions from the Interconnection Customer about the conduct of the contest, and shall reasonably permit the Interconnection Customer or an Interconnection Customer representative to attend contest proceedings.

The Interconnection Customer shall pay to the Participating TO on a periodic basis, as invoiced by the Participating TO, the Participating TO's documented reasonable costs of prosecuting such appeal, protest, abatement or other contest, including any costs associated with obtaining the opinion of independent tax counsel described in this Article 5.17.7. The Participating TO may abandon any contest if the Interconnection Customer fails to provide payment to the Participating TO within thirty (30) Calendar Days of receiving such invoice.

At any time during the contest, the Participating TO may agree to a settlement either with the Interconnection Customer's consent or, if such consent is refused, after obtaining written advice from independent nationally-recognized tax counsel, selected by the Participating TO, but reasonably acceptable to the Interconnection Customer, that the proposed settlement represents a reasonable settlement given the hazards of litigation. The Interconnection Customer's obligation shall be based on the amount of the settlement agreed to by the Interconnection Customer, or if a higher amount, so much of the settlement that is supported by the written advice from nationally-recognized tax counsel selected under the terms of the preceding paragraph. The settlement amount shall be calculated on a fully grossed-up basis to cover any related cost consequences of the current tax liability. The Participating TO may also settle any tax controversy without receiving the Interconnection Customer's consent or any such written advice; however, any such settlement will relieve the Interconnection Customer from any obligation to indemnify the Participating TO for the tax at issue in the contest (unless the failure to obtain written advice is attributable to the Interconnection Customer's unreasonable refusal to the appointment of independent tax counsel).

5.17.8 Refund. In the event that (a) a private letter ruling is issued to the Participating TO which holds that any amount paid or the value of any property transferred by the Interconnection Customer to the Participating TO under the terms of this LGIA is not subject to federal income taxation, (b) any legislative change or administrative announcement, notice, ruling or other determination makes it reasonably clear to the Participating TO in good faith that any amount paid or the value of any property transferred by the Interconnection Customer to the Participating TO under the terms of this LGIA is not taxable to the Participating TO, (c) any abatement, appeal, protest, or other contest results in a determination that any payments or transfers made by the Interconnection Customer to the Participating TO are not subject to federal income tax, or (d) if the Participating TO receives a refund from any taxing authority for any overpayment of tax attributable to any payment or property transfer made by the Interconnection Customer to the Participating TO pursuant to this LGIA, the Participating TO shall promptly refund to the Interconnection Customer the following:

(i) any payment made by Interconnection Customer under this Article 5.17 for taxes that is attributable to the amount determined to be non-taxable, together with interest thereon,

(ii) interest on any amounts paid by the Interconnection Customer to the Participating TO for such taxes which the Participating TO did not submit to the taxing authority, calculated in accordance with the methodology set forth in FERC's regulations at 18 C.F.R. §35.19a(a)(2)(iii) from the date payment was made by the Interconnection Customer to the date the Participating TO refunds such payment to the Interconnection Customer, and

(iii) with respect to any such taxes paid by the Participating TO, any refund or credit the Participating TO receives or to which it may be entitled from any Governmental Authority, interest (or that portion thereof attributable to the payment described in clause (i), above) owed to the Participating TO for such overpayment of taxes (including any reduction in interest otherwise payable by the Participating TO to any Governmental Authority resulting from an offset or credit); provided, however, that the Participating TO will remit such amount promptly to the Interconnection Customer only after and to the extent that the Participating TO has received a tax refund, credit or offset from any Governmental Authority for any applicable overpayment of income tax related to the Participating TO's Interconnection Facilities.

The intent of this provision is to leave the Parties, to the extent practicable, in the event that no taxes are due with respect to any payment for Interconnection Facilities and Network Upgrades hereunder, in the same position they would have been in had no such tax payments been made.

5.17.9 Taxes Other Than Income Taxes. Upon the timely request by the Interconnection Customer, and at the Interconnection Customer's sole expense, the ISO or Participating TO may appeal, protest, seek abatement of, or otherwise contest any tax (other than federal or state income tax) asserted or assessed against the ISO or Participating TO for which the Interconnection Customer may be required to reimburse the ISO or Participating TO under the terms of this LGIA. The Interconnection Customer shall pay to the Participating TO on a periodic basis, as invoiced by the Participating TO, the Participating TO's documented reasonable costs of prosecuting such appeal, protest, abatement, or other contest. The Interconnection Customer, the ISO, and the Participating TO shall cooperate in good faith with respect to any such contest. Unless the payment of such taxes is a prerequisite to an appeal or abatement or cannot be deferred, no amount shall be payable by the Interconnection Customer to the ISO or Participating TO for such taxes until they are assessed by a final, non-appealable order by any court or agency of competent jurisdiction. In the event that a tax payment is withheld and ultimately due and payable after appeal, the Interconnection Customer will be responsible for all taxes, interest and penalties, other than penalties attributable to any delay caused by the Participating TO.

5.18 Tax Status. Each Party shall cooperate with the others to maintain the other Parties' tax status. Nothing in this LGIA is intended to adversely affect the ISO's or any Participating TO's tax exempt status with respect to the issuance of bonds including, but not limited to, Local Furnishing Bonds.

5.19 Modification.

5.19.1 General. The Interconnection Customer or the Participating TO may undertake modifications to its facilities, subject to the provisions of this LGIA and the ISO Tariff. If a Party plans to undertake a modification that reasonably may be expected to affect the other Parties' facilities, that Party shall provide to the other Parties sufficient information regarding such modification so that the other Parties may evaluate the potential impact of such modification prior to commencement of the work. Such information shall be deemed to be confidential hereunder and shall include information concerning the timing of such modifications and whether such modifications are expected to interrupt the flow of electricity from the Large Generating Facility. The Party desiring to perform such work shall provide the relevant drawings, plans, and specifications to the other Parties at least ninety (90) Calendar Days in advance of the commencement of the work or such shorter period upon which the Parties may agree, which agreement shall not unreasonably be withheld, conditioned or delayed.

In the case of Large Generating Facility modifications that do not require the Interconnection Customer to submit an Interconnection Request, the ISO or Participating TO shall provide, within thirty (30) Calendar Days (or such other time as the Parties may agree), an estimate of any additional modifications to the ISO Controlled Grid, Participating TO's Interconnection Facilities, Network Upgrades or Distribution Upgrades necessitated by such Interconnection Customer modification and a good faith estimate of the costs thereof. The Participating TO and the ISO shall determine if a Large Generating Facility modification is a Material Modification in accordance with the LGIP.

5.19.2 Standards. Any additions, modifications, or replacements made to a Party's facilities shall be designed, constructed and operated in accordance with this LGIA and Good Utility Practice.

5.19.3 Modification Costs. The Interconnection Customer shall not be directly assigned the costs of any additions, modifications, or replacements that the Participating TO makes to the Participating TO's Interconnection Facilities or the Participating TO's Transmission System to facilitate the interconnection of a third party to the Participating TO's Interconnection Facilities or the Participating TO's Transmission System, or to provide transmission service to a third party under the ISO Tariff. The Interconnection Customer shall be responsible for the costs of any additions, modifications, or replacements to the Interconnection Facilities that may be necessary to maintain or upgrade such Interconnection Facilities consistent with Applicable Laws and Regulations, Applicable Reliability Standards or Good Utility Practice.

ARTICLE 6. TESTING AND INSPECTION

6.1 Pre-Commercial Operation Date Testing and Modifications. Prior to the Commercial Operation Date, the Participating TO shall test the Participating TO's Interconnection Facilities, Network Upgrades, and Distribution Upgrades and the Interconnection Customer shall test the Large Generating Facility and the Interconnection Customer's Interconnection Facilities to ensure their safe and reliable operation. Similar testing may be required after initial operation. Each Party shall make any modifications to its facilities that are found to be necessary as a result of such testing. The Interconnection Customer shall bear the cost of all such testing and modifications. The Interconnection Customer shall not commence initial parallel operation of an Electric Generating Unit with the Participating TO's Transmission System until the Participating TO provides prior written approval, which approval shall not be unreasonably withheld, for operation of such Electric Generating Unit. The Interconnection Customer shall generate test energy at the Large Generating Facility only if it has arranged for the delivery of such test energy.

6.2 Post-Commercial Operation Date Testing and Modifications. Each Party shall at its own expense perform routine inspection and testing of its facilities and equipment in accordance with Good Utility Practice as may be necessary to ensure the continued interconnection of the Large Generating Facility with the Participating TO's Transmission System in a safe and reliable manner. Each Party shall have the right, upon advance written notice, to require reasonable additional testing of the other Party's facilities, at the requesting Party's expense, as may be in accordance with Good Utility Practice.

6.3 Right to Observe Testing. Each Party shall notify the other Parties at least fourteen (14) days in advance of its performance of tests of its Interconnection Facilities or Generating Facility. The other Parties have the right, at their own expense, to observe such testing.

6.4 **Right to Inspect**. Each Party shall have the right, but shall have no obligation to: (i) observe another Party's tests and/or inspection of any of its System Protection Facilities and other protective equipment, including Power System Stabilizers; (ii) review the settings of another Party's System Protection Facilities and other protective equipment; and (iii) review another Party's maintenance records relative to the Interconnection Facilities, the System Protection Facilities and other protective equipment. A Party may exercise these rights from time to time as it deems necessary upon reasonable notice to the other Party. The exercise or non-exercise by a Party of any such rights shall not be construed as an endorsement or confirmation of any element or condition of the Interconnection Facilities or the System Protection Facilities or other protective equipment or the operation thereof, or as a warranty as to the fitness, safety, desirability, or reliability of same. Any information that a Party obtains through the exercise of any of its rights under this Article 6.4 shall be deemed to be Confidential Information and treated pursuant to Article 22 of this LGIA.

ARTICLE 7. METERING

7.1 **General.** Each Party shall comply with the Applicable Reliability Council requirements. The Interconnection Customer and ISO shall comply with the provisions of the ISO Tariff regarding metering, including Section 10 and the Metering Protocol of the ISO Tariff. Unless otherwise agreed by the Participating TO and the Interconnection Customer, the Participating TO may install additional Metering Equipment at the Point of Interconnection prior to any operation of any Electric Generating Unit and shall own, operate, test and maintain such Metering Equipment. Power flows to and from the Large Generating Facility shall be measured at or, at the ISO's or Participating TO's option for its respective Metering Equipment, compensated to, the Point of Interconnection. The ISO shall provide metering quantities to the Interconnection Customer upon request in accordance with the ISO Tariff by directly polling the ISO's meter data acquisition system. The Interconnection Customer shall bear all reasonable documented costs associated with the purchase, installation, operation, testing and maintenance of the Metering Equipment.

7.2 **Check Meters**. The Interconnection Customer, at its option and expense, may install and operate, on its premises and on its side of the Point of Interconnection, one or more check meters to check the ISO-polled meters or the Participating TO's meters. Such check meters shall be for check purposes only and shall not be used for the measurement of power flows for purposes of this LGIA, except in the case that no other means are available on a temporary basis at the option of the ISO or the Participating TO. The check meters shall be subject at all reasonable times to inspection and examination by the ISO or Participating TO or their designees. The installation, operation and maintenance thereof shall be performed entirely by the Interconnection Customer in accordance with Good Utility Practice.

7.3 **Participating TO Retail Metering**. The Participating TO may install retail revenue quality meters and associated equipment, pursuant to the Participating TO's applicable retail tariffs.

ARTICLE 8. COMMUNICATIONS

8.1 Interconnection Customer Obligations. The Interconnection Customer shall maintain satisfactory operating communications with the ISO in accordance with the provisions of the ISO Tariff and with the Participating TO's dispatcher or representative designated by the Participating TO. The Interconnection Customer shall provide standard voice line, dedicated voice line and facsimile communications at its Large Generating Facility control room or central dispatch facility through use of either the public telephone system, or a voice communications system that does not rely on the public telephone system. The Interconnection Customer shall also provide the dedicated data circuit(s) necessary to provide Interconnection Customer data to the ISO and Participating TO as set forth in Part D, Security Arrangements Details. The data circuit(s) shall extend from the Large Generating Facility to the location(s) specified by the ISO and Participating TO. Any required maintenance of such communications equipment shall be performed by the Interconnection Customer. Operational communications shall be activated and maintained under, but not be limited to, the following events: system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances, and hourly and daily load data.

8.2 Remote Terminal Unit. Prior to the Initial Synchronization Date of each Electric Generating Unit, a Remote Terminal Unit, or equivalent data collection and transfer equipment acceptable to the Parties, shall be installed by the Interconnection Customer, or by the Participating TO at the Interconnection Customer's expense, to gather accumulated and instantaneous data to be telemetered to the location(s) designated by the ISO and by the Participating TO through use of a dedicated point-to-point data circuit(s) as indicated in Article 8.1.

Telemetry to the ISO shall be provided in accordance with the ISO's technical standards for direct telemetry. For telemetry to the Participating TO, the communication protocol for the data circuit(s) shall be specified by the Participating TO. Instantaneous bi-directional real power and reactive power flow and any other required information must be telemetered directly to the location(s) specified by the Participating TO.

Each Party will promptly advise the other Parties if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the attention and/or correction by another Party. The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

8.3 No Annexation. Any and all equipment placed on the premises of a Party shall be and remain the property of the Party providing such equipment regardless of the mode and manner of annexation or attachment to real property, unless otherwise mutually agreed by the Parties.

ARTICLE 9. OPERATIONS

9.1 General. Each Party shall comply with the Applicable Reliability Council requirements, and the Interconnection Customer shall execute the Reliability Management System Agreement of the Applicable Reliability Council attached hereto as Part G. Each Party shall provide to the other Party all information that may reasonably be required by the other Party to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

9.2 Control Area Notification. At least three months before Initial Synchronization Date, the Interconnection Customer shall notify the ISO and Participating TO in writing of the Control Area in which the Large Generating Facility intends to be located. If the Interconnection Customer intends to locate the Large Generating Facility in a Control Area other than the Control Area within whose electrically metered boundaries the Large Generating Facility is located, and if permitted to do so by the relevant transmission tariffs, all necessary arrangements, including but not limited to those set forth in Article 7 and Article 8 of this LGIA, and remote Control Area generator interchange agreements, if applicable, and the appropriate measures under such agreements, shall be executed and implemented prior to the placement of the Large Generating Facility in the other Control Area.

9.3 ISO and Participating TO Obligations. The ISO and Participating TO shall cause the Participating TO's Transmission System to be operated and controlled in a safe and reliable manner and in accordance with this LGIA. The Participating TO at the Interconnection Customer's expense shall cause the Participating TO's Interconnection Facilities to be operated, maintained and controlled in a safe and reliable manner and in accordance with this LGIA. The ISO and Participating TO may provide operating instructions to the Interconnection Customer consistent with this LGIA and Participating TO and ISO operating protocols and procedures as they may change from time to time. The Participating TO and ISO will consider changes to their operating protocols and procedures proposed by the Interconnection Customer.

9.4 Interconnection Customer Obligations. The Interconnection Customer shall at its own expense operate, maintain and control the Large Generating Facility and the Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA. The Interconnection Customer shall operate the Large Generating Facility and the Interconnection Customer's Interconnection Facilities in accordance with all applicable requirements of the Control Area of which it is part, including such requirements as set forth in Part C, Interconnection Details, of this LGIA. Part C, Interconnection Details, will be modified to reflect changes to the requirements as they may change from time to time. A Party may request that another Party provide copies of the requirements set forth in Part C, Interconnection Details, of this LGIA. The Interconnection Customer shall not commence Commercial Operation of an Electric Generating Unit with the Participating TO's Transmission System until the Participating TO provides prior written approval, which approval shall not be unreasonably withheld, for operation of such Electric Generating Unit.

9.5 Start-Up and Synchronization. Consistent with the Parties' mutually acceptable procedures, the Interconnection Customer is responsible for the proper synchronization of each Electric Generating Unit to the ISO Controlled Grid.

9.6 Reactive Power.

9.6.1 Power Factor Design Criteria. The Interconnection Customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the terminals of the Electric Generating Unit at a power factor within the range of 0.95 leading to 0.90 lagging, unless the ISO has established different requirements that apply to all generators in the Control Area on a comparable basis. Power factor design criteria for wind generators are provided in Part H of this LGIA.

9.6.2 Voltage Schedules. Once the Interconnection Customer has synchronized an Electric Generating Unit with the ISO Controlled Grid, the ISO or Participating TO shall require the Interconnection Customer to maintain a voltage schedule by operating the Electric Generating Unit to produce or absorb reactive power within the design limitations of the Electric Generating Unit set forth in Article 9.6.1 (Power Factor Design Criteria). ISO's voltage schedules shall treat all sources of reactive power in the Control Area in an equitable and not unduly discriminatory manner. The Participating TO shall exercise Reasonable Efforts to provide the Interconnection Customer with such schedules at least one (1) day in advance, and the ISO or Participating TO may make changes to such schedules as necessary to maintain the reliability of the ISO Controlled Grid or the Participating TO's electric system. The Interconnection Customer shall operate the Electric Generating Unit to maintain the specified output voltage or power factor within the design limitations of the Electric Generating Unit set forth in Article 9.6.1 (Power Factor Design Criteria), and as may be required by the ISO to operate the Electric Generating Unit at a specific voltage schedule within the design limitations set forth in Article 9.6.1. If the Interconnection Customer is unable to maintain the specified voltage or power factor, it shall promptly notify the ISO and the Participating TO.

9.6.2.1 Governors and Regulators. Whenever an Electric Generating Unit is operated in parallel with the ISO Controlled Grid and the speed governors (if installed on the Electric Generating Unit pursuant to Good Utility Practice) and voltage regulators are capable of operation, the Interconnection Customer shall operate the Electric Generating Unit with its speed governors and voltage regulators in automatic operation. If the Electric Generating Unit's speed governors and voltage regulators are not capable of such automatic operation, the Interconnection Customer shall immediately notify the ISO and the Participating TO and ensure that the Electric Generating Unit operates as specified in Article 9.6.2 through manual operation and that such Electric Generating Unit's reactive power production or absorption (measured in MVARs) are within the design capability of the Electric Generating Unit(s) and steady state stability limits. The Interconnection Customer shall restore the speed governors and voltage regulators to automatic operation as soon as possible and in accordance with the Reliability Management System Agreement in Part G. If the Large Generating Facility's speed governors and voltage regulators are improperly tuned or malfunctioning, the ISO shall have the right to order the reduction in output or disconnection of the Large Generating Facility if the reliability of the ISO Controlled Grid would be adversely affected. The Interconnection Customer shall not cause its Large Generating Facility to disconnect automatically or instantaneously from the ISO Controlled Grid or trip any Electric Generating Unit comprising the Large Generating Facility for an under or over frequency condition unless the abnormal frequency condition persists for a time period beyond the limits set forth in ANSI/IEEE Standard C37.106, or such other standard as applied to other generators in the Control Area on a comparable basis.

9.6.3 Payment for Reactive Power. ISO is required to pay the Interconnection Customer for reactive power that Interconnection Customer provides or absorbs from an Electric Generating Unit when the ISO requests the Interconnection Customer to operate its Electric Generating Unit outside the range specified in Article 9.6.1, provided that if the ISO pays other generators for reactive power service within the specified range, it must also pay the Interconnection Customer. Payments shall be pursuant to Article 11.6 or such other agreement to which the ISO and Interconnection Customer have otherwise agreed.

9.7 Outages and Interruptions.

9.7.1 Outages.

9.7.1.1 Outage Authority and Coordination. Each Party may in accordance with Good Utility Practice in coordination with the other Parties remove from service any of its respective Interconnection Facilities or Network Upgrades that may impact another Party's facilities as necessary to perform maintenance or testing or to install or replace equipment. Absent an Emergency Condition, the Party scheduling a removal of such facility(ies) from service will use Reasonable Efforts to schedule such removal on a date and time mutually acceptable to all Parties. In all circumstances any Party planning to remove such facility(ies) from service shall use Reasonable Efforts to minimize the effect on the other Parties of such removal.

9.7.1.2 Outage Schedules. The ISO shall post scheduled outages of ISO Controlled Grid facilities in accordance with the provisions of the ISO Tariff. The Interconnection Customer shall submit its planned maintenance schedules for the Large Generating Facility to the ISO in accordance with the ISO Tariff. The Interconnection Customer shall update its planned maintenance schedules in accordance with the ISO Tariff. The ISO may request the Interconnection Customer to reschedule its maintenance as necessary to maintain the reliability of the ISO Controlled Grid in accordance with the ISO Tariff. Such planned maintenance schedules and updates and changes to such schedules shall be provided by the Interconnection Customer to the Participating TO concurrently with their submittal to the ISO. The ISO shall compensate the Interconnection Customer for any additional direct costs that the Interconnection Customer incurs as a result of having to reschedule maintenance in accordance with the ISO Tariff. The Interconnection Customer will not be eligible to receive compensation, if during the twelve (12) months prior to the date of the scheduled maintenance, the Interconnection Customer had modified its schedule of maintenance activities.

9.7.1.3 Outage Restoration. If an outage on a Party's Interconnection Facilities or Network Upgrades adversely affects another Party's operations or facilities, the Party that owns or controls the facility that is out of service shall use Reasonable Efforts to promptly restore such facility(ies) to a normal operating condition consistent with the nature of the outage. The Party that owns or controls the facility that is out of service shall provide the other Parties, to the extent such information is known, information on the nature of the Emergency Condition, if the outage is caused by an Emergency Condition, an estimated time of restoration, and any corrective actions required. Initial verbal notice shall be followed up as soon as practicable with written notice explaining the nature of the outage, if requested by a Party, which may be provided by e-mail or facsimile.

9.7.2 **Interruption of Service**. If required by Good Utility Practice to do so, the ISO or the Participating TO may require the Interconnection Customer to interrupt or reduce deliveries of electricity if such delivery of electricity could adversely affect the ISO's or the Participating TO's ability to perform such activities as are necessary to safely and reliably operate and maintain the Participating TO's electric system or the ISO Controlled Grid. The following provisions shall apply to any interruption or reduction permitted under this Article 9.7.2:

9.7.2.1 The interruption or reduction shall continue only for so long as reasonably necessary under Good Utility Practice;

9.7.2.2 Any such interruption or reduction shall be made on an equitable, non-discriminatory basis with respect to all generating facilities directly connected to the ISO Controlled Grid, subject to any conditions specified in this LGIA;

9.7.2.3 When the interruption or reduction must be made under circumstances which do not allow for advance notice, the ISO or Participating TO, as applicable, shall notify the Interconnection Customer by telephone as soon as practicable of the reasons for the curtailment, interruption, or reduction, and, if known, its expected duration. Telephone notification shall be followed by written notification, if requested by the Interconnection Customer, as soon as practicable;

9.7.2.4 Except during the existence of an Emergency Condition, the ISO or Participating TO shall notify the Interconnection Customer in advance regarding the timing of such interruption or reduction and further notify the Interconnection Customer of the expected duration. The ISO or Participating TO shall coordinate with the Interconnection Customer using Good Utility Practice to schedule the interruption or reduction during periods of least impact to the Interconnection Customer, the ISO, and the Participating TO;

9.7.2.5 The Parties shall cooperate and coordinate with each other to the extent necessary in order to restore the Large Generating Facility, Interconnection Facilities, the Participating TO's Transmission System, and the ISO Controlled Grid to their normal operating state, consistent with system conditions and Good Utility Practice.

9.7.3 **Under-Frequency and Over Frequency Conditions**. The ISO Controlled Grid is designed to automatically activate a load-shed program as required by the Applicable Reliability Council in the event of an under-frequency system disturbance. The Interconnection Customer shall implement under-frequency and over-frequency protection set points for the Large Generating Facility as required by the Applicable Reliability Council to ensure "ride through" capability. Large Generating Facility response to frequency deviations of pre-determined magnitudes, both under-frequency and over-frequency deviations, shall be studied and coordinated with the Participating TO and ISO in accordance with Good Utility Practice. The term "ride through" as used herein shall mean the ability of a Generating Facility to stay connected to and synchronized with the ISO Controlled Grid during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice.

9.7.4 System Protection and Other Control Requirements.

9.7.4.1 System Protection Facilities. The Interconnection Customer shall, at its expense, install, operate and maintain System Protection Facilities as a part of the Large Generating Facility or the Interconnection Customer's Interconnection Facilities. The Participating TO shall install at the Interconnection Customer's expense any System Protection Facilities that may be required on the Participating TO's Interconnection Facilities or the Participating TO's Transmission System as a result of the interconnection of the Large Generating Facility and the Interconnection Customer's Interconnection Facilities.

9.7.4.2 The Participating TO's and Interconnection Customer's protection facilities shall be designed and coordinated with other systems in accordance with Applicable Reliability Council criteria and Good Utility Practice.

9.7.4.3 The Participating TO and Interconnection Customer shall each be responsible for protection of its facilities consistent with Good Utility Practice.

9.7.4.4 The Participating TO's and Interconnection Customer's protective relay design shall incorporate the necessary test switches to perform the tests required in Article 6. The required test switches will be placed such that they allow operation of lockout relays while preventing breaker failure schemes from operating and causing unnecessary breaker operations and/or the tripping of the Interconnection Customer's Electric Generating Units.

9.7.4.5 The Participating TO and Interconnection Customer will test, operate and maintain System Protection Facilities in accordance with Good Utility Practice and, if applicable, the requirements of the Participating TO's Interconnection Handbook.

9.7.4.6 Prior to the in-service date, and again prior to the Commercial Operation Date, the Participating TO and Interconnection Customer or their agents shall perform a complete calibration test and functional trip test of the System Protection Facilities. At intervals suggested by Good Utility Practice, the standards and procedures of the Participating TO, including, if applicable, the requirements of the Participating TO's Interconnection Handbook, and following any apparent malfunction of the System Protection Facilities, each Party shall perform both calibration and functional trip tests of its System Protection Facilities. These tests do not require the tripping of any in-service generation unit. These tests do, however, require that all protective relays and lockout contacts be activated.

9.7.5 Requirements for Protection. In compliance with Good Utility Practice and, if applicable, the requirements of the Participating TO's Interconnection Handbook, the Interconnection Customer shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of the Large Generating Facility to any short circuit occurring on the Participating TO's Transmission System not otherwise isolated by the Participating TO's equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of the Participating TO's Transmission System. Such protective equipment shall include, without limitation, a disconnecting device with fault current-interrupting capability located between the Large Generating Facility and the Participating TO's Transmission System at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. The Interconnection Customer shall be responsible for protection of the Large Generating Facility and the Interconnection Customer's other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. The Interconnection Customer shall be solely responsible to disconnect the Large Generating Facility and the Interconnection Customer's other equipment if conditions on the ISO Controlled Grid could adversely affect the Large Generating Facility.

9.7.6 Power Quality. Neither the Participating TO's nor the Interconnection Customer's facilities shall cause excessive voltage flicker nor introduce excessive distortion to the sinusoidal voltage or current waves as defined by ANSI Standard C84.1-1989, in accordance with IEEE Standard 519, any applicable superseding electric industry standard, or any alternative Applicable Reliability Council standard. In the event of a conflict between ANSI Standard C84.1-1989, any applicable superseding electric industry standard, or any alternative Applicable Reliability Council standard, the alternative Applicable Reliability Council standard shall control.

9.8 Switching and Tagging Rules. Each Party shall provide the other Parties a copy of its switching and tagging rules that are applicable to the other Parties' activities. Such switching and tagging rules shall be developed on a non-discriminatory basis. The Parties shall comply with applicable switching and tagging rules, as amended from time to time, in obtaining clearances for work or for switching operations on equipment.

9.9 Use of Interconnection Facilities by Third Parties.

9.9.1 Purpose of Interconnection Facilities. Except as may be required by Applicable Laws and Regulations, or as otherwise agreed to among the Parties, the Interconnection Facilities shall be constructed for the sole purpose of interconnecting the Large Generating Facility to the Participating TO's Transmission System and shall be used for no other purpose.

9.9.2 Third Party Users. If required by Applicable Laws and Regulations or if the Parties mutually agree, such agreement not to be unreasonably withheld, to allow one or more third parties to use the Participating TO's Interconnection Facilities, or any part thereof, the Interconnection Customer will be entitled to compensation for the capital expenses it incurred in connection with the Interconnection Facilities based upon the pro rata use of the Interconnection Facilities by the Participating TO, all third party users, and the Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually-agreed upon methodology. In addition, cost responsibility for ongoing costs, including operation and maintenance costs associated with the Interconnection Facilities, will be allocated between the Interconnection Customer and any third party users based upon the pro rata use of the Interconnection Facilities by the Participating TO, all third party users, and the Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed upon methodology. If the issue of such compensation or allocation cannot be resolved through such negotiations, it shall be submitted to FERC for resolution.

9.10 Disturbance Analysis Data Exchange. The Parties will cooperate with one another in the analysis of disturbances to either the Large Generating Facility or the ISO Controlled Grid by gathering and providing access to any information relating to any disturbance, including information from oscillography, protective relay targets, breaker operations and sequence of events records, and any disturbance information required by Good Utility Practice.

ARTICLE 10. MAINTENANCE

10.1 Participating TO Obligations. The Participating TO shall maintain the Participating TO's Transmission System and the Participating TO's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA.

10.2 Interconnection Customer Obligations. The Interconnection Customer shall maintain the Large Generating Facility and the Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA.

10.3 Coordination. The Parties shall confer regularly to coordinate the planning, scheduling and performance of preventive and corrective maintenance on the Large Generating Facility and the Interconnection Facilities.

10.4 Secondary Systems. The Participating TO and Interconnection Customer shall cooperate with the other Parties in the inspection, maintenance, and testing of control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers that directly affect the operation of a Party's facilities and equipment which may reasonably be expected to impact the other Parties. Each Party shall provide advance notice to the other Parties before undertaking any work on such circuits, especially on electrical circuits involving circuit breaker trip and close contacts, current transformers, or potential transformers.

10.5 Operating and Maintenance Expenses. Subject to the provisions herein addressing the use of facilities by others, and except for operations and maintenance expenses associated with modifications made for providing interconnection or transmission service to a third party and such third party pays for such expenses, the Interconnection Customer shall be responsible for all reasonable expenses including overheads, associated with: (1) owning, operating, maintaining, repairing, and replacing the Interconnection Customer's Interconnection Facilities; and (2) operation, maintenance, repair and replacement of the Participating TO's Interconnection Facilities.

ARTICLE 11. PERFORMANCE OBLIGATION

11.1 Interconnection Customer's Interconnection Facilities. The Interconnection Customer shall design, procure, construct, install, own and/or control the Interconnection Customer's Interconnection Facilities described in Part A at its sole expense.

11.2 Participating TO's Interconnection Facilities. The Participating TO shall design, procure, construct, install, own and/or control the Participating TO's Interconnection Facilities described in Part A at the sole expense of the Interconnection Customer. Unless the Participating TO elects to fund the capital for the Participating TO's Interconnection Facilities, they shall be solely funded by the Interconnection Customer.

11.3 Network Upgrades and Distribution Upgrades. The Participating TO shall design, procure, construct, install, and own the Network Upgrades and Distribution Upgrades described in Part A. The Interconnection Customer shall be responsible for all costs related to Distribution Upgrades. Unless the Participating TO elects to fund the capital for the Distribution Upgrades and Network Upgrades, they shall be solely funded by the Interconnection Customer.

11.4 Transmission Credits. No later than thirty (30) days prior to the Commercial Operation Date, the Interconnection Customer may make a one-time election by written notice to the ISO and the Participating TO to receive Firm Transmission Rights as defined in and as available under the ISO Tariff at the time of the election in accordance with the ISO Tariff, in lieu of a refund of the cost of Network Upgrades in accordance with Article 11.4.1.

11.4.1 Repayment of Amounts Advanced for Network Upgrades. Upon the Commercial Operation Date, the Interconnection Customer shall be entitled to a repayment, equal to the total amount paid to the Participating TO for the cost of Network Upgrades. Such amount shall include any tax gross-up or other tax-related payments associated with Network Upgrades not refunded to the Interconnection Customer pursuant to Article 5.17.8 or otherwise, and shall be paid to the Interconnection Customer by the Participating TO on a dollar-for-dollar basis either through (1) direct payments made on a levelized basis over the five-year period commencing on the Commercial Operation Date; or (2) any alternative payment schedule that is mutually agreeable to the Interconnection Customer and Participating TO, provided that such amount is paid within five (5) years from the Commercial Operation Date. Notwithstanding the foregoing, if this LGIA terminates within five (5) years from the Commercial Operation Date, the Participating TO's obligation to pay refunds to the Interconnection Customer shall cease as of the date of termination. Any repayment shall include interest calculated in accordance with the methodology set forth in FERC's regulations at 18 C.F.R. §35.19a(a)(2)(iii) from the date of any payment for Network Upgrades through the date on which the Interconnection Customer receives a repayment of such payment. Interest shall continue to accrue on the repayment obligation so long as this LGIA is in effect. The Interconnection Customer may assign such repayment rights to any person.

If the Large Generating Facility fails to achieve commercial operation, but it or another Generating Facility is later constructed and makes use of the Network Upgrades, the Participating TO shall at that time reimburse Interconnection Customer for the amounts advanced for the Network Upgrades. Before any such reimbursement can occur, the Interconnection Customer, or the entity that ultimately constructs the Generating Facility, if different, is responsible for identifying the entity to which reimbursement must be made.

11.4.2 Special Provisions for Affected Systems. The Interconnection Customer shall enter into an agreement with the owner of the Affected System and/or other affected owners of portions of the ISO Controlled Grid, as applicable, in accordance with the LGIP. Such agreement shall specify the terms governing payments to be made by the Interconnection Customer to the owner of the Affected System and/or other affected owners of portions of the ISO Controlled Grid as well as the repayment by the owner of the Affected System and/or other affected owners of portions of the ISO Controlled Grid. In no event shall the Participating TO be responsible for the repayment for any facilities that are not part of the Participating TO's Transmission System.

11.4.3 Notwithstanding any other provision of this LGIA, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that the Interconnection Customer shall be entitled to, now or in the future under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades, including the right to obtain cash reimbursements or transmission credits for transmission service that is not associated with the Large Generating Facility.

11.5 Provision of Security. At least thirty (30) Calendar Days prior to the commencement of the procurement, installation, or construction of a discrete portion of a Participating TO's Interconnection Facilities, Network Upgrades, or Distribution Upgrades, the Interconnection Customer shall provide the Participating TO, at the Interconnection Customer's option, a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to the Participating TO and is consistent with the Uniform Commercial Code of the jurisdiction identified in Article 14.2.1. Such security for payment shall be in an amount sufficient to cover the costs for constructing, procuring and installing the applicable portion of the Participating TO's Interconnection Facilities, Network Upgrades, or Distribution Upgrades. Such security shall be reduced on a dollar-for-dollar basis for payments made to the Participating TO for these purposes.

In addition:

11.5.1 The guarantee must be made by an entity that meets the creditworthiness requirements of the Participating TO, and contain terms and conditions that guarantee payment of any amount that may be due from the Interconnection Customer, up to an agreed-to maximum amount.

11.5.2 The letter of credit must be issued by a financial institution reasonably acceptable to the Participating TO and must specify a reasonable expiration date.

11.5.3 The surety bond must be issued by an insurer reasonably acceptable to the Participating TO and must specify a reasonable expiration date.

11.6 Interconnection Customer Compensation. If the ISO requests or directs the Interconnection Customer to provide a service pursuant to Articles 9.6.3 (Payment for Reactive Power) or 13.5.1 of this LGIA, the ISO shall compensate the Interconnection Customer in accordance with the ISO Tariff.

11.6.1 Interconnection Customer Compensation for Actions During Emergency Condition. The ISO shall compensate the Interconnection Customer in accordance with the ISO Tariff for its provision of real and reactive power and other Emergency Condition services that the Interconnection Customer provides to support the ISO Controlled Grid during an Emergency Condition in accordance with Article 11.6.

ARTICLE 12. INVOICE

12.1 General. The Participating TO shall submit to the Interconnection Customer, on a monthly basis, invoices of amounts due pursuant to this LGIA for the preceding month. Each invoice shall state the month to which the invoice applies and fully describe the services and equipment provided. The Parties may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under this LGIA, including interest payments or credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party. Notwithstanding the foregoing, any invoices between the ISO and another Party shall be submitted and paid in accordance with the ISO Tariff.

12.2 Final Invoice. As soon as reasonably practicable, but within twelve months after completion of the construction of the Participating TO's Interconnection Facilities, Network Upgrades, and Distribution Upgrades, the Participating TO shall provide an invoice of the final cost of the construction of the Participating TO's Interconnection Facilities, Network Upgrades, and Distribution Upgrades, and shall set forth such costs in sufficient detail to enable the Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. The Participating TO shall refund to the Interconnection Customer any amount by which the actual payment by the Interconnection Customer for estimated costs exceeds the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice; or, in the event the actual costs of construction exceed the Interconnection Customer's actual payment for estimated costs, then the Interconnection Customer shall pay to the Participating TO any amount by which the actual costs of construction exceed the actual payment by the Interconnection Customer for estimated costs within thirty (30) Calendar Days of the issuance of such final construction invoice.

12.3 Payment. Invoices shall be rendered to the Interconnection Customer at the address specified in Part F. The Interconnection Customer shall pay, or Participating TO shall refund, the amounts due within thirty (30) Calendar Days of the Interconnection Customer's receipt of the invoice. All payments shall be made in immediately available funds payable to the Interconnection Customer or Participating TO, or by wire transfer to a bank named and account designated by the invoicing Interconnection Customer or Participating TO. Payment of invoices by any Party will not constitute a waiver of any rights or claims any Party may have under this LGIA.

12.4 Disputes. In the event of a billing dispute between the Interconnection Customer and the Participating TO, the Participating TO and the ISO shall continue to provide Interconnection Service under this LGIA as long as the Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to the Participating TO or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Interconnection Customer fails to meet these two requirements for continuation of service, then the Participating TO may provide notice to the Interconnection Customer of a Default pursuant to Article 17. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest calculated in accordance with the methodology set forth in FERC's Regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Notwithstanding the foregoing, any billing dispute between the ISO and another Party shall be resolved in accordance with the provisions of Article 27 of this LGIA.

ARTICLE 13. EMERGENCIES

13.1 [Reserved]

13.2 Obligations. Each Party shall comply with the Emergency Condition procedures of the ISO, NERC, the Applicable Reliability Council, Applicable Laws and Regulations, and any emergency procedures set forth in this LGIA.

13.3 Notice. The Participating TO or the ISO shall notify the Interconnection Customer promptly when it becomes aware of an Emergency Condition that affects the Participating TO's Interconnection Facilities or Distribution System or the ISO Controlled Grid, respectively, that may reasonably be expected to affect the Interconnection Customer's operation of the Large Generating Facility or the Interconnection Customer's Interconnection Facilities. The Interconnection Customer shall notify the Participating TO and the ISO promptly when it becomes aware of an Emergency Condition that affects the Large Generating Facility or the Interconnection Customer's Interconnection Facilities that may reasonably be expected to affect the ISO Controlled Grid or the Participating TO's Interconnection Facilities. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of the Interconnection Customer's or Participating TO's facilities and operations, its anticipated duration and the corrective action taken and/or to be taken. The initial notice shall be followed as soon as practicable with written notice, if requested by a Party, which may be provided by electronic mail or facsimile, or in the case of the ISO may be publicly posted on the ISO's internet web site.

13.4 Immediate Action. Unless, in the Interconnection Customer's reasonable judgment, immediate action is required, the Interconnection Customer shall obtain the consent of the ISO and the Participating TO, such consent to not be unreasonably withheld, prior to performing any manual switching operations at the Large Generating Facility or the Interconnection Customer's Interconnection Facilities in response to an Emergency Condition declared by the Participating TO or ISO or in response to any other emergency condition.

13.5 ISO and Participating TO Authority.

13.5.1 General. The ISO and Participating TO may take whatever actions or inactions, including issuance of dispatch instructions, with regard to the ISO Controlled Grid or the Participating TO's Interconnection Facilities or Distribution System they deem necessary during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the ISO Controlled Grid or the Participating TO's Interconnection Facilities or Distribution System, and (iii) limit or prevent damage, and (iv) expedite restoration of service.

The Participating TO and the ISO shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Large Generating Facility or the Interconnection Customer's Interconnection Facilities. The Participating TO or the ISO may, on the basis of technical considerations, require the Large Generating Facility to mitigate an Emergency Condition by taking actions necessary and limited in scope to remedy the Emergency Condition, including, but not limited to, directing the Interconnection Customer to shut-down, start-up, increase or decrease the real or reactive power output of the Large Generating Facility; implementing a reduction or disconnection pursuant to Article 13.5.2; directing the Interconnection Customer to assist with black start (if available) or restoration efforts; or altering the outage schedules of the Large Generating Facility and the Interconnection Customer's Interconnection Facilities. Interconnection Customer shall comply with all of the ISO's and Participating TO's operating instructions concerning Large Generating Facility real power and reactive power output within the manufacturer's design limitations of the Large Generating Facility's equipment that is in service and physically available for operation at the time, in compliance with Applicable Laws and Regulations.

13.5.2 Reduction and Disconnection. The Participating TO or the ISO may reduce Interconnection Service or disconnect the Large Generating Facility or the Interconnection Customer's Interconnection Facilities when such reduction or disconnection is necessary under Good Utility Practice due to Emergency Conditions. These rights are separate and distinct from any right of curtailment of the ISO pursuant to the ISO Tariff. When the ISO or Participating TO can schedule the reduction or disconnection in advance, the ISO or Participating TO shall notify the Interconnection Customer of the reasons, timing and expected duration of the reduction or disconnection. The ISO or Participating TO shall coordinate with the Interconnection Customer using Good Utility Practice to schedule the reduction or disconnection during periods of least impact to the Interconnection Customer and the ISO and Participating TO. Any reduction or disconnection shall continue only for so long as reasonably necessary under Good Utility Practice. The Parties shall cooperate with each other to restore the Large Generating Facility, the Interconnection Facilities, and the ISO Controlled Grid to their normal operating state as soon as practicable consistent with Good Utility Practice.

13.6 Interconnection Customer Authority. Consistent with Good Utility Practice, this LGIA, and the ISO Tariff, the Interconnection Customer may take actions or inactions with regard to the Large Generating Facility or the Interconnection Customer's Interconnection Facilities during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Large Generating Facility or the Interconnection Customer's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service. Interconnection Customer shall use Reasonable Efforts to minimize the effect of such actions or inactions on the ISO Controlled Grid and the Participating TO's Interconnection Facilities. The ISO and Participating TO shall use Reasonable Efforts to assist Interconnection Customer in such actions.

13.7 Limited Liability. Except as otherwise provided in Article 11.6.1 of this LGIA, no Party shall be liable to any other Party for any action it takes in responding to an Emergency Condition so long as such action is made in good faith and is consistent with Good Utility Practice.

ARTICLE 14. REGULATORY REQUIREMENTS AND GOVERNING LAW

14.1 Regulatory Requirements. Each Party's obligations under this LGIA shall be subject to its receipt of any required approval or certificate from one or more Governmental Authorities in the form and substance satisfactory to the applying Party, or the Party making any required filings with, or providing notice to, such Governmental Authorities, and the expiration of any time period associated therewith. Each Party shall in good faith seek and use its Reasonable Efforts to obtain such other approvals. Nothing in this LGIA shall require the Interconnection Customer to take any action that could result in its inability to obtain, or its loss of, status or exemption under the Federal Power Act or the Public Utility Holding Company Act of 1935, as amended, or the Public Utility Regulatory Policies Act of 1978.

14.2 Governing Law.

14.2.1 The validity, interpretation and performance of this LGIA and each of its provisions shall be governed by the laws of the state where the Point of Interconnection is located, without regard to its conflicts of law principles.

14.2.2 This LGIA is subject to all Applicable Laws and Regulations.

14.2.3 Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

ARTICLE 15. NOTICES

15.1 General. Unless otherwise provided in this LGIA, any notice, demand or request required or permitted to be given by a Party to another and any instrument required or permitted to be tendered or delivered by a Party in writing to another shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party, at the address set out in Part F, Addresses for Delivery of Notices and Billings.

A Party must update the information in Part F as information changes. A Party may change the notice information in this LGIA by giving five (5) Business Days written notice prior to the effective date of the change. Such changes shall not constitute an amendment to this LGIA.

15.2 Billings and Payments. Billings and payments shall be sent to the addresses set out in Part F.

15.3 Alternative Forms of Notice. Any notice or request required or permitted to be given by a Party to another and not required by this LGIA to be given in writing may be so given by telephone, facsimile or e-mail to the telephone numbers and e-mail addresses set out in Part F.

15.4 Operations and Maintenance Notice. Each Party shall notify the other Parties in writing of the identity of the person(s) that it designates as the point(s) of contact with respect to the implementation of Articles 9 and 10.

ARTICLE 16. FORCE MAJEURE

16.1 Force Majeure.

16.1.1 Economic hardship is not considered a Force Majeure event.

16.1.2 No Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 4), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this Article shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

ARTICLE 17. DEFAULT

17.1 Default

17.1.1 General. No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of Force Majeure as defined in this LGIA or the result of an act or omission of the other Party. Upon a Breach, the affected non-Breaching Party(ies) shall give written notice of such Breach to the Breaching Party. Except as provided in Article 17.1.2, the Breaching Party shall have thirty (30) Calendar Days from receipt of the Default notice within which to cure such Breach; provided however, if such Breach is not capable of cure within thirty (30) Calendar Days, the Breaching Party shall commence such cure within thirty (30) Calendar Days after notice and continuously and diligently complete such cure within ninety (90) Calendar Days from receipt of the Default notice; and, if cured within such time, the Breach specified in such notice shall cease to exist.

17.1.2 Right to Terminate. If a Breach is not cured as provided in this Article, or if a Breach is not capable of being cured within the period provided for herein, the affected non-Breaching Party(ies) shall have the right to declare a Default and terminate this LGIA by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not such Party(ies) terminates this LGIA, to recover from the Breaching Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this Article will survive termination of this LGIA.

ARTICLE 18. INDEMNITY, CONSEQUENTIAL DAMAGES AND INSURANCE

18.1 Indemnity. Each Party shall at all times indemnify, defend, and hold the other Parties harmless from, any and all Losses arising out of or resulting from another Party's action or inactions of its obligations under this LGIA on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the Indemnified Party.

18.1.1 Indemnified Party. If an Indemnified Party is entitled to indemnification under this Article 18 as a result of a claim by a third party, and the Indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 18.1, to assume the defense of such claim, such Indemnified Party may at the expense of the Indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

18.1.2 Indemnifying Party. If an Indemnifying Party is obligated to indemnify and hold any Indemnified Party harmless under this Article 18, the amount owing to the Indemnified Party shall be the amount of such Indemnified Party's actual Loss, net of any insurance or other recovery.

18.1.3 Indemnity Procedures. Promptly after receipt by an Indemnified Party of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 18.1 may apply, the Indemnified Party shall notify the Indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such Indemnifying Party and reasonably satisfactory to the Indemnified Party. If the defendants in any such action include one or more Indemnified Parties and the Indemnifying Party and if the Indemnified Party reasonably concludes that there may be legal defenses available to it and/or other Indemnified Parties which are different from or additional to those available to the Indemnifying Party, the Indemnified Party shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the Indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an Indemnified Party or Indemnified Parties having such differing or additional legal defenses.

The Indemnified Party shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the Indemnifying Party. Notwithstanding the foregoing, the Indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the Indemnified Party and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the Indemnified Party, or there exists a conflict or adversity of interest between the Indemnified Party and the Indemnifying Party, in such event the Indemnifying Party shall pay the reasonable expenses of the Indemnified Party, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the Indemnified Party, which shall not be unreasonably withheld, conditioned or delayed.

18.2 Consequential Damages. Other than the liquidated damages heretofore described in Article 5.3, in no event shall any Party be liable under any provision of this LGIA for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to another Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

18.3 Insurance. Each Party shall, at its own expense, maintain in force throughout the period of this LGIA, and until released by the other Parties, the following minimum insurance coverages, with insurers rated no less than A- (with a minimum size rating of VII) by Bests' Insurance Guide and Key Ratings and authorized to do business in the state where the Point of Interconnection is located, except in the case of the ISO, the State of California:

18.3.1 Employer's Liability and Workers' Compensation Insurance providing statutory benefits in accordance with the laws and regulations of the state in which the Point of Interconnection is located, except in the case of the ISO, the State of California.

18.3.2 Commercial General Liability Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification) products and completed operations coverage, coverage for explosion, collapse and underground hazards, independent contractors coverage, coverage for pollution to the extent normally available and punitive damages to the extent normally available and a cross liability endorsement, with minimum limits of One Million Dollars ($1,000,000) per occurrence/One Million Dollars ($1,000,000) aggregate combined single limit for personal injury, bodily injury, including death and property damage.

18.3.3 Business Automobile Liability Insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined single limit of One Million Dollars ($1,000,000) per occurrence for bodily injury, including death, and property damage.

18.3.4 Excess Public Liability Insurance over and above the Employer's Liability Commercial General Liability and Business Automobile Liability Insurance coverage, with a minimum combined single limit of Twenty Million Dollars ($20,000,000) per occurrence/Twenty Million Dollars ($20,000,000) aggregate.

18.3.5 The Commercial General Liability Insurance, Business Automobile Insurance and Excess Public Liability Insurance policies shall name the other Parties, their parents, associated and Affiliate companies and their respective directors, officers, agents, servants and employees ("Other Party Group") as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation in accordance with the provisions of this LGIA against the Other Party Group and provide thirty (30) Calendar Days advance written notice to the Other Party Group prior to anniversary date of cancellation or any material change in coverage or condition.

18.3.6 The Commercial General Liability Insurance, Business Automobile Liability Insurance and Excess Public Liability Insurance policies shall contain provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. Each Party shall be responsible for its respective deductibles or retentions.

18.3.7 The Commercial General Liability Insurance, Business Automobile Liability Insurance and Excess Public Liability Insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this LGIA, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed by the Parties.

18.3.8 The requirements contained herein as to the types and limits of all insurance to be maintained by the Parties are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Parties under this LGIA.

18.3.9 Within ten (10) Calendar Days following execution of this LGIA, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) Calendar Days thereafter, each Party shall provide certification of all insurance required in this LGIA, executed by each insurer or by an authorized representative of each insurer.

18.3.10 Notwithstanding the foregoing, each Party may self-insure to meet the minimum insurance requirements of Articles 18.3.2 through 18.3.8 to the extent it maintains a self-insurance program; provided that, such Party's senior unsecured debt or issuer rating is BBB-, or better, as rated by Standard & Poor's and that its self-insurance program meets the minimum insurance requirements of Articles 18.3.2 through 18.3.8. For any period of time that a Party's senior unsecured debt rating and issuer rating are both unrated by Standard & Poor's or are both rated at less than BBB- by Standard & Poor's, such Party shall comply with the insurance requirements applicable to it under Articles 18.3.2 through 18.3.9. In the event that a Party is permitted to self-insure pursuant to this Article 18.3.10, it shall notify the other Parties that it meets the requirements to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in Article 18.3.9.

18.3.11 The Parties agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this LGIA.

ARTICLE 19. ASSIGNMENT

19.1 Assignment. This LGIA may be assigned by a Party only with the written consent of the other Parties; provided that a Party may assign this LGIA without the consent of the other Parties to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this LGIA; and provided further that the Interconnection Customer shall have the right to assign this LGIA, without the consent of the ISO or Participating TO, for collateral security purposes to aid in providing financing for the Large Generating Facility, provided that the Interconnection Customer will promptly notify the ISO and Participating TO of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the ISO and Participating TO of the date and particulars of any such exercise of assignment right(s), including providing the ISO and Participating TO with proof that it meets the requirements of Articles 11.5 and 18.3. Any attempted assignment that violates this Article is void and ineffective. Any assignment under this LGIA shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

ARTICLE 20. SEVERABILITY

20.1 Severability. If any provision in this LGIA is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this LGIA; provided that if the Interconnection Customer (or any third party, but only if such third party is not acting at the direction of the Participating TO or ISO) seeks and obtains such a final determination with respect to any provision of the Alternate Option (Article 5.1.2), or the Negotiated Option (Article 5.1.4), then none of the provisions of Article 5.1.2 or 5.1.4 shall thereafter have any force or effect and the Parties' rights and obligations shall be governed solely by the Standard Option (Article 5.1.1).

ARTICLE 21. COMPARABILITY

21.1 Comparability. The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

ARTICLE 22. CONFIDENTIALITY

22.1 Confidentiality. Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by any of the Parties to the other Parties prior to the execution of this LGIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Parties receiving the information that the information is confidential.

If requested by any Party, the other Parties shall provide in writing, the basis for asserting that the information referred to in this Article 22 warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

22.1.1 Term. During the term of this LGIA, and for a period of three (3) years after the expiration or termination of this LGIA, except as otherwise provided in this Article 22, each Party shall hold in confidence and shall not disclose to any person Confidential Information.

22.1.2 Scope. Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this LGIA; or (6) is required, in accordance with Article 22.1.7 of this LGIA, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this LGIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Parties that it no longer is confidential.

22.1.3 Release of Confidential Information. No Party shall release or disclose Confidential Information to any other person, except to its employees, consultants, Affiliates (limited by the Standards of Conduct requirements set forth in Part 358 of FERC's Regulations, 18 C.F.R. 358), subcontractors, or to parties who may be or considering providing financing to or equity participation with the Interconnection Customer, or to potential purchasers or assignees of the Interconnection Customer, on a need-to-know basis in connection with this LGIA, unless such person has first been advised of the confidentiality provisions of this Article 22 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Article 22.

22.1.4 Rights. Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Parties. The disclosure by each Party to the other Parties of Confidential Information shall not be deemed a waiver by a Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

22.1.5 No Warranties. The mere fact that a Party has provided Confidential Information does not constitute a warranty or representation as to its accuracy or completeness. In addition, by supplying Confidential Information, no Party obligates itself to provide any particular information or Confidential Information to the other Parties nor to enter into any further agreements or proceed with any other relationship or joint venture.

22.1.6 Standard of Care. Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Parties under this LGIA or its regulatory requirements.

22.1.7 Order of Disclosure. If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires any Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Parties with prompt notice of such request(s) or requirement(s) so that the other Parties may seek an appropriate protective order or waive compliance with the terms of this LGIA. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

22.1.8 Termination of Agreement. Upon termination of this LGIA for any reason, each Party shall, within ten (10) Calendar Days of receipt of a written request from another Party, use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the other Party) or return to the other Party, without retaining copies thereof, any and all written or electronic Confidential Information received from the other Party.

22.1.9 Remedies. The Parties agree that monetary damages would be inadequate to compensate a Party for another Party's Breach of its obligations under this Article 22. Each Party accordingly agrees that the other Parties shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Article 22, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Article 22, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article 22.

22.1.10 Disclosure to FERC, its Staff, or a State. Notwithstanding anything in this Article 22 to the contrary, and pursuant to 18 C.F.R. section 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this LGIA, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 C.F.R. section 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Parties to this LGIA prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Parties to the LGIA when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time any of the Parties may respond before such information would be made public, pursuant to 18 C.F.R. section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

22.1.11 Subject to the exception in Article 22.1.10, Confidential Information shall not be disclosed by the other Parties to any person not employed or retained by the other Parties, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Parties, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this LGIA or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or

ISO or to a regional or national reliability organization. The Party asserting confidentiality shall notify the other Parties in writing of the information it claims is confidential. Prior to any disclosures of another Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

ARTICLE 23. ENVIRONMENTAL RELEASES

23.1 Each Party shall notify the other Parties, first orally and then in writing, of the release of any Hazardous Substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Large Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Parties. The notifying Party shall: (i) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than twenty-four hours after such Party becomes aware of the occurrence; and (ii) promptly furnish to the other Parties copies of any publicly available reports filed with any Governmental Authorities addressing such events.

ARTICLE 24. INFORMATION REQUIREMENTS

24.1 **Information Acquisition**. The Participating TO and the Interconnection Customer shall submit specific information regarding the electrical characteristics of their respective facilities to each other as described below and in accordance with Applicable Reliability Standards.

24.2 **Information Submission by Participating TO**. The initial information submission by the Participating TO shall occur no later than one hundred eighty (180) Calendar Days prior to Trial Operation and shall include the Participating TO's Transmission System information necessary to allow the Interconnection Customer to select equipment and meet any system protection and stability requirements, unless otherwise agreed to by the Participating TO and the Interconnection Customer. On a monthly basis the Participating TO shall provide the Interconnection Customer and the ISO a status report on the construction and installation of the Participating TO's Interconnection Facilities and Network Upgrades, including, but not limited to, the following information: (1) progress to date; (2) a description of the activities since the last report; (3) a description of the action items for the next period; and (4) the delivery status of equipment ordered.

24.3 **Updated Information Submission by Interconnection Customer**. The updated information submission by the Interconnection Customer, including manufacturer information, shall occur no later than one hundred eighty (180) Calendar Days prior to the Trial Operation. The Interconnection Customer shall submit a completed copy of the Electric Generating Unit data requirements contained in Part 1 to the LGIP. It shall also include any additional information provided to the Participating TO and the ISO for the Interconnection Studies. Information in this submission shall be the most current Electric Generating Unit design or expected performance data. Information submitted for stability models shall be compatible with the Participating TO and ISO standard models. If there is no compatible model, the Interconnection Customer will work with a consultant mutually agreed to by the Parties to develop and supply a standard model and associated information.

If the Interconnection Customer's data is materially different from what was originally provided to the Participating TO and the ISO for the Interconnection Studies, then the Participating TO and the ISO will conduct appropriate studies pursuant to the LGIP to determine the impact on the

Participating TO's Transmission System and affected portions of the ISO Controlled Grid based on the actual data submitted pursuant to this Article 24.3. The Interconnection Customer shall not begin Trial Operation until such studies are completed and all other requirements of this LGIA are satisfied.

24.4 Information Supplementation. Prior to the Trial Operation date, the Parties shall supplement their information submissions described above in this Article 24 with any and all "as-built" Electric Generating Unit information or "as-tested" performance information that differs from the initial submissions or, alternatively, written confirmation that no such differences exist. The Interconnection Customer shall conduct tests on the Electric Generating Unit as required by Good Utility Practice such as an open circuit "step voltage" test on the Electric Generating Unit to verify proper operation of the Electric Generating Unit's automatic voltage regulator.

Unless otherwise agreed, the test conditions shall include: (1) Electric Generating Unit at synchronous speed; (2) automatic voltage regulator on and in voltage control mode; and (3) a five percent (5 percent) change in Electric Generating Unit terminal voltage initiated by a change in the voltage regulators reference voltage. The Interconnection Customer shall provide validated test recordings showing the responses of Electric Generating Unit terminal and field voltages. In the event that direct recordings of these voltages is impractical, recordings of other voltages or currents that mirror the response of the Electric Generating Unit's terminal or field voltage are acceptable if information necessary to translate these alternate quantities to actual Electric Generating Unit terminal or field voltages is provided. Electric Generating Unit testing shall be conducted and results provided to the Participating TO and the ISO for each individual Electric Generating Unit in a station.

Subsequent to the Commercial Operation Date, the Interconnection Customer shall provide the Participating TO and the ISO any information changes due to equipment replacement, repair, or adjustment. The Participating TO shall provide the Interconnection Customer any information changes due to equipment replacement, repair or adjustment in the directly connected substation or any adjacent Participating TO-owned substation that may affect the Interconnection Customer's Interconnection Facilities equipment ratings, protection or operating requirements. The Parties shall provide such information pursuant to Article 5.19.

ARTICLE 25. INFORMATION ACCESS AND AUDIT RIGHTS

25.1 Information Access. Each Party (the "disclosing Party") shall make available to the other Party information that is in the possession of the disclosing Party and is necessary in order for the other Party to: (i) verify the costs incurred by the disclosing Party for which the other Party is responsible under this LGIA; and (ii) carry out its obligations and responsibilities under this LGIA. The Parties shall not use such information for purposes other than those set forth in this Article 25.1 and to enforce their rights under this LGIA. Nothing in this Article 25 shall obligate the ISO to make available to a Party any third party information in its possession or control if making such third party information available would violate an ISO Tariff restriction on the use or disclosure of such third party information.

25.2 Reporting of Non-Force Majeure Events. Each Party (the "notifying Party") shall notify the other Parties when the notifying Party becomes aware of its inability to comply with the provisions of this LGIA for a reason other than a Force Majeure event. The Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this Article shall not entitle the Party receiving such notification to allege a cause for anticipatory breach of this LGIA.

25.3 Audit Rights. Subject to the requirements of confidentiality under Article 22 of this LGIA, the Parties' audit rights shall include audits of a Party's costs pertaining to such Party's performance or satisfaction of obligations owed to the other Party under this LGIA, calculation of invoiced amounts, the ISO's efforts to allocate responsibility for the provision of reactive support to the ISO Controlled Grid, the ISO's efforts to allocate responsibility for interruption or reduction of generation on the ISO Controlled Grid, and each such Party's actions in an Emergency Condition.

25.3.1 The Interconnection Customer and the Participating TO shall each have the right, during normal business hours, and upon prior reasonable notice to the other Party, to audit at its own expense the other Party's accounts and records pertaining to either such Party's performance or either such Party's satisfaction of obligations owed to the other Party under this LGIA. Subject to Article 25.3.2, any audit authorized by this Article shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to each such Party's performance and satisfaction of obligations under this LGIA. Each such Party shall keep such accounts and records for a period equivalent to the audit rights periods described in Article 25.4.

25.3.2 Notwithstanding anything to the contrary in Article 25.3, each Party's rights to audit the ISO's accounts and records shall be as set forth in Article 12 of the ISO Tariff.

25.4 Audit Rights Periods.

25.4.1 Audit Rights Period for Construction-Related Accounts and Records. Accounts and records related to the design, engineering, procurement, and construction of Participating TO's Interconnection Facilities, Network Upgrades, and Distribution Upgrades constructed by the Participating TO shall be subject to audit for a period of twenty-four months following the Participating TO's issuance of a final invoice in accordance with Article 12.2. Accounts and records related to the design, engineering, procurement, and construction of Participating TO's Interconnection Facilities and/or Stand Alone Network Upgrades constructed by the Interconnection Customer shall be subject to audit and verification by the Participating TO and the ISO for a period of twenty-four months following the Interconnection Customer's issuance of a final invoice in accordance with Article 5.2(8).

25.4.2 Audit Rights Period for All Other Accounts and Records. Accounts and records related to a Party's performance or satisfaction of all obligations under this LGIA other than those described in Article 25.4.1 shall be subject to audit as follows: (i) for an audit relating to cost obligations, the applicable audit rights period shall be twenty-four months after the auditing Party's receipt of an invoice giving rise to such cost obligations; and (ii) for an audit relating to all other obligations, the applicable audit rights period shall be twenty-four months after the event for which the audit is sought; provided that each Party's rights to audit the ISO's accounts and records shall be as set forth in Article 12 of the ISO Tariff.

25.5 Audit Results. If an audit by the Interconnection Customer or the Participating TO determines that an overpayment or an underpayment has occurred with respect to the other Party, a notice of such overpayment or underpayment shall be given to the other Party together with those records from the audit which support such determination. The Party that is owed payment shall render an invoice to the other Party and such invoice shall be paid pursuant to Article 12 hereof.

25.5.1 Notwithstanding anything to the contrary in Article 25.5, the Interconnection Customer's and Participating TO's rights to audit the ISO's accounts and records shall be as set forth in Article 12 of the ISO Tariff, and the ISO's process for remedying an overpayment or underpayment shall be as set forth in the ISO Tariff.

ARTICLE 26. SUBCONTRACTORS

26.1 General. Nothing in this LGIA shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this LGIA; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this LGIA in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

26.2 Responsibility of Principal. The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this LGIA. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the ISO or Participating TO be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under Article 5 of this LGIA. Any applicable obligation imposed by this LGIA upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

26.3 No Limitation by Insurance. The obligations under this Article 26 will not be limited in any way by any limitation of subcontractor's insurance.

ARTICLE 27. DISPUTES

All disputes arising out of or in connection with this LGIA whereby relief is sought by or from the ISO shall be settled in accordance with the provisions of Article 13 of the ISO Tariff, except that references to the ISO Tariff in such Article 13 of the ISO Tariff shall be read as references to this LGIA. Disputes arising out of or in connection with this LGIA not subject to provisions of Article 13 of the ISO Tariff shall be resolved as follows:

27.1 Submission. In the event either Party has a dispute, or asserts a claim, that arises out of or in connection with this LGIA or its performance, such Party (the "disputing Party") shall provide the other Party with written notice of the dispute or claim ("Notice of Dispute"). Such dispute or claim shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the other Party. In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within thirty (30) Calendar Days of the other Party's receipt of the Notice of Dispute, such claim or dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. In the event the Parties do not agree to submit such claim or dispute to arbitration, each Party may exercise whatever rights and remedies it may have in equity or at law consistent with the terms of this LGIA.

27.2 External Arbitration Procedures. Any arbitration initiated under this LGIA shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) Calendar Days of the submission of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) Calendar Days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("Arbitration Rules") and any applicable FERC regulations; provided, however, in the event of a conflict between the Arbitration Rules and the terms of this Article 27, the terms of this Article 27 shall prevail.

27.3 Arbitration Decisions. Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within ninety (90) Calendar Days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this LGIA and shall have no power to modify or change any provision of this Agreement in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with FERC if it affects jurisdictional rates, terms and conditions of service, Interconnection Facilities, or Network Upgrades.

27.4 Costs. Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (1) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or (2) one half the cost of the single arbitrator jointly chosen by the Parties.

ARTICLE 28. REPRESENTATIONS, WARRANTIES AND COVENANTS

28.1 General. Each Party makes the following representations, warranties and covenants:

28.1.1 Good Standing. Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; that it is qualified to do business in the state or states in which the Large Generating Facility, Interconnection Facilities and Network Upgrades owned by such Party, as applicable, are located**;** and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this LGIA and carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this LGIA.

28.1.2 Authority. Such Party has the right, power and authority to enter into this LGIA, to become a Party hereto and to perform its obligations hereunder. This LGIA is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

28.1.3 No Conflict. The execution, delivery and performance of this LGIA does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

28.1.4 Consent and Approval. Such Party has sought or obtained, or, in accordance with this LGIA will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this LGIA, and it will provide to any Governmental Authority notice of any actions under this LGIA that are required by Applicable Laws and Regulations.

ARTICLE 29. [RESERVED]

ARTICLE 30. MISCELLANEOUS

30.1 **Binding Effect**. This LGIA and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

30.2 **Conflicts**. In the event of a conflict between the body of this LGIA and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this LGIA shall prevail and be deemed the final intent of the Parties.

30.3 **Rules of Interpretation**. This LGIA, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this LGIA, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this LGIA), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article of this LGIA or such Appendix to this LGIA, or such Section to the LGIP or such Appendix to the LGIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this LGIA as a whole and not to any particular Article or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

30.4 **Entire Agreement**. This LGIA, including all Appendices and Schedules attached hereto, constitutes the entire agreement among the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between or among the Parties with respect to the subject matter of this LGIA. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, any Party's compliance with its obligations under this LGIA.

30.5 **No Third Party Beneficiaries.** This LGIA is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

30.6 **Waiver**. The failure of a Party to this LGIA to insist, on any occasion, upon strict performance of any provision of this LGIA will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this LGIA shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this LGIA. Termination or Default of this LGIA for any reason by the Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Participating TO. Any waiver of this LGIA shall, if requested, be provided in writing.

30.7 Headings. The descriptive headings of the various Articles of this LGIA have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this LGIA.

30.8 Multiple Counterparts. This LGIA may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

30.9 Amendment. The Parties may by mutual agreement amend this LGIA by a written instrument duly executed by all of the Parties. Such amendment shall become effective and a part of this LGIA upon satisfaction of all Applicable Laws and Regulations.

30.10 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this LGIA by a written instrument duly executed by all of the Parties. Such amendment shall become effective and a part of this LGIA upon satisfaction of all Applicable Laws and Regulations.

30.11 Reservation of Rights. The ISO and Participating TO shall each have the right to make a unilateral filing with FERC to modify this LGIA pursuant to section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder with respect to the following Articles of this LGIA and with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation covered by these Articles:

Recitals, 1, 2.1, 2.2, 2.3, 2.4, 2.6, 3.1, 3.3, 4.1, 4.2, 4.4, 4.5, 5 preamble, 5.4, 5.7, 5.8, 5.9, 5.12, 5.13, 5.18, 5.19.1, 7.1, 7.2, 8, 9.1, 9.2, 9.3, 9.5, 9.6, 9.7, 9.8, 9.10, 10.3, 11.4, 12.1, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24.3, 24.4, 25.1, 25.2, 25.3 (excluding subparts), 25.4.2, 26, 28, 29, 30, Part D, Part F, Part G, and any other Article not reserved exclusively to the Participating TO or the ISO below.

The Participating TO shall have the exclusive right to make a unilateral filing with FERC to modify this LGIA pursuant to section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder with respect to the following Articles of this LGIA and with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation covered by these Articles:

2.5, 5.1, 5.2, 5.3, 5.5, 5.6, 5.10, 5.11, 5.14, 5.15, 5.16, 5.17, 5.19 (excluding 5.19.1), 6, 7.3, 9.4, 9.9, 10.1, 10.2, 10.4, 10.5, 11.1, 11.2, 11.3, 11.5, 12.2, 12.3, 12.4, 24.1, 24.2, 25.3.1, 25.4.1, 25.5 (excluding 25.5.1), 27 (excluding preamble), Part A, Part B, Part C, and Part E.

The ISO shall have the exclusive right to make a unilateral filing with FERC to modify this LGIA pursuant to section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder with respect to the following Articles of this LGIA and with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation covered by these Articles:

3.2, 4.3, 4.6, 11.6, 25.3.2, 25.5.1, and 27 preamble.

The Interconnection Customer, the ISO, and the Participating TO shall have the right to make a unilateral filing with FERC to modify this LGIA pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this LGIA shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

30.12 No Partnership. This LGIA shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership among the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, another Party.

30.13 Joint and Several Obligations. Except as otherwise provided in this LGIA, the obligations of the ISO, the Participating TO, and the Interconnection Customer are several, and are neither joint nor joint and several.

IN WITNESS WHEREOF, the Parties have executed this LGIA in multiple originals, each of which shall constitute and be an original effective agreement among the Parties.

By: ______________________

Title: ______________________

Date:

California Independent System Operator Corporation

By: ______________________

Title: ______________________

Date:

By: ______________________

Title: ______________________

Date:

Appendices to LGIA

Part A
To LGIA

Interconnection Facilities, Network Upgrades and Distribution Upgrades

1. Interconnection Facilities:

(a) [insert Interconnection Customer's Interconnection Facilities]:

(b) [insert Participating TO's Interconnection Facilities]:

2. Network Upgrades:

(a) [insert Stand Alone Network Upgrades]:

(b) [insert Other Network Upgrades]:

(i) [insert Participating TO's Reliability Network Upgrades]

(ii) [insert Participating TO's Delivery Network Upgrades]

3. Distribution Upgrades:

Part B
To LGIA

Milestones

Part C
To LGIA

Interconnection Details

Part D
To LGIA

Security Arrangements Details

Infrastructure security of ISO Controlled Grid equipment and operations and control hardware and software is essential to ensure day-to-day ISO Controlled Grid reliability and operational security. FERC will expect the ISO, all Participating TOs, market participants, and Interconnection Customers interconnected to the ISO Controlled Grid to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and, eventually, best practice recommendations from the electric reliability authority. All public utilities will be expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

The Interconnection Customer shall meet the requirements for security implemented pursuant to the ISO Tariff, including the ISO's standards for information security posted on the ISO's internet web site at the following internet address: http://www.caiso.com/pubinfo/info-security/index.html.

Part E
To LGIA

Commercial Operation Date

This Part E is a part of the LGIA.

[Date]

[ISO Address]

[Participating TO Address]

Re: _____________ Electric Generating Unit

Dear _______________:

On **[Date] [Interconnection Customer]** has completed Trial Operation of Unit No. ___. This letter confirms that [Interconnection Customer] commenced Commercial Operation of Unit No. ___ at the Electric Generating Unit, effective as of **[Date plus one day]**.

Thank you.

[Signature]

[Interconnection Customer Representative]

Part F
To LGIA

Addresses for Delivery of Notices and Billings

Notices:.

ISO:

[To be supplied.]

Participating TO:

[To be supplied.]

Interconnection Customer:

[To be supplied.]

Billings and Payments:

Participating TO:

[To be supplied.]

Interconnection Customer:

[To be supplied.]

ISO:

[To be supplied.]

Alternative Forms of Delivery of Notices (telephone, facsimile or e-mail):

ISO:

[To be supplied.]

Participating TO:

[To be supplied.]

Interconnection Customer:

[To be supplied.]

Part G
To LGIA

Reliability Management System Agreement

RELIABILITY MANAGEMENT SYSTEM AGREEMENT
by and between
[TRANSMISSION OPERATOR]
and
[GENERATOR]

THIS RELIABILITY MANAGEMENT SYSTEM AGREEMENT (the "Agreement"), is entered into this ____ day of _____________, 2002, by and between ________________________ (the “Transmission Operator”) and ________________________ (the “Generator”).

WHEREAS, there is a need to maintain the reliability of the interconnected electric systems encompassed by the WSCC in a restructured and competitive electric utility industry;

WHEREAS, with the transition of the electric industry to a more competitive structure, it is desirable to have a uniform set of electric system operating rules within the Western Interconnection, applicable in a fair, comparable and non-discriminatory manner, with which all market participants comply; and

WHEREAS, the members of the WSCC, including the Transmission Operator, have determined that a contractual Reliability Management System provides a reasonable, currently available means of maintaining such reliability.

NOW, THEREFORE, in consideration of the mutual agreements contained herein, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Transmission Operator and the Generator agree as follows:

1. PURPOSE OF AGREEMENT

The purpose of this Agreement is to maintain the reliable operation of the Western Interconnection through the Generator’s commitment to comply with certain reliability standards.

2. DEFINITIONS

In addition to terms defined in the beginning of this Agreement and in the Recitals hereto, for purposes of this Agreement the following terms shall have the meanings set forth beside them below.

Control Area means an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the Western Interconnection.

FERC means the Federal Energy Regulatory Commission or a successor agency.

Member means any party to the WSCC Agreement.

Party means either the Generator or the Transmission Operator and

Parties means both of the Generator and the Transmission Operator.

Reliability Management System or **RMS** means the contractual reliability management program implemented through the WSCC Reliability Criteria Agreement, the WSCC RMS Agreement, this Agreement, and any similar contractual arrangement.

Western Interconnection means the area comprising those states and provinces, or portions thereof, in Western Canada, Northern Mexico and the Western United States in which Members of the WSCC operate synchronously connected transmission systems.

Working Day means Monday through Friday except for recognized legal holidays in the state in which any notice is received pursuant to Section 8.

WSCC means the Western Systems Coordinating Council or a successor entity.

WSCC Agreement means the Western Systems Coordinating Council Agreement dated March 20, 1967, as such may be amended from time to time.

WSCC Reliability Criteria Agreement means the Western Systems Coordinating Council Reliability Criteria Agreement dated June 18, 1999 among the WSCC and certain of its member transmission operators, as such may be amended from time to time.

WSCC RMS Agreement means an agreement between the WSCC and the Transmission Operator requiring the Transmission Operator to comply with the reliability criteria contained in the WSCC Reliability Criteria Agreement.

WSCC Staff means those employees of the WSCC, including personnel hired by the WSCC on a contract basis, designated as responsible for the administration of the RMS.

3. TERM AND TERMINATION

3.1 Term. This Agreement shall become effective [thirty (30) days after the date of issuance of a final FERC order accepting this Agreement for filing without requiring any changes to this Agreement unacceptable to either Party. Required changes to this Agreement shall be deemed unacceptable to a Party only if that Party provides notice to the other Party within fifteen (15) days of issuance of the applicable FERC order that such order is unacceptable].
[Note: if the interconnection agreement is not FERC jurisdictional, replace bracketed language with: [on the later of: (a) the date of execution; or (b) the effective date of the WSCC RMS Agreement.]]

3.2 Notice of Termination of WSCC RMS Agreement. The Transmission Operator shall give the Generator notice of any notice of termination of the WSCC RMS Agreement by the WSCC or by the Transmission Operator within fifteen (15) days of receipt by the WSCC or the Transmission Operator of such notice of termination.

3.3 Termination by the Generator. The Generator may terminate this Agreement as follows:
(a) following the termination of the WSCC RMS Agreement for any reason by the WSCC or by the Transmission Operator, provided such notice is provided within forty-five (45) days of the termination of the WSCC RMS Agreement;
(b) following the effective date of an amendment to the requirements of the WSCC Reliability Criteria Agreement that adversely affects the Generator, provided notice of such termination is given within forty-five (45) days of the date of issuance of a FERC order accepting such amendment for filing, provided further that the forty-five (45) day period within which notice of termination is required may be extended by the Generator for an additional forty-five (45) days if the Generator gives written notice to the Transmission Operator of such requested extension within the initial forty-five (45) day period; or
(c) for any reason on one year's written notice to the Transmission Operator and the WSCC.

3.4 Termination by the Transmission Operator. The Transmission Operator may terminate this Agreement on thirty (30) days' written notice following the termination of the WSCC RMS Agreement for any reason by the WSCC or by the Transmission Operator, provided such notice is provided within thirty (30) days of the termination of the WSCC RMS Agreement.

3.5 Mutual Agreement. This Agreement may be terminated at any time by the mutual agreement of the Transmission Operator and the Generator.

4. COMPLIANCE WITH AND AMENDMENT OF WSCC RELIABILITY CRITERIA

4.1 Compliance with Reliability Criteria. The Generator agrees to comply with the requirements of the WSCC Reliability Criteria Agreement, including the applicable WSCC reliability criteria contained in Section IV of Annex A thereof, and, in the event of failure to comply, agrees to be subject to the sanctions applicable to such failure. Each and all of the provisions of the WSCC Reliability Criteria Agreement are hereby incorporated by reference into this Agreement as though set forth fully herein, and the Generator shall for all purposes be considered a Participant, and shall be entitled to all of the rights and privileges and be subject to all of the obligations of a Participant, under and in connection with the WSCC Reliability Criteria Agreement, including but not limited to the rights, privileges and obligations set forth in Sections 5, 6 and 10 of the WSCC Reliability Criteria Agreement.

4.2 Modifications to WSCC Reliability Criteria Agreement. The Transmission Operator shall notify the Generator within fifteen (15) days of the receipt of notice from the WSCC of the initiation of any WSCC process to modify the WSCC Reliability Criteria Agreement. The WSCC RMS Agreement specifies that such process shall comply with the procedures, rules, and regulations then applicable to the WSCC for modifications to reliability criteria.

4.3 Notice of Modifications to WSCC Reliability Criteria Agreement. If, following the process specified in Section 4.2, any modification to the WSCC Reliability Criteria Agreement is to take effect, the Transmission Operator shall provide notice to the Generator at least forty-five (45) days before such modification is scheduled to take effect.

4.4 Effective Date. Any modification to the WSCC Reliability Criteria Agreement shall take effect on the date specified by FERC in an order accepting such modification for filing.

4.5 Transfer of Control or Sale of Generation Facilities. In any sale or transfer of control of any generation facilities subject to this Agreement, the Generator shall as a condition of such sale or transfer require the acquiring party or transferee with respect to the transferred facilities either to assume the obligations of the Generator with respect to this Agreement or to enter into an agreement with the Control Area Operator in substantially the form of this Agreement.

5. SANCTIONS

5.1 Payment of Monetary Sanctions. The Generator shall be responsible for payment directly to the WSCC of any monetary sanction assessed against the Generator pursuant to this Agreement and the WSCC Reliability Criteria Agreement. Any such payment shall be made pursuant to the procedures specified in the WSCC Reliability Criteria Agreement.

5.2 Publication. The Generator consents to the release by the WSCC of information related to the Generator's compliance with this Agreement only in accordance with the WSCC Reliability Criteria Agreement.

5.3 Reserved Rights. Nothing in the RMS or the WSCC Reliability Criteria Agreement shall affect the right of the Transmission Operator, subject to any necessary regulatory approval, to take such other measures to maintain reliability, including disconnection, which the Transmission Operator may otherwise be entitled to take.

6. THIRD PARTIES

Except for the rights and obligations between the WSCC and Generator specified in Sections 4 and 5, this Agreement creates contractual rights and obligations solely between the Parties. Nothing in this Agreement shall create, as between the Parties or with respect to the WSCC: (1) any obligation or liability whatsoever (other than as expressly provided in this Agreement), or (2) any duty or standard of care whatsoever. In addition, nothing in this Agreement shall create any duty, liability, or standard of care whatsoever as to any other party. Except for the rights, as a third-party beneficiary with respect to Sections 4 and 5, of the WSCC against Generator, no third party shall have any rights whatsoever with respect to enforcement of any provision of this Agreement. Transmission Operator and Generator expressly intend that the WSCC is a third-party beneficiary to this Agreement, and the WSCC shall have the right to seek to enforce against Generator any provisions of Sections 4 and 5, provided that specific performance shall be the sole remedy available to the WSCC pursuant to this Agreement, and Generator shall not be liable to the WSCC pursuant to this Agreement for damages of any kind whatsoever (other than the payment of sanctions to the WSCC, if so construed), whether direct, compensatory, special, indirect, consequential, or punitive.

7. REGULATORY APPROVALS

This Agreement shall be filed with FERC by the Transmission Operator under Section 205 of the Federal Power Act. In such filing, the Transmission Operator shall request that FERC accept this Agreement for filing without modification to become effective on the day after the date of a FERC order accepting this Agreement for filing. [This section shall be omitted for agreements not subject to FERC jurisdiction.]

8. NOTICES

Any notice, demand or request required or authorized by this Agreement to be given in writing to a Party shall be delivered by hand, courier or overnight delivery service, mailed by certified mail (return receipt requested) postage prepaid, faxed, or delivered by mutually agreed electronic means to such Party at the following address:

_______: ________________________________
____
____
____
Fax: _____________

_______: ________________________________
____
____
____
Fax: _____________

The designation of such person and/or address may be changed at any time by either Party upon receipt by the other of written notice. Such a notice served by mail shall be effective upon receipt. Notice transmitted by facsimile shall be effective upon receipt if received prior to 5:00 p.m. on a Working Day, and if not received prior to 5:00 p.m. on a Working Day, receipt shall be effective on the next Working Day.

9. APPLICABILITY

This Agreement (including all appendices hereto and, by reference, the WSCC Reliability Criteria Agreement) constitutes the entire understanding between the Parties hereto with respect to the subject matter hereof, supersedes any and all previous understandings between the Parties with respect to the subject matter hereof, and binds and inures to the benefit of the Parties and their successors.

10. AMENDMENT

No amendment of all or any part of this Agreement shall be valid unless it is reduced to writing and signed by both Parties hereto. The terms and conditions herein specified shall remain in effect throughout the term and shall not be subject to change through application to the FERC or other governmental body or authority, absent the agreement of the Parties.

11. INTERPRETATION

Interpretation and performance of this Agreement shall be in accordance with, and shall be controlled by, the laws of the State of _______________ but without giving effect to the provisions thereof relating to conflicts of law. Article and section headings are for convenience only and shall not affect the interpretation of this Agreement. References to articles, sections and appendices are, unless the context otherwise requires, references to articles, sections and appendices of this Agreement.

12. PROHIBITION ON ASSIGNMENT

This Agreement may not be assigned by either Party without the consent of the other Party, which consent shall not be unreasonably withheld; provided that the Generator may without the consent of the WSCC assign the obligations of the Generator pursuant to this Agreement to a transferee with respect to any obligations assumed by the transferee by virtue of Section 4.5 of this Agreement.

13. SEVERABILITY

If one or more provisions herein shall be invalid, illegal or unenforceable in any respect, it shall be given effect to the extent permitted by applicable law, and such invalidity, illegality or unenforceability shall not affect the validity of the other provisions of this Agreement.

14. COUNTERPARTS

This Agreement may be executed in counterparts and each shall have the same force and effect as an original.

IN WITNESS WHEREOF, the Transmission Operator and the Generator have each caused this Reliability Management System Agreement to be executed by their respective duly authorized officers as of the date first above written.

____

By: ______________________________
Name:
Title:

____

By: ______________________________
Name:
Title:

Part H
To LGIA

INTERCONNECTION REQUIREMENTS FOR A WIND GENERATING PLANT

Part H sets forth requirements and provisions specific to a wind generating plant. All other requirements of this LGIA continue to apply to wind generating plant interconnections.

A. Technical Standards Applicable to a Wind Generating Plant

i. Low Voltage Ride-Through (LVRT) Capability

A wind generating plant shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the standard below. The LVRT standard provides for a transition period standard and a post-transition period standard.

Transition Period LVRT Standard

The transition period standard applies to wind generating plants subject to FERC Order 661 that have either: (i) interconnection agreements signed and filed with FERC, filed with FERC in unexecuted form, or filed with FERC as non-conforming agreements between January 1, 2006 and December 31, 2006, with a scheduled in-service date no later than December 31, 2007, or (ii) wind generating turbines subject to a wind turbine procurement contract executed prior to December 31, 2005, for delivery through 2007.

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the Participating TO. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles at a voltage as low as 0.15 p.u., as measured at the high side of the wind generating plant step-up transformer (i.e. the transformer that steps the voltage up to the transmission interconnection voltage or “GSU”), after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system.
2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU or to faults that would result in a voltage lower than 0.15 per unit on the high side of the GSU serving the facility.
3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.
4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator, etc.) within the wind generating plant or by a combination of generator performance and additional equipment.
5. Existing individual generator units that are, or have been, interconnected to the network at the same location at the effective date of the Part H LVRT Standard are exempt from meeting the Part H LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Part H LVRT Standard.

Post-transition Period LVRT Standard

All wind generating plants subject to FERC Order No. 661 and not covered by the transition period described above must meet the following requirements:

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the Participating TO. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the ISO Controlled Grid. A wind generating plant shall remain interconnected during such a fault on the ISO Controlled Grid for a voltage level as low as zero volts, as measured at the high voltage side of the wind GSU.
2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU.
3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.
4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator) within the wind generating plant or by a combination of generator performance and additional equipment.
5. Existing individual generator units that are, or have been, interconnected to the ISO Controlled Grid at the same location at the effective date of the Part H LVRT Standard are exempt from meeting the Part H LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Part H LVRT Standard.

ii. Power Factor Design Criteria (Reactive Power)

A wind generating plant shall operate within a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in this LGIA in order to maintain a specified voltage schedule, if the Interconnection System Impact Study shows that such a requirement is necessary to ensure safety or reliability. The power factor range standard can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two, if agreed to by the Participating TO and ISO. The Interconnection Customer shall not disable power factor equipment while the wind plant is in operation. Wind plants shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the Interconnection System Impact Study shows this to be required for system safety or reliability.

iii. Supervisory Control and Data Acquisition (SCADA) Capability

The wind plant shall provide SCADA capability to transmit data and receive instructions from the Participating TO and ISO to protect system reliability. The Participating TO and ISO and the wind plant Interconnection Customer shall determine what SCADA information is essential for the proposed wind plant, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area.

ISO TARIFF APPENDIX W

Interconnection Procedures in Effect Prior to July 1, 2005 ("Amendment 39 Procedures")

Interconnection Procedures in Effect Prior to July 1, 2005 ("Amendment 39 Procedures")

1 Applicability.

These Amendment 39 Procedures are applicable to Small Generating Facilities interconnecting to the ISO Controlled Grid and to Large Generating Facilities in accordance with Section 5.1 of the LGIP. The owner of a planned New Facility, or its designee, is referred to for purposes of this Appendix as a New Facility Operator.

2 Definitions.

2.1 Master Definitions Supplement.

Unless the context otherwise requires, any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Appendix.

2.2 Special Definitions for this Appendix.

In this Appendix, the following words and expressions shall have the meanings set opposite them:

Completed Application Date For purposes of this Appendix, the date on which a New Facility Operator submits an Interconnection Application to the ISO that satisfies the requirements of the ISO Tariff and the TO Tariff of the Interconnecting PTO.

Completed Interconnection Application An Interconnection Application that meets the information requirements as specified by the ISO and posted on the ISO Home Page.

Data Adequacy Requirement Any applicable minimum data requirements of the state agency responsible for generation siting or of any Local Regulatory Authority.

Delivery Upgrade The transmission facilities, other than Direct Assignment Facilities and Reliability Upgrades, necessary to relieve constraints on the ISO Controlled Grid and to ensure the delivery of energy from a New Facility to Load.

Designated Contact Person The person designated by each Participating TO to coordinate with the ISO on the processing and completion of all Interconnection Applications.

Direct Assignment Facility The transmission facilities necessary to physically and electrically interconnect a New Facility Operator to the ISO Controlled Grid at the point of interconnection.

Expedited Interconnection Agreement A contract between a party which has submitted a Request for Expedited Interconnection Procedures and an Interconnection PTO under which the ISO and an Interconnecting PTO agree to process, on an expedited

	basis, the Interconnection Application of a New Facility Operator and which sets forth the terms, conditions, and cost responsibilities for such interconnection.
Good Faith Deposit	The deposit paid to the ISO by a New Facility Operator with submission of its Interconnection Application in accordance with Section 3.2 of this Appendix, in an amount equal to $10,000, including any interest that accrues on the original amount, less any bank fees or other charges assessed on the escrow account. A New Facility Operator may satisfy its deposit obligation through any commercially available financial instrument determined to be satisfactory by the ISO.
Interconnecting PTO	For purposes of this Appendix, the Participating TO that will supply the connection to the New Facility.
Interconnection Application	An application that requests interconnection of a New Facility to the ISO Controlled Grid and that meets the information requirements as specified by the ISO and posted on the ISO Home Page.
New Facility	A planned or Existing Generating Unit that requests, pursuant to this Appendix, to interconnect or modify its interconnection to the ISO Controlled Grid.
New Facility License	A license issued by a federal, state or Local Regulatory Authority that enables an entity to build and operate a Generating Unit.
New Facility Operator	The owner of a planned New Facility, or its designee.
Planning Procedures	Procedures governing the planning, expansion and reliable interconnection to the ISO Controlled Grid that the ISO may, from time to time, develop.
Reliability Upgrade	The transmission facilities, other than Direct Assignment Facilities, beyond the first point of interconnection necessary to interconnect a New Facility safely and reliably to the ISO Controlled Grid, which would not have been necessary but for the interconnection of a New Facility, including network upgrades necessary to remedy short circuit or stability problems resulting from the interconnection of a New Facility to the ISO Controlled Grid. Reliability Upgrades also include, consistent with WSCC practice, the facilities necessary to mitigate any adverse impact a New Facility's interconnection may have on a path's WSCC path rating.
Request for Expedited	
Interconnection Procedures	A written request, submitted pursuant to Section 3.1.1 of this Appendix, by which a New Facility Operator can request expedited processing of its Interconnection Application.
System Impact Study	An engineering study conducted to determine whether a New Facility Operator's request for interconnection to the ISO Controlled Grid would require new transmission additions, upgrades or other mitigation measures.

3 Interconnection Application.

Unless the New Facility Operator has submitted a Completed Interconnection Application to the ISO prior to July 1, 2005, any New Facility Operators shall submit two copies of a Completed Interconnection Application to the ISO in the form specified by the ISO. The ISO will date stamp all copies of the Interconnection Application, retain one executed copy, and, within 1 Business Day, send the other copy to the Designated Contact Person of the Interconnecting PTO. Within 10 Business Days after the Interconnecting PTO receives an Interconnection Application, the ISO and the Interconnecting PTO shall determine whether the application is complete and the ISO will notify the New Facility Operator that its Interconnection Application is complete; or, in the event that the ISO, in consultation with the Interconnecting PTO, determines that the Interconnection Application is incomplete, the ISO will notify the New Facility Operator of the deficiencies or omissions in its application.

3.1 Expedited Procedures For New Facilities.

A New Facility Operator may submit a Request for Expedited Interconnection Procedures in accordance with Section 3.1.1 of this Appendix. The ISO will develop and post on the ISO Home Page the Planning Procedures applicable to such expedited processing of Interconnection Applications.

3.1.1 Request for Expedited Interconnection Procedures.

(a) If it elects to expedite processing of its Completed Interconnection Application, a New Facility Operator shall submit a Request for Expedited Interconnection Procedures within 10 Business Days after receiving a copy of the System Impact Study for the proposed interconnection. The request should be submitted in writing to the ISO and the Interconnecting PTO.

(b) Within 10 Business Days after receiving a Request for Expedited Interconnection Procedures, the ISO and Interconnecting PTO shall provide to applicant the results of any studies required in addition to the System Impact Study, and shall tender an Expedited Interconnection Agreement that requires the applicant to compensate the Interconnecting PTO for all costs reasonably incurred pursuant to the terms of the ISO Tariff and the Interconnecting PTO's applicable TO Tariff for processing the Completed Interconnection Application and providing the requested interconnection.

(c) Concurrent with the provision, by the ISO and the Interconnecting PTO, of the studies referenced in subsection b, above, the Interconnecting PTO and the ISO shall provide to applicant their best estimate of the cost of any needed Direct Assignment Facilities and Reliability Upgrades, Delivery Upgrades, if requested by the New Facility Operator, and other costs that may be incurred in processing the Interconnection Application and providing the requested interconnection, however, unless otherwise agreed by the ISO, and the Interconnecting PTO, and the applicant, such cost estimate shall not be binding and the New Facility Operator shall compensate the ISO and the Interconnecting PTO for all actual interconnection costs reasonably incurred pursuant to the provisions of this Appendix and the Interconnecting PTO's TO Tariff.

(d) The New Facility Operator shall execute and return to the Interconnecting PTO, with a copy to the ISO, such Expedited Interconnection Agreement within 10 Business Days of its receipt or the New Facility Operator's Interconnection Application will be deemed withdrawn. In that event, the New Facility Operator shall reimburse the ISO and the Interconnecting PTO for all costs reasonably incurred in the processing of the Interconnection Application, including the Request for Expedited Interconnection.

3.2 Good Faith Deposit.

(a) Each New Facility Operator that submits an Interconnection Application will on the date of submission also provide a Good Faith Deposit to the ISO. The ISO shall hold the Good Faith Deposit in trust for each applicant in a separate, interest-bearing account.

(b) The ISO shall refund the Good Faith Deposit, with accrued Interest, in the event that:

(i) The ISO determines that the New Facility is not responsible for any interconnection costs, other than study costs; or

(ii) The applicant withdraws its Interconnection Application or its Interconnection Application is deemed withdrawn.

3.3 Posting of Interconnection Applications and Non-disclosure.

The ISO will maintain on its OASIS site an updated list of all pending Interconnection Applications. As soon as practicable after the ISO receives a Completed Interconnection Application, the ISO will post the nearest substation, the capacity (MW) of the New Facility and the year the New Facility is proposed to begin operations. At the time it submits its Interconnection Application, a New Facility Operator may request in writing that the ISO and Interconnecting PTO not publicly disclose the identity of such New Facility Operator. Upon such request, the ISO and Interconnecting PTO will not disclose the identity of the applicant while its Interconnection Application is pending, unless disclosure is permitted under Section 20.3.1 of the ISO Tariff or in the event that an applicant's identity becomes otherwise publicly known.

4 Interconnection.

4.1 Detailed Planning Procedures.

The provisions set forth in this Appendix shall govern the interconnection of New Facilities to the ISO Controlled Grid, including the costs of such interconnection. The ISO shall also maintain on the ISO Home Page detailed Planning Procedures and interconnection standards for all such interconnections.

4.2 Studies.

(a) Except as provided in Section 4.2(d) of this Appendix, for each Completed Interconnection Application, the ISO will direct the Interconnecting PTO to perform the required System Impact Study and Facility Study, and any additional studies the ISO determines to be reasonably necessary.

(b) The Interconnecting PTO will complete or cause to be completed all studies directed by the ISO within the timelines provided in this section. Any studies performed by the ISO or by a third party at the direction of the ISO shall also be completed within the timelines provided in this section.

(c) Each New Facility Operator shall pay the reasonable costs of all System Impact and Facility Studies performed by or at the direction of the ISO or the Interconnecting PTO, and any additional studies the ISO determines to be reasonably necessary in response to the Interconnection Application, including any iterative study costs required for other New Facility Operator's that have established a new queue position due to the New Facility Operator either withdrawing its Interconnection Application or because its queue position has been modified pursuant to the procedures in Section 4.4 of this Appendix. A New Facility Operator shall also pay the reasonable cost of Interconnecting PTO review of any System Impact Study or Facility Study that is performed by a New Facility Operator or its designee pursuant to subsection (d).

(d) A New Facility Operator may perform its own System Impact Study and Facility Study, or contract with a third party to perform the System Impact Study and Facility Study, and shall so notify the ISO and the Interconnecting PTO of this election at the time it submits its Interconnection Application. Any such study or studies performed by a New Facility Operator or third party must be completed within the timelines identified in Sections 4.2.1 and 4.2.2 of this Appendix. To the extent that the ISO and Interconnecting PTO disagree on the adequacy of the New Facility Operator or third party-sponsored study, the ISO will determine the adequacy of the study, subject to the ISO's ADR Procedures. The ISO and Interconnecting PTO shall complete their review of the New Facility Operator's study within 30 calendar days of receipt of the completed study. The results of any study or studies performed by a New Facility Operator or third party must be approved by both the ISO and the Interconnecting PTO.

4.2.1 System Impact Study Procedures.

Within 10 Business Days after receiving a Completed Interconnection Application by the Interconnecting PTO, the ISO and the Interconnecting PTO will determine, on a non-discriminatory basis, whether a System Impact Study is required. The ISO and the Interconnecting PTO will make such determination based on the ISO Grid Planning Criteria and the transmission assessment practices outlined in the ISO Planning Procedures posted on the ISO Home Page. The ISO and Interconnecting PTO will utilize, to the extent possible, existing transmission studies. The System Impact Study will identify whether any Direct Assignment Facilities and Reliability Upgrades are needed, as well as, if requested by the New Facility Operator, any Delivery Upgrades necessary to deliver a New Facility's full output over the ISO Controlled Grid. The System Impact Study will also identify any adverse impact on Encumbrances existing as of the Completed Application Date.

If the ISO and the Interconnecting PTO determine that a System Impact Study is necessary, the Interconnecting PTO shall within 20 Business Days of receipt of Completed Interconnection Application, tender a System Impact Study Agreement that defines the scope, content, assumptions and terms of reference for such study, the estimated time required to complete it, and pursuant to which the applicant shall agree to reimburse the Interconnecting PTO for the reasonable actual costs of performing the required study. The New Facility Operator shall execute the System Impact Study Agreement and return it to the Interconnecting PTO within 10 Business Days, together with payment for the reasonable estimated cost, as provided by the Interconnecting PTO, of the System Impact Study. Alternatively, a New Facility Operator can request that the Interconnecting PTO proceed with the System Impact Study and abide by the terms, conditions, and cost assignment of the System Impact Study Agreement as determined through the ISO ADR Procedures, provided that such request is accompanied by payment for the reasonable estimated cost, as provided by the Interconnecting PTO, of the System Impact Study. If a New Facility Operator elects neither to execute the System Impact Study Agreement nor to rely upon the ISO ADR Procedures, such New Facility Operator's Completed Application will be deemed withdrawn. If the New Facility Operator's application is deemed withdrawn, the New Facility Operator will compensate the Interconnecting PTO for all reasonable costs incurred to that date in processing the Completed Interconnection Application.

The Interconnecting PTO will use due diligence to complete the System Impact Study within 60 calendar days of receipt of payment and the System Impact Study Agreement or initiation of the ISO ADR Procedures. If the Interconnecting PTO cannot complete the System Impact Study within 60 calendar days, the Interconnecting PTO will notify the New Facility Operator, in writing, of the reason why additional time is required to complete the required study and the estimated completion date.

4.2.2 Facility Study Procedures.

If a System Impact Study indicates that additions or upgrades to the ISO Controlled Grid are needed to satisfy a New Facility Operator's request for interconnection, the Interconnecting PTO shall, within 15 Business Days of the completion of the System Impact Study, tender to a New Facility Operator a Facility Study Agreement that defines the scope, content, assumptions and terms of reference for such study, the estimated time to complete the required study, and pursuant to which the applicant agrees to reimburse the Interconnecting PTO for the actual costs of performing the required Facility Study. The New Facility Operator shall execute the Facility Study Agreement and return it to the Interconnecting PTO within 10 Business Days, together with payment for the reasonable estimated cost, as provided by the Interconnecting PTO, of the Facility Study. Alternatively, a New Facility Operator may request that the Interconnecting PTO proceed with the Facility Study and abide by the terms, conditions, and cost assignment of the Facility Study Agreement ultimately determined through the ISO ADR Procedures, provided that such request is accompanied by payment for the reasonable estimated cost, as provided by the Interconnecting PTO, of the Facility Study. If a New Facility Operator elects either to not execute the Facility Study Agreement or to rely upon the ISO ADR Procedures, such New Facility Operator's Completed Application will be deemed withdrawn. If the New Facility Operator's application is deemed withdrawn, the New Facility Operator will compensate the Interconnecting PTO for all reasonable costs incurred to that date in processing the Completed Application.

The Interconnecting PTO will use due diligence to complete the Facility Study within 60 calendar days of receipt of payment and the Facility Study Agreement or initiation of the ISO ADR Procedures. If the Interconnecting PTO cannot complete the Facility Study within 60 calendar days, the Interconnecting PTO will notify the New Facility Operator, in writing, of the reason why additional time is required to complete the required study and the estimated completion date.

A New Facility Operator shall be entitled to amend its Completed Interconnection Application once without losing its queue position. Such amendment shall occur on or before 10 Business Days following the Date the Interconnecting PTO tenders a Facility Study Agreement. Specifically, as an alternative to executing and returning a Facility Study Agreement, a New Facility Operator may submit an amendment to its Completed Interconnection Application to reflect a revised configuration for its New Facility. The amended Completed Interconnection Application shall be treated in accordance with Section 4.2.1 of this Appendix and the New Facility Operator's Completed Interconnection Application shall not be deemed withdrawn, and it shall maintain its exiting queue position, if (a) the amended Completed Interconnection Application is received by the Interconnecting PTO within 10 Business Days of the Interconnecting PTO's tender of a Facility Study Agreement; and (b) the New Facility Operator has not submitted a previous amendment to the Completed Interconnection Application. In the event a New Facility Operator amends its Completed Interconnection Application, it will be responsible for any additional study costs that result from that amendment, including costs associated with revisions to studies for other applicants holding later queue positions.

4.3 Execution of Interconnection Agreement.

Following completion of the Facilities Study, a New Facility Operator proposing to interconnect a Large Generating Facility shall continue the interconnection process in accordance with Section 11.2 of the LGIP. Within 10 Business Days of receipt of a completed Facility Study, a New Facility Operator proposing to interconnect a Small Generating Facility shall request the Interconnecting PTO to provide to such applicant an Interconnection Agreement. The Interconnecting PTO shall provide an Interconnection Agreement to an applicant within 30 Business Days of receipt of the request for an Interconnection Agreement. If the ISO and Interconnecting PTO determine, pursuant to Sections 4.2.1 and 4.2.2 of this Appendix, that either:

(a) a New Facility Operator's Interconnection Application can be accommodated and that such New Facility Operator will not incur costs for Reliability Upgrades, the New Facility Operator shall execute the Interconnection Agreement within 10 Business Days of receipt of the Interconnection Agreement; or

(b) a New Facility Operator's Interconnection Application will necessitate Reliability Upgrades, the New Facility Operator shall execute the Interconnection Agreement within 30 Business Days of receipt of the Interconnection Agreement or, if a New Facility Operator and the Interconnecting PTO are unable to agree on the rates, terms and conditions of the Interconnection Agreement, the New Facility Operator may request that the Interconnecting PTO file an unexecuted Interconnection Agreement at FERC. If a New Facility Operator does request that the Interconnecting PTO file an unexecuted Interconnection Agreement at FERC, the New Facility Operator shall agree to abide by the rates, terms and conditions of such Interconnection Agreement ultimately determined by FERC to be just and reasonable.

4.4 Queuing.

(a) The ISO and Interconnecting PTO will process all Interconnection Applications based on the New Facility's Completed Application Date.

(b) The queue position for each New Facility that has submitted an Interconnection Application will be established according to the Completed Application Date and the New Facility's compliance with the milestones set forth in Section 4.4.1 of this Appendix.

(c) For any New Facility Operator that submitted a request to interconnect to a Interconnecting PTO prior to June 1, 2002 (the effective date of the Amendment 39 Procedures), such New Facility Operator's position in the queue will be based on its Completed Application Date as that term was defined in the Interconnecting PTOs TO Tariff in effect at the time the New Facility Operator submitted a request to interconnect to the Interconnecting PTO.

4.4.1 Queuing Milestones.

(a) To maintain its queue position, each New Facility Operator must timely comply with the requirements of the ISO Tariff and the TO Tariff of the Interconnecting PTO and must, within 6 months of its Completed Application Date, satisfy all applicable Data Adequacy Requirements of state and local siting and other regulatory authorities. Any New Facility Operator not subject to state siting requirements must satisfy the information requirements set forth in 18 C.F.R. § 2.20. The ISO will permit a New Facility Operator to retain its queue position if such New Facility Operator requests an extension of the six-month period at least 5 Business Days prior to the expiration of such period. Such extension will be limited to one period of 30 Business Days and additional extensions shall not be granted. A New Facility Operator that does not maintain its queue position, but later satisfies the Data Adequacy Requirements, or the requirements of 18 C.F.R. § 2.20 if applicable, will be placed in a queue position comparable to that of other New Facility Operators that have satisfied the Data Adequacy Requirements, or the requirements of 18 C.F.R. § 2.20, as of the same date. At that time, the ISO and the Interconnecting PTO will determine whether a new System Impact Study must be performed based on the revised queue position of such New Facility Operator.

(b) Upon satisfaction of the Data Adequacy Requirements, or the requirements of 18 C.F.R. § 2.20 if applicable, each New Facility Operator, in order to maintain its queue position, must obtain a New Facility License within 15 months after satisfying the Data Adequacy Requirements. A New Facility Operator that does not obtain a New Facility License within the allowed time and does not maintain its queue position, but later obtains a New Facility License, will be placed in a queue position comparable to other New Facility Operators that have satisfied comparable milestones as of that date.

(c) Any New Facility whose New Facility License or building permit expires or is rescinded will not maintain its queue position.

(d) A New Facility Operator that has submitted a dispute under Article 13 of the ISO Tariff regarding any part of this Appendix may request that the presiding judge, arbitrator, or mediator of the dispute suspend its obligation to meet milestones in order to maintain its queue position. In the event such a suspension is granted, the New Facility Operator must satisfy the missed milestones specified in this Section 4.4.1 of this Appendix within 30 calendar days of the date the decision on the dispute becomes final.

4.5 Coordination of Critical Protective Systems.

New Facility Operators shall coordinate with the ISO, Participating TOs and UDCs to ensure that a New Facility Operator's Critical Protective Systems, including relay systems, are installed and maintained in order to function on a coordinated and complementary basis with ISO Controlled Grid Critical Protective Systems and the protective systems of the Participating TOs and UDCs. The ISO and Participating TOs will make available all information necessary for a New Facility Operator to determine whether its Critical Protective Systems are compatible with those of the ISO, Participating TOs and UDCs. The ISO and New Facility Operators shall also coordinate with entities that own, operate or control facilities outside of the ISO Controlled Grid to ensure that a New Facility's Critical Protective Systems function on a coordinated and complementary basis with such entities Critical Protective Systems.

5 Cost Responsibility of New Facility Operators.

(a) Each New Facility Operator shall pay the costs of required studies in accordance with Section 4.2 of this Appendix and the costs identified in this Section 5. The ISO and Interconnecting PTO will provide each New Facility Operator an estimate of its total cost responsibility under this Section. A New Facility Operator shall be responsible for the actual costs of all Direct Assignment Facilities and Reliability Upgrades necessitated by its Completed Interconnection Application. The Interconnecting PTO will provide each New Facility Operator a detailed record of the actual costs assessed to it under this Section. A New Facility Operator may request the Interconnecting PTO to provide any additional information reasonably necessary to audit the actual costs the New Facility Operator is assessed.

(b) The ISO and Interconnecting PTO will process all Interconnection Applications, and determine the cost responsibility of each New Facility Operator based on the New Facility Operator's Completed Application Date or, if applicable, based on the queue position determined by the procedure described in Section 4.4.1(b) of this Appendix. The ISO and Interconnecting PTO will process simultaneously all interconnection requests with the same Completed Application Date.

(c) Each New Facility Operator shall pay the costs of planning, installing, operating and maintaining the following facilities: (i) Direct Assignment Facilities, and, if applicable, (ii) Reliability Upgrades. In addition, each New Facility Operator shall implement all existing operating procedures necessary to safely and reliably connect the New Facility to the facilities of the Interconnecting PTO and to ensure the ISO Controlled Grid's conformance with the ISO Grid Planning Criteria, and shall bear all costs of implementing such operating procedures. The New Facility Operator shall be responsible for the costs of Reliability Upgrades only if the necessary facilities are not included in the ISO Controlled Grid Transmission Expansion Plan approved as of the New Facility Operator's Completed Application Date, or the date for the installation of a facility is advanced by the interconnection of the New Facility, in which case the New Facility Operator shall be responsible only for the incremental costs associated with the earlier installation of the facility.

(d) Each New Facility Operator may, at its own discretion, sponsor, pursuant to Section 3.2 of the ISO Tariff, any Delivery Upgrades.

5.1 Maintenance of Encumbrances.

No New Facility shall adversely affect the ability of the Interconnecting PTO to honor its Encumbrances existing as of the time a New Facility submits its Interconnection Application to the ISO. The Interconnecting PTO, in consultation with the ISO, shall identify any such adverse effect on its Encumbrances in the System Impact Study performed under Section 4.2.1 of this Appendix. To the extent the Interconnecting PTO determines that the connection of the New Facility will have an adverse effect on Encumbrances, the New Facility Operator shall mitigate such adverse effect.

5.2 Settlement of Interconnection Costs.

Payment for Direct Assignment Facilities and Reliability Upgrades shall be made by the New Facility Operator to the Interconnecting PTO pursuant to the terms of payment set forth in the Interconnection Agreement between the parties.

6 Energization.

Neither the ISO nor the Interconnecting PTO shall be obligated to energize, nor shall the New Facility Operator be entitled to have its interconnection to the ISO Controlled Grid energized, unless and until an Interconnection Agreement has been executed, or filed at FERC pursuant to Section 4.3 of this Appendix, and becomes effective and such New Facility Operator has demonstrated to the ISO's reasonable satisfaction that it has complied with all of the requirements of this Appendix.

ISO TARIFF APPENDIX X

Dynamic Scheduling Protocol (DSP)

ISO TARIFF APPENDIX X

Dynamic Scheduling Protocol (DSP)

DSP 2 CONSISTENCY WITH NERC/WECC POLICIES AND REQUIREMENTS

DSP 2.1 Scheduling and operation of dynamic scheduling functionalities must comply with all applicable NERC and WECC policies and requirements regarding inter-Control Area scheduling, in accordance with Section 4.5.4.3 of the ISO Tariff.

DSP 2.2 Scheduling and operation of dynamic scheduling functionalities must be consistent with the NERC Dynamic Transfer White Paper and all NERC standards or policies.

DSP 2.3 All new dynamic functionality implementations may be subject to NERC-specified peer review.

DSP 3 CONTRACTUAL RELATIONSHIPS

DSP 3.1 The Host Control Area and all Intermediary Control Areas must each execute an Interconnected Control Area Operating Agreement (“ICAOA”) with the ISO, with accompanying service schedule, or a special agreement particular to the operation of the functionality supporting dynamic imports of Energy, Supplemental Energy, and/or Energy associated with non-regulating Ancillary Services to the ISO Control Area.

DSP 3.2 The Scheduling Coordinator for the System Resource must execute a special agreement with the ISO governing the operation of the dynamic scheduling functionality, which agreement will include a provision for its termination based on failure to comply with these standards.

DSP 3.3 The Scheduling Coordinator for the System Resource must have the necessary operational and contractual arrangements in place with the Host Control Area (*see* Section 5 below). Such arrangements must include the Host Control Area operator's ability to receive telemetry from the System Resource and to issue a dynamic schedule signal pertinent to that System Resource to the ISO. Proof of such arrangements must be provided to the ISO.

DSP 4 COMMUNICATIONS, TELEMETRY, AND OTHER TECHNICAL REQUIREMENTS

DSP 4.1 The communication and telemetry requirements set forth in the ISO’s Standards for Imports of Regulation will apply to all dynamic schedules, except for (a) those dynamic functionalities established prior to the ISO Operations Date, (b) the requirements that are specific solely to Regulation, and (c) the requirements set forth below.

DSP 4.2 Dedicated dual redundant communications links between the ISO's EMS and the Host Control Area EMS are required.

DSP 4.3 The primary circuit will be T1-class, or equivalent, utilizing the inter-control center communications protocol ("ICCP"). The backup circuit will be diversely routed between the Host Control Area EMS and the ISO Control Area EMS on separate physical paths and devices.

DSP 4.4 Dedicated dual redundant communications links between the Host Control Area EMS and every Intermediary Control Area EMS are required.

DSP 4.5 The Control Area hosting a dynamically scheduled System Resource must have a mechanism implemented to override the associated dynamic signal.

DSP 4.6 The dynamic signal must be properly incorporated into all involved Control Areas' ACE equations.

DSP 4.7 The System Resource must have communications links with the Host Control Area consistent with these standards.

DSP 5 LIMITS ON DYNAMIC IMPORTS

DSP 5.1 The ISO reserves the right to establish limits applicable to the amount of any Ancillary Services and/or Supplemental Energy imported into the ISO Control Area, whether delivered dynamically or statically. Such limits may be established based on any one, or a combination, of the following considerations: a percentage of, or a specific import limit applicable to, total ISO Control Area requirements; a percentage at, or a specific import limit applicable to, a particular Scheduling Point or a branch group; a percentage of, or a specific import limit applicable to, total requirements in a specific Congestion Zone; or operating factors which may include, but are not limited to, operating nomograms, Remedial Action Schemes, protection schemes, scheduling and curtailment procedures, or any potential single points of failure associated with the actual delivery process.

DSP 5.2 The ISO may, at its discretion, either limit or forego procuring Ancillary Services at particular Control Area interties to ensure that Operating Reserves are adequately dispersed throughout the ISO Control Area as required by WECC Minimum Operating Reliability Criteria ("MORC").

DSP 5.3 A dynamically scheduled System Resource and its schedules must be permanently associated with a particular ISO intertie (the ISO may, from time to time and at its discretion, allow for a change in such pre-established association of the dynamically scheduled System Resource with a particular ISO intertie).

DSP 6 OPERATING AND SCHEDULING REQUIREMENTS

DSP 6.1 For any operating hour for which Energy, Supplemental Energy, and/or Ancillary Services (and associated Energy) is scheduled dynamically to the ISO from the System Resource, a firm (or non-interruptible for that hour) matching transmission service must be reserved across the entire dynamic schedule transmission path external to the ISO Control Area.

DSP 6.2 All dynamic schedules associated with newly implemented dynamically scheduled System Resources must be electronically tagged (e-tagged).

DSP 6.3 Formal inter-Control Area dynamic schedules may be issued only by the dynamically scheduled System Resource's Host Control Area and must be routed through the EMSs of all Intermediary Control Areas (such schedules would be considered "wheel-through" schedules by Intermediary Control Areas).

DSP 6.4 The ISO will treat dynamically scheduled Energy as a resource contingent firm import. The ISO will procure (or allow for self-provision of) WECC MORC-required Operating Reserves for loads served by dynamically scheduled System Resources.

DSP 6.5 All Energy schedules associated with dynamically scheduled imports of Spinning Reserve and Non-Spinning Reserve will be afforded similar treatment (i.e., resource contingent firm).

DSP 6.6 The dynamic signal must be integrated over time by the Host Control Area for every operating hour.

DSP 6.7 Notwithstanding any dispatches of the System Resource in accordance with the ISO Tariff, the ISO shall have the right to issue operating orders to the System Resource either directly or through the Host Control Area for emergency or contingency reasons, or to ensure the ISO's compliance with operating requirements based on WECC or NERC requirements and policies (e.g., WECC's Unscheduled Flow Reduction Procedure). However, such operating orders may be issued only within the range of the ISO-accepted Energy, Ancillary Services, and/or or Supplemental Energy Schedules and bids for a given operating hour (or the applicable "sub-hour" interval).

DSP 6.8 If there is no dynamic schedule in the ISO's Day-Ahead, Hour-Ahead, or Supplemental Energy markets, the dynamic signal must be at "zero" ("0") except when in response to ISO's Dispatch Instructions associated with accepted Ancillary Services and/or Supplemental Energy bids.

DSP 6.9 The Scheduling Coordinator of the dynamically scheduled System Resource must have the ability to override the associated dynamic schedule in order to respond to the operating orders of the ISO or the Host Control Area.

DSP 6.10 Unless the dynamically scheduled System Resource (1) is implemented as a directly-telemetered load-following functionality, (2) is base-loaded Regulatory Must Take Generation, or (3) responds to an ISO intra-hour Dispatch Instruction, the dynamic schedule representing such resource must follow WECC-approved practice of 20-minute ramps centered at the top of the hour. The ISO does not provide any special settlements treatment nor offer any ISO Tariff exemptions for dynamic load following functionalities.

DSP 6.11 In real time the dynamic schedule may not exceed the maximum value established by the sum of the Day-Ahead and Hour-Ahead accepted Energy and Ancillary Services Schedules plus any accepted Supplemental Energy bids plus any response to the ISO's real-time Dispatch Instructions. The composite value of the dynamic schedule derived from the Day-Ahead and Hour-Ahead accepted Schedules plus any Supplemental Energy bids and Dispatch Instruction response represents not only the estimated dynamically scheduled System Resource's Energy but also the transmission reservation on the associated ISO intertie.

DSP 6.12 Only one dynamically scheduled System Resource may be associated with any one physical generating resource.

DSP 6.13 If the Scheduling Coordinator for the dynamically scheduled System Resource desires to participate in ISO's Regulation market, all provisions of the ISO's Standards for Imports of Regulation shall apply.

DSP 7 CERTIFICATION, TESTING, AND PERFORMANCE MONITORING OF DYNAMIC IMPORTS OF ANCILLARY SERVICES

Scheduling Coordinators and Host Control Areas that are already certified under the ISO's Standards for Imports of Regulation will be deemed to have fulfilled the technical implementation requirements of this Protocol; however, such Scheduling Coordinators and Control Areas must still be certified separately for each non-Regulating Ancillary Service (all presently implemented

Regulation import functionalities may be subject to review to ensure consistency between such functionalities and the requirements of this Protocol). Scheduling Coordinators and Host Control Areas that wish to be certified for imports of Regulation shall be subject to certification under the Standards for Imports of Regulation, subject to verification of consistency with the requirements of this Protocol.

DSP 7.1 The Scheduling Coordinator and Host Control Area operator must jointly request the certification of a System Resource to provide Ancillary Services for the ISO Control Area and cooperate in the testing of such System Resource (see the "Scheduling Coordinator & Host Control Area Operator Request for Certification of Dynamic Imports of Ancillary Services" certification form attached as Attachment A to this Protocol.

DSP 7.2 Only ISO tested and certified System Resources will be allowed to bid and/or self-provide Ancillary Services into the ISO Control Area.

DSP 7.3 Dynamic Ancillary Services imports will be certified through testing, in accordance with the relevant sections of the ISO's Operating Procedure G-213. All requests for certification of dynamic Ancillary Services imports will be reviewed and approved by the ISO with respect to any technical limitations imposed by existing operational considerations, such as Remedial Action Schemes, operating nomograms, and scheduling procedures. These reviews may impose certain Ancillary Services import limits in addition to those outlined in Section 4.1. Therefore, interested parties are advised and encouraged to contact the ISO before they begin the process of the necessary systems design, preparation, and implementation for import of Ancillary Services to the ISO Control Area.

DSP 7.4 The ISO will measure the performance of the dynamic Energy schedule associated with accepted Ancillary Services bids against (1) the awarded range of Ancillary Service capacity; (2) the certified limits; and (3) the bid ramp rate, which shall be validated by the ISO against the certified ramp rate.

DSP 7.5 The Scheduling Coordinator for the System Resource and the Host Control Area must notify the ISO should any changes, modifications, or upgrades affecting control and/or performance of the System Resource be made. Upon such notification, the ISO, at its discretion, may require that the System Resource and Host Control Area be re-certified to import Ancillary Services into the ISO Control Area.

DSP 8 COMPLIANCE, LOSSES, AND FINANCIAL SETTLEMENTS

DSP 8.1 Energy delivered in association with dynamically scheduled System Resources will be subject to all provisions of the ISO's Imbalance Energy markets, including Uninstructed Deviation Penalties ("UDP") (just as is the case with ISO intra-Control Area Generating Units of Participating Generators).

DSP 8.2 Dynamically scheduled and delivered Ancillary Services will be subject to the ISO's compliance monitoring and remedies, just as any ISO intra-Control Area Generating Units of Participating Generators.

DSP 8.3 All Day-Ahead and Hour-Ahead submitted dynamic schedules shall be subject to ISO Congestion mitigation and as such may not exceed their transmission reservations in real time (with the exception of intra-hour Dispatch Instructions of the Energy associated with accepted Ancillary Services or Supplemental Energy bids).

DSP 8.4 All dynamically scheduled and delivered Energy shall be subject to the standard ISO transmission loss calculation associated with the particular intertie ("TMMs" or ISO market redesign alternative).

DSP 8.5 Any transmission losses attributed to the dynamic schedule on transmission system(s) external to the ISO Control Area will be the responsibility of the owner(s)/operator(s) of the dynamically scheduled System Resource.

DSP 8.6 A predetermined, mutually agreed, and achievable "Pmax-like" fixed MW value will be established for every dynamically scheduled System Resource to be used as the basis for the UDP calculation. Responsible Scheduling Coordinators will be able to report de-rates affecting the dynamically scheduled System Resource via the ISO's "SLIC" outage reporting system.

DSP 8.7 Should there be any need or requirement, whether operational or procedural, for the ISO to make real time adjustments to the ISO's inter-Control Area schedules (to include curtailments), dynamic schedules shall be treated in the same manner as similarly situated and/or effective static ISO schedules.

DSP ATTACHMENT A

Scheduling Coordinator & Host Control Area Operator

Request for Certification of

Imports of Spinning and Non-Spinning Reserves for which the associated Energy is delivered dynamically from a System Resource

In accordance with the ISO Tariff, Protocols and Operating Procedures, ______________________________, as Scheduling Coordinator, and ______________________________, as Host Control Area operator (as such term is referred to in the ISO Dynamic Scheduling Protocol), collectively referred to as “Parties,” or individually as “Party,” hereby request the certification of the Parties and the System Resource(s) identified in the table below as a provider of Ancillary Services and associated Energy to the ISO Control Area subject to the Dynamic Scheduling Protocol. Further, the Parties acknowledge that their ability to import Ancillary Services and associated Energy will be tested for certification in accordance with ISO Operating Procedure G-213.

With this request for certification, the Parties recognize that the ISO Tariff, Protocols, and applicable agreements require the Host Control Area operator to issue dynamic Energy schedules to the ISO based on the Scheduling Coordinator's self-provided or bid external imports of non-Regulation Ancillary Services from the System Resource(s) at any time during the operating hour.

With this request for certification, the Host Control Area operator represents and warrants that it has in place the required communications links with the ISO Control Area in order to facilitate the delivery of Ancillary Services and associated Energy from the System Resource.

With this request for certification, the Scheduling Coordinator represents and warrants that it has made the appropriate arrangements for and has put in place the equipment and services necessary for the delivery of Ancillary Services and associated Energy from the System Resource to the point of interchange ("Scheduling Point") with the ISO Control Area in accordance with the Dynamic Scheduling Protocol.

The Scheduling Coordinator further certifies that any and all dynamic imports of Energy associated with self-provided or bid imports of non-Regulation Ancillary Services will be deliverable over non-interruptible, non-recallable transmission rights, from the source of the associated Energy to the Scheduling Point with the ISO Control Area.

System Resource	External Host Control Area in which System Resource is Located	Scheduling Point (ISO interchange ID)	Maximum Amount of Ancillary Services Capacity to be Certified (MW)	Maximum Ramp Rate to be Certified (MW/minute)
1				
2				
3				
4				
5				

Subsequent to the initial filing of this request for certification with the ISO, any prospective changes jointly made by the Parties may be filed with the Scheduling Coordinator's ISO Client Relations representative, who will acknowledge the receipt of such requested changes and indicate the date on which such changes may be tested and become effective if ISO testing proves successful. Such changes will be made by the ISO as soon as practicable, with reasonable efforts made to implement them within sixty (60) days of receipt of the requested changes.

This document _____ (does) _____ (does not) contain requested changes to previously effective certification.

Certification Requested By:

____, as the Scheduling Coordinator

Name: __________________________________

Title: __________________________________

Date: __________________________________

____, as the Host Control Area Operator

Name: __________________________________

Title: __________________________________

Date: __________________________________

CERTIFICATION REQUEST ACKNOWLEDGED by:

____

California Independent System Operator Corporation

Name: __________________________________

Title: __________________________________

Date: __________________________________

ISO TARIFF APPENDIX Y

Scheduling Protocol (SP)

Scheduling Protocol (SP)

SP 3.2 Day-Ahead Market

The Day-Ahead Market is a forward market for Energy and Ancillary Services. The Day-Ahead Market operates individually for each Settlement Period of the Trading Day. The Day-Ahead Market starts at 6:00 pm two days ahead of the Trading Day and ends at 1:00 pm on the day ahead of the Trading Day, at which time the ISO issues the Final Day-Ahead Schedules.

SP 3.2.1 By 6:00 pm, Two Days Ahead

By 6:00 pm two days ahead of the Trading Day (for example, by 6:00 pm on Monday for the Wednesday Trading Day), the ISO will publish, via WEnet, the following information for each Settlement Period of the Trading Day:

(a) a forecast of conditions on the ISO Controlled Grid, including transmission line and other transmission facility Outages;

(b) a forecast of Generation Meter Multipliers (GMMs), as developed in accordance with Section 27.2.1, at each Generator location and Scheduling Point;

(c) a forecast of system Demands by Zone;

(d) an estimate of the Ancillary Services requirements for the ISO Control Area (see the ASRP for the details on these requirements);

(e) a forecast of Loop Flows over interfaces with other Control Areas;

(f) a forecast of the potential for Congestion conditions;

(g) a forecast of total and Available Transfer Capacity over certain rated transmission paths and Inter-Zonal Interfaces;

(h) a description of any temporary adjustments to Ancillary Service standards that the ISO has determined by that time to make, in accordance with Section 8.2.2.

SP 3.2.1.1 By 5:00 am, One Day Ahead

By no later than 5:00 am on the day before the Trading Day, the ISO will notify Scheduling Coordinators of the Energy Requirements from any Reliability Must-Run Units which the ISO requires to run in the Trading Day, except in those instances where a Reliability Must-Run Unit requires more than one day's notice, in which case the ISO may notify the applicable Scheduling Coordinator more than one day in advance of the Trading Day;

SP 3.2.1.2 By 6:00 am, One Day Ahead

By no later than 6:00 am on the day before the Trading Day, Scheduling Coordinators that have been notified that a Reliability Must-Run Unit is required to run in the Trading Day will inform the ISO, with regard to each hour for which the ISO has provided such notice, whether the RMR Owner will take payment from the market or under the RMR Contract.

SP 3.2.2 [Not Used]

SP 3.2.3 By 6:30 am, One Day Ahead

By 6:30 am on the day ahead of the Trading Day (for example, by 6:30 am on Tuesday for the Wednesday Trading Day) and for each Settlement Period of the Trading Day: the ISO will provide to UDCs, via WEnet, the sum of the Scheduling Coordinators' Direct Access Demand Forecasts by UDC Service Area; and

SP 3.2.4 By 8:00 am, One Day Ahead

By 8:00 am on the day ahead of the Trading Day (for example, by 8:00 am on Tuesday for the Wednesday Trading Day), and for each Settlement Period of that Trading Day, Firm Transmission Rights owners will notify the ISO, via the Secondary Registration System or other means established by the ISO, of any transaction of Firm Transmission Rights and of any changes in Scheduling Coordinators' rights to schedule the use of Firm Transmission Rights at particular Inter-Zonal Interfaces.

SP 3.2.5 By 8:30 am, One Day Ahead

By 8:30 am on the day ahead of the Trading Day (for example, by 8:30 am on Tuesday for the Wednesday Trading Day), and for each Settlement Period of that Trading Day, Participating Transmission Owners will notify the ISO, via e-mail of an electronic spreadsheet or other means established by the ISO, of the amounts of transmission capacity to reserve for its transmission service customers under Existing Contracts at particular Inter-Zonal Interfaces. Upon receiving this information, the ISO will, by 9:00 am, calculate the Firm Transmission Rights available on each Inter-Zonal Interface after taking into account transfer capabilities and Existing Contract transmission capacity reservations, and then publish adjusted scheduling rights for Scheduling Coordinators scheduling the use of Firm Transmission Rights and Existing Contract rights. After publishing the adjusted scheduling rights for Existing Contract rights and Firm Transmission Rights, Scheduling Coordinators may submit contract usage templates for validation by the ISO prior to the ISO's deadline for receiving Preferred Day-Ahead Schedules.

SP 3.2.6 By 10:00 am, One Day Ahead

By 10:00 am on the day ahead of the Trading Day (for example, by 10:00 am on Tuesday for the Wednesday Trading Day), the following information flows for each Settlement Period of the Trading Day will be required to take place:

(a) SCs will provide, via WEnet, the ISO with forecasts of their Direct Access Demand by UDC Service Area;

(b) the ISO will publish, via WEnet, an updated forecast of system Demands and of the Ancillary Services requirements; and

(c) the ISO will validate (in accordance with the SBP) the information submitted above by SCs and UDCs.

SP 3.2.6.1 Actions by Scheduling Coordinators and the ISO

By 10:00 am on the day ahead of the Trading Day (for example, by 10:00 am on Tuesday for the Wednesday Trading Day) and for each Settlement Period of that Trading Day (see SP 3.2.6.2 for information on the pre-validation performed at ten (10) minutes prior to the 10:00 am deadline):

(a) Scheduling Coordinators will submit their Preferred Day-Ahead Schedules to the ISO;

(b) Scheduling Coordinators will submit, as part of their Preferred Day-Ahead Schedules, their Adjustment Bids, if any, to the ISO;

(c) Scheduling Coordinators will submit their Ancillary Services bids, if any, to the ISO in accordance with Section 8;

(d) Scheduling Coordinators will submit their schedules for self-provided Ancillary Services, if any, to the ISO in accordance with the Appendix M and Section 2.5;

(e) the ISO will validate all Scheduling Coordinator submitted Preferred Day-Ahead Schedules for Energy and Adjustment Bids and may assist Scheduling Coordinators to resolve mismatches in scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades in accordance with the procedure described in SP 3.2.6.4;

(f) the ISO will validate all Scheduling Coordinator submitted schedules for self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids which were part of their Preferred Day-Ahead Schedules;

(g) the ISO will validate all contract usage templates received from Scheduling Coordinators for scheduled uses of Existing Contract rights and Firm Transmission Rights;

(h) the ISO will validate that all Scheduling Coordinator submitted Preferred Day-Ahead Schedules are compatible with the RMR requirements of which Scheduling Coordinators were notified for that Trading Day and with the Scheduling Coordinators' elected options for delivering the required Energy;

(i) the ISO will start the first iteration of Inter-Zonal Congestion Management process as described in Section 27.1.1; and

(j) the ISO will start the Ancillary Services bid evaluation process as described in Section 8.

SP 3.2.6.2 Pre-validation

At 10 minutes prior to the deadline for submittal of the Preferred Day-Ahead Schedules, Adjustment Bids, schedules for self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids (the "submittal"), the ISO shall conduct a pre-validation of the stage two validation described in Section 30.4. The purpose of this is to allow the Scheduling Coordinators, particularly those involved in the Inter-Scheduling Coordinator Energy Trades, to identify and resolve any validation problems. The ISO will immediately communicate the results of each Scheduling Coordinator's pre-validation to that Scheduling Coordinator via WEnet.

SP 3.2.6.3 Invalidation

Except with respect to invalidated contract usage associated with Existing Contract rights or Firm Transmission Rights, invalidation of the submittal for any Settlement Period results in rejection of the submittal for that Settlement Period. Scheduling Coordinators will be notified of any invalid contract usage via an invalidated contract usage template issued, via the WEnet, by the ISO. Invalidation of contract usage will not cause the rejection of the Scheduling Coordinator's submittal; instead, invalid contract usage will be treated as new firm uses of ISO transmission service without the priorities and protections afforded the scheduled use of Existing Contract rights and Firm Transmission Rights. During the initial operations of the ISO, the ISO may assist Scheduling Coordinators to resolve mismatches in the scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades contained in their Preferred Schedules in accordance with SP 3.2.6.4. Except with respect to contract usage templates (for which Scheduling Coordinators can check whether or not their submittal will pass the ISO's validation checks between 9:00 am and 10:00 am), Scheduling Coordinators may check at any time prior to 10:00 am whether or not their submittal will pass the ISO's validation checks at 10:00 am. It is the responsibility of the Scheduling Coordinators to perform such checks since Preferred Day-Ahead Schedules, Adjustment Bids, Schedules of self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids which are invalidated cannot be resubmitted after 10:00 am for the Day-Ahead Market, except that, during the initial period of ISO operations, the ISO will allow resubmission of Preferred Schedules which have mismatches in the scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades. The ISO will immediately communicate the results of each Scheduling Coordinator's 10:00 am validation to that Scheduling Coordinator via WEnet. If the usage or sum of the usages associated with an Existing Contract results in the contract being over-scheduled, the usages will be adjusted such that a usage in excess of the Existing Contract rights will be considered a new firm use (NFU) and will be exposed to Congestion charges.

SP 3.2.6.4 Inter-Scheduling Coordinator Energy Trades - Mismatches

During the initial period of ISO operations, if the ISO detects a mismatch in the scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades, the ISO will promptly notify both the receiving and sending Scheduling Coordinators that a mismatch exists and will specify the time, which will allow them approximately one half-hour, by which they may submit modified Schedules which resolve the mismatch. If the Scheduling Coordinators are unable to resolve the mismatch as to quantities in the allotted time and provided there is no dispute as to whether the trade occurred or over its location, then the ISO may adjust the Scheduling Cordinators' Schedules in accordance with the following procedure:

(a) The ISO will determine which Schedule contains the higher scheduled quantity of Energy for the Inter-Scheduling Coordinator Energy Trade and will reduce it so that it is equal to the lower scheduled quantity. However, if the Schedule specifying the higher scheduled quantity of Energy contains only Inter-Scheduling Coordinator Energy Trades, the ISO will increase the Schedule specifying the lower quantity of Energy so that it is equal to the higher scheduled quantity of Energy.

(b) If there is a dispute between the Scheduling Coordinators as to whether the trade occurred or over its location, the ISO will remove the disputed trade from the Schedules in which it appears.

(c) As a consequence of the adjustments under (a) or (b) above, the Scheduling Coordinators whose Schedules have been adjusted will no longer have a Balanced Schedule. The ISO will adjust their resources based on the following priority: Demands, exports, imports, Generation, and other Inter-Scheduling Coordinator Energy Trades.

(d) The adjustments to each Scheduling Coordinator's portfolio will be based on the Adjustment Bids provided by the Scheduling Coordinator.

(e) The ISO will notify each Scheduling Coordinator whose Schedule has been adjusted as to the adjustment in its Schedule.

SP 3.2.7 By 11:00 am, One Day Ahead

By 11:00 am on the day ahead of the Trading Day (for example, by 11:00 am on Tuesday for the Wednesday Trading Day) and for each Settlement Period of that Trading Day:

(a) the ISO will complete the first iteration of the Inter-Zonal Congestion Management process described in SP 10 (if Inter-Zonal Congestion does not exist in any Settlement Period of the Trading Day, the scheduling process will continue with the steps at SP 3.2.9);

(b) the ISO will provide, via WEnet, Suggested Adjusted Day-Ahead Schedules for Energy to <u>all</u> Scheduling Coordinators which submitted Preferred Day-Ahead Schedules at 10:00 am, including the Scheduling Coordinators which it is proposed should, as a result of Inter-Zonal Congestion Management, have their Preferred Day-Ahead Schedules modified;

(c) the ISO will publish on WEnet the estimated Day-Ahead Usage Charge rate (in $/MWh of scheduled flow) for Energy transfers between Zones; and

(d) the ISO will provide, via WEnet, along with the Suggested Adjusted Day-Ahead Schedules, schedules for Ancillary Services to the Scheduling Coordinators which either:

(i) submitted Ancillary Services bids and which, as a result, are proposed to supply Ancillary Services; or

(ii) submitted schedules to self-provide Ancillary Services and which schedules have been accepted by the ISO.

(e) the ISO will provide, via WEnet, the available contract capacity template associated with the Scheduling Coordinator's scheduled use of any Existing Contract rights or Firm Transmission Rights. If any derate of an Inter-Zonal Interface has occurred, the ISO will provide, via WEnet, the invalidated usage information template.

SP 3.2.8 By 12:00 Noon, Day Ahead

By 12:00 noon on the day ahead of the Trading Day (for example, by 12:00 noon on Tuesday for the Wednesday Trading Day) and for each Settlement Period of that Trading Day (except where Inter-Zonal Congestion does not exist, in which case, the scheduling process will omit this step):

SP 3.2.8.1 Actions by Scheduling Coordinators and the ISO

(a) Scheduling Coordinators will submit Revised Day-Ahead Schedules to the ISO, in response to the ISO's Suggested Adjusted Day-Ahead Schedules;

(b) Scheduling Coordinators will submit, as part of their Revised Day-Ahead Schedules, revised Adjustment Bids (allowing the range of usage to change, but not the prices), if any, to the ISO;

(c) Scheduling Coordinators will submit revised Ancillary Services bids, if any, to the ISO in accordance with Section 8;

(d) Scheduling Coordinators will submit their schedules for self-provided Ancillary Services, if any, to the ISO in accordance with Section 8;

(e) the ISO will validate all Scheduling Coordinator submitted Revised Day-Ahead Schedules for Energy and Adjustment Bids and may assist Scheduling Coordinators to resolve mismatches in scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades in accordance with the same procedure described in SP 3.2.8.4;

(f) the ISO will validate all Scheduling Coordinator submitted schedules for self-provided Ancillary Services and Ancillary Services bids which were part of their Revised Day-Ahead Schedules;

(g) the ISO will validate all contract usage templates received from Scheduling Coordinators for scheduled uses of Existing Contract rights and Firm Transmission Rights.

(h) the ISO will start the second (and final) iteration of the Inter-Zonal Congestion Management process as described in Section 27.1.1;

(i) the ISO will start the second (and final) iteration of the Ancillary Services bid evaluation process as described in Section 8; and

(j) the ISO will use the Scheduling Coordinator's Preferred Day-Ahead Schedule in the event the Scheduling Coordinator does not submit a Revised Day-Ahead Schedule. If a Scheduling Coordinator desires to revise only part of its Preferred Day-Ahead Schedule, those portions of the Revised Day-Ahead Schedule must be submitted, including both the removal of any resources in the Preferred Day-Ahead Schedule which are not to be included in the Revised Day-Ahead Schedule and the addition of any resources that were not included in the Preferred Day-Ahead Schedule but that are to be included in the Revised Day-Ahead Schedule. A Scheduling Coordinator's failure to remove such resources will cause the Revised Schedule to be unbalanced, and rejected as such in the ISO's validation process.

SP 3.2.8.2 Pre-validation

At 10 minutes prior to the deadline for submittal of the Revised Day-Ahead Schedules, Adjustment Bids, schedules for self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids (the “submittal”), the ISO shall conduct a pre-validation of the stage two validation described in Section 30.4. The purpose of this is to allow the Schedule Coordinators, particularly those involved in Inter-Scheduling Coordinator Energy Trades, to identify and resolve any validation problems. The ISO will immediately communicate the results of the pre-validation of each Schedule Coordinator’s submittal to that Scheduling Coordinator via WEnet.

SP 3.2.8.3 Invalidation

Except with respect to invalidated contract usage associated with Existing Contract rights or Firm Transmission Rights, invalidation of the submittal for any Settlement Period results in rejection of the submittal for that Settlement Period. Scheduling Coordinators will be notified of any invalid contract usage via an invalidated contract usage template issued, via the WEnet, by the ISO. Invalidation of contract usage will not cause the rejection of the Scheduling Coordinator's submittal; instead, invalid contract usage will be treated as new firm uses of ISO transmission service without the priorities and protections afforded the scheduled use of Existing Contract rights and Firm Transmission Rights. During the initial operations of the ISO, the ISO may assist Scheduling Coordinators to resolve mismatches in the scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades in accordance with 3.2.8.4. Except with respect to contract usage templates, Scheduling Coordinators may check at any time prior to 12:00 noon whether or not their submittal will pass the ISO’s validation checks (which are undertaken at 12:00 noon). It is the responsibility of the Scheduling Coordinators to perform such checks since Revised Day-Ahead Schedules, Adjustment Bids, schedules of self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids which are invalidated cannot be resubmitted after 12:00 noon for the Day-Ahead Market, except that during the initial period of operations, the ISO will allow resubmission of Schedules to resolve mismatches in the scheduled quantities and locations for Inter-Scheduling Coordinator Energy Trades. The ISO will immediately communicate the results of each Scheduling Coordinator’s 12:00 noon validation to that Scheduling Coordinator via WEnet. If the usage or sum of the usages associated with an Existing Contract results in the contract being over-scheduled, the usages will be adjusted such that a usage in excess of the Existing Contract rights will be considered a new firm use (NFU) and will be exposed to Congestion charges.

SP 3.2.8.4 Inter-Scheduling Coordinator Energy Trades - Mismatches

During the initial period of ISO operations, if the ISO detects a mismatch in the scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades, the ISO will promptly notify both the receiving and sending Scheduling Coordinators that a mismatch exists and will specify the time, which will allow them approximately one half-hour, by which they may submit modified Schedules which resolve the mismatch. If the Scheduling Coordinators are unable to resolve the mismatch as to quantities in the allotted time and provided there is no dispute as to whether the trade occurred or over its location, the ISO may adjust the Scheduling Coordinators’ Schedules in accordance with the following procedure:

(a) The ISO will determine which Schedule contains the higher scheduled quantity of Energy for the Inter-Scheduling Coordinator Energy Trade and will reduce it so that it is equal to the lower scheduled quantity. However, if the Schedule specifying the higher scheduled quantity of Energy contains only Inter-

Scheduling Coordinator Energy Trades, the ISO will increase the Schedule specifying the lower quantity of Energy so that it is equal to the higher scheduled quantity of Energy.

(b) If there is a dispute between the Scheduling Coordinators as to whether the trade occurred or over its location, the ISO will remove the disputed trade from the Schedules in which it appears.

(c) As a consequence of the adjustments under (a) or (b) above, the Scheduling Coordinators whose Schedules have been adjusted will no longer have a Balanced Schedule. The ISO will adjust their resources based on the following priority: Demands, exports, imports, Generation, and other Inter-Scheduling Coordinator Energy Trades.

(d) The adjustments to each Scheduling Coordinator's portfolio will be based on the Adjustment Bids provided by the Scheduling Coordinator.

(e) The ISO will notify each Scheduling Coordinator whose Schedule has been adjusted as to the adjustment in its Schedule.

SP 3.2.9 By 1:00 pm, Day Ahead

By 1:00 pm on the day ahead of the Trading Day (for example, by 1:00 pm on Tuesday for the Wednesday Trading Day) and for each Settlement Period of that Trading Day:

(a) the ISO will complete the second iteration, if necessary, of the Inter-Zonal Congestion Management process described in Section 27.1.1;

(b) the ISO will provide, via WEnet, Final Day-Ahead Schedules to all Scheduling Coordinators which, depending on the existence of Inter-Zonal Congestion, could be:

(i) the Preferred Day-Ahead Schedules (when no Congestion was found at 11:00 am and no mismatched Inter-Scheduling Coordinator Energy Trades);

(ii) the Revised Day-Ahead Schedules (when no Congestion was found at 1:00 pm and no mismatched Inter-Scheduling Coordinator Energy Trades);

(iii) modified Revised Day-Ahead Schedules for those Scheduling Coordinators which had their Revised Day-Ahead Schedules for Energy modified for Inter-Zonal Congestion or mismatches in Inter-Scheduling Coordinator Energy Trades; or

(iv) modified Preferred Day-Ahead Schedules for those Scheduling Coordinators which had their Preferred Schedule for Energy modified for Inter-Scheduling Coordinator Energy Trade mismatches;

(c) the ISO will publish on WEnet the Day-Ahead Usage Charge rate (in $/MWh of scheduled flow) for Energy transfer between Zones, if any;

(d) the ISO will provide, via WEnet, as part of the Final Day-Ahead Schedules, schedules for Ancillary Services to the Scheduling Coordinators which either:

(i) submitted Ancillary Services bids and which, as a result, have been selected to supply Ancillary Services; or

(ii) submitted schedules to self-provide Ancillary Services and which schedules have been validated by the ISO; and

(iii) specified Inter-Scheduling Coordinator Ancillary Service Trades which have been validated by the ISO; and

(e) the ISO will coordinate with adjacent Control Areas on the net schedules between the ISO Control Area and such other Control Areas. If the ISO and the operator of an adjacent Control Area have different records with respect to the net schedules, individual Scheduling Coordinator intertie schedules will be examined. If the other Control Area's records are determined to be correct, the

ISO will notify the affected Scheduling Coordinator. If the other Control Area Operator's records are in error, no changes will be required by the ISO or affected Scheduling Coordinators. The affected Scheduling Coordinator is required to correct its schedule in the Hour-Ahead Market.

SP 3.2.10 By 1:30 pm, Day Ahead

By 1:30 pm on the day ahead of the Trading Day (for example, by 1:30 pm on Tuesday for the Wednesday Trading Day) and for each Settlement Period of the Trading Day the ISO will publish, via WEnet, an updated forecast of system Demands.

SP 3.2.11 Between 1:00 p.m. and 10:00 p.m.

If, at any time after 1:00 p.m. and before 10:00 p.m. of the day prior to the Trading Day, the ISO determines that it requires Ancillary Services in addition to those provided through the Final Day-Ahead Schedules issued under SP 3.2.9, it may procure such additional Ancillary Services by providing to Scheduling Coordinators, via WEnet, amended schedules for Ancillary Services that had been bid in the Day-Ahead Market but were not previously selected in the Final Day-Ahead Schedules, and have not been previously withdrawn. The ISO shall select such Ancillary Services in price merit order (and in the relevant Zone if the ISO is procuring Ancillary Services on a Zonal basis). Such amended schedules shall be provided to the Scheduling Coordinators no later than 10:00 p.m. of the day prior to the Trading Day.

SP 3.3 Hour-Ahead Market

(a) The Hour-Ahead Market is a "deviations" market in that it represents changes from the Day-Ahead Market commitments already made for each Settlement Period in the Trading Day. The Scheduling Coordinators do not schedule these deviations. Instead, these deviations are calculated by the ISO as the difference between the Final Hour-Ahead Schedules (reflecting updated forecasts of Generation, Demand, external imports/exports and Inter-Scheduling Coordinator Energy Trades) and the Final Day-Ahead Schedules. If a Scheduling Coordinator does not submit a valid Preferred Hour-Ahead Schedule, its Final Day-Ahead Schedule will be deemed to be its Preferred Hour-Ahead Schedule.

(b) The Hour-Ahead Markets for each Settlement Period of each Trading Day open when the Day-Ahead Market commitments are made for the same Trading Day. Hour-Ahead Market commitments are made one hour ahead of the start of the applicable Settlement Period, at which time the ISO issues the Final Hour-Ahead

Schedules. There is an option in the bid submittal process for a Scheduling Coordinator to submit a Schedule or bid for one Settlement Period of the Trading Day or a set of Schedules and bids for all Settlement Periods of the Trading Day (but only between 1:00 pm and 12:00 midnight the day before).

(c) For each Hour-Ahead Market of the Trading Day the ISO's validation of Scheduling Coordinators' contract usage templates, associated with Existing Contract rights or Firm Transmission Rights, will be performed. If a derate of an Inter-Zonal Interface has occurred which affects a Scheduling Coordinator's Final Day-Ahead Schedule or Ancillary Service commitments, the ISO will notify the Scheduling Coordinator, via the WEnet, of its available contract capacity. Additionally, the ISO will validate Scheduling Coordinators' scheduled usage against Scheduling Coordinators' contract usage templates and notify Scheduling Coordinators of any invalidated usage. Such validations and notifications associated with contract usage, available contract capacities and invalidated contract usage will occur during the two hours prior to the ISO's deadline for receiving Preferred Hour-Ahead Schedules.

SP 3.3.1 By Two Hours and Fifteen Minutes Ahead

By two hours and fifteen minutes ahead of the Settlement Period (for example, by 9:45 am for the Settlement Period starting at 12:00 noon [or hour ending 1300]) and with respect to that Settlement Period:

SP 3.3.1.1 Actions by Scheduling Coordinators and the ISO

(a) Scheduling Coordinators will submit their Preferred Hour-Ahead Schedules to the ISO;

(b) Scheduling Coordinators will submit, as part of their Preferred Hour-Ahead Schedules, their Adjustment Bids, if any, to the ISO;

(c) Scheduling Coordinators will submit their Ancillary Services bids, if any, to the ISO in accordance with Section 8;

(d) Scheduling Coordinators will submit their Schedules for self-provided Ancillary Services and Inter-Scheduling Coordinator Ancillary Service Trades, if any, to the ISO in accordance with Section 8;

(e) the ISO will validate all Scheduling Coordinator submitted Preferred Hour-Ahead Schedules for Energy and Adjustment Bids;

(f) Scheduling Coordinators will submit contract usage templates for scheduled uses of Existing Contract rights and Firm Transmission Rights in accordance with the Hour-Ahead Market schedule, including usage template changes needed in response to line derations;

(g) the ISO will validate all contract usage templates received from Scheduling Coordinators for scheduled uses of Existing Contract rights and Firm Transmission Rights;

(h) the ISO will validate all Scheduling Coordinator submitted Schedules for self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service

Trades, and Ancillary Services bids which were part of their Preferred Hour-Ahead Schedules;

(i) the ISO will start the Inter-Zonal Congestion Management process as described in Section 27.1.1;

(j) the ISO will start the Ancillary Services bid evaluation process as described in Section 2.5; and

(k) the ISO will validate that all Scheduling Coordinator submitted Preferred Hour-Ahead Schedules are compatible with the RMR requirements of which Scheduling Coordinators were notified for that Trading Day and with the Scheduling Coordinators' elected options for delivering the required Energy.

SP 3.3.1.2 Pre-validation

At 10 minutes prior to the deadline for submittal of the Preferred Hour-Ahead Schedules, Adjustment Bids, schedules for self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids (the "submittal"), the ISO shall conduct a pre-validation of the stage two validation described in Section 30.4. The purpose of this is to allow the Scheduling Coordinators, particularly those involved in the Inter-Scheduling Coordinator Energy Trades, to identify and resolve any validation problems. The ISO will immediately communicate the results of the pre-validation of each Scheduling Coordinator's submittal to that Scheduling Coordinator via WEnet.

SP 3.3.1.3 Invalidation

Except with respect to invalidated contract usage associated with Existing Contract rights or Firm Transmission Rights, invalidation of the submittal results in rejection of the submittal. Scheduling Coordinators will be notified of any invalid contract usage via an invalidated contract usage template issued, via the WEnet, by the ISO. Invalidation of contract usage will not cause the rejection of the Scheduling Coordinator's submittal; instead, invalid contract usage will be treated as new firm uses of ISO transmission service without the priorities and protections afforded the scheduled use of Existing Contract rights and Firm Transmission Rights. Scheduling Coordinators may check at any time prior to two hours and fifteen minutes ahead of the relevant Settlement Period whether or not their submittals will pass the ISO's validation checks (which are undertaken at two hours and fifteen minutes ahead of the Settlement Period). It is the responsibility of Scheduling Coordinators to perform such checks since Preferred Hour-Ahead Schedules, Adjustment Bids, schedules of self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades and Ancillary Services bids which are invalidated cannot be resubmitted for the Hour-Ahead Market after two hours and fifteen minutes ahead of the relevant Settlement Period. The ISO will immediately communicate the results of each Scheduling Coordinator's two hour and fifteen minute ahead validation to that Scheduling Coordinator via WEnet. If the usage or sum of the usages associated with an Existing Contract results in the contract being over-scheduled, the usages will be adjusted such that a usage in excess of the Existing Contract rights will be considered a new firm use (NFU) and will be exposed to Congestion charges.

SP 3.3.2 By One Hour Ahead

By one hour ahead of the Settlement Period (for example, by 11:00 am for the Settlement Period starting at 12:00 noon [or hour ending 1300]) and in respect of that Settlement Period:

(a) The ISO will use the Scheduling Coordinator's Final Day-Ahead Schedule, without any Day-Ahead Adjustment Bids or Day-Ahead Ancillary Service bids, in the event the Scheduling Coordinator's Preferred Hour-Ahead Schedule fails validation. If a Scheduling Coordinator desires to submit an Hour-Ahead Schedule that is different than its Final Day-Ahead Schedule the Scheduling Coordinator must submit the Hour-Ahead Schedule including the addition or removal of any resources (i.e., for those resources to be removed, a zero value for the hourly MW quantity) in its Final Day-Ahead Schedule that are to be added, or that are not to be included, in the Hour-Ahead Schedule. A Scheduling Coordinator's failure to add or remove such resources will cause the Hour-Ahead Schedule to be unbalanced, and rejected as such in the ISO's validation process.

(b) the ISO will complete, if necessary, the Inter-Zonal Congestion Management process described in Section 27.1.1;

(c) the ISO will provide, via WEnet, Final Hour-Ahead Schedules for Energy to the ISO's real-time dispatchers for use under the DP and to all Scheduling Coordinators which, depending on the existence of Inter-Zonal Congestion, could be:

(i) the Preferred Hour-Ahead Schedules (when no Congestion was found at one hour ahead); or

(ii) modified Preferred Hour-Ahead Schedules for those Scheduling Coordinators which had their Preferred Hour-Ahead Schedules for Energy modified for Inter-Zonal Congestion; and

(d) the ISO will publish on WEnet the Hour-Ahead Usage Charge rate (in $/MWh of scheduled flow) for Energy transfers between Zones, if any;

(e) the ISO will provide, via WEnet, as part of the Final Hour-Ahead Schedules, schedules for Ancillary Services to the ISO's real-time dispatchers and to the Scheduling Coordinators which either:

(i) submitted Ancillary Services bids and which, as a result, have been selected to supply Ancillary Services; or

(ii) specified Inter-Scheduling Coordinator Ancillary Service Trades, or submitted schedules to self-provide Ancillary Services and which schedules have been validated by the ISO; and

(f) each Scheduling Coordinator will provide the ISO, via a form and by means of communication specified by the ISO, resource specific information for all Generating Units and Curtailable Demands constituting its System Unit, if any, scheduled or bid into the ISO's Day-Ahead Market and/or Hour-Ahead Market for Ancillary Services.

(g) the ISO will coordinate with adjacent Control Areas on the net schedules between the ISO Control Area and such other Control Areas. If the ISO and the operator of an adjacent Control Area have different records with respect to the net schedules, individual Scheduling Coordinator intertie schedules will be examined. If the other Control Area operator's records were in error, no changes will be required by the ISO or Scheduling Coordinators. If the other Control Area operator's records are determined to be correct, the ISO will notify the affected Scheduling Coordinator. The ISO will manually adjust the affected Scheduling

Coordinator's schedule to conform with the other Control Area operator's net schedule, in real time, and the affected Scheduling Coordinator will be responsible for managing any resulting Energy imbalance.

[NOT USED]

Appendix Z (Sheets 1171 through 1206)

Rejected by FERC – April 19, 2007 Order (119 FERC ¶ 61,053)

Docket: ER06-700-002 and ER06-700-003

ISO TARIFF APPENDIX AA

SMALL GENERATOR
INTERCONNECTION PROCEDURES (SGIP)

SMALL GENERATOR INTERCONNECTION PROCEDURES (SGIP)

(For Generating Facilities No Larger Than 20 MW)

TABLE OF CONTENTS

SECTION 1. OBJECTIVES, DEFINITIONS, AND APPLICATION.

1.1 Objectives

The objective of this SGIP is to implement FERC's Order No. 2006 setting forth the requirements for Small Generating Facility interconnections to the ISO Controlled Grid.

1.2 Definitions

1.2.1 Master Definitions Supplement

Unless the context otherwise requires, any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this SGIP. A reference to a Section or an Appendix is a reference to a Section or an Appendix of the ISO Tariff. References to SGIP are to this Protocol or to the stated paragraph of this Protocol.

1.2.2 Special Definitions for this SGIP

In this SGIP, the following words and expressions shall have the meanings set opposite them:

"10 kW Inverter Process" shall mean the procedure for evaluating an Interconnection Request for a certified inverter-based Small Generating Facility no larger than 10 kW that uses the SGIP Section 2 screens. The application process uses an all-in-one document that includes a simplified Interconnection Request, simplified procedures, and a brief set of terms and conditions. See SGIP Attachment 5.

"Fast Track Process" shall mean the procedure for evaluating an Interconnection Request for a certified Small Generating Facility no larger than 2 MW that includes the SGIP Section 2 screens, customer options meeting, and optional supplemental review.

"Governmental Authority" shall mean any federal, state, local or other governmental, regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the Interconnection Customer, ISO, or Participating TO, or any affiliate thereof.

"Party" or "Parties" shall mean the ISO, Participating TO(s), Interconnection Customer or the applicable combination of the above.

"Study Process" shall mean the procedure for evaluating an Interconnection Request that includes the Scoping Meeting, feasibility study, system impact study, and facilities study, as set forth in Section 3 of this SGIP.

1.3 Application

The applicability of this SGIP is set forth in Section 5.7 of the ISO Tariff. As specified in more detail in Section 5.7 of the ISO Tariff, these procedures are applicable to each new Generating Facility with a Generating Facility Capacity of 20 MW or less, or the expansion of an existing Generating Facility with a resultant Generating Facility Capacity of 20 MW or less, that seeks to interconnect to the ISO Controlled Grid. Any proposed interconnection of a new Generating Facility to a Participating TO's Distribution System will be processed, as applicable, pursuant to the applicable Participating TO's Wholesale Distribution Access Tariff or CPUC Rule 21, or other Local Regulatory Authority requirements of the Participating TO. For any proposed interconnection of a new Generating Facility with a Generating Facility Capacity of 20 MW or less wherein the Interconnection Customer desires the ISO to perform a Deliverability Assessment, the Interconnection Customer shall submit an Interconnection Request to the ISO under the Large Generator Interconnection Procedures in lieu of these Small Generator Interconnection Procedures, as specified in Section 2.8 of this SGIP.

1.3.1 <u>Applicability</u>

1.3.1.1 A request to interconnect a certified Small Generating Facility (See Attachments 3 and 4 for description of certification criteria) no larger than 2 MW shall be evaluated under the SGIP Section 2 Fast Track Process. A request to interconnect a certified inverter-based Small Generating Facility no larger than 10 kW shall be evaluated under the Attachment 5 10 kW Inverter Process. A request to interconnect a Small Generating Facility larger than 2 MW but no larger than 20 MW or a Small Generating Facility that does not pass the Fast Track Process or the 10 kW Inverter Process shall be evaluated under the Study Process set forth in Section 3 of this SGIP.

1.3.1.2 Neither these procedures nor the requirements included hereunder apply to Small Generating Facilities interconnected or approved for interconnection prior to 60 Business Days after the effective date of these procedures.

1.3.1.3 Prior to submitting its Interconnection Request (Attachment 2), the Interconnection Customer may ask the ISO's interconnection contact employee or office whether the proposed interconnection is subject to these procedures. The ISO shall respond within 15 Business Days.

1.3.1.4 Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. The Federal Energy Regulatory Commission expects all transmission providers, market participants, and Interconnection Customers interconnected with electric systems to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and best practice recommendations from the electric reliability authority. All public utilities are expected to meet basic standards for electric system infrastructure and operational security, including physical, operational, and cyber-security practices.

1.3.1.5 References in these procedures to interconnection agreement are to the Small Generator Interconnection Agreement (SGIA).

1.3.2 Pre-Application

The ISO shall designate an employee or office from which information on the application process and on an Affected System can be obtained through informal requests from the Interconnection Customer presenting a proposed project for a specific site. The name, telephone number, and e-mail address of such contact employee or office shall be made available on the ISO's Internet web site. The ISO Controlled Grid information provided to the Interconnection Customer should include relevant system studies, interconnection studies, and other materials useful to an understanding of an interconnection at a particular point on the ISO Controlled Grid, to the extent such provision does not violate confidentiality provisions of prior agreements or critical infrastructure requirements. The ISO shall comply with reasonable requests for such information.

1.3.3 Interconnection Request

The Interconnection Customer shall submit its Interconnection Request to the ISO, together with the processing fee or deposit specified in the Interconnection Request. The Interconnection Request shall be date- and time-stamped upon receipt. The original date and time stamp applied to the Interconnection Request at the time of its original submission shall be accepted as the qualifying date- and time-stamp for the purposes of any timetable in these procedures. The Interconnection Customer shall be notified of receipt by the ISO within three (3) Business Days of receiving the Interconnection Request. The ISO shall notify the Interconnection Customer within ten (10) Business Days of the receipt of the Interconnection Request as to whether the

Interconnection Request is complete or incomplete. If the Interconnection Request is incomplete, the ISO shall provide a notice that the Interconnection Request is incomplete, along with a written list detailing all information that must be provided to complete the Interconnection Request. The Interconnection Customer will have ten (10) Business Days after receipt of the notice to submit the listed information or to request an extension of time to provide such information. If the Interconnection Customer does not provide the listed information or a request for an extension of time within the deadline, the Interconnection Request will be deemed withdrawn. An Interconnection Request will be deemed complete upon submission of the listed information to the ISO.

1.3.4 Modification of the Interconnection Request

Any modification to machine data or equipment configuration, or to the interconnection site of the Small Generating Facility not agreed to in writing by the ISO and the Interconnection Customer may be deemed a withdrawal of the Interconnection Request and may require submission of a new Interconnection Request, unless proper notification of each Party by the other and a reasonable time to cure the problems created by the changes are undertaken.

1.3.5 Site Control

Documentation of site control must be submitted with the Interconnection Request. Site control may be demonstrated through:

1.3.5.1 Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Small Generating Facility;

1.3.5.2 An option to purchase or acquire a leasehold site for such purpose; or

1.3.5.3 An exclusivity or other business relationship between the Interconnection Customer and the entity having the right to sell, lease, or grant the Interconnection Customer the right to possess or occupy a site for such purpose.

1.3.6 Queue Position

The ISO shall assign a Queue Position based upon the date- and time- stamp of the Interconnection Request. The Queue Position of each Interconnection Request will be used to determine the cost responsibility for the Upgrades necessary to accommodate the interconnection. The ISO shall maintain a single queue for the ISO Control Area. At the ISO's option, in coordination with the applicable Participating TO, Interconnection Requests may be studied serially or in clusters for the purpose of the system impact study.

1.3.7 Interconnection Requests Submitted Prior to the Effective Date of the SGIP

Nothing in this SGIP affects an Interconnection Customer's Queue Position assigned before the effective date of this SGIP. The Parties agree to complete work on any interconnection study agreement executed prior the effective date of this SGIP in accordance with the terms and conditions of that interconnection study agreement. Any new studies or other additional work will be completed pursuant to this SGIP.

1.3.8 Request for Deliverability Assessment

An Interconnection Customer seeking to interconnect to the ISO Controlled Grid that desires to have a Deliverability Assessment performed for the Small Generating Facility shall be required to have its Interconnection Request processed under the Large Generator Interconnection Procedures (LGIP) or ISO Tariff Appendix W, as applicable.

SECTION 2. FAST TRACK PROCESS

2.1 Applicability

The Fast Track Process is available to an Interconnection Customer proposing to interconnect its Small Generating Facility with the ISO Controlled Grid if the Small Generating Facility is no larger than 2 MW and if the Interconnection Customer's proposed Small Generating Facility meets the codes, standards, and certification requirements of Attachments 3 and 4 of these procedures, or the applicable Participating TO has reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.

2.2 Initial Review

Within 15 Business Days after the ISO notifies the Interconnection Customer it has received a complete Interconnection Request, the applicable Participating TO shall perform an initial review using the screens set forth below, shall notify the Interconnection Customer of the results, and include with the notification copies of the analysis and data underlying the Participating TO's determinations under the screens.

2.2.1 Screens

2.2.1.1 The proposed Small Generating Facility's Point of Interconnection must be on a portion of the Participating TO's Distribution System that is subject to the ISO Tariff.

2.2.1.2 For interconnection of a proposed Small Generating Facility to a radial distribution circuit, the aggregated generation, including the proposed Small Generating Facility, on the circuit shall not exceed 15% of the line section annual peak load as most recently measured at the substation. A line section is that portion of a Participating TO's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.

2.2.1.3 For interconnection of a proposed Small Generating Facility to the load side of spot network protectors, the proposed Small Generating Facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5% of a spot network's maximum load or 50 kW[3].

2.2.1.4 The proposed Small Generating Facility, in aggregation with other generation on the distribution circuit, shall not contribute more than 10% to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership.

2.2.1.5 The proposed Small Generating Facility, in aggregate with other generation on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5% of the short circuit interrupting capability; nor shall the interconnection proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability.

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[3] A spot Network is a type of distribution system found within modern commercial buildings to provide high reliability of service to a single customer. (Standard Handbook for Electrical Engineers, 11th edition, Donald Fink, McGraw Hill Book Company)

2.2.1.6 Using the table below, determine the type of interconnection to a primary distribution line. This screen includes a review of the type of electrical service provided to the Interconnecting Customer, including line configuration and the transformer connection to limit the potential for creating over-voltages on the Participating TO's electric power system due to a loss of ground during the operating time of any anti-islanding function.

Primary Distribution Line Type	**Type of Interconnection to Primary Distribution Line**	**Result/Criteria**
Three-phase, three wire	3-phase or single phase, phase-to-phase	Pass screen
Three-phase, four wire	Effectively-grounded 3 phase or Single-phase, line-to-neutral	Pass screen

2.2.1.7 If the proposed Small Generating Facility is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed Small Generating Facility, shall not exceed 20 kW.

2.2.1.8 If the proposed Small Generating Facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.

2.2.1.9 The Small Generating Facility, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Small Generating Facility proposes to interconnect shall not exceed 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission busses from the point of interconnection).

2.2.1.10 No construction of facilities by the Participating TO on its own system shall be required to accommodate the Small Generating Facility.

2.2.2 If the proposed interconnection passes the screens, the Interconnection Request shall be approved and the Participating TO will provide the Interconnection Customer an executable interconnection agreement within five Business Days after the determination.

2.2.3 If the proposed interconnection fails the screens, but the Participating TO determines that the Small Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the Participating TO shall provide the Interconnection Customer an executable interconnection agreement within five Business Days after the determination.

2.2.4 If the proposed interconnection fails the screens, but the Participating TO does not or cannot determine from the initial review that the Small Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards unless the Interconnection Customer is willing to consider minor modifications or further study, the Participating TO shall provide the Interconnection Customer with the opportunity to attend a customer options meeting.

2.3 Customer Options Meeting

If the Participating TO determines the Interconnection Request cannot be approved without minor modifications at minimal cost; or a supplemental study or other additional studies or actions; or at significant cost to address safety, reliability, or power quality problems, within the five Business Day period after the determination, the Participating TO shall notify the Interconnection Customer and provide copies of all data and analyses underlying its conclusion. Within ten Business Days of the Participating TO's determination, the Participating TO shall offer to convene a customer options meeting with the Participating TO to review possible Interconnection Customer facility modifications or the screen analysis and related results, to determine what further steps are needed to permit the Small Generating Facility to be connected safely and reliably. At the time of notification of the Participating TO's determination, or at the customer options meeting, the Participating TO shall:

2.3.1 Offer to perform facility modifications or minor modifications to the Participating TO's electric system (e.g., changing meters, fuses, relay settings) and provide a non-binding good faith estimate of the limited cost to make such modifications to the Participating TO's electric system; or

2.3.2 Offer to perform a supplemental review if the Participating TO concludes that the supplemental review might determine that the Small Generating Facility could continue to qualify for interconnection pursuant to the Fast Track Process, and provide a non-binding good faith estimate of the costs of such review; or

2.3.3 Obtain the Interconnection Customer's agreement to continue evaluating the Interconnection Request under the SGIP Section 3 Study Process.

2.4 Supplemental Review

If the Interconnection Customer agrees to a supplemental review, the Interconnection Customer shall agree in writing within 15 Business Days of the offer, and submit a deposit for the estimated costs. The Interconnection Customer shall be responsible for the Participating TO's actual costs for conducting the supplemental review. The Interconnection Customer must pay any review costs that exceed the deposit within 20 Business Days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced costs, the Participating TO will return such excess within 20 Business Days of the invoice without interest.

2.4.1 Within ten Business Days following receipt of the deposit for a supplemental review, the Participating TO will determine if the Small Generating Facility can be interconnected safely and reliably.

2.4.1.1 If so, the Participating TO shall forward an executable an interconnection agreement to the Interconnection Customer within five Business Days.

2.4.1.2 If so, and Interconnection Customer facility modifications are required to allow the Small Generating Facility to be interconnected consistent with safety, reliability, and power quality standards under these procedures, the Participating TO shall forward an executable interconnection agreement to the Interconnection Customer within five Business Days after confirmation that the Interconnection Customer has agreed to make the necessary changes at the Interconnection Customer's cost.

2.4.1.3 If so, and minor modifications to the Participating TO's electric system are required to allow the Small Generating Facility to be interconnected consistent with safety, reliability, and power quality standards under the Fast Track Process, the Participating TO shall forward an executable interconnection agreement to the Interconnection Customer within ten Business Days that requires the Interconnection Customer to pay the costs of such system modifications prior to interconnection.

2.4.1.4 If not, the Interconnection Request will continue to be evaluated under the SGIP Section 3 Study Process.

SECTION 3. STUDY PROCESS

3.1 Applicability

The Study Process shall be used by an Interconnection Customer proposing to interconnect its Small Generating Facility to the ISO Controlled Grid if the Small Generating Facility (1) is larger than 2 MW but no larger than 20 MW, (2) is not certified, or (3) is certified but did not pass the Fast Track Process or the 10 kW Inverter Process.

3.1.1 Centralized Study Process

3.1.1.1 The ISO will be the single point of contact for Interconnection Customer.

3.1.1.2 The ISO will be the central point of coordination to involve any Affected Systems.

3.1.1.3 The ISO will collect and disburse monies received from Interconnection Customers.

3.1.1.4 The ISO will execute interconnection study agreements. Each Interconnection Request will be subject to the direction and oversight of the ISO. The ISO will conduct or cause to be performed the required small generator interconnection studies and any additional studies the ISO determines to be reasonably necessary and will direct the applicable Participating TO to perform portions of studies where the Participating TO has specific and non-transferable expertise or data and can conduct the studies more efficiently and cost effectively than the ISO. The study results and final study report must be approved by the ISO.

3.2 Scoping Meeting

3.2.1 A Scoping Meeting will be held within ten (10) Business Days after the Interconnection Request is deemed complete, or as otherwise mutually agreed to by the Parties. The ISO, applicable Participating TO, and the Interconnection Customer will bring to the meeting personnel, including system engineers and other resources as may be reasonably required to accomplish the purpose of the meeting.

3.2.2 The purpose of the Scoping Meeting is to discuss the Interconnection Request and review existing studies relevant to the Interconnection Request. The Parties shall further discuss whether the ISO should conduct, or caused to be performed, a feasibility study or proceed directly to a system impact study, or a facilities study, or an interconnection agreement. If the Parties agree that a feasibility study should be performed, the ISO shall provide the Interconnection Customer, as soon as possible, but not later than five (5) Business Days after the Scoping Meeting, a feasibility study agreement (Attachment 6) including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

3.2.3 The Scoping Meeting may be omitted by mutual agreement. In order to remain in consideration for interconnection, an Interconnection Customer who has requested a feasibility study must return the executed feasibility study agreement within fifteen (15) Business Days. If the Parties agree not to perform a feasibility study, the ISO shall provide the Interconnection Customer, no later than five (5) Business Days after the Scoping Meeting, a system impact study agreement (Attachment 7) including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

3.3 Feasibility Study

3.3.1 The feasibility study shall identify any potential adverse system impacts or financial impacts, if any, on Local Furnishing Bonds that would result from the interconnection of the Small Generating Facility.

3.3.2 A deposit of the lesser of 50 percent of the good faith estimated feasibility study costs or earnest money of $1,000 will be required from the Interconnection Customer.

3.3.3 The scope of, and cost responsibilities for, the feasibility study are described in the attached feasibility study agreement.

3.3.4 If the feasibility study shows no potential for adverse system impacts and financial impacts on Local Furnishing Bonds, the ISO shall send the Interconnection Customer a facilities study agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study. If no additional facilities are required, the Participating TO shall send the Interconnection Customer an executable interconnection agreement within five (5) Business Days.

3.3.5 If the feasibility study shows the potential for adverse system impacts or financial impacts on Local Furnishing Bonds, the review process shall proceed to the appropriate system impact study(s).

3.4 System Impact Study

3.4.1 A system impact study shall identify and detail the electric system impacts, including Local Furnishing Bond impacts, that would result if the proposed Small Generating Facility were interconnected without project modifications or electric system modifications, focusing on the adverse system impacts identified in the feasibility study, or to study potential impacts, including but not limited to those identified in the Scoping Meeting. A system impact study shall evaluate the impact of the proposed interconnection on the reliability of the electric system.

3.4.2 If no ISO Controlled Grid system impact study is required, but potential electric power Distribution System adverse system impacts or Local Furnishing Bond impacts are identified in the Scoping Meeting or shown in the feasibility study, a Distribution System impact study must be performed by the applicable Participating TO. The applicable Participating TO shall send the Interconnection Customer a Distribution System impact study agreement within fifteen (15) Business Days of transmittal of the feasibility study report, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, or following the Scoping Meeting if no feasibility study is to be performed.

3.4.3 In instances where the feasibility study or the Distribution System impact study shows potential for ISO Controlled Grid adverse system impacts or Local Furnishing Bond adverse impacts, within five (5) Business Days following transmittal of the feasibility study report, the ISO shall send the Interconnection Customer a system impact study agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, if such a study is required.

3.4.4 If an ISO Controlled Grid system impact study is not required, but electric power Distribution System adverse system impacts are shown by the feasibility study to be possible and no Distribution System impact study has been conducted, the applicable Participating TO shall send the Interconnection Customer a Distribution System impact study agreement.

3.4.5 If the feasibility study shows no potential for ISO Controlled Grid, Local Furnishing Bond, or Distribution System adverse system impacts, the ISO shall send the Interconnection Customer either a facilities study agreement (Attachment 8), including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, or the applicable Participating TO shall send an executable interconnection agreement, as applicable.

3.4.6 In order to remain under consideration for interconnection, the Interconnection Customer must return executed system impact study agreements, if applicable, within thirty (30) Business Days.

3.4.7 A deposit of the good faith estimated costs for each system impact study will be required from the Interconnection Customer.

3.4.8 The scope of, and cost responsibilities for, a system impact study are described in the attached system impact study agreement.

3.4.9 Where transmission systems and Distribution Systems have separate owners, such as is the case with transmission-dependent utilities ("TDUs") – whether investor-owned or not – the Interconnection Customer may apply to the nearest transmission provider (transmission owner, Regional Transmission Operator, or independent system operator) providing transmission service to the TDU to request project coordination. Affected Systems shall participate in the study and provide all information necessary to prepare the study.

3.5 Facilities Study

3.5.1 Once the required system impact study(s) is completed, a system impact study report shall be prepared and transmitted to the Interconnection Customer along with a facilities study agreement within five (5) Business Days, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the facilities study. In the case where one or both impact studies are determined to be unnecessary, a notice of the fact shall be transmitted to the Interconnection Customer within the same timeframe.

3.5.2 In order to remain under consideration for interconnection, or, as appropriate, in the ISO's interconnection queue, the Interconnection Customer must return the executed facilities study agreement or a request for an extension of time within thirty (30) Business Days.

3.5.3 The facilities study shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the system impact study(s).

3.5.4 **[INTENTIONALLY LEFT BLANK]**

3.5.5 A deposit of the good faith estimated costs for the facilities study will be required from the Interconnection Customer.

3.5.6 The scope of, and cost responsibilities for, the facilities study are described in the attached facilities study agreement.

3.5.7 Within 30 Business Days after completion of the facilities study, the Interconnection Customer shall take one of the following actions: (i)agree to pay for Interconnection Facilities and Upgrades identified in the facilities study and request that the Participating TO tender an executable interconnection agreement, (ii) withdraw its Interconnection Request, or (iii) request that the Participating TO tender an executable interconnection agreement despite its disagreement with the costs therein. If requested, the Participating TO shall provide the Interconnection Customer an executable interconnection agreement within five (5) Business Days. Upon option (iii) herein, the Interconnection Customer may request that the interconnection agreement be filed unilaterally at FERC.

3.5.8 **[INTENTIONALLY LEFT BLANK]**

3.5.9 Engineering and Procurement Agreement
Prior to executing an SGIA, an Interconnection Customer may, in order to advance the implementation of its interconnection, request and the applicable Participating TO(s) shall offer the Interconnection Customer, an E&P Agreement that authorizes the applicable Participating TO(s) to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection. However, the applicable Participating TO(s) shall not be obligated to offer an E&P Agreement if the Interconnection Customer is in Dispute Resolution as a result of an allegation that the Interconnection Customer has failed to meet any milestones or comply with any prerequisites specified in other parts of the SGIP. The E&P Agreement is an optional procedure and it will not alter the Interconnection Customer's Queue Position or In-Service Date. The E&P Agreement shall provide for the Interconnection Customer to pay the cost of all activities authorized by the Interconnection Customer and to make advance payments or provide other satisfactory security for such costs.

The Interconnection Customer shall pay the cost of such authorized activities and any cancellation costs for equipment that is already ordered for its interconnection, which cannot be mitigated as hereafter described, whether or not such items or equipment later become unnecessary. If the Interconnection Customer withdraws its application for interconnection or either Party terminates the E&P Agreement, to the extent the equipment ordered can be canceled under reasonable terms, the Interconnection Customer shall be obligated to pay the associated cancellation costs. To the extent that the equipment cannot be reasonably canceled, the applicable Participating TO(s) may elect: (i) to take title to the equipment, in which event the applicable Participating TO(s) shall refund the Interconnection Customer any amounts paid by Interconnection Customer for such equipment and shall pay the cost of delivery of such equipment, or (ii) to transfer title to and deliver such equipment to the Interconnection Customer, in which event the Interconnection Customer shall pay any unpaid balance and cost of delivery of such equipment.

SECTION 4. PROVISIONS THAT APPLY TO ALL INTERCONNECTION REQUESTS

4.1 Reasonable Efforts
The ISO shall make reasonable efforts to meet all time frames provided in these procedures unless the ISO and the Interconnection Customer agree to a different schedule. If the ISO cannot meet a deadline provided herein, it shall notify the Interconnection Customer, explain the reason for the failure to meet the deadline, and provide an estimated time by which it will complete the applicable interconnection procedure in the process.

4.2 Disputes

4.2.1 The Parties agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this section.

4.2.2 In the event of a dispute, either Party shall provide the other Party with a written Notice of Dispute. Such Notice shall describe in detail the nature of the dispute.

4.2.3 If the dispute has not been resolved within two (2) Business Days after receipt of the Notice, either Party may contact FERC's Dispute Resolution Service (DRS) for assistance in resolving the dispute.

4.2.4 The DRS will assist the Parties in either resolving their dispute or in selecting an appropriate dispute resolution venue (e.g., mediation, settlement judge, early neutral evaluation, or technical expert) to assist the Parties in resolving their dispute. DRS can be reached at 1-877-337-2237 or via the internet at http://www.ferc.gov/legal/adr.asp.

4.2.5 Each Party agrees to conduct all negotiations in good faith and will be responsible for one-half of any costs paid to neutral third-parties.

4.2.6 If neither Party elects to seek assistance from the DRS, or if the attempted dispute resolution fails, then either Party may exercise whatever rights and remedies it may have in equity or law consistent with the terms of this SGIP.

4.3 Interconnection Metering
Any metering necessitated by the use of the Small Generating Facility shall be installed at the Interconnection Customer's expense in accordance with Federal Energy Regulatory Commission, state, or local regulatory requirements or the ISO's specifications.

4.4 Commissioning
Commissioning tests of the Interconnection Customer's installed equipment shall be performed pursuant to applicable codes and standards. The ISO and applicable Participating TO must be given at least five (5) Business Days written notice, or as otherwise mutually agreed to by the Parties, of the tests and may be present to witness the commissioning tests.

4.5. Confidentiality

4.5.1 Confidential Information shall mean any confidential and/or proprietary information provided by one Party to another Party that is clearly marked or otherwise designated "Confidential." For purposes of this SGIP, all design, operating specifications, and metering data provided by the Interconnection Customer shall be deemed Confidential Information regardless of whether it is clearly marked or otherwise designated as such.

4.5.2 Confidential Information does not include information previously in the public domain, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Parties and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce this SGIP. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under this SGIP, or to fulfill legal or regulatory requirements.

4.5.2.1 Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Parties as it employs to protect its own Confidential Information.

4.5.2.2 Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

4.5.3 Notwithstanding anything in this section to the contrary, and pursuant to 18 CFR § 1b.20, if FERC, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this SGIP, the Party shall provide the requested information to FERC, within the time provided for in the request for information. In providing the information to FERC, the Party may, consistent with 18 CFR § 388.112, request that the information be treated as confidential and non-public by FERC and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Parties prior to the release of the Confidential Information to FERC. The Party shall notify the other Parties when it is notified by FERC that a request to release Confidential Information has been received by FERC, at which time any of the Parties may respond before such information would be made public, pursuant to 18 CFR § 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

4.6 Comparability
The ISO shall receive, process and analyze all Interconnection Requests in a timely manner as set forth in this SGIP. The ISO shall use the same reasonable efforts in processing and analyzing Interconnection Requests from all Interconnection Customers, whether the Small Generating Facility is owned or operated by the applicable Participating TO, its subsidiaries or affiliates, or others.

4.7 Record Retention
The ISO shall maintain for three (3) years records, subject to audit, of all Interconnection Requests received under these procedures, the times required to complete Interconnection Request approvals and disapprovals, and justification for the actions taken on the Interconnection Requests.

4.8 Interconnection Agreement
The Participating TO, with the ISO's review and concurrence, shall issue a SGIA to the Interconnection Customer. After receiving an interconnection agreement from the Participating TO, the Interconnection Customer shall have thirty (30) Business Days or another mutually agreeable timeframe to sign and return the interconnection agreement, or request that the ISO and Participating TO file an unexecuted interconnection agreement with the Federal Energy Regulatory Commission. If the Interconnection Customer does not sign the interconnection agreement, or ask that it be filed unexecuted by the ISO and Participating TO within thirty (30) Business Days, the Interconnection Request shall be deemed withdrawn. After the

interconnection agreement is signed by the Parties, the interconnection of the Small Generating Facility shall proceed under the provisions of the interconnection agreement.

4.9 Coordination with Affected Systems

The ISO shall coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System operators and, if possible, include those results (if available) in its applicable interconnection study within the time frame specified in these procedures. The ISO will include such Affected System operators in all meetings held with the Interconnection Customer as required by these procedures. The Interconnection Customer will cooperate with the ISO in all matters related to the conduct of studies and the determination of modifications to Affected Systems. A transmission provider, which may be an Affected System, shall cooperate with the ISO in all matters related to the conduct of studies and the determination of modifications to Affected Systems.

4.10 Capacity of the Small Generating Facility

4.10.1 If the Interconnection Request is for an increase in capacity for an existing Small Generating Facility, the Interconnection Request shall be evaluated on the basis of the new total capacity of the Small Generating Facility.

4.10.2 If the Interconnection Request is for a Small Generating Facility that includes multiple energy production devices at a site for which the Interconnection Customer seeks a single Point of Interconnection, the Interconnection Request shall be evaluated on the basis of the aggregate capacity of the multiple devices.

4.10.3 The Interconnection Request shall be evaluated using the maximum rated capacity of the Small Generating Facility.

Attachment 1

[INTENTIONALLY LEFT BLANK]

Attachment 2

SMALL GENERATOR INTERCONNECTION REQUEST
(Application Form)

California Independent System Operator

Designated Contact Person: ____

Address: ____

Telephone Number: ____

Fax: ____

E-Mail Address: ____

An Interconnection Request is considered complete when it provides all applicable and correct information required below. Per SGIP Section 1.3.5, documentation of Site Control must be submitted with the Interconnection Request.

Preamble and Instructions

Request for Deliverability Assessment – Yes ___ No ___

An Interconnection Customer seeking to interconnect to the ISO Controlled Grid that desires to have a Deliverability Assessment performed for the Small Generating Facility is required to have its Interconnection Request processed under the Large Generator Interconnection Procedures (LGIP) or ISO Tariff Appendix W, as applicable.

An Interconnection Customer who requests a Federal Energy Regulatory Commission jurisdictional interconnection must submit this Interconnection Request by hand delivery, mail, e-mail, or fax to the ISO.

Processing Fee or Deposit:

If the Interconnection Request is submitted under the Fast Track Process, the non-refundable processing fee is $500.

If the Interconnection Request is submitted under the Study Process, whether a new submission or an Interconnection Request that did not pass the Fast Track Process, the Interconnection Customer shall submit to the ISO a deposit not to exceed $1,000 towards the cost of the feasibility study.

Interconnection Customer Information

Legal Name of the Interconnection Customer (or, if an individual, individual's name)

Name: ____

Contact Person: ____

Mailing Address: ____

City: ____________________ State: __________ Zip: ____________

Facility Location (if different from above): ______________________________

Telephone (Day): ______________________ Telephone (Evening): _____________________

Fax: _______________________________ E-Mail Address: __________________________________

Alternative Contact Information (if different from the Interconnection Customer)

Contact Name: ____

Title: ____

Address: ____

____

Telephone (Day): ______________________ Telephone (Evening): ______________________

Fax: _____________________________________ E-Mail Address: _________________________

Application is for:
______New Small Generating Facility
______Capacity addition to Existing Small Generating Facility

If capacity addition to existing facility, please describe: ______________________________________
____

Will the Small Generating Facility be used for any of the following?

Net Metering? Yes ___ No ___
To Supply Power to the Interconnection Customer? Yes ___No ___
To Supply Power to Others? Yes ____ No ____

For installations at locations with existing electric service to which the proposed Small Generating Facility will interconnect, provide:

____ _________________________________
(Local Electric Service Provider*) (Existing Account Number*)

[*To be provided by the Interconnection Customer if the local electric service provider is different from the Participating TO]

Contact Name: ____

Title: ____

Address: ____

____

Telephone (Day): _____________________________ Telephone (Evening): ______________________

Fax: ____ E-Mail Address: _________________________

Requested Point of Interconnection: ____

Interconnection Customer's Requested In-Service Date: ____

Small Generating Facility Information
Data apply only to the Small Generating Facility, not the Interconnection Facilities.

Energy Source: ___ Solar ___ Wind ___ Hydro ___ Hydro Type (e.g. Run-of-River):_____________
Diesel ___ Natural Gas ___ Fuel Oil ___ Other (state type) ___________________________

Prime Mover: ___Fuel Cell ___Recip Engine ___Gas Turb ___Steam Turb
___Microturbine ___PV ___Other

Type of Generator: ____Synchronous ____Induction ____ Inverter

Generator Nameplate Rating: ________kW (Typical) Generator Nameplate kVAR: _______

Interconnection Customer or Customer-Site Load: _________________kW (if none, so state)

Typical Reactive Load (if known): _________________

Maximum Physical Export Capability Requested: ______________ kW

List components of the Small Generating Facility equipment package that are currently certified:

	Equipment Type	Certifying Entity
1.	_____________________	________________________________
2.	_____________________	________________________________
3.	_____________________	________________________________
4.	_____________________	________________________________
5.	_____________________	________________________________

Is the prime mover compatible with the certified protective relay package? ____Yes ____No

Generator (or solar collector)
Manufacturer, Model Name & Number: ____
Version Number: _________________________

Nameplate Output Power Rating in kW: (Summer) _____________ (Winter) ______________
Nameplate Output Power Rating in kVA: (Summer) _____________ (Winter) ______________

Individual Generator Power Factor
Rated Power Factor: Leading: _____________Lagging: _______________

Total Number of Generators in wind farm to be interconnected pursuant to this
Interconnection Request: __________ Elevation: ______ ___Single phase ___Three phase

Inverter Manufacturer, Model Name & Number (if used): _____________________________________

List of adjustable set points for the protective equipment or software: __________________________

Note: A completed Power Systems Load Flow data sheet must be supplied with the Interconnection Request.

Small Generating Facility Characteristic Data (for inverter-based machines)

Max design fault contribution current: _________________ Instantaneous _____ or RMS? __________

Harmonics Characteristics: ____

Start-up requirements: ____

Small Generating Facility Characteristic Data (for rotating machines)

RPM Frequency: _____________
(*) Neutral Grounding Resistor (If Applicable): ____________

Synchronous Generators:

Direct Axis Synchronous Reactance, Xd: _______ P.U.
Direct Axis Transient Reactance, X'_d: ___________ P.U.
Direct Axis Subtransient Reactance, X''_d: ______________ P.U.
Negative Sequence Reactance, X_2: _________ P.U.
Zero Sequence Reactance, X_0: ____________ P.U.
KVA Base: __________________________
Field Volts: ______________
Field Amperes: ______________

Induction Generators:

Motoring Power (kW): ______________
I_2^2t or K (Heating Time Constant): ______________
Rotor Resistance, Rr: ______________
Stator Resistance, Rs: ______________
Stator Reactance, Xs: ______________
Rotor Reactance, Xr: ______________
Magnetizing Reactance, Xm: ______________
Short Circuit Reactance, Xd'': ______________
Exciting Current: ______________
Temperature Rise: ______________
Frame Size: ______________
Design Letter: ______________
Reactive Power Required In Vars (No Load): ______________
Reactive Power Required In Vars (Full Load): ______________
Total Rotating Inertia, H: _____________ Per Unit on kVA Base

Note: Please contact the ISO prior to submitting the Interconnection Request to determine if the specified information above is required.

Excitation and Governor System Data for Synchronous Generators Only

Provide appropriate IEEE model block diagram of excitation system, governor system and power system stabilizer (PSS) in accordance with the regional reliability council criteria. A PSS may be determined to be required by applicable studies. A copy of the manufacturer's block diagram may not be substituted.

Interconnection Facilities Information

Will a transformer be used between the generator and the point of common coupling? ___Yes ___No

Will the transformer be provided by the Interconnection Customer? ____Yes ____No

Transformer Data (If Applicable, for Interconnection Customer-Owned Transformer):

Is the transformer: ____single phase _____three phase? Size: ___________kVA
Transformer Impedance: _______% on __________kVA Base

If Three Phase:
Transformer Primary: _____ Volts _____ Delta _____Wye _____ Wye Grounded
Transformer Secondary: _____ Volts _____ Delta _____Wye _____ Wye Grounded
Transformer Tertiary: _____ Volts _____ Delta _____Wye _____ Wye Grounded

Transformer Fuse Data (If Applicable, for Interconnection Customer-Owned Fuse):

(Attach copy of fuse manufacturer's Minimum Melt and Total Clearing Time-Current Curves)

Manufacturer: __________________ Type: _______________ Size: ________Speed: ______________

Interconnecting Circuit Breaker (if applicable):

Manufacturer: ____________________________ Type: __________
Load Rating (Amps): _______ Interrupting Rating (Amps): ________ Trip Speed (Cycles): __________

Interconnection Protective Relays (If Applicable):

If Microprocessor-Controlled:

List of Functions and Adjustable Setpoints for the protective equipment or software:

	Setpoint Function	Minimum	Maximum
1.			
2.			
3.			
4.			
5.			
6.			

If Discrete Components:

(Enclose Copy of any Proposed Time-Overcurrent Coordination Curves)

Manufacturer: ___________ Type: _______ Style/Catalog No.: _________ Proposed Setting: _______
Manufacturer: ___________ Type: _______ Style/Catalog No.: _________ Proposed Setting: _______
Manufacturer: ___________ Type: _______ Style/Catalog No.: _________ Proposed Setting: _______
Manufacturer: ___________ Type: _______ Style/Catalog No.: _________ Proposed Setting: _______
Manufacturer: ___________ Type: _______ Style/Catalog No.: _________ Proposed Setting: _______

Current Transformer Data (If Applicable):

(Enclose Copy of Manufacturer's Excitation and Ratio Correction Curves)

Manufacturer: ____
Type: _________________ Accuracy Class: _________________ Proposed Ratio Connection: ______

Manufacturer: ____
Type: __________________ Accuracy Class: _______________ Proposed Ratio Connection: ____

Potential Transformer Data (If Applicable):

Manufacturer: ____
Type: ______________________ Accuracy Class: _________ Proposed Ratio Connection: ____

Manufacturer: ____
Type: _____________________ Accuracy Class: _______________ Proposed Ratio Connection: ____

General Information

Enclose copy of site electrical one-line diagram showing the configuration of all Small Generating Facility equipment, current and potential circuits, and protection and control schemes. This one-line diagram must be signed and stamped by a licensed Professional Engineer if the Small Generator Facility is larger than 50 kW. Is One-Line Diagram Enclosed? ____Yes ____No

Enclose copy of any site documentation that indicates the precise physical location of the proposed Small Generating Facility (e.g., USGS topographic map or other diagram or documentation).

Proposed location of protective interface equipment on property (include address if different from the Interconnection Customer's address) ____

Enclose copy of any site documentation that describes and details the operation of the protection and control schemes. Is Available Documentation Enclosed? ___Yes ____No

Enclose copies of schematic drawings for all protection and control circuits, relay current circuits, relay potential circuits, and alarm/monitoring circuits (if applicable).
Are Schematic Drawings Enclosed? ___Yes ____No

Applicant Signature

I hereby certify that, to the best of my knowledge, all the information provided in this Interconnection Request is true and correct.

For Interconnection Customer: ____________________________________Date: ____________

Attachment 3

Certification Codes and Standards

IEEE1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity)

UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems

IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems

NFPA 70 (2002), National Electrical Code

IEEE Std C37.90.1-1989 (R1994), IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems

IEEE Std C37.90.2 (1995), IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE Std C37.108-1989 (R2002), IEEE Guide for the Protection of Network Transformers

IEEE Std C57.12.44-2000, IEEE Standard Requirements for Secondary Network Protectors

IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits

IEEE Std C62.45-1992 (R2002), IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V and Less) AC Power Circuits

ANSI C84.1-1995 Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic Terms
NEMA MG 1-1998, Motors and Small Resources, Revision 3

IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems

NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1

Attachment 4

Certification of Small Generator Equipment Packages

1.0 Small Generating Facility equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if (1) it has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed in SGIP Attachment 3, (2) it has been labeled and is publicly listed by such NRTL at the time of the interconnection application, and (3) such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.

2.0 The Interconnection Customer must verify that the intended use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.

3.0 Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for an on-site commissioning test by the parties to the interconnection nor follow-up production testing by the NRTL.

4.0 If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an Interconnection Customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.

5.0 Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no further design review, testing or additional equipment on the customer side of the point of common coupling shall be required to meet the requirements of this interconnection procedure.

6.0 An equipment package does not include equipment provided by the utility.

7.0 Any equipment package approved and listed in a state by that state's regulatory body for interconnected operation in that state prior to the effective date of these small generator interconnection procedures shall be considered certified under these procedures for use in that state.

Attachment 5

Application, Procedures, and Terms and Conditions for Interconnecting a Certified Inverter-Based Small Generating Facility No Larger than 10 kW ("10 kW Inverter Process")

1.0 The Interconnection Customer ("Customer") completes the Interconnection Request ("Application") and submits it to the Participating TO ("Company").

2.0 The Company acknowledges to the Customer receipt of the Application within three Business Days of receipt.

3.0 The Company evaluates the Application for completeness and notifies the Customer within ten Business Days of receipt that the Application is or is not complete and, if not, advises what material is missing.

4.0 The Company verifies that the Small Generating Facility can be interconnected safely and reliably using the screens contained in the Fast Track Process in the Small Generator Interconnection Procedures (SGIP). The Company has 15 Business Days to complete this process. Unless the Company determines and demonstrates that the Small Generating Facility cannot be interconnected safely and reliably, the Company approves the Application and returns it to the Customer. Note to Customer: Please check with the Company before submitting the Application if disconnection equipment is required.

5.0 After installation, the Customer returns the Certificate of Completion to the Company. Prior to parallel operation, the Company may inspect the Small Generating Facility for compliance with standards which may include a witness test, and may schedule appropriate metering replacement, if necessary.

6.0 The Company notifies the Customer in writing that interconnection of the Small Generating Facility is authorized. If the witness test is not satisfactory, the Company has the right to disconnect the Small Generating Facility. The Customer has no right to operate in parallel until a witness test has been performed, or previously waived on the Application. The Company is obligated to complete this witness test within ten Business Days of the receipt of the Certificate of Completion. If the Company does not inspect within ten Business Days or by mutual agreement of the Parties, the witness test is deemed waived.

7.0 Contact Information – The Customer must provide the contact information for the legal applicant (i.e., the Interconnection Customer). If another entity is responsible for interfacing with the Company, that contact information must be provided on the Application.

8.0 Ownership Information – Enter the legal names of the owner(s) of the Small Generating Facility. Include the percentage ownership (if any) by any utility or public utility holding company, or by any entity owned by either.

9.0 UL1741 Listed – This standard ("Inverters, Converters, and Controllers for Use in Independent Power Systems") addresses the electrical interconnection design of various forms of generating equipment. Many manufacturers submit their equipment to a Nationally Recognized Testing Laboratory (NRTL) that verifies compliance with UL1741. This "listing" is then marked on the equipment and supporting documentation.

Application for Interconnecting a Certified Inverter-Based Small Generating Facility No Larger than 10kW

This Application is considered complete when it provides all applicable and correct information required below. Additional information to evaluate the Application may be required.

Processing Fee
A non-refundable processing fee of $100 must accompany this Application.

Interconnection Customer
Name: ____________________
Contact Person: ____________________
Address: ____________________
City: __________ State: __________ Zip __________:
Telephone (Day): __________ (Evening): __________
Fax: __________ E-Mail Address: __________

Contact (if different from Interconnection Customer)
Name: ____________________
Address: ____________________
City: __________ State: __________ Zip: __________
Telephone (Day): __________ (Evening): __________
Fax: __________ __E-Mail Address: __________

Owner of the facility (include % ownership by any electric utility): __________

Small Generating Facility Information
Location (if different from above): ____________________
Electric Service Company: ____________________
Account Number: ____________________
Inverter Manufacturer: _ __________ Model __________
Nameplate Rating: __________ (kW) __________ (kVA) __________ (AC Volts) __________
Single Phase __________ Three Phase __________
System Design Capacity: __________ (kW) __________ (kVA) __________
Prime Mover: Photovoltaic Reciprocating Engine Fuel Cell
Turbine Other __________
Energy Source: Solar Wind Hydro Diesel Natural Gas
Fuel Oil Other (describe) __________
Is the equipment UL1741 Listed? __________ Yes __________ No __________
If Yes, attach manufacturer's cut-sheet showing UL1741 listing

Estimated Installation Date: __________ Estimated In-Service Date: __________

The 10 kW Inverter Process is available only for inverter-based Small Generating Facilities no larger than 10 kW that meet the codes, standards, and certification requirements of Attachments 3 and 4 of the Small Generator Interconnection Procedures (SGIP), or the Participating TO has reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.

List components of the Small Generating Facility equipment package that are currently certified:

	Equipment Type	Certifying Entity
1.	__________	__________
2.	__________	__________
3.	__________	__________
4.	__________	__________
5.	__________	__________

Interconnection Customer Signature
I hereby certify that, to the best of my knowledge, the information provided in this Application is true. I agree to abide by the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return the Certificate of Completion when the Small Generating Facility has been installed.

Signed: ____

Title: ____ Date: __________________________

Contingent Approval to Interconnect the Small Generating Facility

(For Company use only)

Interconnection of the Small Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return of the Certificate of Completion.

Company Signature: ____

Title: _______________________________________ Date: ________________

Application ID number: __________________

Company waives inspection/witness test? Yes___ No___

Small Generating Facility Certificate of Completion

Is the Small Generating Facility owner-installed? Yes______ No ______

Interconnection Customer: ____

Contact Person:____

Address: ____

Location of the Small Generating Facility (if different from above):

____

City: ______________________ State: ____________________Zip Code: __________

Telephone (Day): ____________________ (Evening): ______________________

Fax: ________________________ E-Mail Address: ______________________

Electrician:

Name: ____

Address: ____

City: ____________________________ State: __________ Zip Code: __________

Telephone (Day): ____________________ (Evening): ______________________

Fax: ____________________________ E-Mail Address: ____________________

License number: ____

Date Approval to Install Facility granted by the Company: ______________________

Application ID number: ____

Inspection:

The Small Generating Facility has been installed and inspected in compliance with the local

building/electrical code of ____

Signed (Local electrical wiring inspector, or attach signed electrical inspection):

____

Print Name: ____

Date: ____

As a condition of interconnection, you are required to send/fax a copy of this form along with a copy of the signed electrical permit to (insert Company information below):

Name: ____

Company: ____

Address:____

City ____________________________State _________________________ZIP: _________

Fax: ____

Approval to Energize the Small Generating Facility (For Company use only)
Energizing the Small Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW

Company Signature: ____

Title: ______________________________________ Date: __________________________

Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW

1.0 Construction of the Facility

The Interconnection Customer (the "Customer") may proceed to construct (including operational testing not to exceed two hours) the Small Generating Facility when the Participating TO (the "Company") approves the Interconnection Request (the "Application") and returns it to the Customer.

2.0 Interconnection and Operation

The Customer may operate Small Generating Facility and interconnect with the Company's electric system once all of the following have occurred:

2.1 Upon completing construction, the Customer will cause the Small Generating Facility to be inspected or otherwise certified by the appropriate local electrical wiring inspector with jurisdiction, and

2.2 The Customer returns the Certificate of Completion to the Company, and

2.3 The Company has either:

2.3.1 Completed its inspection of the Small Generating Facility to ensure that all equipment has been appropriately installed and that all electrical connections have been made in accordance with applicable codes. All inspections must be conducted by the Company, at its own expense, within ten Business Days after receipt of the Certificate of Completion and shall take place at a time agreeable to the Parties. The Company shall provide a written statement that the Small Generating Facility has passed inspection or shall notify the Customer of what steps it must take to pass inspection as soon as practicable after the inspection takes place; or

2.3.2 If the Company does not schedule an inspection of the Small Generating Facility within ten business days after receiving the Certificate of Completion, the witness test is deemed waived (unless the Parties agree otherwise); or

2.3.3 The Company waives the right to inspect the Small Generating Facility.

2.4 The Company has the right to disconnect the Small Generating Facility in the event of improper installation or failure to return the Certificate of Completion.

2.5 Revenue quality metering equipment must be installed and tested in accordance with applicable ANSI standards.

3.0 Safe Operations and Maintenance

The Customer shall be fully responsible to operate, maintain, and repair the Small Generating Facility as required to ensure that it complies at all times with the interconnection standards to which it has been certified.

4.0 Access

The Company shall have access to the disconnect switch (if the disconnect switch is required) and metering equipment of the Small Generating Facility at all times. The Company shall provide reasonable notice to the Customer when possible prior to using its right of access.

5.0 Disconnection

The Company may temporarily disconnect the Small Generating Facility upon the following conditions:

5.1 For scheduled outages upon reasonable notice.

5.2 For unscheduled outages or emergency conditions.

5.3 If the Small Generating Facility does not operate in the manner consistent with these Terms and Conditions.

5.4 The Company shall inform the Customer in advance of any scheduled disconnection, or as is reasonable after an unscheduled disconnection.

6.0 Indemnification

The Parties shall at all times indemnify, defend, and save the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inactions of its obligations under this agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

7.0 Insurance

The Parties each agree to maintain commercially reasonable amounts of insurance.

8.0 Limitation of Liability

Each party's liability to the other party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either party be liable to the other party for any indirect, incidental, special, consequential, or punitive damages of any kind whatsoever, except as allowed under paragraph 6.0.

9.0 Termination

The agreement to operate in parallel may be terminated under the following conditions:

9.1 By the Customer
By providing written notice to the Company.

9.2 By the Company
If the Small Generating Facility fails to operate for any consecutive 12 month period or the Customer fails to remedy a violation of these Terms and Conditions.

9.3 Permanent Disconnection
In the event this Agreement is terminated, the Company shall have the right to disconnect its facilities or direct the Customer to disconnect its Small Generating Facility.

9.4 Survival Rights
This Agreement shall continue in effect after termination to the extent necessary to allow or require either Party to fulfill rights or obligations that arose under the Agreement.

10.0 Assignment/Transfer of Ownership of the Facility

This Agreement shall survive the transfer of ownership of the Small Generating Facility to a new owner when the new owner agrees in writing to comply with the terms of this Agreement and so notifies the Company.

Attachment 6

Feasibility Study Agreement

THIS AGREEMENT is made and entered into this_____day of______________ 20___ by and between____, a____________________________organized and existing under the laws of the State of ____, ("Interconnection Customer,") and the California Independent System Operator Corporation, a California nonprofit public benefit corporation existing under the laws of the State of California, ("ISO"). Interconnection Customer and ISO each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by Interconnection Customer on_________________________; and

WHEREAS, Interconnection Customer desires to interconnect the Small Generating Facility with the ISO Controlled Grid; and

WHEREAS, Interconnection Customer has requested the ISO to conduct or cause to be performed a feasibility study to assess the feasibility of interconnecting the proposed Small Generating Facility with the ISO Controlled Grid, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the Master Definitions Supplement, Appendix A of the ISO Tariff.

2.0 The Interconnection Customer elects and the ISO shall conduct or cause to be performed an interconnection feasibility study consistent the standard Small Generator Interconnection Procedures in accordance with the ISO Tariff.

3.0 The scope of the feasibility study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The feasibility study shall be based on the technical information provided by the Interconnection Customer in the Interconnection Request, as may be modified as the result of the Scoping Meeting. The ISO reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the feasibility study and as designated in accordance with the standard Small Generator Interconnection Procedures. If the Interconnection Customer modifies its Interconnection Request, the time to complete the feasibility study may be extended by agreement of the Parties.

5.0 In performing the study, the ISO shall rely, to the extent reasonably practicable, on existing studies of recent vintage. The Interconnection Customer shall not be charged for such existing studies; however, the Interconnection Customer shall be responsible for charges associated with any new study or modifications to existing studies that are reasonably necessary to perform the feasibility study.

6.0 The feasibility study report shall provide the following analyses for the purpose of identifying any potential adverse system impacts that would result from the interconnection of the Small Generating Facility as proposed:

6.1 Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

6.2 Initial identification of any thermal overload or voltage limit violations resulting from the interconnection;

6.3 Initial review of grounding requirements and electric system protection;

6.4 preliminary identification of financial impacts, if any, on Local Furnishing Bonds; and

6.5 Description and non-bonding estimated cost of facilities required to interconnect the proposed Small Generating Facility and to address the identified short circuit and power flow issues.

7.0 The feasibility study shall model the impact of the Small Generating Facility regardless of purpose in order to avoid the further expense and interruption of operation for reexamination of feasibility and impacts if the Interconnection Customer later changes the purpose for which the Small Generating Facility is being installed.

8.0 The study shall include the feasibility of any interconnection at a proposed project site where there could be multiple potential Points of Interconnection, as requested by the Interconnection Customer and at the Interconnection Customer's cost.

9.0 A deposit of the lesser of 50 percent of good faith estimated feasibility study costs or earnest money of $1,000 shall be required from the Interconnection Customer.

10.0 Once the feasibility study is completed, a feasibility study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the feasibility study must be completed and the feasibility study report transmitted within 30 Business Days of the Interconnection Customer's agreement to conduct a feasibility study.

11.0 Any study fees shall be based on the ISO's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 Calendar Days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the ISO shall refund such excess within 30 Calendar Days of the invoice without interest.

13.0 Miscellaneous.

13.1 Dispute Resolution. Any dispute, or assertion of a claim, arising out of or in connection with this Agreement, shall be resolved in accordance with Section 4.2 of the SGIP.

13.2 Confidentiality. Confidential Information shall be treated in accordance with Section 4.5 of the SGIP.

13.3 Binding Effect. This Agreement and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

13.4 Conflicts. In the event of a conflict between the body of this Agreement and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Agreement shall prevail and be deemed the final intent of the Parties.

13.5 Rules of Interpretation. This Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Agreement, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this Feasibility Study Agreement), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any applicable laws and regulations means such applicable laws and regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section, Attachment, or Appendix means such Article or Section of this Agreement or such Attachment or Appendix to this Agreement, or such Section of the SGIP or such Attachment or Appendix to the SGIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this Agreement as a whole and not to any particular Section; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

13.6 Governing Law, Regulatory Authority, and Rules. The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state where the Point of Interconnection is located, without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

13.7 No Third Party Beneficiaries. This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

13.8 Waiver. The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by the Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Participating TO or ISO. Any waiver of this Agreement shall, if requested, be provided in writing.

Any waivers at any time by any Party of its rights with respect to any default under this Agreement, or with respect to any other matter arising in connection with this Agreement, shall not constitute or be deemed a waiver with respect to any subsequent default or other matter arising in connection with this Agreement. Any delay, short of the statutory period of limitations, in asserting or enforcing any right under this Agreement shall not constitute or be deemed a waiver of such right.

13.9 Headings. The descriptive headings of the various Articles and Sections of this Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Agreement.

13.10 Multiple Counterparts. This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

13.11 Amendment. The Parties may by mutual agreement amend this Agreement by a written instrument duly executed by both of the Parties.

13.12 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this Agreement by a written instrument duly executed by both of the Parties. Such amendment shall become effective and a part of this Agreement upon satisfaction of all applicable laws and regulations.

13.13 Reservation of Rights. The ISO shall have the right to make a unilateral filing with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Agreement pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

13.14 No Partnership. This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, another Party.

13.15 Assignment. This Agreement may be assigned by a Party only with the written consent of the other Party; provided that a Party may assign this Agreement without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement; and provided further that the Interconnection Customer shall have the right to assign this Agreement, without the consent of the other Party, for collateral security purposes to aid in providing financing for the Generating Unit, provided that the Interconnection Customer will require any secured party, trustee or mortgagee to notify the other Party of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the other Party of the date and particulars of any such exercise of assignment right(s). Any attempted assignment that violates this Article is void and ineffective. Any assignment under this Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

13.16 Severability. If any provisions or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

13.17 Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Parties for the performance of such subcontractor.

The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Parties for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Transmission Provider Participating TO or the ISO be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

California Independent System Operator Corporation

Signed____

Name (Printed):____

Title____

[Insert name of Interconnection Customer]

Signed____

Name (Printed):____

Title____

**Attachment A to
Feasibility Study Agreement**

Assumptions Used in Conducting the Feasibility Study

The feasibility study will be based upon the information set forth in the Interconnection Request and agreed upon in the Scoping Meeting held on _____________________:

1) Designation of Point of Interconnection and configuration to be studied.

2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the ISO.

Attachment 7

System Impact Study Agreement

THIS AGREEMENT is made and entered into this_____day of______________ 20___ by and between____, a____________________________organized and existing under the laws of the State of ____, ("Interconnection Customer,") and the California Independent System Operator Corporation, a California nonprofit public benefit corporation existing under the laws of the State of California, ("ISO"). Interconnection Customer and ISO each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by the Interconnection Customer on________________________; and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the ISO Controlled Grid;

WHEREAS, the ISO has completed a feasibility study and provided the results of said study to the Interconnection Customer (This recital to be omitted if the Parties have agreed to forego the feasibility study.); and

WHEREAS, the Interconnection Customer has requested the ISO to conduct or cause to be performed a system impact study(s) to assess the impact of interconnecting the Small Generating Facility with the ISO Controlled Grid, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the Master Definitions Supplement, Appendix A of the ISO Tariff.

2.0 The Interconnection Customer elects and the ISO shall conduct or cause to be performed a system impact study(s) consistent with the standard Small Generator Interconnection Procedures in accordance with the ISO Tariff.

3.0 The scope of a system impact study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 A system impact study will be based upon the results of the feasibility study and the technical information provided by Interconnection Customer in the Interconnection Request. The ISO reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the system impact study. If the Interconnection Customer modifies its designated Point of Interconnection, Interconnection Request, or the technical information provided therein is modified, the time to complete the system impact study may be extended.

5.0 A system impact study shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, an assessment of the potential magnitude of financial impacts, if any, on Local Furnishing Bonds and a proposed resolution, and grounding reviews, as necessary. A system impact study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. A system impact study shall provide a list of facilities that are required as a result of the Interconnection Request and non-binding good faith estimates of cost responsibility and time to construct.

6.0 A Distribution System impact study shall incorporate a distribution load flow study, an analysis of equipment interrupting ratings, protection coordination study, voltage drop and flicker studies, protection and set point coordination studies, grounding reviews, and the impact on electric system operation, as necessary.

7.0 Affected Systems may participate in the preparation of a system impact study, with a division of costs among such entities as they may agree. All Affected Systems shall be afforded an opportunity to review and comment upon a system impact study that covers potential adverse system impacts on their electric systems, and the ISO has 20 additional Business Days to complete a system impact study requiring review by Affected Systems.

8.0 If the ISO uses a queuing procedure for sorting or prioritizing projects and their associated cost responsibilities for any required Network Upgrades, the system impact study shall consider all generating facilities (and with respect to paragraph 8.3 below, any identified Upgrades associated with such higher queued interconnection) that, on the date the system impact study is commenced –

8.1 Are directly interconnected with the ISO Controlled Grid; or

8.2 Are interconnected with Affected Systems and may have an impact on the proposed interconnection; and

8.3 Have a pending higher queued Interconnection Request to interconnect with the ISO Controlled Grid.

9.0 A Distribution System impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 30 Business Days after this Agreement is signed by the Parties. An ISO Controlled Grid system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 45 Business Days after this Agreement is signed by the Parties, or in accordance with the ISO queuing procedures.

10.0 A deposit of the equivalent of the good faith estimated cost of a Distribution System impact study and one half the good faith estimated cost of an ISO Controlled Grid system impact study shall be required from the Interconnection Customer.

11.0 Any study fees shall be based on the ISO actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 Calendar Days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the ISO shall refund such excess within 30 Calendar Days of the invoice without interest.

13.0 Miscellaneous.

13.1 Dispute Resolution. Any dispute, or assertion of a claim, arising out of or in connection with this Agreement, shall be resolved in accordance with Section 4.2 of the SGIP.

13.2 Confidentiality. Confidential Information shall be treated in accordance with Section 4.5 of the SGIP.

13.3 Binding Effect. This Agreement and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

13.4 Conflicts. In the event of a conflict between the body of this Agreement and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Agreement shall prevail and be deemed the final intent of the Parties.

13.5 Rules of Interpretation. This Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Agreement, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this System Impact Study Agreement), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any applicable laws and regulations means such applicable laws and regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section, Attachment, or Appendix means such Article or Section of this Agreement or such Attachment or Appendix to this Agreement, or such Section of the SGIP or such Attachment or Appendix to the SGIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this Agreement as a whole and not to any particular Section; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

13.6 Governing Law, Regulatory Authority, and Rules. The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state where the Point of Interconnection is located, without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

13.7 No Third Party Beneficiaries. This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

13.8 Waiver. The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by the Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Participating TO or ISO. Any waiver of this Agreement shall, if requested, be provided in writing.

Any waivers at any time by any Party of its rights with respect to any default under this Agreement, or with respect to any other matter arising in connection with this Agreement, shall not constitute or be deemed a waiver with respect to any subsequent default or other matter arising in connection with this Agreement. Any delay, short of the statutory period of limitations, in asserting or enforcing any right under this Agreement shall not constitute or be deemed a waiver of such right.

13.9 Headings. The descriptive headings of the various Articles and Sections of this Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Agreement.

13.10 Multiple Counterparts. This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

13.11 Amendment. The Parties may by mutual agreement amend this Agreement by a written instrument duly executed by both of the Parties.

13.12 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this Agreement by a written instrument duly executed by both of the Parties. Such amendment shall become effective and a part of this Agreement upon satisfaction of all applicable laws and regulations.

13.13 Reservation of Rights. The ISO shall have the right to make a unilateral filing with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Agreement pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

13.14 No Partnership. This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, another Party.

13.15 Assignment. This Agreement may be assigned by a Party only with the written consent of the other Party; provided that a Party may assign this Agreement without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement; and provided further that the Interconnection Customer shall have the right to assign this Agreement, without the consent of the other Party, for collateral security purposes to aid in providing financing for the Generating Unit, provided that the Interconnection Customer will require any secured party, trustee or mortgagee to notify the other Party of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the other Party of the date and particulars of any such exercise of assignment right(s). Any attempted assignment that violates this Article is void and ineffective. Any assignment under this Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

13.16 Severability. If any provisions or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

13.17 Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Parties for the performance of such subcontractor.

The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Parties for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Transmission Provider Participating TO or the ISO be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

California Independent System Operator Corporation

Signed____

Name (Printed):____

Title____

[Insert name of Interconnection Customer]

Signed____

Name (Printed):____

Title____

**Attachment A to System
Impact Study Agreement**

Assumptions Used in Conducting the System Impact Study

The system impact study shall be based upon the results of the feasibility study, subject to any modifications in accordance with the standard Small Generator Interconnection Procedures, and the following assumptions:

1) Designation of Point of Interconnection and configuration to be studied.

2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the ISO.

Attachment 8

Facilities Study Agreement

THIS AGREEMENT is made and entered into this_____day of______________ 20___ by and between____, a____________________________organized and existing under the laws of the State of ____, ("Interconnection Customer,") and the California Independent System Operator Corporation, a California nonprofit public benefit corporation existing under the laws of the State of California, ("ISO"). Interconnection Customer and ISO each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by the Interconnection Customer on______________________; and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the ISO Controlled Grid;

WHEREAS, the ISO has completed a system impact study and provided the results of said study to the Interconnection Customer; and

WHEREAS, the Interconnection Customer has requested the ISO to conduct or cause to be performed a facilities study to specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the system impact study in accordance with Good Utility Practice to physically and electrically connect the Small Generating Facility with the ISO Controlled Grid.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the Master Definitions Supplement, Appendix A of the ISO Tariff.

2.0 The Interconnection Customer elects and the ISO shall cause a facilities study consistent with the standard Small Generator Interconnection Procedures to be performed in accordance with the ISO Tariff.

3.0 The scope of the facilities study shall be subject to data provided in Attachment A to this Agreement.

4.0 The facilities study shall specify and estimate the cost, including, if applicable, the cost of remedial measures that address the financial impacts, if any, on Local Furnishing Bonds, of the equipment, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the system impact study(s). The facilities study shall also identify (1) the electrical switching configuration of the equipment, including, without limitation, transformer, switchgear, meters, and other station equipment, (2) the nature and estimated cost of the Participating TO's Interconnection Facilities and Upgrades necessary to accomplish the interconnection, and (3) an estimate of the time required to complete the construction and installation of such facilities or for effecting remedial measures that address the financial impacts, if any, on Local Furnishing Bonds.

5.0 The ISO may propose to group facilities required for more than one Interconnection Customer in order to minimize facilities costs through economies of scale, but any Interconnection Customer may require the installation of facilities required for its own Small Generating Facility if it is willing to pay the costs of those facilities.

6.0 A deposit of the good faith estimated facilities study costs shall be required from the Interconnection Customer.

7.0 In cases where Upgrades are required, the facilities study must be completed within 45 Business Days of the receipt of this Agreement. In cases where no Upgrades are necessary, and the required facilities are limited to Interconnection Facilities, the facilities study must be completed within 30 Business Days.

8.0 Once the facilities study is completed, a facilities study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the facilities study must be completed and the facilities study report transmitted within 30 Business Days of the Interconnection Customer's agreement to conduct a facilities study.

9.0 Any study fees shall be based on the ISO's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

10.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 Calendar Days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the ISO shall refund such excess within 30 Calendar Days of the invoice without interest.

11.0 Miscellaneous.

11.1 Dispute Resolution. Any dispute, or assertion of a claim, arising out of or in connection with this Agreement, shall be resolved in accordance with Section 4.2 of the SGIP.

11.2 Confidentiality. Confidential Information shall be treated in accordance with Section 4.5 of the SGIP.

11.3 Binding Effect. This Agreement and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

11.4 Conflicts. In the event of a conflict between the body of this Agreement and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Agreement shall prevail and be deemed the final intent of the Parties.

11.5 Rules of Interpretation. This Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Agreement, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this Facilities Study Agreement), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any applicable laws and regulations means such applicable laws and regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section, Attachment, or Appendix means such Article or Section of this Agreement or such Attachment or Appendix to this Agreement, or such Section of the SGIP or such Attachment or Appendix to the SGIP, as the case may be; (6) “hereunder”, “hereof”, “herein”, “hereto” and words of similar import shall be deemed references to this Agreement as a whole and not to any particular Section; (7) “including” (and with correlative meaning “include”) means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, “from” means “from and including”, “to” means “to but excluding” and “through” means “through and including”.

11.6 Governing Law, Regulatory Authority, and Rules. The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state where the Point of Interconnection is located, without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

11.7 No Third Party Beneficiaries. This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

11.8 Waiver. The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by the Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Participating TO or ISO. Any waiver of this Agreement shall, if requested, be provided in writing.

Any waivers at any time by any Party of its rights with respect to any default under this Agreement, or with respect to any other matter arising in connection with this Agreement, shall not constitute or be deemed a waiver with respect to any subsequent default or other matter arising in connection with this Agreement. Any delay, short of the statutory period of limitations, in asserting or enforcing any right under this Agreement shall not constitute or be deemed a waiver of such right.

11.9 Headings. The descriptive headings of the various Articles and Sections of this Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Agreement.

11.10 Multiple Counterparts. This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

11.11 Amendment. The Parties may by mutual agreement amend this Agreement by a written instrument duly executed by both of the Parties.

11.12 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this Agreement by a written instrument duly executed by both of the Parties. Such amendment shall become effective and a part of this Agreement upon satisfaction of all applicable laws and regulations.

11.13 Reservation of Rights. The ISO shall have the right to make a unilateral filing with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal

Power Act and FERC's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Agreement pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

11.14 No Partnership. This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, another Party.

11.15 Assignment. This Agreement may be assigned by a Party only with the written consent of the other Party; provided that a Party may assign this Agreement without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement; and provided further that the Interconnection Customer shall have the right to assign this Agreement, without the consent of the other Party, for collateral security purposes to aid in providing financing for the Generating Unit, provided that the Interconnection Customer will require any secured party, trustee or mortgagee to notify the other Party of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the other Party of the date and particulars of any such exercise of assignment right(s). Any attempted assignment that violates this Article is void and ineffective. Any assignment under this Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

11.16 Severability. If any provisions or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

11.17 Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Parties for the performance of such subcontractor.

The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Parties for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Transmission Provider Participating TO or the ISO be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

California Independent System Operator Corporation

Signed____

Name (Printed):____

Title____

[Insert name of Interconnection Customer]

Signed____

Name (Printed):____

Title____

**Attachment A to
Facilities Study Agreement**

**Data to Be Provided by the Interconnection Customer
with the Facilities Study Agreement**

Provide location plan and simplified one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, transmission circuits, etc.

On the one-line diagram, indicate the generation capacity attached at each metering location. (Maximum load on CT/PT)

On the one-line diagram, indicate the location of auxiliary power. (Minimum load on CT/PT) Amps

One set of metering is required for each generation connection to the new ring bus or existing Participating TO station. Number of generation connections: _____________

Will an alternate source of auxiliary power be available during CT/PT maintenance?
Yes _____ No ______

Will a transfer bus on the generation side of the metering require that each meter set be designed for the total plant generation? Yes ______ No _____
(Please indicate on the one-line diagram).

What type of control system or PLC will be located at the Small Generating Facility?

____

____

What protocol does the control system or PLC use?

____

____

Please provide a 7.5-minute quadrangle map of the site. Indicate the plant, station, transmission line, and property lines.

Physical dimensions of the proposed interconnection station:

____

Bus length from generation to interconnection station:

____

Line length from interconnection station to ISO Controlled Grid.

____

Tower number observed in the field. (Painted on tower leg)*:

____

Number of third party easements required for transmission lines*:

____

* To be completed in coordination with Participating TO.

Is the Small Generating Facility located in Participating TO's service area?

Yes ______ No ______ If No, please provide name of local provider:

____

Please provide the following proposed schedule dates:

Begin Construction Date:____________________________

Generator step-up transformers receive back feed power Date:____________________________

Generation Testing Date:____________________________

Commercial Operation Date:____________________________

Attachment 9

INTERCONNECTION PROCEDURES FOR A WIND GENERATING PLANT

Attachment 9 sets forth procedures specific to a wind generating plant. All other requirements of this SGIP continue to apply to wind generating plant interconnections.

A. Special Procedures Applicable to Wind Generators

The wind plant Interconnection Customer, in completing the Interconnection Request required by Section 2.3 of this SGIP, may provide to the ISO a set of preliminary electrical design specifications depicting the wind plant as a single equivalent generator. Upon satisfying these and other applicable Interconnection Request conditions, the wind plant may enter the queue and receive the Base Case data as provided for in this SGIP.

No later than six months after submitting an Interconnection Request completed in this manner, the wind plant Interconnection Customer must submit completed detailed electrical design specifications and other data (including collector system layout data) needed to allow the ISO to complete the interconnection study.

ISO TARIFF APPENDIX BB

Prior to the date that the CAISO Tariff as filed in FERC Docket No. ER06-615 shall become effective, the CAISO will continue to operate as provided in the ISO Tariff in effect prior to such time. For purposes of activity related to the preparation for allocation, auction and transfer of Congestion Revenue Rights, the CAISO shall operate pursuant to this Appendix BB. This Appendix BB is included in the CAISO Tariff to set forth temporary provisions that are derived from conditionally accepted the CAISO Tariff in FERC Docket ER06-615 that enable the CAISO to implement certain activities in preparation of its first annual and monthly CRR Allocation and CRR Auction. These provisions enable the CAISO to: 1) register and qualify entities that intend to participate in the CRR Allocation, CRR Auction, or to transfer and obtain allocated or awarded CRRs through the Secondary Registration System; 2) provide to Market Participants any relevant information to enable such parties to participate in the CRR Allocation, CRR Auction or the Secondary Registration System; 3) obtain from Candidate CRR Holders eligible to participate in the CRR Allocation information necessary to verify the load metric that is eligible for allocation of CRRs; and 4) obtain from Participating TOs, entities that have TORs, and New Participating TOs the Transmission Rights and Transmission Curtailment Instructions that will be used to validate ETC, TOR and Converted Rights Self-Schedules submitted consistent with such rights as well as to model usage under such rights in the allocation and auction of CRRs.

This Appendix BB, therefore, does not replace or supersede the provisions contained in the ISO Tariff in effect prior to the effective date of the version of the tariff as filed and accepted in FERC Docket ER06-615, which will continue to apply until such time that the tariff provisions as filed and finally approved in Docket ER06-615 become fully effective. When all the provisions as filed and conditionally accepted in Docket ER06-615 become fully effective the CAISO will conform its tariff accordingly.

PART A. INFORMATION TO BE PROVIDED BY THE CAISO TO MARKET PARTICIPANTS.

The provisions of this Part A are necessary to enable the CAISO to provide information to Market Participants, Candidate CRR Holders, and CRR Holders that will enable entities to prepare for participation in the CRR Allocation and CRR Auction to be conducted in the summer and fall of 2007.

6.5.1 Communication With Market Participants, Congestion Revenue Rights Participants, and the Public.

6.5.1.1 Market Participants With Non-Disclosure Agreements.

6.5.1.1.1 Annually, the CAISO shall provide information that will include, but is not limited to, the following:

(a) CRR Full Network Model;

(b) Constraints and interface definitions;

(c) Load Distribution Factors for each CRR Allocation and CRR Auction that are published prior to the CRR Allocation and CRR Auction; and

(d) Nominations and/or parameters to be used for modeling in each annual CRR Allocation and CRR Auction processes: Transmission Ownership Rights, Existing Contracts and Converted Rights expected usage, and Merchant Transmission CRRs.

6.5.1.1.2 Monthly, the CAISO shall provide information that will include, but is not limited to, the following:

(a) CRR Full Network Model;

(b) Constraints and interface definitions;

(c) Load Distribution Factors for each CRR Allocation and CRR Auction that is published prior to the CRR Allocation and CRR Auction; and

(d) Nominations and/or parameters to be used for modeling in each monthly CRR Allocation and CRR Auction processes: Transmission Ownership Rights, Existing Contracts and Converted Rights expected usage, and Merchant Transmission CRRs.

6.5.1.2 CRR Participants Without Non-Disclosure Agreements.

6.5.1.2.1 Annually, the CAISO shall provide CRR information specific to that CRR Holder or Candidate CRR Holder as it relates to participation in the annual CRR Allocation or CRR Auction.

6.5.1.2.2 Monthly, the CAISO shall provide CRR information specific to that CRR Holder or Candidate CRR Holder as it relates to participation in the monthly CRR Allocation or CRR Auction.

6.5.1.3 Public Market Information.

6.5.1.3.1 Annually, the CAISO shall publish the following information including, but not limited to:

(a) Market Clearing Prices for all Aggregated PNodes used in the CRR Auction clearing for on-peak and off-peak;

(b) CRR Holdings by CRR Holder (including):

(i) CRR Source name(s);

(ii) CRR Sink name(s);

(iii) CRR quantity (MW) for each CRR Source(s) and CRR Sink(s);

(iv) CRR start and end dates;

(v) Time of use specifications for the CRR(s); and

(vi) Whether the CRR is a CRR Option or CRR Obligation.

6.5.1.3.2 Monthly, the CAISO shall publish the following information including, but not limited to:

(a) Market Clearing Prices for all Aggregated PNodes used in the CRR Auction clearing for on-peak and off-peak;

(b) CRR Holdings by CRR Holder (including):

(i) CRR Source name(s);

(ii) CRR Sink name(s);

(iii) CRR quantity (MW) for each CRR Source(s) and CRR Sink(s);

(iv) CRR start and end dates;

(v) Time of use specifications for the CRR(s); and

(vi) Whether the CRR is a CRR Option or a CRR Obligation.

6.5.1.3.3 Seasonally, the CAISO shall publish the following information including, but not limited to:

(a) Set of LDFs that represent typical seasonal on-peak and off-peak values, not used for Settlements, before the new season.

PART B. TRANSMISSION RIGHTS AND TRANSMISSION CURTAILMENT (TRTC) INSTRUCTIONS

The provisions of this Part B are necessary to enable the CAISO to collect and implement the Transmission Rights and Transmission Curtailment Instructions that will be used to model ETCs, TORs, and Converted Rights in the CRR Allocation and CRR Auction to be conducted in the summer and fall of 2007.

4.3.1.2.1 New Participating TOs shall complete TRTC Instructions for their Converted Rights as provided in Section 16.4.5 of this Appendix. To the extent such Converted Rights derive from ETCs with Original Participating TOs, the New Participating TOs and the appropriate Original Participating TO shall develop the TRTC Instructions together.

16.4 Transmission Rights and Transmission Curtailment Instructions

16.4.1 Responsibility to Create TRTC Instructions

Each Participating TO and Existing Rights holder will work with the CAISO to develop the Transmission Rights and Transmission Curtailment ("TRTC") Instructions that allow Existing Contracts to be exercised in a way that: (i) maintains the existing scheduling and curtailment priorities under the Existing Contract; (ii) is minimally burdensome to the CAISO (i.e., creates the least impact on the CAISO's preferred operational policies and procedures); (iii) to the extent possible, imposes no additional financial burden on either the Participating TO or the holder of Existing Rights (beyond that in the Existing Contract); (iv) consistent with the terms of the Existing Contracts, makes as much transmission capacity not otherwise utilized by the holder of Existing Rights available as possible to the CAISO for allocation to Market Participants; (v) is minimally burdensome to the Participating TO and the Existing Rights holder from an operational point of view; and (vi) does not require the CAISO to interpret or underwrite the economics of the Existing Contract. The parties to Existing Contracts will attempt to jointly develop and agree on any TRTC Instructions that will be submitted to the CAISO. The parties to an Existing Contract shall also be responsible to submit to the CAISO any other necessary operating instructions based on their contract interpretations needed by the CAISO to enable the CAISO to perform its duties.

16.4.2 Responsible PTO for Multiple Participating TO Parties to an Existing Contract.

To the extent there is more than one Participating TO providing transmission service under an Existing Contract or there is a set of Existing Contracts which are interdependent from the point of view of submitting instructions to the CAISO involving more than one Participating TO, the relevant Participating TOs will designate a single Participating TO as the responsible PTO and will notify the CAISO accordingly. If no such responsible PTO is designated by the relevant Participating TOs or the CAISO is not notified of such designation, the CAISO shall designate one of them as the responsible PTO and notify the relevant Participating TOs accordingly. The responsible PTO designated pursuant to this section shall have the same responsibility as the Participating TO under this Section 16.4.

16.4.3 Scheduling Coordinator Responsibilities

The Scheduling Coordinator designated by the parties to an Existing Contract as the responsible entity for submitting ETC Self-Schedules for the relevant Existing Contract shall submit ETC Self-Schedules consistent with the terms and conditions specified in the TRTC Instructions.

16.4.4 Submission of TRTC Instructions.

For each Existing Contract, the Participating TO providing transmission service under the Existing Contract (or the responsible PTO identified in Section 16.4.2) shall be obligated to submit the TRTC Instructions to the CAISO electronically on behalf of the holders of Existing Rights, unless the parties to the Existing Contract agree otherwise. The Participating TO shall notify the CAISO in writing the identity of the responsible party for submission of the TRTC Instructions as decided by the parties to the Existing Contract and the term of such agreement between the parties to the Existing Contract. The Participating TO shall undertake all obligations with respect to the submission of the TRTC Instructions to the CAISO and any subsequent obligations that follow with respect to the creation, management and updates to the TRTC Instructions. The CAISO is responsible for implementing only one set of TRTC Instructions for each Existing Contract and only those TRTC Instructions that have been received and accepted by the CAISO. The Participating TO shall submit the TRTC Instructions to the CAISO associated with Existing Contracts or sets of interdependent Existing Contracts thirty (30) days prior to the date on which the scheduling or curtailment of the use of the Existing Rights is to change or commence.

16.4.5 TRTC Instructions Content.

TRTC Instructions will include the following information at a minimum and such other information as the CAISO may reasonably require the Participating TO to provide to enable the CAISO to carry out its functions under the CAISO Tariff, Operating Procedures and Business Practice Manuals:

(1) A unique Contract Reference Number for each source and sink combination applicable to the Existing Contract (i.e., the CRN that will be assigned by the CAISO and

communicated to the Participating TO that references a single Existing Contract or a set of interdependent Existing Contracts for each source and sink combination);

(2) Whether the instruction can be exercised independent of the CAISO's day-to-day involvement ("Yes/No");

(3) Name of an operational single point of contact for instructions and a 24-hour a day telephone number for the Participating TO contact for Existing Contract issues or the agreed upon party;

(4) Name(s) and number(s) of Existing Contract(s) that are represented by the unique CRN;

(5) The following information as stored in the Master File: (a) the applicable Point(s) of Receipt and Point(s) of Delivery; (b) for each Point of Receipt, the resource names for the physical resources as the eligible sources (eligible physical sources include Generating Units and System Resources), and for each Point of Delivery the resource names for the physical resources as the eligible sinks (eligible physical sinks include Load PNodes, custom Load Aggregation Points and System Resources); (c) for each physical source or sink the maximum Existing Rights capacity (MW) that can be scheduled as an Existing Right under the Existing Contract; and (d) for each physical source and sink the Scheduling Coordinator(s) and their Business Associate Identification ("BAID") that is(are) eligible to submit ETC Self-Schedules utilizing these sources and sinks;

(6) Names of the party(ies) to the Existing Contract(s);

(7) The Scheduling Coordinator BAID that is entitled to the Settlement of reversal of Congestion Charges;

(8) Type(s) of service rights by the holder of the Existing Rights, by type of service (firm, conditional firm, or non-firm), with priorities for firm and conditional firm transmission services and maximum amounts of service right in MW;

(9) Instructions for the allowable timeframes at which the ETC Self-Schedules and ETC Self-Schedule changes may be submitted to the CAISO, which include whether the Scheduling Coordinator may submit ETC Self-Schedules or ETC Self-Schedule changes: (a) into the DAM; (b) into the HASP and the RTM; (c) after the close of the bidding into the HASP and the RTM, but before T-20 minutes for that Trading Hour of Trading Day; and (d) at or after T-20 minutes and into the Trading Hour of Trading Day; in addition, the TRTC Instructions may also include any additional comments and restrictions on the submission time of ETC Self-Schedules and ETC Self-Schedule changes;

(10) Term or service period(s) of the Existing Contract(s);

(11) Any special procedures that would require the CAISO to implement curtailments in any manner different from pro rata reduction of the transfer capability of the transmission line; any such TRTC Instructions submitted to the CAISO must be clear, unambiguous, and not require the CAISO to make any judgments or interpretations as to the meaning intent, results, or purpose of the curtailment procedures or the Existing Contract and the section of the Existing Contract that provides this right for reference, otherwise, they will not be accepted by the CAISO;

(12) The forecasted usage patterns for each Existing Contract for the upcoming annual period of the annual CRR release processes as well as for the upcoming monthly period of the monthly CRR release processes, which will consist of hourly MWh data over the whole year for those resources that will use the Existing Contract; this information will be considered by the CAISO in managing its accounting for usage of Existing Rights in the release of CRRs; this information shall not be used by the CAISO to validate ETC Self-Schedules when submitted by Scheduling Coordinators and therefore shall not affect the Existing Rights holder’s ability to utilize its rights under the Existing Contract;

(13) Whether or not the Existing Contract provides for the right to self-provide Ancillary Services; and

(14) Specification of any contract requirements in the ETC that warrants special consideration in the implementation of the physical rights under the ETC.

16.4.6 Changes and Updates to TRTC Instructions.

Updates or changes to the TRTC Instructions must be submitted to the CAISO through a revised set of TRTC Instructions by the Participating TO, on an as needed or as required basis determined by the parties to the Existing Contracts. The CAISO will implement the updated or changed TRTC Instructions as soon as practicable but no later than seven (7) days after receiving clear and unambiguous details of the updated or changed instructions under normal conditions. If the CAISO finds the TRTC Instructions to be inconsistent with the CAISO Tariff, the CAISO will notify the Participating TO within forty-eight (48) hours after receipt of the updated or changed TRTC Instructions indicating the nature of the problem and allowing the Participating TO to resubmit the TRTC Instructions as if they were new, updated or changed TRTC Instructions. If the CAISO finds the updated or changed TRTC Instructions to be acceptable, the CAISO will time-stamp the updated TRTC Instructions as received, confirm such receipt to the Participating TO, and indicate the time at which the updated TRTC Instructions take effect if prior to the seven (7) day deadline referred to above. In the event of a System Emergency, the CAISO will implement such submitted changes to the TRTC Instructions as soon as practical.

16.4.7 Treatment of TRTC Instructions.

16.4.7.1 TRTC Instructions Can Be Exercised Independently.

To the extent that the TRTC Instructions can be exercised independently of the CAISO by the parties to the Existing Contract and the results forwarded to the CAISO, the TRTC Instructions shall be exercised by the Participating TOs, and the outcomes shall be forwarded to the CAISO. The determination of whether the TRTC Instructions can be "exercised independently of the CAISO by the parties to the Existing Contract" shall be made using the same procedures described in Section 16.4.8 of this Appendix.

16.4.7.2 TRTC Instructions Cannot Be Exercised Independently.

To the extent that the TRTC Instructions cannot be exercised independently of the CAISO and the results forwarded to the CAISO (because, for example, they require iteration with the CAISO's Bid submission and scheduling process, would unduly interfere with the CAISO's management of the Real-Time Market, including curtailments, or would unduly interfere with the ability of the holder of rights to exercise its rights), the TRTC Instructions will be provided to the CAISO for day-to-day implementation. The TRTC Instructions will be provided by the Participating TO to the CAISO for implementation unless the parties to the Existing Contracts otherwise agree that the holder of the Existing Rights will do so. For these TRTC Instructions, the Scheduling Coordinators representing the holders of Existing Rights will submit their Bids to the CAISO for implementation in accordance with the TRTC Instructions. In this case, the CAISO shall act as the scheduling agent for the Participating TO with regard to Existing Rights.

16.4.8 CAISO Role in Existing Contracts.

The CAISO will have no role in interpreting Existing Contracts. The parties to an Existing Contract will, in the first instance, attempt jointly to agree on any TRTC Instructions that will be submitted to the CAISO. In the event that the parties to the Existing Contract cannot agree upon the TRTC Instructions submitted by the parties to the Existing Contract, the dispute resolution provisions of the Existing Contract, if applicable, shall be used to resolve the dispute; provided that, until the dispute is resolved, and unless the Existing Contract specifies otherwise, the CAISO shall implement the Participating TO's TRTC Instructions. If both parties to an Existing Contract are Participating TOs and the parties cannot agree to the TRTC Instructions submitted by the parties, until the dispute is resolved, and unless the Existing Contract specifies otherwise, the CAISO shall implement the TRTC Instructions of the first Participating TO for which the Existing Contract is an Encumbrance. The CAISO shall not be responsible for resolution of any disputes that arise over the accuracy of the TRTC Instructions consistent with its obligations in Section 16.4.5 of this Appendix.

16.4.9 Implementation of TRTC Instructions.

The CAISO shall determine, based on the information provided by the Participating TOs under TRTC Instructions, the transmission capacities that (i) must be reserved for firm Existing Rights at Scheduling Points, (ii) may be allocated for use as CAISO transmission service (i.e., new firm uses), (iii) must be reserved by the CAISO for conditional firm Existing Rights, and (iv) remain for any non-firm Existing Rights for which a Participating TO has no discretion over whether or not to provide such non-firm service.

The CAISO shall coordinate the scheduling of Existing Rights with the scheduling of CAISO transmission service, using the CAISO's Bid submission rules. In doing so, the CAISO shall create an automated day-to-day verification process based on parameters provided by the Participating TO for the Existing Contract to serve as the basis for ETC Self-Schedule validation. The Participating TO will be responsible for: (1) the accuracy of the data files against which the CAISO will validate the ETC Self-Schedule; and (2) providing the data file to the holder of Existing Rights as well as the CAISO.

The CAISO shall recognize that the obligations, terms or conditions of Existing Contracts may not be changed without the voluntary consent of all parties to the contract (unless such contract may be changed pursuant to any applicable dispute resolution provisions in the contract or pursuant to Section 205 or Section 206 of the FPA and the FERC's Rules and Regulations or as otherwise provided by law).

The parties to Existing Contracts shall remain liable for their performance under the Existing Contracts. The CAISO shall be liable in accordance with the provisions of this CAISO Tariff for any damage or injury caused by its non-compliance with the TRTC Instructions submitted to it pursuant to this Section 16.4.

Unless specified otherwise, in the event that the dispute resolution mechanisms prescribed in an Existing Contract, including all recourses legally available under the contract, cannot, in the first instance, result in a resolution of such a dispute, the ISO ADR Procedures will be used to resolve any disputes between the CAISO and the Participating TO regarding any aspects of the implementation of this Section 16.4, including the reasonableness of a Participating TO's TRTC Instructions or any other decision rules which the Participating TO may submit to the CAISO as part of the TRTC Instructions. The holders of Existing Rights under the Existing Contract shall have standing to participate in the ISO ADR Procedures.

17.1 Transmission Rights and Transmission Curtailment Instructions

17.1.1 Responsibility to Create TRTC Instructions

To enable the CAISO to exercise its responsibilities as Control Area Operator in accordance with Applicable Reliability Criteria, each Non-Participating TO holding a TOR must work with the CAISO to develop the TRTC Instructions that allow the TOR to be accommodated in a way that: (i) maintains the existing scheduling and curtailment priorities of the TOR holder; (ii) is minimally burdensome to the CAISO (i.e., creates the least impact on the CAISO's preferred operational policies and procedures); (iii) to the extent possible, imposes no additional financial burden on the TOR holder (beyond that set forth in an applicable Existing Contract or any other contract pertaining to the TOR); (iv) is minimally burdensome to the TOR holder from an operational point of view; and (v) does not require the CAISO to interpret or underwrite the economics of any applicable Existing Contract. To enable the CAISO to exercise its responsibilities as Control Area Operator in accordance with Applicable Reliability Criteria, the parties holding joint ownership interests and Entitlements in facilities including TORs must attempt to jointly develop and agree on any TRTC Instructions that will be submitted to the CAISO. TOR holders and any other parties holding joint ownership interests and Entitlements in facilities including TORs shall also be responsible to submit to the CAISO any other necessary operating instructions based on their interpretations of the agreements applicable to those TORs and joint ownership interests and Entitlements needed by the CAISO to enable the CAISO to perform its duties.

17.1.2 TOR Scheduling Coordinator Responsibilities

To enable the CAISO to exercise its responsibilities as Control Area Operator in accordance with Applicable Reliability Criteria, each TOR holder must designate a Scheduling Coordinator as the responsible entity for submitting TOR Self-Schedules for the relevant TOR. The designated Scheduling Coordinator shall submit TOR Self-Schedules consistent with the terms and conditions specified in the TRTC Instructions.

17.1.3 Submission of TRTC Instructions.

For each TOR, the Non-Participating TO holding the TOR shall be obligated to submit TRTC Instructions to the CAISO electronically, unless the Non-Participating TO specifies to the CAISO otherwise. The Non-Participating TO shall notify the CAISO in writing the identity of the responsible party for submission of the TRTC Instructions, subject to the terms of any applicable Existing Contract that may specify the responsible party for submission of the TRTC Instructions and the term of such agreement between the parties to the Existing Contract. The Non-Participating TO shall undertake all obligations with respect to the submission of the TRTC Instructions to the CAISO and any subsequent obligations that follow with respect to the creation, management and updates to the TRTC Instructions. The CAISO is responsible for implementing only one set of TRTC Instructions for each TOR and for implementing only those TRTC Instructions that have been received and accepted by the CAISO. The Non-Participating TO shall submit the TRTC Instructions to the CAISO associated with its TORs thirty (30) days prior to the date on which the scheduling or curtailment of the use of the TORs is to change or commence.

17.1.4 TRTC Instructions Content.

TRTC Instructions will include the following information at a minimum and such other information as the CAISO may reasonably require the Non-Participating TO holder of a TOR to provide to enable the CAISO to carry out its functions under the CAISO Tariff, Operating Procedures and Business Practice Manuals:

(1) A unique Contract Reference Number for each source and sink combination applicable to the TOR (TOR reference number or CRN that will be assigned by the CAISO and communicated to the Non-Participating TO that references a single TOR or a set of interdependent TORs for each source and sink combination);

(2) Whether the instruction can be exercised independent of the CAISO’s day-to-day involvement (“Yes/No”);

(3) Name of an operational single point of contact for instructions and a 24-hour a day telephone number for the Non-Participating TO contact for TOR issues or the agreed upon party;

(4) Name(s) and number(s) of TOR(s) that are represented by the unique CRN;

(5) The following information, as stored in the Master File: (a) the applicable Point(s) of Receipt and Point(s) of Delivery; (b) for each Point of Receipt, the resource names for the physical resources as the eligible sources (eligible physical sources include Generating Units and System Resources), and for each Point of Delivery the resource names for the physical resources as the eligible sinks (eligible physical sinks include Load PNodes, Custom Load Aggregation Points and System Resources); (c) for each physical source or sink the maximum capacity (MW) that can be scheduled as a TOR under the Existing Contract; and (d) for each physical source and sink the Scheduling Coordinator(s) and their Business Associate Identification ("BAID") that is(are) eligible to submit TOR Self-Schedules utilizing these sources and sinks;

(6) Names of the party(ies) holding the TOR(s) and the parties to any agreements applicable to the TORs;

(7) The Scheduling Coordinator BAID that is entitled to the Settlement of reversal of Congestion Charges;

(8) Amount of TORs, in maximum MW, that may be utilized under the relevant TRTC Instructions;

(9) Instructions for the allowable timeframes at which the TOR Self-Schedules and TOR Self-Schedule changes may be submitted to the CAISO, which include whether the Scheduling Coordinator may submit TOR Self-Schedules or TOR Self-Schedule changes: (a) into the DAM; (b) into the HASP and the RTM; (c) after the close of the bidding into the HASP and the RTM, but before T-20 minutes for that Trading Hour of

Trading Day; and (d) at or after T-20 minutes and into the Trading Hour of Trading Day; in addition, the Non-Participating TO may also provide any additional comments and restrictions on the submission time of TOR Self-Schedules and TOR Self-Schedule changes;

(10) Term of ownership interest in the TOR(s) and of any agreements applicable to the TOR(s);

(11) Any special procedures that would require the CAISO to implement curtailments in any manner different than pro rata reduction of the transfer capability of the transmission line; any such instructions submitted to the CAISO must be clear, unambiguous, and not require the CAISO to make any judgments or interpretations as to the meaning intent, results, or purpose of the curtailment procedures or of any applicable Existing Contract, otherwise, they will not be accepted by the CAISO; and

(12) Whether or not the TOR provides the right to self-provide Ancillary Services.

17.1.5 Changes and Updates to TRTC Instructions.

Updates or changes to the TRTC Instructions must be submitted to the CAISO through a revised set of TRTC Instructions by the Non-Participating TO, on an as needed or as required basis. The CAISO will implement the updated or changed TRTC Instructions as soon as practicable but no later than seven (7) days after receiving clear and unambiguous details of the updated or changed instructions under normal conditions. If the CAISO finds the TRTC Instructions to be inconsistent with the CAISO Tariff, the CAISO will notify the Non-Participating TO within forty-eight (48) hours after receipt of the updated or changed TRTC Instructions indicating the nature of the problem and allowing the Non-Participating TO to resubmit the TRTC Instructions as if they were new, updated or changed TRTC Instructions. If the CAISO finds the updated or changed TRTC Instructions to be acceptable, the CAISO will time-stamp the updated TRTC Instructions as received, confirm such receipt to the Non-Participating TO, and indicate the time at which the updated instructions take effect if prior to the seven (7) day deadline referred to above. In theevent of a System Emergency, the CAISO will implement such submitted changes to the TRTC Instructions as soon as practical.

17.1.6 CAISO Role in Accepting TRTC Instructions.

The parties holding joint ownership interests and Entitlements in a facility including a TOR must, in the first instance, attempt jointly to agree on any TRTC Instructions that will be submitted to the CAISO. In the event that the parties holding joint ownership interests and Entitlements in a facility including a TOR cannot agree upon the TRTC Instructions, the dispute resolution provisions of any applicable Existing Contract shall be used to resolve the dispute; provided that, until the dispute is resolved, and unless the applicable Existing Contract specifies otherwise, the CAISO shall implement the Participating TO's TRTC Instructions, if one of the parties holding a joint ownership interest or an Entitlement in the facility is a Participating TO. If no party holding a joint ownership interest or Entitlement in a facility including a TOR is a Participating TO and the parties cannot agree to the TRTC Instructions to be submitted by the parties, until the dispute is resolved, the CAISO shall implement the TRTC Instructions of the Non-Participating TO with the greatest ownership interest in the TOR. The CAISO shall not be responsible for resolution of any disputes that arise over the accuracy of the TRTC Instructions consistent with its obligations in Section 17.1.4 of this Appendix.

17.1.7 Implementation of TRTC Instructions.

The CAISO shall determine, based on the information provided by the Non-Participating TOs under TRTC Instructions, the transmission capacities that must be reserved for TORs at Scheduling Points.

The CAISO shall coordinate the scheduling of TORs with the scheduling of CAISO transmission service, using the CAISO's Bid submission rules. In doing so, the CAISO shall create an automated day-to-day verification process based on parameters provided by the Non-Participating TO for the TOR to serve as the basis for TOR Self-Schedule validation. The Non-Participating TO will be responsible for: (1) the accuracy of the data files against which the CAISO will validate the TOR Self-Schedule; and (2) providing the data file to the CAISO.

The TOR holders shall remain liable for their performance under any applicable Existing Contracts or other agreements pertaining to their TORs. The CAISO shall be liable in accordance with the provisions of this CAISO Tariff for any damage or injury caused by its non-compliance with the TRTC Instructions submitted to it pursuant to this Section 17.1.

Unless specified otherwise, in the event that the dispute resolution mechanisms prescribed in an Existing Contract applicable to a TOR, including all recourses legally available under the contract, cannot, in the first instance, result in a resolution of such a dispute, the ISO ADR Procedures will be used to resolve any disputes between the CAISO and the Non-Participating TO regarding any aspects of the implementation of this Section 17.1, including the reasonableness of a Non-Participating TO's TRTC Instructions or any other decision rules which the Non-Participating TO may submit to the CAISO as part of the TRTC Instructions. The holders of TORs shall have standing to participate in the ISO ADR Procedures.

PART C. MSS OPERATOR SETTLEMENT OPTIONS

In preparation for the first annual CRR Allocation to be held in 2007 prior to the date on which the version of the CAISO Tariff as filed and accepted in FERC Docket No. ER06-615 shall become effective, an MSS Operator Candidate CRR Holder's load eligibility for allocation of CRRs in the annual and monthly CRR Allocation will depend on its election of Settlement options as follows.

[NOT USED]

[NOT USED]

[NOT USED]

4.9.13.1 Gross or Net Settlement.

An MSS Operator has the option to settle with the CAISO on either a gross basis or a net basis for its Load and generating resources. This election shall be made annually for a period consistent with annual CRR Allocation. If the MSS Operator elects net settlement, then CRRs would be allocated on MSS net Load and the MSS may choose the MSS LAP as its CRR Sink in the first tiers of CRR Allocation. If the MSS Operator elects gross settlement, then CRRs would be allocated on a gross load basis and the MSS may not choose the MSS LAPs as its CRR Sink in the first tiers of CRR Allocation.

PART D. CANDIDATE CRR HOLDER AND CRR HOLDER REQUIREMENTS

The provisions of this Part D are necessary to enable the CAISO to register and certify Candidate CRR Holders in advance of their participation in the CRR Allocation and CRR Auction to be conducted in the summer and fall of 2007.

4.10 Candidate CRR Holder and CRR Holder Registration.

Only entities that are registered and qualified as a Candidate CRR Holder or CRR Holder shall: 1) submit nominations to CRR Allocations; 2) submit bids to CRR Auctions; and 3) register as a CRR Holder through the Secondary Registration System. In order to be registered and qualified as Candidate CRR Holders or CRR Holders, entities must have met the all of the requirements specified in this Section 4.10.

4.10.1 Procedure to Become a Candidate CRR Holder.

4.10.1.1 Candidate CRR Holder Application.

To become a Candidate CRR Holder, a Candidate CRR Holder applicant must submit a completed written application, as provided in the applicable form posted on the CAISO Website, to the CAISO by mail, or in person. A Candidate CRR Holder applicant may retrieve the application and necessary information from the CAISO Website.

4.10.1.2 CAISO Information.

The CAISO will provide the following information, in its most current form, on the CAISO Website and, upon request by a Candidate CRR Holder applicant, the CAISO will send the requested information by electronic mail:

(a) the Candidate CRR Holder application form;

(b) the CAISO Tariff and Business Practice Manuals; and

(c) an application for an Unsecured Credit Limit for Candidate CRR Holder applicants requesting an Unsecured Credit Limit in lieu of another form of Financial Security.

4.10.1.3 Candidate CRR Holder Applicant Submits Application.

At least 60 days before the proposed commencement of the CRR Allocation or CRR Auction, or the effective date of the CRR transfer through the Secondary Registration System, in which a Candidate CRR Holder desires to participate as applicable, the Candidate CRR Holder applicant must return a completed application form with the non-refundable application fee set by the CAISO Governing Board to cover the application processing costs and the costs of furnishing the CAISO Tariff and other documents.

4.10.1.4 Notice of Receipt.

Within three (3) Business Days of receiving the application, the CAISO will send a written notification to the Candidate CRR Holder applicant that it has received the application and the non-refundable fee.

4.10.1.5 CAISO Review of Application.

Within ten (10) Business Days after receiving an application, the CAISO will notify the Candidate CRR Holder applicant whether the Candidate CRR Holder applicant has fulfilled all necessary information as set forth in Section 4.10.1 of this Appendix. If the Candidate CRR Holder applicant fails to fulfill all application requirements within a year from the date that the CAISO acknowledges receipt of the Candidate CRR Holder application, the application will be nullified and the applicant will be required to resubmit a new application in order to reinstate its status as a Candidate CRR Holder applicant.

4.10.1.5.1 Information Requirements.

The Candidate CRR Holder applicant must submit with its application:

(a) the proposed date for commencement of the CRR Allocation, CRR Auction or Secondary Registration System in which the applicant intends to qualify to participate, which may not be less than sixty (60) days after the date the application was filed, unless waived by the CAISO;

(b) Financial Security information as set forth in Section 12.1 of the ISO Tariff and Section 12.6 of this Appendix;

(c) proof of completion of CRR training or expected completion of CRR training; and

(d) the prescribed non-refundable application fee.

4.10.1.5.2 Candidate CRR Holder Load Serving Entity Certifications.

A Candidate CRR Holder applicant that intends to obtain CRRs through the CRR Allocation process must certify that it qualifies as a Load Serving Entity as defined in the CAISO Tariff. A Candidate CRR Holder applicant that intends to participate in the CRR Allocation for load it serves located outside the CAISO Control Area must certify that it qualifies as that load's load serving entity and prior to actual participation in the CRR Allocation will also be required to fulfill the requirements in Section 36.9 of this Appendix.

4.10.1.6 Deficient Application.

In the event that the CAISO has determined that the Candidate CRR Holder application as submitted is deficient the CAISO will send a written notification of the deficiency to the Candidate CRR Holder applicant within ten (10) Business Days of receipt by the CAISO of the application explaining the deficiency and requesting additional information.

4.10.1.6.1 Candidate CRR Holder Applicant's Additional Information.

Once the CAISO requests additional information, the Candidate CRR Holder applicant has five (5) Business Days, or such longer period as the CAISO may agree, to provide the additional material requested by the CAISO.

4.10.1.6.2 No Response from Candidate CRR Holder Applicant.

If the Candidate CRR Holder applicant does not submit additional information within five (5) Business Days or the longer period referred to in Section 4.10.1.6.1 of this Appendix, the application may be rejected by the CAISO.

4.10.1.7 CAISO Acceptance or Rejection of an Application.

4.10.1.7.1 Acceptance or Rejection Notification.

(a) If the CAISO accepts the application, it will send a written notification to the Candidate CRR Holder applicant stating that its application has been accepted.

(b) If the CAISO rejects the application, the CAISO will send a rejection letter stating one or more of the following grounds:

i. incomplete information;

ii. non-compliance with Financial Security requirements; or

iii. non-compliance with any other CAISO Tariff requirements.

Upon request, the CAISO will provide guidance as to how the Candidate CRR Holder applicant can cure the grounds for the rejection.

4.10.1.7.2 Time for Processing Application.

The CAISO will make a decision whether to accept or reject the application within ten (10) Business Days of receipt of the application. If more information is requested, the CAISO will make a final decision within ten (10) Business Days of the receipt of all outstanding or additional information requested.

4.10.1.8 Candidate CRR Holder Applicant's Response.

4.10.1.8.1 Candidate CRR Holder Applicant's Acceptance.

If the CAISO accepts the application, the Candidate CRR Holder applicant must return an executed CRR Entity Agreement and any required letter of credit, guaranty, escrow agreement or other form of Financial Security for the CAISO Security Amount, as applicable.

4.10.1.8.2 Candidate CRR Holder Applicant's Rejection.

4.10.1.8.2.1 Resubmittal.

If a Candidate CRR Holder's application is rejected, the Candidate CRR Holder applicant may resubmit its application at any time. An additional application fee will not be required for the second application submitted within six (6) months after the CAISO's issuance of a rejection.

4.10.1.8.2.2 Appeal.

The Candidate CRR Holder applicant may also appeal against the rejection of an application by the CAISO. An appeal must be submitted within twenty (20) Business Days following the CAISO's issuance of a rejection of its application.

4.10.1.9 Final Registration and Qualification of Candidate CRR Holder Applicant.

4.10.1.9.1 Notice of Completed Registration and Qualification of Candidate CRR Holder.

Once the CAISO has accepted a Candidate CRR Holder applicant's application, the CAISO will provide the Candidate CRR Holder applicant with a final written notice to certify that a Candidate CRR Holder applicant has become a Candidate CRR Holder. The CAISO shall issue such final written notice of full registration and qualification as a Candidate CRR Holder after the CAISO has determined that the Candidate CRR Holder applicant has fully satisfied all the following requirements:

(a) fully executed a CRR Entity Agreement with the CAISO;

(b) provided its bank account information and arranged for Fed-Wire transfers;

(c) met the Financial Security requirements of Section 12.1 of the ISO Tariff and Section 12.6 of this Appendix;

(d) certified that it has attended required CRR training; and

(e) obtained and installed any necessary software for communication with the CAISO as necessary.

4.10.1.9.2 Market Notice

The CAISO shall issue a Market Notice stating the new Candidate CRR Holder status.

4.10.2 Candidate CRR Holder's and CRR Holder's Ongoing Obligations After Registration and Qualification.

4.10.2.1 Candidate CRR Holder and CRR Holder Obligation to Report Changes.

4.10.2.1.1 Obligation to Report a Change in Filed Information.

Each Candidate CRR Holder and CRR Holder has an ongoing obligation to inform the CAISO of any changes to any of the information submitted by it to the CAISO as part of its application to become a Candidate CRR Holder, including any changes to the additional information requested by the CAISO. The applicable Business Practice Manual sets forth the procedures for changing the Candidate CRR Holder or CRR Holder information and timing of notifying the CAISO of such changes.

4.10.2.1.2 Obligation to Report a Material Change in Financial Condition.

The Candidate CRR Holder or CRR Holder that has been granted Unsecured Credit Limit has an ongoing obligation to inform the CAISO within five (5) Business Days of any Material Change in Financial Condition including but not limited to credit rating changes described in Section 12.1.1.3 of the CAISO Tariff.

4.10.2.2 Failure to Promptly Report a Material Change.

If a Candidate CRR Holder or CRR Holder fails to inform the CAISO of a material change in its information provided to the CAISO including a Material Change in Financial Condition, that may affect the Financial Security of the CAISO, the CAISO may suspend or terminate the Candidate CRR Holder or CRR Holder's rights under the CAISO Tariff in accordance with the terms of Section 12.3 of the CAISO Tariff and Section 4.10.4.2 of this Appendix, respectively. If the CAISO intends to terminate the Candidate CRR Holder's status, it shall file a notice of termination with FERC in accordance with the terms of the CRR Entity Agreement. Such termination shall be effective upon acceptance by FERC of a notice of termination in accordance with the terms of the CRR Entity Agreement.

4.10.3 Termination of a CRR Entity Agreement.

4.10.3.1 Prior Notice Requirements.

(a) A CRR Entity Agreement may be terminated by the CAISO on written notice to the Candidate CRR Holder or CRR Holder that is a party to the CRR Entity Agreement in accordance with the terms of the CRR Entity Agreement:

(i) if the Candidate CRR Holder or CRR Holder no longer meets the requirements for eligibility set out in Section 4.10 of this Appendix and fails to remedy the default within a period of seven (7) days after the CAISO has given written notice of the default;

(ii) if the Candidate CRR Holder or CRR Holder fails to pay any sum under this CAISO Tariff and fails to remedy the default within a period of five (5) Business Days after the CAISO has given written notice of the default; or

(iii) if the Candidate CRR Holder or CRR Holder commits any other default under this CAISO Tariff or any of the Business Practice Manuals which, if capable of being remedied, is not remedied within thirty (30) days after the CAISO has given it written notice of the default.

(b) The Candidate CRR Holder or CRR Holder may terminate its CRR Entity Agreement in accordance with the provisions of that agreement.

(c) Upon termination of the CRR Entity Agreement, Candidate CRR Holders or CRR Holders shall continue to be liable for any outstanding financial or other obligations incurred under the CAISO Tariff as a result of their status as a Candidate CRR Holder or CRR Holder.

(d) The CAISO shall, following termination of a CRR Entity Agreement and within thirty (30) days of being satisfied that no sums remain owing by the Candidate CRR Holder or CRR Holder under the CAISO Tariff, return or release to the Candidate CRR Holder or CRR Holder, as appropriate, any Financial Security support provided by such Candidate CRR Holder or CRR Holder to the CAISO under Section 12.1 of the CAISO Tariff and Section 12.6 of this Appendix.

4.10.3.2 Suspension of Registration and Qualification

Pending FERC acceptance of termination of service pursuant to the filing of a notice of termination of the CRR Entity Agreement, the CAISO will suspend the registration and qualification of a Candidate CRR Holder or CRR Holder that has received a notice of termination under the CRR Entity Agreement and the Candidate CRR Holder will not be able to submit nominations in the CRR Allocation or bids in the CRR Auction, or to register as a CRR Holder in the Secondary Registration System.

[NOT USED]

PART E. PRO FORMA CRR ENTITY AGREEMENT

The provisions of this Part E are necessary to enable the CAISO to establish the terms of a *pro forma* service agreement by which the CASIO will enter into a direct relationship with entities that desire to participate in the CRR Allocation and CRR Auction to be conducted in the summer and fall of 2007.

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

AND

[CONGESTION REVENUE RIGHTS ENTITY]

CRR ENTITY AGREEMENT

CRR ENTITY AGREEMENT

THIS AGREEMENT is dated this _____ day of _____________, ______, and is entered into, by and between:

(1) **[Full Legal Name]** having its registered and principal place of business located at **[Address]** (the "CRR Entity");

and

(2) **California Independent System Operator Corporation,** a California nonprofit public benefit corporation having a principal executive office located at such place in the State of California as the CAISO Governing Board may from time to time designate, initially 151 Blue Ravine Road, Folsom, California 95630 (the "CAISO").

The CRR Entity and the CAISO are hereinafter referred to individually as a "Party" and collectively as the "Parties."

Whereas:

A. The CAISO Tariff provides that any entity that holds or intends to hold CRRs must register and qualify with the CAISO and comply with the terms of the CAISO Tariff, regardless of whether they are to acquire CRRs through the CRR Allocation or CRR Auction, or through the Secondary Registration System.

B. The CRR Entity has completed the Candidate CRR Holder application process and is eligible to participate in the CRR Allocation or CRR Auction or register as a CRR Holder through the Secondary Registration System.

C. The CAISO Tariff further provides that any entity who wishes to participate in the CRR Allocation or CRR Auction or register as a CRR Holder through the Secondary Registration System must meet all of the Candidate CRR Holder requirements and creditworthiness provisions in the CAISO Tariff and the relevant Business Practice Manual, including demonstration of its ability to accommodate the financial responsibility associated with holding CRRs.

D. The CRR Entity intends to obtain CRRs either through the CRR Allocation or CRR Auction or to register as a CRR Holder through the Secondary Registration System and, therefore, wishes to undertake to the CAISO that it will comply with the applicable provisions of the CAISO Tariff.

E. The Parties are entering into this Agreement in order to establish the terms and conditions pursuant to which the CAISO and the CRR Entity will discharge their respective duties and responsibilities under the CAISO Tariff.

NOW THEREFORE, in consideration of the mutual covenants set forth herein, **THE PARTIES AGREE** as follows:

ARTICLE I
DEFINITIONS AND INTERPRETATION

1.1 Master Definitions Supplement. All terms and expressions used in this Agreement shall have the same meaning as those contained in the Master Definitions Supplement in Appendix A of the CAISO Tariff.

1.2 Rules of Interpretation. The following rules of interpretation and conventions shall apply to this Agreement:

(a) if there is any inconsistency between this Agreement and the CAISO Tariff, the CAISO Tariff will prevail to the extent of the inconsistency;

(b) the singular shall include the plural and vice versa;

(c) the masculine shall include the feminine and neutral and vice versa;

(d) “includes” or “including” shall mean “including without limitation”;

(e) references to a Section, Article, or Schedule shall mean a Section, Article, or a Schedule of this Agreement, as the case may be, unless the context otherwise requires;

(f) a reference to a given agreement or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented, or restated through the date as of which such reference is made;

(g) unless the context otherwise requires, references to any law shall be deemed references to such law as it may be amended, replaced, or restated from time to time;

(h) unless the context otherwise requires, any reference to a “person” includes any individual, partnership, firm, company, corporation, joint venture, trust, association, organization, or other entity, in each case whether or not having separate legal personality;

(i) unless the context otherwise requires, any reference to a Party includes a reference to its permitted successors and assigns;

(j) any reference to a day, week, month, or year is to a calendar day, week, month, or year; and

(k) the captions and headings in this Agreement are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Agreement.

ARTICLE II
ACKNOWLEDGEMENTS OF CRR ENTITY AND CAISO

2.1 Scope of Application to Parties. The CRR Entity and CAISO acknowledge that all Candidate CRR Holders or CRR Holders must sign this Agreement in accordance with section 4.10.1.9.1 of the CAISO Tariff.

ARTICLE III
TERM AND TERMINATION

3.1 Effective Date. This Agreement shall be effective as of the later of the date it is executed by both Parties or the date accepted for filing and made effective by FERC if such FERC filing is required, and shall remain in full force and effect until terminated pursuant to Section 3.2 of this Agreement.

3.2 Termination

3.2.1 Termination by CAISO. Subject to Article V, the CAISO may terminate this Agreement by giving written notice to the CRR Entity of termination in the event that the CRR Entity commits any material default under this Agreement and/or the CAISO Tariff as it pertains to this Agreement which, if capable of being remedied, is not remedied within thirty (30) days after the CAISO has given, to the CRR Entity, written notice of the default, unless excused by reason of Uncontrollable Forces in accordance with Article X of this Agreement or unless the CAISO agrees, in writing, to an extension of the time to remedy such material default. With respect to any notice of termination given pursuant to this Section, the CAISO must file a timely notice of termination with FERC, if this Agreement was filed with FERC, or must otherwise comply with the requirements of FERC Order No. 2001 and related FERC orders. The filing of the notice of termination by the CAISO with FERC will be considered timely if: (1) the filing of the notice of termination is made after the preconditions for termination have been met and (2) the CAISO files the notice of termination within sixty (60) days after issuance of the notice of default or (3) the CAISO files the notice of termination in accordance with the requirements of FERC Order No. 2001. This Agreement shall terminate upon acceptance by FERC of such a notice of termination, if filed with FERC, or thirty (30) days after the date of the CAISO's notice of default, if terminated in accordance with the requirements of FERC Order No. 2001 and related FERC orders.

3.2.2 Termination by CRR Entity. In the event that the CRR Entity is no longer a CRR Holder, it may terminate this Agreement, on giving the CAISO not less than ninety (90) days' written notice; provided, however any outstanding financial right or obligation or any other obligation under the CAISO Tariff of the Candidate CRR Holder or CRR Holder that have arisen while the CRR Entity was a Candidate CRR Holder or a CRR Holder, and any provision of this Agreement necessary to give effect to such right or obligation shall survive until satisfied. With respect to any notice of termination given pursuant to this Section, the ISO must file a timely notice of termination with FERC, if this Agreement has been filed with FERC, or must otherwise comply with the requirements of FERC Order No. 2001 and related FERC orders. The filing of the notice of termination by the CAISO with FERC will be considered timely if: (1) the request to file a notice of termination is made after the preconditions for termination have been met and (2) the CAISO files the notice of termination within sixty (60) days after receipt of such request or (3) the CAISO files the notice of termination in accordance with the requirements of FERC Order No. 2001. This Agreement shall terminate upon acceptance by FERC of such a notice of termination, if such notice is required to be filed with FERC, or upon ninety (90) days after the CAISO's receipt of the CRR Entity's notice of termination, if terminated in accordance with the requirements of FERC Order No. 2001 and related FERC orders.

ARTICLE IV
GENERAL TERMS AND CONDITIONS

4.1 CRR Holder Requirements. The CRR Entity must register and qualify with the CAISO and comply with all terms of the CAISO Tariff applicable to Candidate CRR Holders or CRR Holders, regardless of the manner in which they acquire CRRs whether by CRR Allocation, CRR Auction, or through the Secondary Registration System.

4.2 CRR Holder Creditworthiness Requirements. The CRR Entity must comply with the requirements for creditworthiness applicable to Candidate CRR Holders or CRR Holders, including the creditworthiness provisions of the CAISO Tariff and the relevant Business Practice Manual.

4.3 Settlement Account. The CRR Entity shall maintain at all times an account with a bank capable of Fed-Wire transfer to which credits or debits shall be made in accordance with the billing and Settlement provisions of Section 11 of the CAISO Tariff. Such account shall be the account referred to in Schedule 2 hereof or as notified by the CRR Entity to the CAISO from time to time by giving at least seven (7) days written notice before the new account becomes operational. Such changes to Schedule 2 shall not constitute an amendment to this Agreement.

4.4 Electronic Contracting. All submitted applications, bids, confirmations, changes to information on file with the CAISO and other communications conducted via electronic transfer (*e.g.*, direct computer link, FTP file transfer, bulletin board, e-mail, facsimile or any other means established by the CAISO) shall have the same legal rights, responsibilities, obligations and other implications as set forth in the terms and conditions of the CAISO Tariff as if executed in written format.

4.5 Agreement Subject to CAISO Tariff. The Parties will comply with all provisions of the CAISO Tariff applicable to Candidate CRR Holders or CRR Holders. This Agreement shall be subject to the CAISO Tariff, which shall be deemed to be incorporated herein.

ARTICLE V
PERFORMANCE

5.1 Penalties. The CRR Entity shall be subject to all penalties made applicable to Candidate CRR Holders and CRR Holders set forth in the CAISO Tariff. Nothing in this Agreement, with the exception of the provisions relating to ADR, shall be construed as waiving the rights of the CRR Entity to oppose or protest the specific imposition by the CAISO of any FERC-approved penalty on the CRR Entity.

5.2 Corrective Measures. If the CRR Entity of the CAISO fails to meet or maintain the requirements set forth in this Agreement and/or the CAISO Tariff as it pertains to this Agreement, the CAISO or the CRR Entity shall be permitted to take any of the measures, contained or referenced in the CAISO Tariff, which the Party seeking enforcement deems to be necessary to correct the situation.

ARTICLE VI
COSTS

6.1 Operating and Maintenance Costs. The CRR Entity shall be responsible for all its costs incurred in connection with all its CRR related activities.

ARTICLE VII
DISPUTE RESOLUTION

7.1 Dispute Resolution. The Parties shall make reasonable efforts to settle all disputes arising out of or in connection with this Agreement. In the event any dispute is not settled, the Parties shall adhere to the ISO ADR Procedures set forth in Section 13 of the CAISO Tariff, which is incorporated by reference, except that any reference in Section 13 of the CAISO Tariff to Market Participants shall be read as a reference to the CRR Entity and references to the CAISO Tariff shall be read as references to this Agreement.

ARTICLE VIII
REPRESENTATIONS AND WARRANTIES

8.1 Representation and Warranties. Each Party represents and warrants that the execution, delivery and performance of this Agreement by it has been duly authorized by all necessary corporate and/or governmental actions, to the extent authorized by law.

ARTICLE IX
LIABILITY

9.1 Liability. The provisions of Section 14 of the CAISO Tariff will apply to liability arising under this Agreement, except that all references in Section 14 of the CAISO Tariff to Market Participants shall be read as references to the CRR Entity and references to the CAISO Tariff shall be read as references to this Agreement.

ARTICLE X
UNCONTROLLABLE FORCES

10.1 Uncontrollable Forces Tariff Provisions. Section 14.1 of the CAISO Tariff shall be incorporated by reference into this Agreement except that all references in Section 14.1 of the CAISO Tariff to Market Participants shall be read as a reference to the CRR Entity and references to the CAISO Tariff shall be read as references to this Agreement.

ARTICLE XI
MISCELLANEOUS

11.1 Assignments. Either Party may assign or transfer any or all of its rights and/or obligations under this Agreement with the other Party’s prior written consent in accordance with Section 22.2 of the

CAISO Tariff and other CAISO Tariff requirements as applied to Candidate CRR Holders or CRR Holders. Such consent shall not be unreasonably withheld. Any such transfer or assignment shall be conditioned upon the successor in interest accepting the rights and/or obligations under this Agreement as if said successor in interest was an original Party to this Agreement.

11.2 Notices. Any notice, demand, or request which may be given to or made upon either Party regarding this Agreement shall be made in accordance with Section 22.4 of the CAISO Tariff. A Party must update the information in Schedule 1 of this Agreement as information changes. Such changes to Schedule 1 shall not constitute an amendment to this Agreement.

11.3 Waivers. Any waivers at any time by either Party of its rights with respect to any default under this Agreement, or with respect to any other matter arising in connection with this Agreement, shall not constitute or be deemed a waiver with respect to any subsequent default or other matter arising in connection with this Agreement. Any delay, short of the statutory period of limitations, in asserting or enforcing any right under this Agreement shall not constitute or be deemed a waiver of such right.

11.4 Governing Law and Forum. This Agreement shall be deemed to be a contract made under, and for all purposes shall be governed by and construed in accordance with, the laws of the State of California, except its conflict of law provisions. The Parties irrevocably consent that any legal action or proceeding arising under or relating to this Agreement to which the ISO ADR Procedures do not apply, shall be brought in any of the following forums, as appropriate: (i) any court of the State of California, (ii) any federal court of the United States of America located in the State of California, except to the extent subject to the protections of the Eleventh Amendment of the United States Constitution or, (iii) where subject to its jurisdiction, before the Federal Energy Regulatory Commission.

11.5 Consistency with Federal Laws and Regulations. This Agreement shall incorporate by reference Section 22.9 of the CAISO Tariff as if the references to the CAISO Tariff were referring to this Agreement.

11.6 Merger. This Agreement constitutes the complete and final agreement of the Parties with respect to the subject matter hereto and supersedes all prior agreements, whether written or oral, with respect to such subject matter.

11.7 Severability. If any term, covenant, or condition of this Agreement or the application or effect of any such term, covenant, or condition is held invalid as to any person, entity, or circumstance, or is determined to be unjust, unreasonable, unlawful, imprudent, or otherwise not in the public interest by any court or government agency of competent jurisdiction, then such term, covenant, or condition shall remain in force and effect to the maximum extent permitted by law, and all other terms, covenants, and conditions of this Agreement and their application shall not be affected thereby, but shall remain in force and effect and the Parties shall be relieved of their obligations only to the extent necessary to eliminate such regulatory or other determination unless a court or governmental agency of competent jurisdiction holds that such provisions are not separable from all other provisions of this Agreement.

11.8 Section Headings. Section headings provided in this Agreement are for ease of reading and are not meant to interpret the text in each Section.

11.9 Amendments. This Agreement and the Schedules attached hereto may be amended from time to time by the mutual agreement of the Parties in writing. Amendments that require FERC approval shall not take effect until FERC has accepted such amendments for filing and made them effective. If the amendment does not require FERC approval, the amendment will be filed with FERC for informational purposes. Nothing herein shall be construed as affecting in any way the right of the CAISO to make unilateral application to FERC for a change in the rates, terms, and conditions of this Agreement under Section 205 of the FPA and pursuant to FERC's rules and regulations promulgated thereunder. The standard of review the Commission shall apply when acting upon proposed modifications to this Agreement by the CAISO shall be the "just and reasonable" standard of review rather than the "public interest" standard of review. The standard of review the Commission shall apply when acting upon proposed modifications to this Agreement by the Commission's own motion or by a signatory other than the CAISO or non-signatory entity shall also be the "just and reasonable" standard of review. Schedules 1 and 2 are provided for informational purposes and revisions to those schedules do not constitute a material change in the Agreement warranting Commission review.

11.10 Counterparts. This Agreement may be executed in one or more counterparts at different times, each of which shall be regarded as an original and all of which, taken together, shall constitute one and the same Agreement.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be duly executed on behalf of each by and through their authorized representatives as of the date hereinabove written.

California Independent System Operator Corporation

By: ____

Name: ____

Title: ____

Date: ____

[Name of CRR Entity]

By: ____

Name: ____

Title: ____

Date: ____

SCHEDULE 1

NOTICES
[Section 11.2]

CRR Entity

Name of Primary
Representative: ______________________
Title: ______________________
Company: ______________________
Address: ______________________
City/State/Zip Code: ______________________
Email Address: ______________________
Phone: ______________________
Fax No: ______________________

Name of Alternative
Representative: ______________________
Title: ______________________
Company: ______________________
Address: ______________________
City/State/Zip Code: ______________________
Email Address: ______________________
Phone: ______________________
Fax No: ______________________

CAISO

Name of Primary
Representative: ______________________
Title: ______________________
Address: ______________________
City/State/Zip Code: ______________________
Email address: ______________________
Phone: ______________________
Fax: ______________________

Name of Alternative
Representative: ______________________________

Title: ______________________________

Address: ______________________________

City/State/Zip Code: ______________________________

Email address: ______________________________

Phone: ______________________________

Fax: ______________________________

SCHEDULE 2

SETTLEMENT ACCOUNT

[SECTION 4.3]

CRR Entity Account Information

Settlement Account No:

____

Title:

____

Sort Code:

____

Bank:

____

PART F. MISCELLANEOUS SECTIONS

27.2 Load Aggregation Points (LAP).

The CAISO shall create Load Aggregation Points and shall maintain Default LAPs at which all Demand shall Bid and be settled, except as provided in Section 27.2.1 and Section 30.5.3.2 of this Appendix.

27.2.1 Metered Subsystems.

The CAISO shall define specific MSS-LAPs for each MSS. The MSS LAP shall be made up the PNodes within the MSS that have Load served off of those Nodes. The MSS-LAPs have unique Load Distribution Factors that reflect the distribution of the MSS Demand to the network nodes within the MSS. These MSS LAPs are separate from the Default LAPs, and the load distribution factors of the Default LAP do not reflect any MSS Load.

30.5.3.2 Exceptions to Requirement for Submission of Demand Bids and Settlement at the LAP.

The following are exceptions to the requirement that Demand Bids be submitted and settled at the LAP:

(a) ETC or TOR Self-Schedules submitted consistent with the submitted TRTC Instructions;

(b) Participating Load Bids for Supply and Demand may be submitted and settled at a PNode; and

(c) Export Bids are submitted and settled at Scheduling Points, which do not constitute a LAP.

PART G. DEFINITIONS

Unless defined in this Appendix BB or the context otherwise requires, all capitalized terms and expressions used in this Appendix BB shall have the meaning as defined in the Master Definitions Supplement in Appendix A. The following capitalized terms and expressions used in this Appendix BB shall have the meanings set forth below unless otherwise stated or the context otherwise requires. If two or more capitalized terms are used together in a manner not uniquely defined in Appendix A or this Appendix BB, the meanings of each defined term apply.

Aggregated PNodes	A Load Aggregation Point, Trading Hub or any group of Pricing Nodes as defined by the CAISO.
Bid	An offer for the Supply or Demand of Energy or Ancillary Services, including Self-Schedules, submitted by Scheduling Coordinators for specific resources, conveyed through several components that apply differently to the different types of service offered to or demanded from any of the CAISO Markets.
Business Practice Manual (BPM)	A collection of documents made available by the CAISO on the CAISO Website that contain the rules, polices, procedures and guidelines established by the CAISO for operational, planning, accounting and settlement requirements of CAISO Market activities, consistent with the CAISO Tariff.
CAISO	The California Independent System Operator Corporation, a California non-profit public benefit corporation that operates the transmission facilities of all Participating TOs and dispatches certain Generating Units and Loads
CAISO Markets	Any of the markets administered by the CAISO under the CAISO Tariff, including, without limitation, the DAM, HASP, RTM, Transmission, and Congestion Revenue Rights.
Candidate CRR Holder	An entity that is registered and qualified by the CAISO to participate in the CRR Allocation, the CRR Auction or in the Secondary Registration System to become a CRR Holder and is a party to a fully executed CRR Entity Agreement, and therefore must comply with the requirements for Candidate CRR Holders under the CAISO Tariff.

Congestion Charge	A charge attributable to the Marginal Cost of Congestion at a given pricing PNode.
CRR Allocation	The process of nominations and awards held monthly and annually through which the CAISO will distribute CRRs to Candidate CRR Holders.
CRR Auction	The annual and monthly market process that will follow CRR Allocation through which the CAISO makes CRRs available to Candidate CRR Holders that submit offers to purchase CRRs.
CRR Eligible Quantity	The Seasonal CRR Eligible Quantity or the Monthly CRR Eligible Quantity.
CRR Entity Agreement	An agreement between the CAISO and a Candidate CRR Holder or CRR Holder that must be fully executed in order for such an entity to participate in the CRR Allocation, CRR Auction, or Secondary Registration System, a *pro forma* of which is set forth in Part E of this Appendix.
CRR Holder	A Candidate CRR Holder that has acquired CRR(s) either through the CRR Allocation, the CRR Auction, or through a transaction registered in the Secondary Registration System.
CRR Load Metric	The Seasonal CRR Load Metric or Monthly CRR Load Metric.
CRR Obligations	A financial instrument that entitles the holder to a CRR Payment when Congestion is in the direction of the CRR Source to CRR Sink specification and imposes on its holder a CRR Charge when Congestion is in the opposite direction of the CRR Source to CRR Sink specification.
CRR Payment	A payment from the CAISO to a CRR Holder.
CRR Sink	A PNode or a Trading Hub specified as the point of withdrawal for a Congestion Revenue Right.
CRR Source	A PNode or a Trading Hub specified as the point of receipt for a Congestion Revenue Right.
Custom Load Aggregation Point (Custom LAP)	An aggregation of Load PNodes created by the CAISO based on a set of custom LDFs submitted by an SC, at which such SC may submit a single Bid and settle Demand consistent with the CAISO Tariff rules, and for which the SC is required to submit to the CAISO metered data for the nodal Load represented in such aggregation
Day-Ahead	The twenty-four hour time period prior to the Trading Day.

Day-Ahead Market (DAM)	A series of processes conducted in the Day-Ahead that includes the Market Power Mitigation-Reliability Requirement Determination, the Integrated Forward Market and the Residual Unit Commitment.
Default LAP	The LAP defined for the TAC Area at which all Bids for Demand shall be submitted and settled, except as provided in Sections 27.2.1 and 30.5.3.2 of this Appendix.
ETC Self-Schedule	Self-Schedules submitted by Scheduling Coordinators pursuant to Existing Rights as reflected in the TRTC Instructions.
Existing Zone Generation Trading Hub	Trading Hubs specifically developed to represent the average price paid to generation resources within Existing Zones.
Existing Zone	Regions formally referred to as NP15, SP15, and ZP26 prior to implementation of the CAISO LMP market design.
Full Network Model (FNM)	A computer-based model that includes all CAISO Control Area transmission network (load and generation) busses, transmission constraints, and interface busses between the CAISO Control Area and adjacent Control Areas. The FNM models the transmission facilities internal to the CAISO Control Area as elements of a looped network and models the CAISO Control Area interties with adjacent Control Areas in a radial fashion.
Hour Ahead Scheduling Process (HASP)	The process conducted by the CAISO beginning at seventy-five minutes prior to the Trading Hour through which the CAISO conducts the following activities: 1) accepts Bids for Supply of Energy, including imports, exports and Ancillary Services imports to be supplied during the next Trading Hour that apply to the MPM-RRD, RTUC, STUC, and RTD; 2) conducts the MPM-RRD on the Bids that apply to the RTUC, STUC, and RTD; and 3) conducts the RTUC for the hourly pre-dispatch of Energy and Ancillary Services.
Integrated Forward Market (IFM)	The pricing run conducted by the CAISO using a security constrained unit commitment in the Day-Ahead Market, after the MPM-RRD process, which includes unit commitment, Ancillary Service procurement, Congestion Management and Energy procurement based on Supply and Demand Bids.
Load Aggregation Point	A set of Pricing Nodes as specified in Section 27.2 of this Appendix that are used for the submission of Bids and Settlement of Demand.

Load Distribution Factors (LDF)	A number that reflects the relative amount of Load at each PNode within a Load Aggregation Point. Load Distribution Factors determine how the aggregated Load at a given LAP is distributed to the associated power system Nodes. The sum of all Load Distribution Factors for a single Load Aggregation Point equals one.
Long Term CRR	A Congestion Revenue Right differentiated by season and time-of-use period (on-peak and off-peak) with a term of ten years.
Marginal Cost of Congestion (MCC)	The component of LMP at a PNode that accounts for the cost of congestion, as measured between that Node and a Reference Bus.
Marginal Cost of Losses (MCL)	The component of LMP at a PNode that accounts for the marginal real power losses, as measured between that Node and a Reference Bus.
Market Power Mitigation - Reliability Requirement Determination (MPM-RRD)	The two-optimization run process conducted in both the Day-Ahead Market and the HASP that determines the need for the CAISO to employ market power mitigation measures or Dispatch RMR Units.
Monthly CRR Eligible Quantity	The MW quantity of CRRs an LSE is eligible to nominate for the relevant month in a monthly CRR Allocation.
Monthly CRR Load Metric	The MW level of Load on an Load Serving Entity's load duration curve that is exceeded only 0.5% of the time in the relevant month based on Load forecast data.
MSS Aggregator	An entity that has executed an agreement with the CAISO that enables it to represent individual MSS Operators in the CAISO Markets on an aggregated basis, which agreement has been accepted by FERC.
Pricing Node (PNode)	A single network Node or subset of network Nodes where a physical injection or withdrawal is modeled and for which a Locational Market Price is calculated and used for financial settlements.
Pumped-Storage Hydro Units	Hydroelectric dam with capability to produce electricity by pumping water between reservoirs at different elevations.
Real-Time Market (RTM)	The spot market conducted by the CAISO using SCUC and SCED in the Real-Time, after the HASP is completed for the purpose of unit commitment, Ancillary Service procurement, Congestion Management and Energy procurement based on Supply Bids and CAISO Forecast of CAISO Demand.
Reference Bus	The Location(s) on the CAISO Controlled Grid relative to which mathematical quantities relating to powerflow solution will be calculated.

Residual Unit Commitment (RUC)	The process conducted by the CAISO in the Day-Ahead Market after the IFM has been executed to ensure sufficient Generating Units, System Units, System Resources and Participating Loads are committed to meet the CAISO Forecast of CAISO Demand.
Seasonal CRR	A Congestion Revenue Right that is valid for one season and one time-of-use period in a given year.
Seasonal CRR Eligible Quantity	The MW quantity of CRRs an LSE is eligible to nominate for the relevant season in the annual CRR Allocation.
Seasonal CRR Load Metric	The MW level of Load that is exceeded only in 0.5 percent of the hours for each season and time of use period based on the LSE's historical Load.
Secondary Registration System	The computer interface through which CRR Holders and Candidate CRR Holders register any bilateral CRR transactions with the CAISO.
Self-Schedule	The Bid component that indicates the quantities in MWhs with no specification of a price that the Scheduling Coordinator is submitting to the CAISO, which indicates that the Scheduling Coordinator is a Price Taker, Regulatory Must-Run Generation or Regulatory Must-Take Generation, which includes ETC and TOR Self-Schedules and Self-Schedules for Converted Rights.
Simultaneous Feasibility Test ("SFT")	The process that the CAISO will conduct to ensure that allocated and auction CRRs do not exceed relevant transmission system constraints.
TOR Self-Schedule	Self-Schedules submitted by Scheduling Coordinators pursuant to Transmission Ownership Rights as reflected in the TRTC Instructions.
Trading Hub	An aggregation of network Pricing Nodes, such as Existing Zone Generation Trading Hubs, maintained and calculated by the CAISO for settlement and trading purposes posted by the CAISO on its CAISO Website.
Transmission Rights and Transmission Curtailment (TRTC) Instructions	Operational directives developed between Existing Rights holders and the Participating TO, submitted to the CAISO by the Participating TO, unless otherwise agreed to by the Participating TO and the Existing Rights holder to facilitate the accommodation of Existing Rights in the CAISO Markets.

Adjusted Load Metric	A Load Serving Entity's Load Metric minus the megawatts of Load served using Existing Transmission Contracts, Converted Rights, and Transmission Ownership Rights.
Adjusted Verified CRR Source Quantity	The MW amount eligible for nomination by an LSE or Qualified OCALSE in a verified tier of the CRR Allocation process, determined by reducing a Verified CRR Source Quantity to account for circumstances where the ownership or contract right to a generating resource is effective only for a portion of a particular season or month for which CRRs are being nominated.
CAISO	See ISO in Appendix A.
CAISO Controlled Grid	The system of transmission lines and associated facilities of the Participating TOs that have been placed under the CAISO's Operational Control.
CAISO Tariff	The California Independent System Operator Corporation Operating Agreement and Tariff, dated March 31, 1997, as it may be modified from time to time.
CAISO Website	The CAISO internet home page at http://www.caiso.com / or such other internet address as the CAISO shall publish from time to time.
CRR Balancing Account	The financial account held by the CAISO for CRRs.
CRR Charge	The Charge assessed by the CAISO on the holder of a CRR Obligation when Congestion is in the opposite direction of the CRR Source to CRR Sink specification.
CRR Year Four	The fourth period of time for which the CAISO conducts an annual CRR Allocation, as defined in the Business Practice Manual.
CRR Year One	The first period of time for which the CAISO conducts an annual CRR Allocation, as defined in the Business Practice Manuals.
CRR Year Three	The third period of time for which the CAISO conducts an annual CRR Allocation, as defined in the Business Practice Manual.
CRR Year Two	The second period of time for which the CAISO conducts an annual CRR Allocation, as defined in the Business Practice Manual.
Existing Transmission Contract (ETC) or Existing Contracts	The contracts which grant transmission service rights in existence on the CAISO Operations Date (including any contracts entered into pursuant to such contracts) as may be amended in accordance with their terms or by agreement between the parties thereto from time to time.

Fixed CRRs	Congestion Revenue Rights that are used in the running of an SFT to represent known encumbrances on the transmission system and which may include some or all of the following: previously allocated or awarded Monthly, Seasonal, Long Term, and Merchant Transmission CRRs, Existing Transmission Contracts, and Converted Rights.
Inter-SC Trade	A trade between Scheduling Coordinators of Energy or Ancillary Services in accordance with the CAISO Tariff.
Load Migration	The transfer of the responsibility to serve Load from one Load Serving Entity to another.
Load-Serving Entity (LSE)	Any entity (or the duly designated agent of such an entity, including, e.g. a Scheduling Coordinator), including a load aggregator or power marketer, that (a) (i) serves End Users within the CAISO Control Area and (ii) has been granted authority or has an obligation pursuant to California state or local law, regulation, or franchise to sell electric energy to End Users located within the CAISO Control Area; (b) is a federal power marketing authority that serves End Users; or (c) is the State Water Resources Development System commonly known as the State Water Project of the California Department of Water Resources.
Merchant Transmission CRRs	Incremental CRRs that are created by the addition of a Merchant Transmission Facility. Merchant Transmission CRRs are effective for thirty (30) years or for the pre-specified intended life of the facility, whichever is less.
Merchant Transmission Facility	A transmission facility or upgrade that is part of the CAISO Controlled Grid and whose costs are paid by a Project Sponsor that does not recover the cost of the transmission investment through the CAISO's Access Charge or WAC or other regulatory cost recovery mechanism.
Monthly CRR	A Congestion Revenue Right whose term is one calendar month in length and distributed in the monthly CRR Allocation and monthly CRR Auction.
Multi-Point CRR	A CRR Obligation specified according to one or more CRR Sources and one or more CRR Sinks and a flow from the CRR Source(s) to the CRR Sink(s), provided that at least the CRR Sink or the CRR Source identifies more than one point.

Offsetting CRR	One of the pair of new equal and opposite CRRs created and allocated by the CAISO to reflect Load Migration between two LSEs pursuant to the provisions in Section 36.8.5 of this Appendix, which is allocated to the Load losing LSE and is opposite in direction to the corresponding CRR previously allocated to that LSE and is denominated in a MW quantity that reflects the net amount of Load Migration between the two LSEs.
Out-of-Control Area Load Serving Entity (OCALSE)	An entity serving end-users located outside the CAISO Control Area and that has been granted authority or has an obligation pursuant to Federal, State or local law, or under contracts to provide electric service to such end-users located outside the CAISO Control Area.
PMax	The maximum normal capability of the Generating Unit. PMax should not be confused as an emergency rating of the Generating Unit.
PNP Eligible Quantity	The maximum MW quantity of CRRs an LSE is eligible to nominate in the Priority Nomination Process of the CRR Allocation.
Point-to-Point CRR	A CRR Option or CRR Obligation with a single CRR Source to a single CRR Sink.
Priority Nomination Process (PNP)	The step in an annual CRR Allocation in years beyond CRR Year One through which CRR Holders re-nominate (1) Seasonal CRRs they were allocated in the prior year, (2) Long Term CRRs that are expiring, and (3) Existing Transmission Contracts and Converted Rights that are expiring.
Qualified OCALSE	An OCALSE which the CAISO has certified has met all the requirements for eligibility for CRR Allocation in accordance with Section 36.9 of this Appendix.
Real-Time Interchange Export Schedule	An agreement to transfer Energy from the CAISO Control Area to a interconnected Control Area at a Scheduling Point based on agreed-upon size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and Energy between the source and sink Control Areas involved in the transaction.

Seasonal Available CRR Capacity	The upper limit of network capacity that will be used in the annual CRR Allocation and annual CRR Auction calculated by effectively reducing OTC for Transmission Ownership Rights as if all lines will be in service for the relevant year.
Sub-LAP	A CAISO defined subset of PNodes within a Default LAP.
Tier LT	The tier of the annual CRR Allocation process through which the CAISO allocates Long Term CRRs.
Verified CRR Source Quantity	The MW amount corresponding to a verified CRR Source and the LSE or OCALSE that submitted that verified CRR Source to the CAISO, as described in Section 36.8.3.4 of this Appendix.

PART H. CONGESTION REVENUE RIGHTS

36 Congestion Revenue Rights.

36.1 Overview of CRRs and Procurement of CRRs.

The CAISO distributes CRRs through an allocation and auction process as described in this Section 36. CRR Holders and Market Participants eligible to become CRR Holders can also buy, sell, or trade CRRs bilaterally as described in Section 36.7 of this Appendix.

36.2 Types of CRR Instruments.

CRRs can be CRR Obligations or CRR Options. Each CRR is fully specified by its type (CRR Obligation or CRR Option), its CRR Source(s), its CRR Sink(s), its MW quantity, and the Trading Hours for which it is valid. The CRR Source(s) and CRR Sink(s) determine the direction of the CRR, which is from CRR Source(s) to CRR Sink(s).

36.2.1 CRR Obligations.

A CRR Obligation entitles its holder to receive a CRR Payment if the Congestion in a given Trading Hour is in the same direction as the CRR Obligation, and requires the CRR Holder to pay a CRR Obligation charge if the Congestion in a given Trading Hour is in the opposite direction of the CRR. The CRR Payment or CRR Obligation charge is equal to the per-MWh cost of Congestion (which equals the MCC at the CRR Sink minus the MCC at the CRR Source) multiplied by the MW quantity of the CRR.

36.2.2 CRR Options.

A CRR Option entitles its CRR Holder to a CRR Payment if the Congestion is in the same direction as the CRR Option, but requires no CRR Obligation charge if the Congestion is in the opposite direction of the CRR. The CRR Payment is equal to the per-MWh cost of Congestion (which equals the MCC at the CRR Sink minus the MCC at the CRR Source, when this quantity is positive and zero otherwise) multiplied by the MW quantity of the CRR.

36.2.3 Point-to-Point CRRs.

A Point-to-Point CRR is a CRR Option or CRR Obligation defined from a single CRR Source to a single CRR Sink.

36.2.4 Multi-Point CRRs.

A Multi-Point CRR is a CRR Obligation defined by more than one CRR Source and/or more than one CRR Sink, plus a specified distribution of the total MW value of the CRR over the multiple CRR Sources and/or multiple CRR Sinks such that the total MW assigned to all CRR Sources equals the total MW assigned to all CRR Sinks equals the MW value of the CRR. For the allocation of CRRs under this Section 36, an LSE seeking to be allocated a Multi-Point CRR must specify a single CRR Sink in its nomination.

36.2.5 Monthly CRRs.

Monthly CRRs have a term of one month, are differentiated by time of use periods (on-peak and off-peak), and are available through the monthly CRR Allocation and CRR Auction processes in advance of each month.

36.2.6 Seasonal CRRs.

Seasonal CRRs have a term of three months, and are differentiated by the different time of use periods (on-peak and off-peak) for each day within a season. Seasonal CRRs are made available through the annual CRR Allocation and CRR Auction processes conducted each year prior to the year in which the Seasonal CRR applies.

36.2.7 Long Term CRRs.

Long Term CRRs have a term of ten years. Long Term CRRs are seasonal and are differentiated by the different time of use periods (on-peak and off-peak) for each day within a season. When Long Term CRRs are nominated and allocated they apply to the same season and time of use period for each year of the ten-year term and represent binding ten-year commitments by the CRR Holders that hold Long Term CRRs. Long Term CRRs are nominated and allocated to LSEs in Tier LT that is one tier in the sequence of tiers in the annual CRR Allocation process. Long Term CRRs are not available through the CRR Auction.

36.2.8 Full Funding of CRRs.

All CRRs will be fully funded; provided however, that full funding of CRRs will be suspended if a System Emergency as described in Section 7.7.4, an Uncontrollable Force as described in Section 14, or a Participating TO's withdrawal of facilities or Entitlements from the CAISO Controlled Grid as described in Section 36.8.7 of this Appendix leaves the CAISO with inadequate revenues.

36.3 CRR Specifications.

36.3.1 Quantity.

CRRs are distributed and settled in no less than one-tenth of a MW denomination.

36.3.2 Term.

CRRs are Monthly CRRs, Seasonal CRRs, Long Term CRRs or Merchant Transmission CRRs. For CRR purposes, the applicable seasons are conventional calendar quarters as defined in the Business Practice Manual.

36.3.3 On-Peak and Off-Peak Specifications.

CRRs are defined either for on-peak or off-peak hours as specified by the CAISO in the applicable Business Practice Manuals consistent with the WECC standards at the time of the relevant CRR Allocation or CRR Auction.

36.4 FNM for CRR Allocation and CRR Auction.

When the CAISO conducts its CRR Allocation and CRR Auction, the CAISO shall use the most up-to-date DC FNM which is based on the AC FNM used in the Day-Ahead Market. The Seasonal Available CRR Capacity shall be based on the DC FNM, taking into consideration the following, all of which are discussed in the applicable Business Practice Manual: (i) any long-term scheduled transmission Outages, (ii) OTC adjusted for any long-term scheduled derates, and (iii) a downward adjustment due to TOR as determined by the CAISO. The Monthly Available CRR Capacity shall be based on the DC FNM, taking into consideration: (i) any scheduled transmission Outages known at least thirty (30) days in advance of the start of that month, (ii) adjustments to compensate for the expected impact of Outages that are not required to be scheduled thirty (30) days in advance, including unplanned transmission Outages,

(iii) adjustments to restore Outages or derates that were applied for use in calculating Seasonal Available CRR Capacity but are not applicable for the current month, (iv) any new transmission facilities added to the CAISO Controlled Grid that were not part of the DC FNM used to determine the prior Seasonal Available CRR Capacity and that have already been placed in-service and energized at the time the CAISO starts the applicable monthly process, (v) OTC adjusted for any scheduled derates or Outages for that month, and (vi) a downward adjustment due to TOR as determined by the CAISO. For the first monthly CRR Allocation and CRR Auction for CRR Year One, to account for any planned or unplanned Outages that may occur for the first month of CRR Year One, the CAISO will derate all flow limits, including Transmission Interface limits and normal thermal limits based on statistical factors determined as provided in the Business Practice Manuals.

36.4.1 Transmission Capacity Available for CRR Allocation and CRR Auction.

With the exception of the Tier LT, the CAISO makes available seventy-five percent (75%) of Seasonal Available CRR Capacity for the annual CRR Allocation and CRR Auction processes, and one hundred percent (100%) of Monthly Available CRR Capacity for the monthly CRR Allocation and CRR Auction processes. The CAISO makes available sixty percent (60%) of Seasonal Available CRR Capacity in the Tier LT. Available capacity at Scheduling Points shall be determined in accordance with Section 36.8.4.2 of this Appendix for the purposes of CRR Allocation and CRR Auction of CRRs that have a CRR Source identified at a Scheduling Point. Before commencing with the annual or monthly CRR Allocation and CRR Auction processes, the CAISO may distribute Merchant Transmission CRRs and will model those as fixed injections and withdrawals on the DC FNM to be used in the allocation and auction. These fixed injections and withdrawals are not modified by the Simultaneous Feasibility Test. Similarly, before commencing the annual or monthly CRR Allocation and CRR Auction processes, the CAISO will model any previously allocated Long Term CRRs as fixed injections and withdrawals on the DC FNM to be used in the CRR Allocation and CRR Auction. These fixed injections and withdrawals are not modified by the Simultaneous Feasibility Test, which will ensure no degradation of previously allocated and outstanding Long Term CRRs due to the CRR Allocation and CRR Auction processes. Maintaining the feasibility of allocated Long Term CRRs over the length of their terms also is accomplished through the transmission planning process in Section 24.1.3.

36.4.2 Simultaneous Feasibility.

The annual and monthly CRR Allocation processes release CRRs to fulfill CRR nominations as fully as possible subject to a Simultaneous Feasibility Test. To the extent that nominations are not simultaneously feasible, the nominations are reduced in accordance with the CRR Allocation optimization formulation until simultaneous feasibility is achieved. The CRR Allocation optimization formulation, detailed in the Business Practice Manuals, reduces nominated CRRs based on effectiveness in relieving overloaded constraints in order to minimize the total MW volume reduction of nominations while achieving simultaneous feasibility. In the event that there are two or more identical nominations for a specific combination of CRR Source and CRR Sink that affect an overloaded constraint, the CRR Allocation optimization formulation cannot distinguish these nominations based on effectiveness and, therefore, the CRR Allocation optimization formulation will award each such Candidate CRR Holder a pro rata share of the CRRs that can be awarded based on each Candidate CRR Holder's nominated MW amount. In addition to the adjustments in Section 36.4.1, the SFT for each CRR Allocation considers:

a. CRRs representing ETCs, Converted Rights and any TOR capacity that was not captured in the adjustments described in Section 36.4 of this Appendix, which the CAISO deems necessary to prevent the Congestion Settlement of ETCs, Converted Rights, and TORs from causing revenue inadequacy of allocated and auctioned CRRs;

b. In the case of the monthly CRR Allocation, the CRRs already released for that month in the annual CRR Allocation and Auction; and,

c. The CRRs allocated in previous CRR Allocation tiers as described in Sections 36.8.3.1 through 36.8.3.6 of this Appendix.

In the event that transmission Outages and derates modeled for the monthly CRR Allocation and CRR Auction render previously issued Seasonal CRRs infeasible, the CAISO will increase the transfer capacity on the overloaded facilities just enough to render all Seasonal CRRs issued for the month feasible without creating any additional capacity beyond what is needed for the feasibility of the Seasonal CRRs. The CAISO will announce these adjustments to the market prior to conducting the monthly CRR Allocation and CRR Auction so that Candidate CRR Holders can take these facts into consideration in preparing their nominations and bids.

36.5 Candidate CRR Holder and CRR Holder Requirements.

Any entity that holds or intends to hold CRRs must register and qualify with the CAISO and comply with the other terms of this Section, regardless of whether they acquire CRRs by CRR Allocation, CRR Auction, or the Secondary Registration System, or are assigned CRRs for Load Migration.

36.5.1 Creditworthiness Requirements.

All CRR Holders and Candidate CRR Holders must comply fully with all creditworthiness requirements as provided in Section 12 of the CAISO Tariff and Section 12.6 of this Appendix and as further developed in the applicable Business Practice Manuals. The amount of available credit for participating in a CRR Auction cannot exceed the entity's Aggregate Credit Limit as provided in Section 12.

36.5.2 Required Training.

CRR Holders and Candidate CRR Holders must attend a training class at least once prior to participating in the CRR Allocations or CRR Auctions. The CAISO may update training requirements annually or on an as-needed basis. Unless granted a waiver by the CAISO, Candidate CRR Holders and CRR Holders shall at all times have in their employment a person that has attended the CAISO's CRR training class and shall notify the CAISO as soon as practicable of a change in such status.

36.6 [NOT USED]

36.7 Bilateral CRR Transactions.

36.7.1 Transfer of CRRs.

36.7.1.1 General Provisions of CRR Transfers.

A CRR Holder may sell or otherwise transfer CRRs in increments of at least a tenth of a MW. Sales or other such transfers must be for at least a full day term consistent with the on-peak or off-peak specification of the CRR. The transferee may be any entity that is a Candidate CRR Holder or a CRR Holder consistent with the CAISO Tariff and the applicable Business Practice Manuals. All CRRs that are so sold or otherwise transferred by the CRR Holder continue to be subject to the relevant terms and conditions set forth in the CAISO Tariff and the applicable Business Practice Manuals.

36.7.1.2 Specific Provisions for Transfer of Long Term CRRs.

A CRR Holder that holds Long Term CRRs may sell or transfer through the Secondary Registration System MW portions and temporal segments of a Long Term CRR corresponding to the current calendar year as well as the calendar year covered by the most recently completed annual CRR Allocation. For such sales or transfers the Long Term CRR will be subject to the same limits on granularity that apply to Seasonal CRRs and Monthly CRRs, as specified in Section 36.7.1 of this Appendix. A CRR Holder that holds Long Term CRRs may not transfer or sell through the Secondary Registration System any temporal segment of a Long Term CRR beyond the calendar year covered by the most recently completed annual CRR Allocation. For temporal segments beyond the year covered by the most recently completed annual CRR Allocation, the CRR Holder to whom a Long Term CRR was originally allocated remains the holder of record of the entire Long Term CRR for CAISO Settlement purposes. Allocated Long Term CRRs represent binding ten-year commitments by a CRR Holder that holds Long Term CRRs and may not be terminated or otherwise modified by the CRR Holder prior to the end of the Long Term CRR's ten-year term.

36.7.2 Responsibility of the CAISO.

The CAISO provides Market Participants a Secondary Registration System to facilitate and track CRR bilateral transactions. The bulletin board of the Secondary Registration System enables any entity that wishes to purchase or sell CRRs to post that information.

36.7.3 CRR Holder Reporting Requirement.

CRR Holders must report to the CAISO by way of the Secondary Registration System all bilateral CRR transactions consistent with the terms of this CAISO Tariff and the Business Practice Manuals. Both the transferor and the transferee of the CRRs must register the transfer of the CRR with the CAISO using the Secondary Registration System at least five (5) Business Days prior to the effective date of transfer of revenues associated with a CRR. The CAISO shall not transfer any Settlement related to any CRR until such time that the CRR transfer has been successfully recorded through the SRS and the transferee has met all the creditworthiness requirements as specified in Section 12 of the CAISO Tariff and Section 12.6 of this Appendix. Both the transferor and transferee shall submit the following information to the Secondary Registration System: (i) the effective start and end dates of the transfer of the CRR; (ii) the identity of the transferor; (iii) the identity of the transferee; (iv) the quantity of CRRs being transferred; (v) the CRR Sources and CRR Sinks of the CRRs being transferred; and (vi) time of use period of the CRR. The transferee must meet all requirements of CRR Holders, including disclosure to the CAISO of all entities with which the transferee is affiliated that are CRR Holders or Market Participants as defined in Section 36.5 of this Appendix.

36.8 CRR Allocation.

The CAISO allocates CRRs to Load Serving Entities serving Load internal to CAISO Control Area, including MSS Operators as described in Section 36.10 of this Appendix, as well as Qualified OCALSEs. All CRRs allocated under the terms of this Section 36.8 will be CRR Obligations.

36.8.1 Structure of the CRR Allocation Process.

The CAISO conducts an annual CRR Allocation: (i) once a year for the entire year for Seasonal CRRs; and (ii) once a year for the ten-year term of Long Term CRRs. The annual CRR Allocation releases Seasonal CRRs and Long Term CRRs for four seasonal periods. The CAISO also conducts monthly CRR Allocations twelve times a year in advance of each month. Within each annual and monthly CRR Allocation process the CAISO performs distinct allocation processes for each on-peak and off-peak time of use specification. The CRR Allocation process for CRR Year One is a distinct process that differs from subsequent CRR Allocations as described in Sections 36.8.3.1 and 36.8.3.2 of this Appendix. Each CRR Allocation procedure is based on nominations to the CAISO by LSEs or Qualified OCALSEs eligible to receive CRRs. The CAISO performs adjustments to the Seasonal and Long Term CRRs allocated to LSEs as necessary to reflect Load Migration between LSEs, as described in Section 36.8.5 of this Appendix. A timeline of the CRR Allocation and CRR Auction processes is contained in the BPMs.

36.8.2 Load Eligible for CRRs and Eligible CRR Sinks.

Any entity that wishes to participate in the CRR Allocation process must provide information that demonstrates that it has an obligation to serve load. An LSE's eligibility for allocation of CRRs is measured by the quantity of Load that it serves that is exposed to Congestion Charges for the use of the CAISO Controlled Grid as determined in Sections 36.8.2.1 and 36.8.2.2 of this Appendix. An OCALSE's eligibility for allocation of CRRs is also measured by the quantity of load that it serves that is exposed to Congestion Charges for the use of the CAISO Controlled Grid as determined in Section 36.9.3 of this Appendix. For LSEs, the information necessary may include, but is not limited to, Settlement Quality Meter Data or relevant documents filed with the California Energy Commission. For OCALSEs, the necessary information may include, but is not limited to, historical tagged Real-Time Interchange Export Schedules and historical load data reflecting the load they serve that is exposed to Congestion Charges for the use of the CAISO Controlled Grid. In addition, each such OCALSE shall support its data submission with a written sworn affidavit by an executive authorized to represent the OCALSE attesting to the accuracy of the data, and the CAISO will have the right to audit the raw data and calculations used to develop the submitted data set. An LSE serving internal Load is eligible for CRRs up to its Seasonal or Monthly CRR Eligible Quantity, which is derived from its Seasonal or Monthly CRR Load Metric as described in Sections 36.8.2.1 and 36.8.2.2 of this Appendix, respectively. Seasonal and Monthly CRR Eligible Quantities for Qualified OCALSEs are determined as provided in Section 36.9.3 of this Appendix. These quantities are calculated for each LSE or Qualified OCALSE separately for each combination of season and time of use period for the annual CRR Allocation process, and for each time of use period for each monthly CRR Allocation process, and for each CRR Sink at which the eligible LSE serves Load or the Qualified OCALSE exports Energy from the CAISO Control Area. MSS eligibility for CRRs will account for net or gross MSS Settlement in accordance with Section 4.9.13.1 of this Appendix. If the MSS Operator elects net Settlement, LSEs for such MSS Load Operator shall submit CRR Sink nominations at the MSS LAP. If the MSS elects for gross Settlement, LSEs for such MSS Load shall submit CRRs Sink nominations at the applicable Default LAP. Load that is Pumped-Storage Hydro Units but is not Participating Load may be scheduled and settled at a PNode or Custom Load Aggregation Point and therefore LSEs for such Load shall submit CRR Sink nominations at the applicable PNode or Custom Load Aggregation Point. Load that is a Participating Load that is also aggregated is scheduled and settled at a Custom Load Aggregation Point that is customized specifically for such Load and, therefore, LSEs for such Participating Load shall submit CRR Sink nominations at the Custom Load Aggregation Point. Load that is Participating Load is scheduled and settled at an individual PNode, and therefore LSEs for such Load shall submit CRR Sink nominations at the applicable PNode. Load that is non-Participating Load, is not Pumped-Storage Hydro Units, and is not Load associated with ETCs, TORs, or MSS Operators that elect net Settlement, is scheduled and settled at the Default LAP. Therefore, LSEs for such Load shall submit CRR Sink nominations at their assigned Default LAP or Default LAPs if the Load they serve is located in more than one Default LAP. In tier 3 of the annual process and tier 2 of the monthly process, such LSEs may also submit CRR Sink nominations at a Sub-LAP of their assigned Default LAP. The CAISO will make available, prior to the beginning of the CRR Allocation process, a list of allowable CRR Sinks to be used in the allocation.

36.8.2.1 Seasonal CRR Eligible Quantity.

The CAISO constructs load duration curves by season and time of use periods for the annual CRR Allocation process for each LSE based on the LSE's submission to the CAISO of its historical hourly Load data for the prior year, for each LAP within which the LSE serves Load. An LSE's Seasonal CRR Load Metric for each season and time of use period is the MW level of Load that is exceeded only in 0.5% of the hours based on the LSE's historical Load data. In the event that the LSE has lost or gained net Load through Load Migration during the course of the prior year, the historical Load data will be adjusted to reflect the loss or gain in accordance with the applicable BPM. The CAISO calculates an LSE's Seasonal CRR Eligible Quantity by first subtracting from that LSE's Seasonal CRR Load Metric the quantity of Load served by its TORs, ETCs, and Converted Rights to form the LSE's Adjusted Load Metric, and then multiplying the result by 0.75.

36.8.2.2 Monthly CRR Eligible Quantity.

Each month the CAISO uses the LSE's submitted hourly load forecast data for the relevant month to calculate two load duration curves (one on-peak and one off-peak load duration curve for the applicable month) to form the basis for monthly allocations for each CRR Sink in which the LSE serves Load. Each LSEs submitted hourly forecast data should reflect any Load growth that is not due to Load Migration as well as the effect of net Load Migration for that LSE. The Monthly CRR Load Metric is the MW level of Load that is exceeded only in 0.5% of the hours based on the LSE's submitted load forecast. The CAISO will calculate an LSE's Monthly CRR Eligible Quantity by subtracting from that LSE's Monthly CRR Load Metric the quantity of Load served by its TORs, ETCs, and Converted Rights. In addition the CAISO will adjust the LSE's Monthly CRR Eligible Quantity, if such an adjustment is determined to be necessary pursuant to Section 36.8.6 of this Appendix.

36.8.3 CRR Allocation Process.

36.8.3.1 Annual CRR Allocation for CRR Year One.

The annual CRR Allocation process for CRR Year One consists of a sequence of four (4) tiers for each season and time of use period (on-peak and off-peak). Each tier will feature a SFT applied to the CRR nominations submitted by eligible LSEs or Qualified OCALSEs, the results of which are provided by the CAISO to the respective LSEs or Qualified OCALSEs prior to the LSEs or Qualified OCALSEs submitting their nominations to the next tier. Allocations of CRRs in each tier are considered final once they are provided by the CAISO to the respective LSEs or Qualified OCALSEs. After each tier, LSEs or Qualified OCALSEs will have an amount of time as specified in the Business Practice Manual after their receipt of the results of each tier to submit their nominations for the next tier, if there is one. The annual CRR Allocation allows LSEs or Qualified OCALSEs to submit nominations for Seasonal CRRs up to their Seasonal CRR Eligible Quantities for each season of the relevant year, each time of use CRR Sink as provided in Sections 36.8.3.1.1, 36.8.3.1.2 and 36.8.3.1.4 of this Appendix. The annual CRR Allocation also allows LSEs to submit nominations for Long Term CRRs up to twenty percent (20%) of their Adjusted Load Metric for each season, time of use period and each LAP; except that an LSE that demonstrates that more than twenty percent (20%) of its Adjusted Load Metric is covered by a combination of long-term procurement arrangements of ten (10) years or greater and ownership of generation resources is able to submit nominations for a greater amount as specified in Section 36.8.3.1.3 of this Appendix. As provided in Section 36.8.3.1.3.2 of this Appendix, the annual CRR Allocation allows a Qualified OCALSE to submit nominations for Long Term CRRs up to fifty percent (50%) of its Adjusted Load Metric for each season, time of use period and Scheduling Point provided that the Qualified OCALSE demonstrates that all of its nominated Long Term CRR Sources are covered by a combination of long-term procurement arrangements of ten (10) years or greater and ownership of generation resources. The annual CRR Allocation for CRR Year One will be conducted in the following sequence of tiers:

36.8.3.1.1 Tier 1. In tier 1, an LSE or a Qualified OCALSE may nominate and the CAISO will allocate to the LSE or a Qualified OCALSE Seasonal CRRs up to fifty percent (50%) of its Seasonal CRR Eligible Quantity for each season, time of use period and CRR Sink. An LSE or a Qualified OCALSE can nominate Seasonal CRRs sourced at Trading Hubs in accordance with the LSE's or Qualified OCALSE's verified CRR Sources. In running the SFT the CAISO shall disaggregate the Seasonal CRR nominations sourced at Trading Hubs as described in Section 36.8.4.1 of this Appendix. All allocated CRRs that result from such disaggregation will be Point-to-Point CRRs each of whose CRR Source is a Generating Unit PNode that is an element of the Trading Hub.

36.8.3.1.2 Tier 2. In tier 2, an LSE or a Qualified OCALSE may nominate and the CAISO will allocate to the LSEs or Qualified OCALSEs Seasonal CRRs up to seventy-five percent (75%) of its Seasonal CRR Eligible Quantity for each season, time of use period and CRR Sink, minus the quantity of CRRs allocated to that LSE or Qualified OCALSE in tier 1. An LSE or a Qualified OCALSE can nominate Seasonal CRRs sourced at Trading Hubs in accordance with the LSE's or Qualified OCALSE's verified CRR Sources. In tier 2 an LSE or a Qualified OCALSE with a verified Trading Hub CRR Source may nominate up to seventy-five percent (75%) of the Adjusted Verified CRR Source Quantity for that Trading Hub, minus the total MW quantity of Point-to-Point CRRs the LSE or Qualified OCALSE was allocated in tier 1 as a result of its tier 1 nomination of CRRs sourced at that Trading Hub. In running the SFT the CAISO shall disaggregate the Seasonal CRR nominations sourced at Trading Hubs as described in Section 36.8.4.1 of this Appendix. All allocated CRRs that result from such disaggregation will be Point-to-Point CRRs each of whose CRR Source is a Generating Unit PNode that is an element of the Trading Hub.

36.8.3.1.3 Tier LT. Tier LT will follow tier 2 for CRR Year One. In Tier LT, an LSE or a Qualified OCALSE may nominate Long Term CRRs from the Seasonal CRRs allocated in tiers 1 and 2 as provided in this Section 36.8.3.1. The cleared Point-to-Point CRRs awarded in tier 1 and tier 2 that resulted from disaggregated CRR nominations sourced at a Trading Hub may not be nominated in Tier LT in CRR Year One. Any Point-to-Point CRRs awarded as a result of disaggregated CRR nominations sourced at a Trading Hub, as described in Section 36.8.4.1 of this Appendix, must be nominated as Trading Hub CRRs as described in this Section 36.8.3.1.3 of this Appendix. In running the SFT the CAISO shall disaggregate the Seasonal CRR nominations sourced at Trading Hubs as described in Section 36.8.4.1 of this Appendix. All allocated Long Term CRRs that result from such disaggregation will be Point-to-Point CRRs each of whose CRR Source is a Generating Unit PNode that is an element of the Trading Hub.

36.8.3.1.3.1 Tier LT for LSEs.

The quantity of Seasonal CRRs that an LSE can nominate as Long Term CRRs is limited to twenty percent (20%) of the LSE's Adjusted Load Metric, except that an LSE that can demonstrate that more than twenty percent (20%) of its Adjusted Load Metric is covered by a combination of long-term procurement arrangements of ten (10) years or greater and ownership of generation resources is able to submit nominations for a greater amount as provided in this section. Such demonstrations shall be provided by the requesting LSE to the CAISO through the submission of a written sworn declaration by an executive employee authorized to represent the LSE and attest to the accuracy of the data demonstration. As necessary, the CAISO may request, and such LSE must produce in a timely manner, documents in support of such declaration. If the LSE has demonstrated that more than twenty percent (20%) of its Adjusted Load Metric is covered by a combination of long-term procurement arrangements of ten (10) years or greater and ownership of generation resources, the amount of Long Term CRRs that it may nominate is equal to the minimum of: (i) the sum of the owned resources and long-term procurement arrangements of ten (10) years or more and (ii) fifty percent (50%) of the LSE's Adjusted Load Metric. Subject to the maximum quantities described above in this Section 36.8.3.1.3.1, an LSE can nominate CRRs sourced at a Trading Hub in Tier LT up to the total MW amount of the Point-to-Point CRRs the LSE was allocated in tiers 1 and 2 as a result of its disaggregated tier 1 and 2 nominations of CRRs sourced at that Trading Hub.

36.8.3.1.3.2 Tier LT for Qualified OCALSEs.

A Qualified OCALSE may submit nominations for Long Term CRRs up to fifty percent (50%) of its Adjusted Load Metric for each season, time of use period and Scheduling Point. The Qualified OCALSE must demonstrate that all of its nominated Long Term CRRs are supported by a combination of long-term procurement arrangements of ten (10) years or greater and ownership of generation resources. Such demonstrations shall be provided by the requesting Qualified OCALSE to the CAISO through the submission of a written sworn declaration by an executive employee authorized to represent the Qualified OCALSE attesting to the accuracy of the data demonstration. As necessary, the CAISO may request, and such Qualified OCALSE must produce in a timely manner, documents in support of such declaration.

36.8.3.1.3.3 Tier LT SFT.

After receiving nominations for Long Term CRRs from LSEs and Qualified OCALSEs, the CAISO will run SFTs to ensure the feasibility of the nominated Long Term CRRs for the remaining nine years of the ten-year term of the Long Term CRR. The SFT runs in Tier LT will test the feasibility of only the Long Term CRR nominations and will not include in the analysis those Seasonal CRRs allocated in tiers 1 and 2 that are not nominated as Long Term CRRs. The quantity of Long Term CRRs that can be allocated for any season and time of use period must be feasible for the entire ten-year term of the Long Term CRR. As a result of the Tier LT SFT runs, Long Term CRR nominations may not be fully allocated; however, such a result will not affect the CRR Year One validity of the Seasonal CRR allocated in tiers 1 and 2. The CAISO will inform the nominating entity of the results of the Tier LT SFTs before the deadline for submission of the tier 3 nominations.

36.8.3.1.4 Tier 3. In tier 3, an LSE or a Qualified OCALSE may nominate and the CAISO will allocate to the LSE or Qualified OCALSE Seasonal CRRs up to one hundred percent (100%) of its Seasonal CRR Eligible Quantity for each season, minus the quantity of CRRs allocated to that LSE or Qualified OCALSE in tiers 1 and 2. In tier 3, Sub-LAPs will be eligible CRR Sinks provided that the Sub-LAP is within the nominating LSE's Default LAP. An LSE or a Qualified OCALSE can nominate Seasonal CRRs sourced at Trading Hubs. In running the SFT the CAISO shall disaggregate the Seasonal CRR nominations sourced at Trading Hubs as described in Section 36.8.4.1 of this Appendix. All allocated CRRs that result from such disaggregation will be Point-to-Point CRRs each of whose CRR Source is a Generating Unit PNode that is an element of the Trading Hub. A Qualified OCALSE can only nominate CRRs from its verified CRR Sources as provided in Section 36.8.3.4 of this Appendix.

36.8.3.2 Monthly CRR Allocation for CRR Year One.

The monthly CRR Allocation in CRR Year One shall consist of a sequence of two (2) tiers for each time of use period (on-peak and off-peak). The monthly CRR Allocation will distribute Monthly CRRs to each LSE or Qualified OCALSE up to one hundred percent (100%) of its Monthly CRR Eligible Quantity, minus CRRs allocated to that LSE or Qualified OCALSE in the annual CRR Allocation for the relevant month and time of use period. The monthly CRR Allocation for CRR Year One will be conducted as follows:

36.8.3.2.1 Tier 1. In tier 1 of the monthly CRR Allocations, an LSE or a Qualified OCALSE may nominate and the CAISO will allocate to the LSE or Qualified OCALSE Monthly CRRs up to fifty percent (50%) of the difference between its Monthly CRR Eligible Quantity and the quantity of Seasonal CRRs and previously allocated Long Term CRRs that apply to that month and time of use period. An LSE or a Qualified OCALSE can nominate Monthly CRRs sourced at Trading Hubs in accordance with the LSE's or Qualified OCALSE's verified CRR Sources. In running the SFT the CAISO shall disaggregate the Monthly CRR nominations sourced at Trading Hubs as described in Section 36.8.4.1 of this Appendix. All allocated CRRs that result from such disaggregation will be Point-to-Point CRRs each of whose CRR Source is a Generating Unit PNode that is an element of the Trading Hub.

36.8.3.2.2 Tier 2. In tier 2 of the monthly CRR Allocations, an LSE or a Qualified OCALSE may nominate and the CAISO will allocate to the LSE or Qualified OCALSE Monthly CRRs up to one hundred percent (100%) of the difference between its CRR Eligible Quanty and the quantity of Seasonal CRRs and previously allocated Long Term CRRs that apply to that month and time of use period, minus the quantity of CRRs the entity was allocated in tier 1 of the CRR Year One monthly CRR Allocation. An LSE or a Qualified OCALSE can nominate Monthly CRRs sourced at Trading Hubs. In running the SFT the CAISO shall disaggregate the Monthly CRR nominations sourced at Trading Hubs as described in Section 36.8.4.1 of this Appendix. In tier 2 of the monthly CRR Allocation, Sub-LAPs will be eligible CRR Sinks provided that the Sub-LAP is within the nominating LSE's Default LAP. A Qualified OCALSE can only nominate CRRs from its verified CRR Sources as provided in Section 36.8.3.4.2 of this Appendix.

36.8.3.3 [NOT USED]

36.8.3.4 Source Verification.

Source verification is required for LSE CRR nominations in tiers 1 and 2 of the CRR Year One annual allocation process and in tier 1 of each CRR Year One monthly allocation process. Source verification is required for all Qualified OCALSE CRR nominations in all tiers of all CRR Allocation processes.

36.8.3.4.1 CRR Year One Source Verification for LSEs.

In CRR Year One, nominations for tier 1 and tier 2 of the annual CRR Allocation and tier 1 of the monthly CRR Allocations must be source verified for all LSEs. The CAISO will make available, prior to the beginning of the allocation process, a list of allowable CRR Sources to be used in the allocation. An LSE must demonstrate that it could actually submit Bids, including Self-Schedules and Inter-SC Trades, for Energy from the locations to be nominated as CRR Sources to serve its Load either through ownership of, or contractual rights to receive Energy from, the relevant Generating Units, or a contract to take ownership of power at the relevant source such as a Trading Hub or a Scheduling Point. Source verification will use data for the period beginning January 1, 2006 and ending December 31, 2006 as the basis for verification. Such demonstrations shall be provided by the requesting LSE to the CAISO through the submission of a written sworn declaration by an executive employee authorized to represent the LSE and attest to the accuracy of the data demonstration. As necessary, the CAISO may request, and such LSE must produce in a timely manner, documents in support of such declaration.

36.8.3.4.2 Source Verification for Qualified OCALSEs.

All CRR nominations by Qualified OCALSEs must be source verified. A Qualified OCALSE's source verification will be based on its legitimate need showing as specified in Section 36.9.1 of this Appendix.

36.8.3.4.3 Calculation of Verified CRR Source Quantity.

The Verified CRR Source Quantity associated with each verified CRR Source for a particular LSE or Qualified OCALSE will be: (i) for an owned generation resource the PMax of the unit multiplied by the LSE's or Qualified OCALSE's ownership share; (ii) for a contract with a generation resource, the hourly MWh of Energy specified in the contract averaged over all hours of the relevant time of use period, but no greater than the PMax of the unit; or (iii) for a contract that delivers Energy to a Trading Hub or Scheduling Point, the hourly MWh of energy specified in the contract for delivery from the supplier to the LSE or Qualified OCALSE at the Trading Hub or Scheduling Point, averaged over all hours of the relevant time of use period. Energy contracts submitted by an LSE to demonstrate that the LSE can submit Bids, including Self-Schedules and Inter-SC Trades, for Energy from the nominated CRR Sources to serve its Load must be at least one month in duration. Energy contracts submitted by a Qualified OCALSE to demonstrate that the Qualified OCALSE can submit Bids, including Self-Schedules and Inter-SC Trades, for Energy from the nominated CRR Sources to serve its Load must be at least one month in duration to support nominations of Monthly and Seasonal CRRs, and at least ten (10) years in duration to support nominations of Long Tem CRRs. Nominations of CRRs for which the CRR Source is a Scheduling Point must be source verified in accordance with Section 36.8.4.2 of this Appendix.

36.8.3.4.4 Calculation of Adjusted Verified CRR Source Quantity.

For nominations by an LSE and a Qualified OCALSE, except for a Qualified OCALSE's nomination of Long Term CRRs, the CAISO will consider a contract that covers a portion of a season (but not less than one month) to be acceptable verification, with the adjustment described below, for the entire season for which a CRR is nominated. The CAISO will also consider a contract not less than one month in duration that covers portions of two consecutive months to be acceptable verification, with the adjustment described below, for both of the months that are partially covered. In such cases, for a contract that covers only a portion of the season or month for which the

LSE or Qualified OCALSE wishes to nominate source-verified CRRs, the CAISO will calculate an Adjusted Verified CRR Source Quantity, which equals the Verified CRR Source Quantity times the ratio of the number of days covered by the contract for a particular month or season to the total number of days in that month or season, consistent with the time of use period of the CRRs being nominated. Contracts submitted by a Qualified OCALSE to support nomination of Long Term CRRs must be at least ten (10) years in duration and cover the entire season of the Long Term CRR being nominated, and therefore the Adjusted Verified CRR Source Quantity calculation does not apply to such nominations.

36.8.3.5 Annual CRR Allocation Beyond CRR Year One.

The annual CRR Allocation for years beyond CRR Year One consists of a sequence of four (4) tiers for each season and time of use period (on-peak and off-peak). Allocations of CRRs in each tier are considered final once they are provided by the CAISO to the respective LSEs or Qualified OCALSEs. After each tier, LSEs or Qualified OCALSEs will have an amount of time as specified in the Business Practice Manual after their receipt of the results of each tier to submit their nominations for the next tier, if there is one. The annual CRR Allocation will allow LSEs or Qualified OCALSEs to submit nominations up to their Seasonal CRR Eligible Quantities minus the quantity of previously allocated Long Term CRRs for each season of the relevant year, each time of use period and each CRR Sink at which they serve Load. Annual CRR Allocations for years beyond CRR Year One will be conducted in the following sequence of tiers:

36.8.3.5.1 Tier 1 – Priority Nomination Process.

Tier 1 of the annual CRR Allocation in years beyond CRR Year One will be a Priority Nomination Process through which CRR Holders may nominate some of the same CRRs that they were allocated in the immediately previous year. As provided in Section 36.8.3.4.2 of this Appendix, nominations by a Qualified OCALSE in the PNP are subject to source verification. In all annual CRR Allocations after CRR Year One, an LSE or a Qualified OCALSE may make PNP nominations up to the lesser of: (1) two-thirds of its Seasonal CRR Eligible Quantity, minus the quantity of previously allocated Long Term CRRs for each season, time of use period and CRR Sink for that year; or, (2) the total quantity of Seasonal CRRs allocated to that LSE in the previous annual CRR Allocation, minus the quantity of previously allocated Long Term CRRs for each season, time of use period and CRR Sink, and minus any reduction for net loss of Load or plus any increase for net gain of Load through retail Load Migration as described in Section 36.8.5.1 of this Appendix. In addition, an LSE's or Qualified OCALSE's nomination of any particular CRR Source-Sink combination in the PNP may not exceed the MW quantity of CRRs having that CRR Source and CRR Sink that the LSE or Qualified OCALSE was allocated in the previous annual CRR Allocation for the same season and time of use period, and in the case of an LSE, adjusted for net Load loss or gain resulting from Load Migration as described in Section 36.8.5.2.2 of this Appendix. An LSE or a Qualified OCALSE may not nominate CRRs sourced at Trading Hubs in the PNP. CRRs whose CRR Sink is a Sub-LAP are not eligible for nomination in the PNP. A CRR whose CRR Sink is a Custom LAP or PNode is eligible for nomination in the PNP. PNP Eligible Quantities are not affected by secondary transfers of CRRs, except as performed by the CAISO to reflect Load Migration as described in Section 36.8.5 of this Appendix. That is, with the exception of transfers to reflect Load Migration: (i) an LSE or a Qualified OCALSE may nominate in the PNP a CRR it was allocated in the prior annual CRR Allocation even though it transferred that CRR to another party during the year, and (ii) an LSE or a Qualified OCALSE may not nominate in the PNP a CRR that it received through a secondary transfer from another party. CRRs received through a CRR Auction are not eligible for nomination in the PNP. CRRs received as Offsetting CRRs to reflect Load Migration are not eligible for nomination in the PNP. The maximum quantity of CRRs that an LSE or a Qualified OCALSE may nominate in the PNP is fifty percent (50%) of its Adjusted Load Metric, minus any previously allocated Long Term CRRs that are valid for the term of the CRRs being nominated. The CAISO does not guarantee that all CRR nominations in the PNP will be allocated. The CAISO will conduct an SFT to determine whether all CRR nominations in the PNP are simultaneously feasible. If the SFT determines that all priority nominations are not simultaneously feasible, the CAISO will reduce the allocated CRRs until simultaneous feasibility is achieved.

36.8.3.5.2 Tier LT.

In years subsequent to CRR Year One, Long Term CRRs will be allocated as provided in this section.

36.8.3.5.2.1 Tier LT for LSEs.

In Tier LT of CRR Year Two, an LSE may nominate Long Term CRRs from any of the Seasonal CRRs it was allocated in the PNP up to a maximum of thirty percent (30%) of its Adjusted Load Metric, minus the quantity of previously allocated Long Term CRRs that are valid for that year; except that the LSE may nominate Long Term CRRs in amounts greater than thirty percent (30%) but no more than fifty percent (50%) of its Adjusted Load Metric if the LSE demonstrates that more than thirty percent (30%) of its Adjusted Load Metric is covered by a combination of long-term procurement arrangements of ten (10) years or greater and ownership of generation resources. Such demonstrations shall be provided by the requesting LSE to the CAISO through the submission of a written sworn declaration by an executive employee authorized to represent the LSE and attest to the accuracy of the data demonstration. As necessary, the CAISO may request, and such LSE must produce in a timely manner, documents in support of such declaration. If the LSE has demonstrated that more than thirty percent (30%) of its Adjusted Load Metric is covered by a combination of long-term procurement arrangements of ten (10) years or greater and ownership of generation resources, the amount of Long Term CRRs that it may nominate is equal to the minimum of: (i) the sum of the owned resources and long-term procurement arrangements of ten (10) years or more, minus the quantity of previously allocated Long Term CRRs that are valid for that CRR year, and (ii) fifty percent (50%) of the LSE's Adjusted Load Metric, minus the quantity of previously allocated Long Term CRRs that are valid for that CRR year. In CRR Year Three, the limit on Long Term CRR nominations will increase by ten percent (10%) to forty percent (40%) of the eligible entity's Adjusted Load Metric but shall not exceed fifty percent (50%) of the Adjusted Load Metric. In CRR Year Three, an LSE may exceed the forty percent (40%) limit on Long Term CRR nominations if it demonstrates that its Adjusted Load Metric is covered by a combination of long-term procurement arrangements of ten (10) years or greater and ownership of generation resources. The amount of Long Term CRRs that it may nominate is equal to the minimum of: (i) the sum of the owned resources and long-term procurement arrangements of ten (10) years or more, minus the quantity of previously allocated Long Term CRRs that are valid for that CRR year, and (ii) fifty percent (50%) of the LSE's Adjusted Load Metric, minus the quantity of previously allocated Long Term CRRs that are valid for that CRR year. In CRR Year Four and all subsequent years, an LSE may nominate Long Term CRRs from any of the Seasonal CRRs allocated in the PNP up to the maximum of fifty percent (50%) of its Adjusted Load Metric, minus the quantity of previously allocated Long Term CRRs that are valid for that year.

36.8.3.5.2.2 Tier LT for Qualified OCALSEs.

A Qualified OCALSE may submit nominations for Long Term CRRs up to the portion of its Adjusted Load Metric for which it has demonstrated coverage by a combination of long-term procurement arrangements of ten (10) years or greater and ownership of generation resources, up to a maximum of fifty percent (50%) of its Adjusted Load Metric for each season, time of use period and Scheduling Point, minus the quantity of previously allocated Long Term CRRs that are valid for that CRR year. Such demonstrations shall be provided by the requesting Qualified OCALSE to the CAISO through the submission of a written sworn declaration by an executive employee authorized to represent the Qualified OCALSE and attest to the accuracy of the data demonstration. As necessary, the CAISO may request, and such Qualified OCALSE must produce in a timely manner, documents in support of such declaration. Contracts submitted in support of OCALSE nominations of Long Term CRRs must cover the entire season of the Long Term CRR being nominated.

36.8.3.5.2.3 Tier LT SFT.

After receiving nominations for Long Term CRRs, the CAISO will run SFTs to ensure the feasibility of the nominated Long Term CRRs for the remaining nine years of the ten (10) year term of the Long Term CRR. The SFT run in Tier LT will test the feasibility of only the Long Term CRR nominations and will not include in the analysis those Seasonal CRRs allocated in the PNP that were not nominated as Long Term CRRs. The quantity of Long Term CRRs that can be allocated for any season and time of use period must be feasible for the entire ten (10) year term of the Long Term CRR. As a result of the Tier LT SFT runs, Long Term CRR nominations may not be fully allocated; however, such a result will not affect the validity of: (i) the Long Term CRRs allocated in previous years, or (ii) the Seasonal CRRs allocated in the PNP. The CAISO will inform nominating eligible entities of the results of the Tier LT SFTs before the deadline for submission of the tier 2 nominations.

36.8.3.5.3 **Tier 2.** In tier 2 of the annual CRR Allocation, the CAISO will allocate Seasonal CRRs to each LSE and Qualified OCALSE up to two-thirds of its Seasonal CRR Eligible Quantity for each season, time of use period and CRR Sink, minus the quantity of: (i) CRRs allocated to that LSE or Qualified OCALSE in tier 1, and (ii) Long Term CRRs previously allocated to it that are valid for the CRR term currently being allocated. An LSE or a Qualified OCALSE can nominate Seasonal CRRs sourced at Trading Hubs. In running the SFT the CAISO shall disaggregate the Seasonal CRR nominations sourced at Trading Hubs as described in Section 36.8.4.1 of this Appendix.

36.8.3.5.4 **Tier 3.** In tier 3 of the annual CRR Allocation, the CAISO will allocate Seasonal CRRs to each LSE or Qualified OCALSE up to one hundred percent (100%) of its Seasonal CRR Eligible Quantity for each season, time of use period and CRR Sink, minus the quantity of: (i) CRRs allocated to that LSE or Qualified OCALSE in tiers 1 and 2, and (ii) Long Term CRRs previously allocated to that eligible entity that are valid for the CRR term currently being allocated. In tier 3 of the annual CRR Allocation, Sub-LAPs will be eligible CRR Sinks provided that the Sub-LAP is within the nominating LSE's Default LAP. An LSE or a Qualified OCALSE can nominate Seasonal CRRs where the CRR Source is a Trading Hub. In running the SFT the CAISO shall disaggregate the Seasonal CRR nominations sourced at Trading Hubs as described in Section 36.8.4.1 of this Appendix.

36.8.3.5.5 Alternatives for Renewal of Long Term CRRs and for the Transition of Expiring ETCs and Converted Rights to Long Term CRRs.

Eligible entities may, in the final year of a Long Term CRR, nominate the identical CRR Source, CRR Sink, and MW terms of the expiring Long Term CRR in the PNP conducted that year, subject to any applicable quantity limitations specified in this Section 36. An eligible entity with an Existing Transmission Contract or Converted Rights that expire by the start of the year for which the CRR Allocation process is conducted may participate in the PNP as if its Existing Transmission Contract or Converted Rights sources and sinks were previously allocated Seasonal CRRs, subject to any applicable quantity limitations specified in this Section 36. In either case, if Seasonal CRRs are awarded to an LSE or Qualified OCALSE in the PNP based on its nomination of its expiring rights, such entity may then nominate those Seasonal CRRs in Tier LT of the same year's annual CRR Allocation process, subject to any applicable quantity limitations specified in this Section 36. Alternatively, CRR Holders of expiring LT CRRs, expiring Existing Transmission Contracts or expiring Converted Rights may bypass the tier 1 Priority Nomination Process and nominate their expiring rights as Long Term CRRs in Tier LT one year prior to the year of expiration, subject to any applicable quantity limitations specified in this Section 36. This alternative allows the holder of the expiring rights to nominate Long Term CRRs in the first Tier LT SFT in which the capacity corresponding to the expiring rights becomes available for the full nine year period of the Tier LT SFT. For any entity who elects this alternative and obtains an allocated Long Term CRR, the length of the renewed Long Term CRR (or initial Long Term CRR in the case of expiring Existing Transmission Contracts or expiring Converted Rights) will be nine years, corresponding to the years included in the Tier LT SFT.

36.8.3.6 Monthly CRR Allocation Beyond CRR Year One.

The monthly CRR Allocation shall consist of a sequence of two (2) tiers of allocations for each time of use period (on-peak and off-peak). The monthly CRR Allocation will distribute Monthly CRRs and will allow an LSE and a Qualified OCALSE to nominate CRRs up to one hundred percent (100%) of its Monthly CRR Eligible Quantity, minus the total of any Seasonal CRRs allocated in the annual CRR Allocation, and minus any holdings of Long Term CRRs that are valid for the month and time of use of the CRRs being nominated. All CRR nominations by Qualified OCALSEs must be source verified.

36.8.3.6.1 **Tier 1.** In tier 1 of the monthly CRR Allocations, each LSE or Qualified OCALSE may nominate Monthly CRRs up to fifty percent (50%) of the difference between its Monthly CRR Eligible Quantity and the total of any Seasonal CRRs allocated in the annual CRR Allocation and any holdings of Long Term CRRs that are valid for the month and time of use of the CRRs being nominated. An LSE or a Qualified OCALSE can nominate Monthly CRRs where the CRR Source is a Trading Hub. In running the SFT the CAISO shall disaggregate the Monthly CRR nominations sourced at Trading Hubs as described in Section 36.8.4.1 of this Appendix.

36.8.3.6.2 **Tier 2.** In tier 2 of the monthly CRR Allocations, each LSE or Qualified OCALSE may nominate Monthly CRRs up to one hundred percent (100%) the difference between its Monthly CRR Eligible Quantity and the total of any Seasonal CRRs allocated in the annual CRR Allocation and any holdings of Long Term CRRs that are valid for the month and time of use of the CRRs being nominated, minus the quantity of CRRs allocated to that LSE or Qualified OCALSE in tier 1 of the current monthly CRR Allocation. In tier 2 of the monthly CRR Allocation, Sub-LAPs will be eligible CRR Sinks, provided that the Sub-LAP is within the nominating LSE's Default LAP. An LSE or a Qualified OCALSE can nominate Monthly CRRs sourced at Trading Hubs. In running the SFT the CAISO shall disaggregate the Monthly CRR nominations sourced at Trading Hubs as described in Section 36.8.4.1 of this Appendix.

36.8.4 Eligible Sources for CRR Allocation.

In the CRR Allocation processes for Seasonal CRRs, Monthly CRRs, and Long Term CRRs, nominated CRR Sources can be either PNodes (including Scheduling Points) or Trading Hubs. An LSE or a Qualified OCALSE may nominate up to one hundred percent (100%) of its Adjusted Verified CRR Source Quantities for Seasonal or Monthly CRRs in the combined tiers of the annual and monthly CRR Allocation processes as provided in this Section. For tiers 1 and 2 of the annual CRR Allocation in CRR Year One, an LSE may nominate CRRs from each of its verified CRR Sources in a quantity no greater than seventy-five percent (75%) of the Adjusted Verified CRR Source Quantity corresponding to each verified CRR Source. The LSE may then use tier 1 of the monthly CRR Allocations in CRR Year One to nominate up to the full one hundred percent (100%) of the Adjusted Verified CRR Source Quantity corresponding to each verified CRR Source. In tiers 1, 2 and 3 of the annual CRR Allocation in each year in which it participates, a Qualified OCALSE may nominate CRRs from each of its verified CRR Sources in a quantity no greater than seventy-five percent (75%) of the Adjusted Verified CRR Source Quantity corresponding to each CRR Source. The Qualified OCALSE may then use tiers 1 and 2 of the monthly CRR Allocations in the same year to nominate up to the full one hundred percent (100%) of the Adjusted Verified CRR Source Quantity corresponding to each verified CRR Source.

36.8.4.1 CRRs with Trading Hub Sources.

For purposes of the CRR Allocation processes the CAISO shall disaggregate CRR nominations with Trading Hub CRR Sources into Point-to-Point CRR nominations each of whose CRR Source is a Generating Unit PNode that is an element of the Trading Hub. In performing this disaggregation the MW quantity of each Point-to-Point CRR nomination will equal the MW quantity of the CRR nomination multiplied by the weighting factor of the corresponding Generating Unit PNode in the defined Trading Hub. The disaggregated, individual Point-to-Point CRRs will be used by the CAISO in conducting the SFTs for the nominated CRRs. In CRR years other than CRR Year One, an LSE may nominate in the PNP any Point-to-Point CRRs it was allocated the previous year as a result of Seasonal CRR nominations with Trading Hubs as CRR Sources, and may then nominate those Seasonal CRRs awarded in the PNP as Long Term CRRs in Tier LT. In CRR Year One, an LSE that was allocated individual Point-to-Point CRRs in tiers 1 and 2 as a result of nominating CRRs sourced at a Trading Hub must nominate CRRs sourced at Trading Hubs in Tier LT in accordance with Section 36.8.3.1.3.1 of this Appendix. For Qualified OCALSEs, all nominated CRR Sources must be source verified as specified in Section 36.9.1 of this Appendix. Any Long Term CRRs allocated by the CAISO as a result of nominations of CRRs sourced at Trading Hubs will be Point-to-Point CRRs each of whose CRR Sources is a Generating Unit PNode that is an element of the Trading Hub.

36.8.4.2 Import CRRs.

An LSE or a Qualified OCALSE may nominate Seasonal, Monthly or Long Term CRRs whose CRR Source is a Scheduling Point in the annual and monthly CRR Allocation in accordance with this Section.

36.8.4.2.1 Scheduling Points as CRR Sources for LSEs in CRR Year One.

In CRR Year One, in tiers 1 and 2 of the annual CRR Allocation process an LSE may nominate Seasonal CRRs whose CRR Source is a Scheduling Point to the extent that it can demonstrate to the CAISO that, for the verification period stated in Section 36.8.3.4 of this Appendix, it owned or was a party to a contract with a System Resource, and that it or the counter-party to the contract had procured appropriate transmission from the applicable transmission provider outside the CAISO to the Scheduling Point. In addition, also in tiers 1 and 2 of the annual CRR Allocation in CRR Year One, all LSEs eligible to nominate CRRs under this Section 36.8 may nominate as CRR Sources, without any verification, shares of the residual import CRR capacity at each Scheduling Point that remains after the completion of the CRR Source verification process. Each LSE's share of the residual import CRR capacity will be calculated as follows. Starting with the total capacity at each Scheduling Point that is available in the DC FNM for the annual CRR Allocation and Auction process, the CAISO will calculate the residual amount of capacity that remains at each Scheduling Point after subtracting the capacity accounted for by those Scheduling Point CRR Sources submitted by LSEs for verification that have been verified. The CAISO will then set aside fifty percent (50%) of this residual amount at each Scheduling Point for the annual CRR Auction, and will allow LSEs to nominate pro rata shares of the other fifty percent (50%) in proportion to their Seasonal CRR Eligible Quantities. In each monthly CRR Allocation during CRR Year One, CRR Source verification will be required in tier 1 as in the annual CRR Allocation process. Following the verification process, the CAISO will calculate and set aside for the monthly CRR Auction fifty percent (50%) of the import capacity that remains at each Scheduling Point after accounting for the verified Scheduling Point CRR Source submissions to the monthly process and the annual CRR Allocation and Auction results for that month, and will allow LSEs to nominate in tier 1 Monthly CRRs with CRR Sources at each Scheduling Point in quantities up to their pro rata shares of the other fifty percent (50%) in proportion to their Monthly CRR Eligible Quantities.

36.8.4.2.2 Scheduling Points as CRR Sources for LSEs Beyond CRR Year One.

In the annual CRR Allocation processes subsequent to CRR Year One, there will be no special provisions regarding CRR Sources at Scheduling Points in tiers 1 and 2 for LSEs. For tier 3 the CAISO will calculate and set aside for the annual CRR Auction fifty percent (50%) of the import capacity at each Scheduling Point that remains after the tier 1 and tier 2 CRR Allocations and after considering any previously allocated Long Term CRRs that are valid for that month as described in Section 36.4.1 of this Appendix. In the monthly CRR Allocation processes subsequent to CRR Year One there will be no special provisions regarding CRR Sources at Scheduling Points in tier 1 for LSEs. For tier 2 the CAISO will calculate and set aside for the monthly CRR Auction fifty percent (50%) of the import capacity that remains at each Scheduling Point after accounting for the annual CRR Allocation and Auction results for that month, any previously allocated Long Term CRRs that are valid for that month, and the results of tier 1 of the monthly CRR Allocation.

36.8.4.2.3 Scheduling Points as CRR Sources for Qualified OCALSEs.

In the annual CRR Allocation process a Qualified OCALSE may nominate CRRs whose CRR Source is a Scheduling Point to the extent it meets the requirements of Section 36.9.1 of this Appendix.

36.8.5 Load Migration Between LSEs.

The CAISO shall track Load Migration between LSEs through Load Migration data provided to the CAISO by each UDC, MSS Operator or other entity that provides distribution serve to customers. Load Migration will be reflected in the hourly Load data and load forecasts used by the CAISO to calculate the CRR Load Metrics and Seasonal and Monthly CRR Eligible Quantities for each LSE, in accordance with procedures set forth in the applicable Business Practice Manual. Load Migration will be reflected in appropriate adjustments to each affected LSE's Seasonal and Monthly CRR Eligible Quantities in subsequent annual and monthly CRR Allocations, as well as its PNP Eligible Quantities in the next annual CRR Allocation. LSEs that hold Seasonal CRRs or Long Term CRRS and that lose or gain Load through Load Migration must comply with Section 36.8.5.3 of this Appendix regarding the transfers of current CRR holdings to reflect Load Migration.

36.8.5.1 Tracking of Load Migration by CAISO.

The CAISO will implement all appropriate adjustments due to Load Migration on a monthly basis. In order to enable the CAISO to track Load Migration and determine the appropriate adjustments, each UDC, MSS Operator, and other entity that provides distribution service to customers will provide to the CAISO the following minimum information on each customer that migrates between LSEs: (i) customer identification information, (ii) information to establish the customer's retail customer class, (iii) the original and new LSEs serving the customer, (iv) the effective date of the Load Migration, and (v) the most recent twelve (12) months of billing data for the customer. Each UDC, MSS Operator and other entity that provides distribution service to customers will also provide to the CAISO the number of customers served by each LSE in each retail customer class as of the start of each month, plus information on the average consumption by customers in each retail customer class. Further details regarding the information to be supplied to the CAISO is set forth in the applicable Business Practice Manual. The CAISO will receive information from each UDC, MSS Operator, and other entity providing distribution service on an ongoing daily basis, and will perform the calculations for any appropriate adjustments due to Load Migration on a monthly basis. New CRRs allocated due to Load Migration in accordance with Section 36.8.5.3 of this Appendix will be made effective on the first day of the first month, following the CAISO's performance of the calculations, in which the Load Migration is effective by the first of the month.

36.8.5.2 Adjustments to CRR Eligible Quantities to Reflect Load Migration.

An LSE who loses or gains net Load through Load Migration in a given year will have its Seasonal CRR Eligible Quantities in the next annual CRR Allocation reduced or increased, respectively, in proportion to the net Load lost or gained through Load Migration. In addition, an LSE that loses Load through Load Migration in a given year will have its PNP Eligible Quantities reduced in proportion to the amount of Load lost through Load Migration. An LSE that gains Load through Load Migration in a given year will have its PNP Eligible Quantities increased in proportion to the amount of Load gained through Load Migration.

36.8.5.3 Adjustments to Current CRR Holdings to Reflect Load Migration.

Because in between CRR Allocations each LSE can both lose Load and gain Load between itself and multiple other LSEs, the CAISO will calculate and perform appropriate adjustments to current CRR holdings for each pair of LSEs affected by Load Migration to reflect the net amount of Load that migrated between those two LSEs during each Load Migration tracking period and for each LAP in which the LSEs serve Load. The CAISO will perform such calculations in accordance with the appropriate Business Practice Manual, and will perform the adjustments by creating and allocating equal and opposite sets of new CRRs for each pair of LSEs affected by Load Migration. The net Load gaining LSE of the pair will receive a set of new CRRs that match the CRR Sources and CRR Sinks of all the Seasonal and Long Term CRRs previously allocated to the net Load losing LSE of the pair, in MW quantities proportional to the net amount of the net Load losing LSE’s Load that migrated to the net Load gaining LSE of the pair within each LAP in which the LSEs serve Load. The net Load losing LSE of the pair will receive a set of new Offsetting CRRs. After the assignment of Offsetting CRRs, the net Load losing LSE will still hold the CRRs it held before it was assigned the Offsetting CRRs. The Load gaining LSE may nominate its new Seasonal CRRs in the Priority Nomination Process of the next annual CRR Allocation process. The net Load losing LSE may not nominate in the Priority Nomination Process either: (i) the Seasonal CRRs corresponding to the new CRRs allocated to the Load gaining LSE, or (ii) the Offsetting CRRs allocated due to Load Migration. An LSE to which the CAISO allocates new CRRs to reflect Load Migration must be either a Candidate CRR Holder or a CRR Holder and meet all requirements applicable to such entities.

36.8.5.4 Load Migration and Compliance with CAISO Credit Requirements.

To the extent that the credit requirements of an LSE as specified in Section 12 are updated by the allocation of new CRRs to reflect Load Migration, the CAISO will do the following. For new CRRs that result in net charges to the affected LSE over a Settlement period these charges will appear on the LSE's Settlement Statement irrespective whether the LSE has met the updated credit requirement. For new CRRs that result in net payments to the affected LSE over a Settlement period and that LSE has not met the updated credit requirements affected by the allocation of new CRRs to reflect Load Migration, the CAISO shall withhold payment until those updated credit requirements are met. At the end of each Settlement period, if the LSE has not met the updated credit requirements resulting from Load Migration CRR transfers, the CAISO will add any net payments that accrued to the transferred CRRs to the CRR Balancing Account to be included in the end-of-month clearing of the CRR Balancing Account, and those net payments will no longer be recoverable by the LSE. The CAISO may place new allocated CRRs into CRR Auctions if the non-compliance with credit or applicable Financial Security requirements is persistent.

36.8.5.5 Load Migration Adjustment for CRR Year One.

For the CRR Year One CRR Allocation process, the CAISO will account for the cumulative Load Migration that takes place between the beginning of the CRR Year One CRR Allocation process and the first date that the Day-Ahead Market is operational as a single adjustment as described in the Business Practice Manuals.

36.8.5.6 Load Migration Reflected in the Monthly CRR Allocation Process.

An LSE who loses or gains net Load through Load Migration must reflect that loss or gain in the monthly Load forecasts it submits to the CAISO for determining its monthly CRR Eligible Quantities for future monthly CRR Allocations.

36.8.6 Load Forecasts Used to Calculate CRR MW Eligibility.

The CAISO will work closely with appropriate state and Local Regulatory Authorities and agencies to ensure that historical Load data and load forecasts used to establish Seasonal and Monthly CRR Eligible Quantities are consistent with the data and forecasts used to establish resource adequacy requirements.

36.8.7 Long Term CRRs and Participating TO Withdrawals from the CAISO Controlled Grid.

In the event a Participating TO gives the required notice and withdraws facilities or Entitlements from the CAISO Controlled Grid, the CAISO will reconfigure Long Term CRRs as necessary to reflect the CAISO Controlled Grid after the withdrawal. After reconfiguration, the CAISO will run SFTs on the reconfigured Long Term CRRs and, if necessary, reduce some of the reconfigured Long Term CRRs to ensure their feasibility. If the CRR Source and CRR Sink for an allocated Long Term CRR both are located within a departing Participating TO Service Territory, the Long Term CRR would expire on the effective date of the Participating TO's withdrawal.

36.9 CRR Allocation to OCALSEs.

OCALSEs who wish to nominate and be allocated CRR Obligations in the same annual and monthly CRR Allocation processes described in Section 36.8 of this Appendix may do so subject to the provisions of this Section 36.9 of this Appendix and if such OCALSEs are qualified and registered as Candidate CRR Holders or CRR Holders. An OCALSE may participate in the CRR Allocation processes and be allocated CRRs to the extent that: (1) such OCALSE makes a showing of legitimate need for the CRRs nominated as provided by Section 36.9.1 of this Appendix; (2) such OCALSE pre-pays or commits to pay the appropriate Wheeling Access Charge in the amount of MW of CRRs nominated as provided in Section 36.9.2 of this Appendix; (3) the external load for which CRRs are nominated will be exposed to CAISO Congestion charges because it is not served by Supply resources other than exports from the CAISO Control Area; (4) the external load for which CRRs are nominated is not served through an ETC, TOR or Converted Rights by which it has been designated as eligible to receive the reversal of Congestion charges; (5) such OCALSE complies with the verification requirements in Section 36.9.4 of this Appendix; and (6) the nominated CRRs clear the relevant SFTs. An OCALSE that participates in the CRR Allocation processes will be subject to the applicable rules governing the tiered structure of these processes. All CRRs allocated under the terms of this Section 36.9 will be CRR Obligations.

36.9.1 Showing of Legitimate Need.

An OCALSE must make a showing to the CAISO of legitimate need to enable the CAISO to verify the CRR Sources it wants to nominate. All CRR nominations by OCALSEs in all CRR years must be source verified based on the showing of legitimate need. The CAISO's verification of legitimate need will be based on demonstration by the OCALSE of an executed Energy contract from a Generating Unit or System Resource that covers the time period of the CRRs nominated, or ownership of such Generating Unit or System Resource. For such CRR Sources the showing of legitimate need must be made for each CRR term for which the OCALSE wants to nominate CRRs in a timely manner prior to the start of the relevant annual or monthly CRR

Allocation process. For CRR Sources that will be verified based on generating resources located outside the CAISO Control Area, a Scheduling Point must be nominated as the corresponding CRR Source. Generating resources located outside of the CAISO Control Area to be used by the OCALSE to verify a Scheduling Point as a CRR Source must not be located within the OCALSE's own Control Area. The Verified CRR Source Quantity and Adjusted Verified CRR Source Quantity corresponding to any CRR Source nominated by an OCALSE will be calculated in accordance with Section 36.8.3.4 of this Appendix, with the modification that for an OCALSE these quantities will be calculated for each CRR Allocation process in which the Qualified OCALSE wants to participate, consistent with the requirement for ongoing source verification based on a forward showing in conjunction with the OCALSE's annual showing of legitimate need. For a CRR Source that is a Scheduling Point, pursuant to the legitimate need showing requirement, an OCALSE must demonstrate that it has procured the appropriate transmission service from the transmission provider outside the CAISO Control Area to the Scheduling Point that the OCALSE intends to nominate as a CRR Source for the term of the CRR being nominated. Such demonstrations shall be provided by the OCALSE to the CAISO through the submission of a written sworn declaration by an executive employee authorized to represent the OCALSE and attest to the accuracy of the data demonstration. As necessary, the CAISO may request, and such OCALSE must produce in a timely manner, documents in support of such declaration.

36.9.2 Prepayment of Wheeling Access Charges.

36.9.2.1 Prepayment of Wheeling Access Charges for Allocated CRRs.

An OCALSE will be required to prepay relevant Wheeling Access Charges, to be calculated as described in this section and further specified in the Business Practice Manual, for the full term of the Monthly, Seasonal and Long Term CRRs it intends to nominate in order to participate in the CRR Allocation processes and be allocated CRRs. To be eligible for the allocation of Seasonal CRRs or Monthly CRRs the OCALSE must submit the full required prepayment and have it accepted by the CAISO prior to the OCALSE's submission of nominations for the relevant annual or monthly CRR Allocation, except as provided below in Section 36.9.2.2 of this Appendix. To be eligible for nominations of Long Term CRRs, the OCALSE must submit the full prepayment and have it accepted by the CAISO prior to the OCALSE's submission of nominations of Long Term CRRs in Tier LT, except as provided below in Section 36.9.2.2 of this Appendix. For each MW of Monthly, Seasonal or Long Term CRR to be nominated the nominating OCALSE must prepay one MW of the relevant Wheeling Access Charge, which equals the per-MWh WAC that is associated with the Scheduling Point the OCALSE intends to nominate as a CRR Sink and that is expected at the time the CRR Allocation process is conducted to be applicable for the period of the CRR nominated, times the number of hours comprising the period of the CRR nominated as further specified in the applicable Business Practice Manual.

36.9.2.2 Eligibility for Prepayment of WAC on an Annual or Monthly Basis.

An OCALSE deemed creditworthy pursuant to the requirements of Section 12 may elect to prepay the determined WAC responsibility on a monthly basis for the Seasonal or Long Term CRRs that it seeks to be allocated, provided that such OCALSE has demonstrated a commitment to pay the required WAC for the entire term of the CRRs sought by submitting to the CAISO a written sworn statement by an executive that can bind the entity. In order to be eligible for this option, the OCALSE must submit and the CAISO must accept this sworn statement prior to the applicable CRR Allocation process in which the OCALSE intends to nominate a CRR. An OCALSE choosing to pay on a monthly basis shall make its monthly payments on a schedule specified in the applicable Business Practice Manual. An OCALSE deemed creditworthy pursuant to the requirements of Section 12 may also elect to prepay its determined WAC responsibility associated with an allocated Long Term CRR on an annual basis, provided that such OCALSE has demonstrated a commitment to pay for the entire term of the Long Term CRRs sought by submitting to the CAISO and the CAISO accepting a written sworn statement by an executive that can bind the entity. An OCALSE choosing to pay such WAC obligation on an annual basis shall make its payment each year on a schedule specified in the applicable Business Practice Manual.

36.9.2.3 Refund of Prepaid WAC for Unallocated CRRs.

To the extent that an OCALSE prepays a quantity of the WAC and is not allocated the full amount of CRRs nominated, WAC prepayment for CRRs not allocated will be refunded by the CAISO within thirty (30) days following the completion of the relevant CRR Allocation process.

36.9.3 CRR Eligible Quantities.

The CAISO will calculate the Seasonal and Monthly CRR Eligible Quantities for OCALSEs as described in Section 36.8.2 of this Appendix with the following modifications. The OCALSE must submit two sets of hourly data from which the CAISO will construct load duration curves for determining the Seasonal and Monthly CRR Eligible Quantities. One set of hourly data must reflect the OCALSE's historical hourly exports at the Scheduling Point that is the CRR Sink of the nominated CRRs. The historical hourly exports shall be based on the tagged Real-Time Interchange Export Schedules for the OCALSE. An OCALSE that wishes to nominate multiple Scheduling Points as CRR Sinks in the CRR Allocation process will have distinct CRR Eligible Quantities for each nominated Scheduling Point, and prior to each annual CRR Allocation process must submit historical hourly export data at each such Scheduling Point from which the CAISO will calculate the associated CRR Eligible Quantities. The second set of hourly data must reflect the prior year's hourly metered load for the end-use customers the OCALSE served outside the CAISO Control Area and that were not served from sources other than exports from the CAISO Control Area. The OCALSE's Seasonal and Monthly CRR Eligible Quantities will be based on the lesser of (1) the total historical hourly export data for all Scheduling Points submitted as CRR Sinks, and (2) the hourly metered load for the external end-use customers served by the OCALSE and that were not served from sources other than exports from the CAISO Control Area. An OCALSE also must demonstrate that it has firm transmission rights pursuant to the tariffs of intervening transmission providers from its Scheduling Point sink to the end-use customers in the OCALSE's Control Area. The OCALSE shall support its data submission and the demonstration of transmission rights to its end-use customers with a sworn affidavit by an executive employee authorized to represent the OCALSE and attest to the accuracy of the data and demonstration. As necessary, the CAISO may request, and such OCALSE must produce in a timely manner, the raw data and calculations used to develop the submitted data set and the demonstration of transmission rights to its end-use customers.

36.9.4 Eligible CRR Sources and Sinks.

Eligible CRR Sources will be the PNodes of the Generating Units or Scheduling Points for which the OCALSE has made a legitimate need showing as described above in Section 36.9.1 of this Appendix. Eligible CRR Sinks will be the Scheduling Points for which the CAISO has established Seasonal and Monthly CRR Eligible Quantities as described in Section 36.9.3 of this Appendix. An OCALSE nominating CRRs having CRR Sources internal to the CAISO Control Area will be limited to seventy-five percent (75%) of each of its corresponding Adjusted Verified CRR Source Quantities in all tiers of the annual CRR Allocation process in CRR Year One and in subsequent years. An OCALSE nominating CRRs having CRR Sources external to the CAISO Control Area will be limited to seventy-five percent (75%) of each of its corresponding Adjusted Verified CRR Source Quantities in all tiers of the annual CRR Allocation process in CRR Year One. In CRR years subsequent to CRR Year One, the OCALSE may renew previously allocated CRRs having external CRR Sources, subject to the applicable quantity limitations and other requirements specified in this Section 36.

36.9.5 Priority Nomination Process.

CRRs allocated pursuant to this Section 36.9 shall be eligible for nomination in the Priority Nomination Process to the extent that the requirements of this Section 36.9 are met at the time of the relevant CRR Allocation.

36.10 CRR Allocation to Metered Subsystems.

An MSS Operator that elects gross Settlement may participate in the CRR Allocation processes and be allocated CRR Obligations. An MSS Operator that elects net Settlement may participate in the CRR Allocation processes and be allocated CRRs, except that its Seasonal and Monthly CRR Eligible Quantities will reflect its net Load and its allocated CRRs will use MSS-LAPs as CRR Sinks. The MSS Operator will be required to submit to the CAISO the appropriate hourly historical net Load data and net Load forecast data from which the CAISO will construct net Load duration curves to determine the Seasonal and Monthly CRR Eligible Quantities.

36.11 CRR Allocation to Merchant Transmission Facilities.

Project Sponsors of Merchant Transmission Facilities who turn such facilities over to CAISO Operational Control and do not recover the cost of the transmission investment through the CAISO's Access Charge or WAC or other regulatory cost recovery mechanism may be allocated, at the Project Sponsor's election, either CRR Options or Obligations that reflect the contribution of the facility to grid transfer capacity as determined below.

36.11.1 Eligibility for Merchant Transmission CRRs.

The Project Sponsor of a Merchant Transmission Facility shall be entitled to receive Merchant Transmission CRRs as determined in accordance with this Section 36.11. A Merchant Transmission CRR allocated through this process is effective for thirty (30) years or for the pre-specified intended life of the Merchant Transmission Facility, whichever is less. Merchant Transmission CRRs represent binding commitments for thirty (30) years or for the pre-specified intended life of the Merchant Transmission Facility, whichever is less. The binding commitment by a CRR Holder that holds Merchant Transmission CRRs may not be terminated or otherwise modified by the CRR Holder prior to the end of the term of the Merchant Transmission CRR.

36.11.2 Procedure for Allocating Merchant Transmission CRRs.

No less than forty-five (45) days prior to the in-service date of a Merchant Transmission Facility, the Project Sponsor of the facility will inform the CAISO of the in-service date of the facility and that the Project Sponsor will be requesting Merchant Transmission CRRs associated with the Merchant Transmission Facility. The CAISO will complete the Merchant CRR Allocation after the in-service date of the facility and will allocate Merchant Transmission CRRs whose payment stream will be retroactive back to the in-service date.

36.11.3 Determination of Merchant Transmission CRRs to be Allocated to a Project Sponsor of a Merchant Transmission Facility.

36.11.3.1 Nominations of Merchant Transmission CRRs.

The Project Sponsor of a Merchant Transmission Facility must submit nominations for Merchant Transmission CRRs at least twenty-one (21) days prior to the in-service date of the facility. The Project Sponsor may nominate up to five individual, Point-to-Point CRRs for each of the two on-peak and off-peak time of use periods. Each of the individual, point-to-point nominations must specify: (i) a single CRR Source location; (ii) a single CRR Sink location, (iii) a MW quantity; (iv) a time of use period (on-peak or off-peak); and (v) a CRR type, either CRR Options or CRR Obligations.

36.11.3.2 Methodology to Determine Merchant Transmission CRRs.

The CAISO shall determine the incremental Merchant Transmission CRRs associated with a Merchant Transmission Facility pursuant to this Section 36.11.3.2. The determination will include an assessment of the simultaneous feasibility of the incremental Merchant Transmission CRRs and all other outstanding CRRs. The CAISO will determine the feasible incremental Merchant Transmission CRRs using a three-step process.

36.11.3.2.1 Step One: the Capability of the Existing Transmission System.

In step one the CAISO will determine the base CRR capability of the system using a Simultaneous Feasibility Test that incorporates as Fixed CRRs all existing encumbrances through the end of the CRR year for which the annual CRR Allocation and Auction process has already been conducted, including encumbrances for the month covered by the most recently conducted monthly CRR Allocation and Auction process. This analysis will determine the extent to which the nominated Merchant Transmission CRRs are feasible on the existing transmission system absent the Merchant Transmission Facility. As a result of this analysis, the CAISO will create temporary test CRR Options to reserve grid capacity that the Project Sponsor of the Merchant Transmission Facility is not eligible to receive. The temporary test CRR Options will have the same CRR Source and CRR Sink pairs as the Merchant Transmission CRR nominations submitted by the Project Sponsor.

36.11.3.2.2 Step Two: Mitigation of Impacts on Existing Encumbrances.

In the second step, the CAISO will add the proposed Merchant Transmission Facility to the DC FNM and run a SFT using the Fixed CRRs. The second step will ensure that the addition of a Merchant Transmission Facility does not negatively impact any existing encumbrances through the end of the CRR year for which the annual CRR Allocation and Auction process for Annual CRRs has already been conducted, including encumbrances for the month covered by the most recently conducted monthly CRR Allocation and Auction process. For any impacts identified in this step the Project Sponsor of the Merchant Transmission Facility will be required to mitigate the impacts for the same period. The mitigation can include having the Project Sponsor of the Merchant Transmission Facility hold counterflow CRRs that maintain the feasibility of the existing encumbrances over the same period.

36.11.3.2.3 Step Three: the Incremental Merchant Transmission CRRs.

In the third step, the CAISO will determine the Merchant Transmission CRRs to be allocated to the Project Sponsor of the Merchant Transmission Facility. The CAISO will determine the capability of the system to award incremental Merchant Transmission CRRs using a DC FNM that incorporates the proposed Merchant Transmission Facility. The CAISO will conduct separate SFTs for each time of use period. For each time of use period, the CAISO will perform a multi-period SFT that simultaneously evaluates two sets of grid conditions. The first set of grid conditions includes all existing encumbrances for the month covered by the most recently conducted CRR Allocation and Auction process for Monthly CRRs including any temporary test CRRs from step one and any counterflow CRRs from step two. The second set of grid conditions models only Transmission Ownership Rights. Each SFT will consider the entire set of Merchant Transmission CRR nominations for the time of use period and will solve to maximize the MWs of Merchant Transmission CRRs to be allocated to the Project Sponsor of the Merchant Transmission Facility, subject to simultaneous feasibility. The nominated Merchant Transmission CRRs that are feasible in the multi-period SFTs for each time of use period will be allocated to the Project Sponsor of the Merchant Transmission Facility.

36.12 [NOT USED]

36.13 CRR Auction.

The CAISO shall conduct CRR Auctions on an annual and monthly basis subsequent to each annual and monthly CRR Allocation process. Candidate CRR Holders may bid to purchase and may acquire CRR Obligations through the CAISO's annual and monthly CRR Auctions in accordance with the provisions of this Section 36.13. CRR Auction results shall be settled as provided in Section 11.2.4.3 of this Appendix.

36.13.1 Scope of the CRR Auctions.

The CAISO will conduct a CRR Auction corresponding to and subsequent to the completion of each CRR Allocation process, and prior to the start of the period to which the auctioned CRRs will apply. Each CRR Auction will release CRRs having the same seasons, months and time of use specifications as the CRRs released in the corresponding CRR Allocation. Each CRR Auction will utilize the same DC FNM that was utilized in the corresponding CRR Allocation. For each CRR Auction, the CRRs allocated in the corresponding CRR Allocation will be modeled as fixed injections and withdrawals on the DC FNM and will not be adjusted by the SFT in the CRR Auction process. Thus the CRR Auction will release only those CRRs that are feasible given the results of the corresponding CRR Allocation. CRRs released in a CRR Auction will be indistinguishable from CRRs released in the corresponding CRR Allocation for purposes of settlement and secondary trading. The following additional provisions apply. First, participants in the CRR Auctions will have more choices regarding CRR Sources and CRR Sinks than are eligible for nomination in the CRR Allocations, as described in Section 36.13.5 of this Appendix. Second, to the extent a Market Participant receives CRRs in both a CRR Allocation and the corresponding CRR Auction, the CRRs obtained in the CRR Auction will not be eligible for nomination in the PNP. Third, in CRR Year One the CRR Auction cannot be used by CRR Holders to offer for sale CRRs they acquired in a prior CRR Allocation, CRR Auction or through the Secondary Registration System. In the annual and monthly CRR Auction processes for years following CRR Year One, CRR Holders may offer for sale any CRRs held by such holders, subject to the limitations on sale and transfer of Long Term CRRs specified in Section 36.7.1.2 of this Appendix. Merchant Transmission CRRs that are CRR Options may be offered for sale in the annual and monthly CRR Auctions for years following CRR Year One, subject to the same temporal limitations that apply to Long Term CRRs as specified in Section 36.7.1.2 of this Appendix.

36.13.2 Responsibilities of the CAISO Prior to Each CRR Auction.

The CAISO shall publish on the CAISO Website a notice of upcoming CRR Auctions at least seven (7) days prior to the CRR Auction. The CAISO will also provide additional information needed by CRR Auction participants in accordance with the provisions of Section 6.5.1 of this Appendix.

36.13.3 CRR Holder Creditworthiness.

All Market Participants are eligible to acquire CRRs by participating in the CRR Auction, provided that the Market Participant has met all the CRR Holder requirements described in Section 36.5, the creditworthiness provisions in Section 12 of the CAISO Tariff and Section 12.6 of this Appendix and the relevant Business Practice Manual.

36.13.4 Bids in the CRR Auctions.

Bids to purchase CRRs shall be submitted in accordance with the requirements set out in this Section 36.13.4 and as further specified in the applicable Business Practice Manuals. Once submitted to the CAISO, CRR bids may not be cancelled or rescinded by the Market Participant after the CRR Auction is closed. Market Participants may bid for Point-to-Point CRRs and Multi-Point CRRs. Each bid for a Point-to-Point CRR shall specify:

a) The associated month or season and time of use period;

b) The associated CRR Source and CRR Sink;

c) A monotonically non-increasing piecewise linear bid curve in quantities (denominated in tenths of MW) and prices ($/MW).

Each bid for a Multi-Point CRR shall specify:

d) The associated month or season and time of use period;

e) The associated CRR Sources and CRR Sinks;

f) For each CRR Source, a monotonically non-decreasing piecewise linear bid curve in quantities (denominated in tenths of MW) and prices ($/MW).

g) For each CRR Sink, a monotonically non-increasing piecewise linear bid curve in quantities (denominated in tenths of MW) and prices ($/MW).

Bid prices in all CRR bids may be negative.

36.13.5 Eligible Sources and Sinks for CRR Auction.

Allowable CRR Sources for CRRs acquired in the CRR Auction will be PNodes, Scheduling Points, Trading Hubs, LAPs, MSS-LAPs and Sub-LAPs. Allowable CRR Sinks for CRRs acquired in the CRR Auction will be PNodes, Scheduling Points, Trading Hubs, LAPs, MSS-LAPs and Sub-LAPs.

36.13.6 Clearing of the CRR Auction.

The SFT used to clear the CRR Auction will utilize the same DC FNM and optimization algorithm as the corresponding CRR Allocation, except that nominations to the CRR Auction will have associated price-quantity bid curves. The CRR Auction SFT will use the bid prices in determining which CRRs to award when not all nominations are simultaneously feasible, will select the set of simultaneously feasible CRRs with the highest total auction value as determined by the CRR bids, and will calculate nodal prices at each PNode of the DC FNM. In the event that there are two or more identical bids for a specific combination of CRR Source and CRR Sink that affect an overloaded constraint, the CRR Auction optimization cannot distinguish these bids based on either effectiveness or price and therefore the CRR Auction optimization will award each CRR bidder a pro rata share of the CRRs that can be awarded based on the bid MW amounts. Based on the nodal prices calculated by the CRR Auction SFT, the CRR Market Clearing Price per MW for a specific CRR will equal the nodal price at the CRR Sink minus the nodal price at the CRR Source. For a Multi-Point CRR the CRR Market Clearing Price will equal the sum over all relevant CRR Sinks of the nodal price at each CRR Sink times that CRR Sink's share of the total MW of the CRR, minus the sum over all relevant CRR Sources of the nodal price at each CRR Source times that CRR Source's share of the total MW of the CRR Market Participants shall pay the associated CRR Market Clearing Prices for all CRRs bought through the CRR Auction.

36.13.7 Announcement of CRR Auction Results.

Within five (5) Business Days after the close of a CRR Auction, the CAISO shall post the results. The results shall include but are not limited to the MW quantity, the CRR Source and CRR Sink for each CRR awarded, the nodal prices calculated by the CRR Auction SFT, and the parties to whom the CRRs were awarded. The CAISO shall not disclose prices specified in any CRR bid.

PART I. MISCELLANEOUS SECTIONS

11.2.4.3 Payments and Charges for Monthly and Annual Auctions.

The CAISO shall charge CRR Holders for the market clearing price for CRRs obtained through the clearing of the CRR Auction as described in Section 36.13.6 of this Appendix. To the extent the CRR Holder purchases a CRR through a CRR Auction that has a negative value, the CAISO shall pay the CRR Holder for taking the applicable CRR. The CAISO shall net all revenue received and payments made through this process and shall add the net remaining seasonal and monthly CRR Auction revenue amounts (either negative or positive amounts) to the CRR Balancing Account for the appropriate month. CRR Auction revenues for each season are allocated uniformly across the three monthly accounts comprising each season.

24.7.3 Provided that the CAISO has Operational Control of the Merchant Transmission Facility, a Project Sponsor that does not recover the investment cost under a FERC-approved rate through the Access Charge or a reimbursement or direct payment from a Participating TO shall be entitled to receive Merchant CRRs as provided in Section 36.11 of this Appendix. The full amount of capacity added to the system by such transmission upgrades or additions will be as determined through the regional reliability council process of the Western Electricity Coordinating Council or its successor. Pursuant to its Project Sponsor status as specified in Section 4.3.1.3, consistent with FERC's findings in Docket Nos. EL04-133-001, ER04-1198-000, and ER04-1198-001, issued on May 16, 2006 (115 FERC ¶ 61,178), Western Path 15 shall receive compensation associated with transmission usage rights modeled for Western Path 15. In the event that Western Path 15 has an approved rate schedule that returns excess revenue from any compensation obtained from the CAISO associated with the transmission usage rights for Western Path 15, such revenue shall be returned to the CAISO through a procedure established by the CAISO and the Western Area Power Administration for that purpose.

PART J. PRO FORMA MSS AGGREGATOR CRR ENTITY AGENT AGREEMENT

The provisions of this Part J are necessary to enable the CAISO to establish the terms of a *pro forma* service agreement by which the CAISO will enter into a direct relationship with MSS Aggregators that desire to participate in the CRR Allocation and CRR Auction to be conducted in the summer and fall of 2007.

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

AND

[METERED SUBSYSTEM AGGREGATOR]

MSS AGGREGATOR CRR ENTITY AGENT AGREEMENT

MSS AGGREGATOR CRR ENTITY AGENT AGREEMENT

THIS AGREEMENT is dated this _____ day of _____________, ______, and is entered into, by and between:

(1) **[INSERT NAME OF MSS AGGREGATOR],** a **[INSERT TYPE OF ENTITY]**, having its registered and principal place of business located at **[INSERT ADDRESS]**, acting as the agent on behalf of the following principals: **[INSERT NAMES OF MSS OPERATOR LSEs],** all of which are MSS Operators and Load Serving Entities, ("MSS Operators") pursuant to the terms of that certain **[INSERT TITLE OF MSS AGGREGATOR AGREEMENT]** ("MSSAA") dated ___________ (the "CRR Entity Agent");

and

(2) **California Independent System Operator Corporation,** a California nonprofit public benefit corporation having a principal executive office located at such place in the State of California as the CAISO Governing Board may from time to time designate, initially 151 Blue Ravine Road, Folsom, California 95630 (the "CAISO").

The CRR Entity Agent and the CAISO are hereinafter referred to individually as a "Party" and collectively as the "Parties."

Whereas:

A. The CAISO Tariff provides that any entity that holds or intends to hold CRRs must register and qualify with the CAISO and comply with the terms of the CAISO Tariff (either directly or through its agent), regardless of whether they are to acquire CRRs through the CRR Allocation or CRR Auction, or through the Secondary Registration System.

B. The CRR Entity Agent pursuant to the terms of the MSSAA is authorized by the aggregated MSS Operators to act on the behalf of the MSS Operators with regard to matters relating to CRRs, including, but not limited to, allowing the CRR Entity Agent to participate in the CRR nomination process on behalf of the MSS Operators, to accept financial responsibility under this Agreement, to perform settlement functions, and to comply with CAISO Tariff requirements.

C. The CRR Entity Agent has completed the Candidate CRR Holder application process on behalf of its aggregated MSS Operators and pursuant to the terms of the MSSAA is eligible to participate on behalf of the MSS Operators in the CRR Allocation or CRR Auction or register through the Secondary Registration System on behalf of the MSS Operators. However, the CRR Entity Agent will not hold title to or ownership of any CRRs issued to any of its aggregated MSS Operators through the CRR Allocation, CRR Auction, or Secondary Registration System processes. Rather, the CRR Entity Agent will hold title for the CRRs allocated to the individual MSS Operator's Load in trust on behalf of the MSS Operator.

D. The CAISO Tariff further provides that any entity that wishes to participate in the CRR Allocation or CRR Auction or register as a CRR Holder through the Secondary Registration System must meet all of the Candidate CRR Holder requirements and creditworthiness provisions in the CAISO Tariff and the relevant Business Practice Manual, including demonstration of its ability to accommodate the financial responsibility associated with holding CRRs.

E. The aggregated MSS Operators desire to act through the CRR Entity Agent to comply with all requirements referenced in part D, above, in order to obtain CRRs through the CRR Allocation, CRR Auction, or Secondary Registration System.

F. The CRR Entity Agent, on behalf of its aggregated MSS Operators, wishes to undertake such necessary tasks and requirements set forth herein to comply with the applicable provisions of the CAISO Tariff in order to allow the MSS Operators to participate in the CRR Allocation, CRR Auction, and Secondary Registration System processes.

G. The Parties are entering into this Agreement in order to establish the terms and conditions pursuant to which the CAISO and the CRR Entity Agent will discharge their respective duties and responsibilities under the CAISO Tariff.

NOW THEREFORE, in consideration of the mutual covenants set forth herein, **THE PARTIES AGREE** as follows:

ARTICLE I
DEFINITIONS AND INTERPRETATION

1.1 Master Definitions Supplement. All terms and expressions used in this Agreement shall have the same meaning as those contained in the Master Definitions Supplement in Appendix A of the CAISO Tariff, unless otherwise defined herein.

1.2 Rules of Interpretation. The following rules of interpretation and conventions shall apply to this Agreement:

(a) if there is any inconsistency between this Agreement and the CAISO Tariff, the CAISO Tariff will prevail to the extent of the inconsistency;

(b) the singular shall include the plural and vice versa;

(c) the masculine shall include the feminine and neutral and vice versa;

(d) “includes” or “including” shall mean “including without limitation”;

(e) references to a Section, Article, or Schedule shall mean a Section, Article, or a Schedule of this Agreement, as the case may be, unless the context otherwise requires;

(f) a reference to a given agreement or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented, or restated through the date as of which such reference is made;

(g) unless the context otherwise requires, references to any law shall be deemed references to such law as it may be amended, replaced, or restated from time to time;

(h) unless the context otherwise requires, any reference to a “person” includes any individual, partnership, firm, company, corporation, joint venture, trust, association, organization, or other entity, in each case whether or not having separate legal personality;

(i) unless the context otherwise requires, any reference to a Party includes a reference to its permitted successors and assigns;

(j) any reference to a day, week, month, or year is to a calendar day, week, month, or year; and

(k) the captions and headings in this Agreement are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Agreement.

ARTICLE II
ACKNOWLEDGEMENTS OF CRR ENTITY AGENT AND CAISO

2.1 Scope of Application to Parties. The CRR Entity Agent and CAISO acknowledge that all MSS Aggregators that are authorized by their aggregated MSS Operators to act as the agent of those MSS Operators in undertaking all obligations and responsibilities of Candidate CRR Holders or CRR Holders must sign this Agreement in accordance with section 4.10.1.9.1 of the CAISO Tariff.

ARTICLE III
TERM AND TERMINATION

3.1 Effective Date. This Agreement shall be effective as of the later of the date it is executed by both Parties or the date accepted for filing and made effective by FERC if such FERC filing is required, and shall remain in full force and effect until terminated pursuant to Section 3.2 of this Agreement.

3.2 Termination

3.2.1 Termination by CAISO. Upon notice that the agency relationship between all of the aggregated MSS Operators and the CRR Entity Agent has terminated, including any notice that the MSSAA has terminated, the CAISO may terminate this Agreement by giving written notice to the CRR Entity Agent of termination. Further, subject to Article V, the CAISO may terminate this Agreement by giving written notice to the CRR Entity Agent of termination in the event that the CRR Entity Agent commits any material default under this Agreement and/or the CAISO Tariff as it pertains to this Agreement which, if capable of being remedied, is not remedied within thirty (30) days after the CAISO has given, to the CRR Entity Agent, written notice of the default, unless excused by reason of Uncontrollable Forces in accordance with Article X of this Agreement or unless the CAISO agrees, in writing, to an extension of the time to remedy such material default. With respect to any notice of termination given pursuant to this Section, the CAISO must file a timely notice of termination with FERC, if this Agreement was filed with FERC, or must otherwise comply with the requirements of FERC Order No. 2001 and related FERC orders. The filing of the notice of termination by the CAISO with FERC will be considered timely if: (1) the filing of the notice of termination is made after the preconditions for termination have been met and (2) the CAISO files the notice of termination within sixty (60) days after issuance of the notice of default or (3) the CAISO files the notice of termination in accordance with the requirements of FERC Order No. 2001. This Agreement shall terminate upon acceptance by FERC of such a notice of termination, if filed with FERC, or thirty (30) days after the date of the CAISO's notice of default, if terminated in accordance with the requirements of FERC Order No. 2001 and related FERC orders.

3.2.2 Termination by CRR Entity Agent. In the event that the CRR Entity Agent is no longer a CRR Holder as trustee for any or all of its aggregated MSS Operators, the CRR Entity Agent may terminate this Agreement, on giving the CAISO not less than ninety (90) days' written notice; provided, however, any outstanding financial right or obligation or any other obligation under the CAISO Tariff of the Candidate CRR Holder or CRR Holder (regardless of whether such obligation shall be borne by an aggregated MSS Operator or the CRR Entity Agent) that has arisen while the CRR Entity Agent was a Candidate CRR Holder or a CRR Holder as trustee for any or all of its MSS Operators, and any provision of this Agreement necessary to give effect to such right or obligation, shall survive until satisfied. With respect to any notice of termination given pursuant to this Section, CAISO must file a timely notice of termination with FERC, if this Agreement has been filed with FERC, or must otherwise comply with the requirements of FERC Order No. 2001 and related FERC orders. The filing of the notice of termination by the CAISO with FERC will be considered timely if: (1) the request to file a notice of termination is made after the preconditions for termination have been met and (2) the CAISO files the notice of termination within sixty (60) days after receipt of such request or (3) the CAISO files the notice of termination in accordance with the requirements of FERC Order No. 2001. This Agreement shall terminate upon acceptance by FERC of such a notice of termination, if such notice is required to be filed with FERC, or upon ninety (90) days after the CAISO's receipt of the CRR Entity Agent's notice of termination, if terminated in accordance with the requirements of FERC Order No. 2001 and related FERC orders.

ARTICLE IV
GENERAL TERMS AND CONDITIONS

4.1 CRR Holder Requirements. The CRR Entity Agent acting on behalf of its aggregated MSS Operators must register and qualify on behalf of the MSS Operators with the CAISO and comply with all terms of the CAISO Tariff applicable to Candidate CRR Holders or CRR Holders, regardless of the manner in which it acquires the CRRs on behalf of its aggregated MSS Operators, whether by CRR Allocation or CRR Auction, or through the Secondary Registration System. The CRR Entity Agent shall participate in the CRR nomination process on an aggregated basis on behalf of each of its aggregated MSS Operators on the basis of that individual MSS Operator's Load ratio share set forth in Schedule 3. The CAISO shall allocate CRRs to each individual MSS Operator based on its Load ratio share set forth in Schedule 3, which CRRs will be held in the aggregate by the CRR Entity Agent on behalf of its aggregated MSS Operators. The CRR Entity Agent acknowledges and agrees that it shall not hold title to or ownership of any of the CRRs of its aggregated MSS Operators. Ownership and title of any obtained CRRs shall be held in trust by the CRR Entity Agent on behalf of the applicable MSS Operator in accordance with each MSS Operator's Load share ratio as set forth in Schedule 3.

4.2 CRR Holder Creditworthiness Requirements. The CRR Entity Agent acting on behalf of its aggregated MSS Operators must comply with the requirements for creditworthiness applicable to Candidate CRR Holders or CRR Holders, including the creditworthiness provisions of the CAISO Tariff and the relevant Business Practice Manual.

4.3 Settlement Account. The CRR Entity Agent on behalf of its aggregated MSS Operators shall maintain at all times an account with a bank capable of Fed-Wire transfer to which credits or debits shall be made in accordance with the billing and Settlement provisions of Section 11 of the CAISO Tariff. Such account shall be the account referred to in Schedule 2 hereof or as notified by the CRR Entity Agent to the CAISO from time to time by giving at least seven (7) days written notice before the new account becomes operational. Such changes to Schedule 2 shall not constitute an amendment to this Agreement.

4.4 CRR Entity Agent Responsibility for MSS Operator Load Share Ratio. The CRR Entity Agent shall track each aggregated MSS Operator's Load share ratio of CRRs separately as set forth in Schedule 3 and shall be solely responsible for tracking such allocations. The CRR Entity Agent acknowledges and agrees that CAISO shall have no responsibility with regard to such pro rata allocations of CRRs as set forth in Schedule 3. The CAISO shall issue CRRs allocated to the aggregated MSS Operators in aggregate to the CRR Entity Agent, and the CRR Entity Agent shall be solely responsible for ensuring the proper allocation of such CRRs to each aggregated MSS Operator. In the event the MSS Operator and CRR Entity Agent aggregation or agency relationship terminates, the CRR Entity Agent shall be solely responsible for ensuring that the appropriate pro rata share of every CRR Source is properly assigned to the applicable MSS Operator.

4.5 Provision of Evidence of CRR Entity Agent Authority. The CRR Entity Agent shall provide the CAISO with a copy of the MSSAA or other sufficient evidence to assure the CAISO of its authority to act as agent on behalf of its aggregated MSS Operators with regard to the matters addressed in this Agreement. The CRR Entity Agent shall provide the CAISO with the contact name, address, e-mail address, and phone number of an individual representative of each of its aggregated MSS Operators whom the CAISO may contact regarding matters addressed in this Agreement. The CRR Entity Agent shall immediately notify the CAISO in writing of any revision to the terms of the MSSAA that affects its authority to act as agent on behalf of its aggregated MSS Operators or any other change in its relationship with any of its aggregated MSS Operators.

4.6 Electronic Contracting. All submitted applications, bids, confirmations, changes to information on file with the CAISO and other communications conducted via electronic transfer (*e.g.*, direct computer link, FTP file transfer, bulletin board, e-mail, facsimile or any other means established by the CAISO) shall have the same legal rights, responsibilities, obligations and other implications as set forth in the terms and conditions of the CAISO Tariff as if executed in written format.

4.7 Agreement Subject to CAISO Tariff. The Parties will comply with all provisions of the CAISO Tariff applicable to Candidate CRR Holders or CRR Holders. This Agreement shall be subject to the CAISO Tariff, which shall be deemed to be incorporated herein.

ARTICLE V
PERFORMANCE

5.1 Penalties. The CRR Entity Agent on behalf of its aggregated MSS Operators shall be subject to all penalties made applicable to Candidate CRR Holders and CRR Holders set forth in the CAISO Tariff. Nothing in this Agreement, with the exception of the provisions relating to ADR, shall be construed as waiving the rights of the CRR Entity Agent on behalf of its aggregated MSS Operators to oppose or protest the specific imposition by the CAISO of any FERC-approved penalty on the CRR Entity Agent or any MSS Operator.

5.2 Corrective Measures. If the CRR Entity Agent or the CAISO fails to meet or maintain the requirements set forth in this Agreement and/or the CAISO Tariff, the CAISO or the CRR Entity Agent shall be permitted to take any of the measures, contained or referenced in the CAISO Tariff as it pertains to this Agreement, which the Party seeking enforcement deems to be necessary to correct the situation.

ARTICLE VI
COSTS

6.1 Operating and Maintenance Costs. The CRR Entity Agent shall be responsible for all its costs and any costs of its aggregated MSS Operators incurred in connection with all its CRR related activities.

ARTICLE VII
DISPUTE RESOLUTION

7.1 Dispute Resolution. The Parties shall make reasonable efforts to settle all disputes arising out of or in connection with this Agreement. In the event any dispute is not settled, the Parties shall adhere to the ISO ADR Procedures set forth in Section 13 of the CAISO Tariff, which is incorporated by reference, except that any reference in Section 13 of the CAISO Tariff to Market Participants shall be read as a reference to one or more aggregated MSS Operators and/or the CRR Entity Agent (as applicable) and references to the CAISO Tariff shall be read as references to this Agreement.

ARTICLE VIII
REPRESENTATIONS AND WARRANTIES

8.1 Representation and Warranties. Each Party represents and warrants that the execution, delivery and performance of this Agreement by it has been duly authorized by all necessary corporate and/or governmental actions, to the extent authorized by law, and that the proper agreements providing for the CRR Entity Agent relationship with each aggregated MSS Operator, including, but not limited to, the MSSAA, are in full force and effect.

ARTICLE IX
LIABILITY

9.1 Liability. The provisions of Section 14 of the CAISO Tariff will apply to liability arising under this Agreement, except that all references in Section 14 of the CAISO Tariff to Market Participants shall be read as references to one or more aggregated MSS Operators and/or the CRR Entity Agent (as applicable), and references to the CAISO Tariff shall be read as references to this Agreement. Further, in reliance on the agency relationship between the CRR Entity Agent and each aggregated MSS Operator, CAISO shall treat the CRR Entity Agent as the MSS Operators and shall not be liable to any aggregated MSS Operator for any claims, liabilities, or errors arising from this agency relationship, including, but not limited to, CRR ownership or Settlement Accounts, unless the CAISO causes such claim(s), liability(ies) or error(s) due to its gross negligence or willful conduct.

ARTICLE X
UNCONTROLLABLE FORCES

10.1 Uncontrollable Forces Tariff Provisions. Section 14.1 of the CAISO Tariff shall be incorporated by reference into this Agreement except that all references in Section 14.1 of the CAISO Tariff to Market Participants shall be read as a reference to one or more aggregated MSS Operators and/or the CRR Entity Agent (as applicable) and references to the CAISO Tariff shall be read as references to this Agreement.

ARTICLE XI
MISCELLANEOUS

11.1 Assignments. Either Party may assign or transfer any or all of its rights and/or obligations under this Agreement with the other Party's prior written consent in accordance with Section 22.2 of the CAISO Tariff and other CAISO Tariff requirements as applied to Candidate CRR Holders or CRR Holders. Such consent shall not be unreasonably withheld. Any such transfer or assignment shall be conditioned upon the successor in interest accepting the rights and/or obligations under this Agreement as if said successor in interest was an original Party to this Agreement.

11.2 Notices. Any notice, demand, or request which may be given to or made upon either Party regarding this Agreement shall be made in accordance with Section 22.4 of the CAISO Tariff. A Party must update the information in Schedule 1 of this Agreement as information changes. Such changes to Schedule 1 shall not constitute an amendment to this Agreement.

11.3 Waivers. Any waivers at any time by either Party of its rights with respect to any default under this Agreement, or with respect to any other matter arising in connection with this Agreement, shall not constitute or be deemed a waiver with respect to any subsequent default or other matter arising in connection with this Agreement. Any delay, short of the statutory period of limitations, in asserting or enforcing any right under this Agreement shall not constitute or be deemed a waiver of such right.

11.4 Governing Law and Forum. This Agreement shall be deemed to be a contract made under, and for all purposes shall be governed by and construed in accordance with, the laws of the State of California, except its conflict of law provisions. The Parties irrevocably consent that any legal action or proceeding arising under or relating to this Agreement to which the ISO ADR Procedures do not apply, shall be brought in any of the following forums, as appropriate: (i) any court of the State of California, (ii) any federal court of the United States of America located in the State of California, except to the extent subject to the protections of the Eleventh Amendment of the United States Constitution, or (iii) where subject to its jurisdiction, before the Federal Energy Regulatory Commission.

11.5 Consistency with Federal Laws and Regulations. This Agreement shall incorporate by reference Section 22.9 of the CAISO Tariff as if the references to the CAISO Tariff were referring to this Agreement.

11.6 Merger. This Agreement constitutes the complete and final agreement of the Parties with respect to the subject matter hereto and supersedes all prior agreements, whether written or oral, with respect to such subject matter.

11.7 Severability. If any term, covenant, or condition of this Agreement or the application or effect of any such term, covenant, or condition is held invalid as to any person, entity, or circumstance, or is determined to be unjust, unreasonable, unlawful, imprudent, or otherwise not in the public interest by any court or government agency of competent jurisdiction, then such term, covenant, or condition shall remain in force and effect to the maximum extent permitted by law, and all other terms, covenants, and conditions of this Agreement and their application shall not be affected thereby, but shall remain in force and effect and the Parties shall be relieved of their obligations only to the extent necessary to eliminate such regulatory or other determination unless a court or governmental agency of competent jurisdiction holds that such provisions are not separable from all other provisions of this Agreement.

11.8 Section Headings. Section headings provided in this Agreement are for ease of reading and are not meant to interpret the text in each Section.

11.9 Amendments. This Agreement and the Schedules attached hereto may be amended from time to time by the mutual agreement of the Parties in writing. Amendments that require FERC approval shall not take effect until FERC has accepted such amendments for filing and made them effective. If the amendment does not require FERC approval, the amendment will be filed with FERC for informational purposes. Nothing herein shall be construed as affecting in any way the right of the CAISO to make unilateral application to FERC for a change in the rates, terms, and conditions of this Agreement under Section 205 of the FPA and pursuant to FERC's rules and regulations promulgated thereunder. The standard of review the Commission shall apply when acting upon proposed modifications to this Agreement by the CAISO shall be the "just and reasonable" standard of review rather than the "public interest" standard of review. The standard of review the Commission shall apply when acting upon proposed modifications to this Agreement by the Commission's own motion or by a signatory other than the CAISO or non-signatory entity shall also be the "just and reasonable" standard of review. Schedules 1 and 2 are provided for informational purposes and revisions to those schedules do not constitute a material change in the Agreement warranting Commission review.

11.10 Counterparts. This Agreement may be executed in one or more counterparts at different times, each of which shall be regarded as an original and all of which, taken together, shall constitute one and the same Agreement.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be duly executed on behalf of each by and through their authorized representatives as of the date hereinabove written.

California Independent System Operator Corporation

By: ______________________________

Name: ______________________________

Title: ______________________________

Date: ______________________________

[INSERT NAME OF CRR ENTITY AGENT]

By: ______________________________

Name: ______________________________

Title: ______________________________

Date: ______________________________

SCHEDULE 1

NOTICES

[Section 11.2]

CRR Entity Agent

Name of Primary
Representative: ______________________________
Title: ______________________________
Company: ______________________________
Address: ______________________________
City/State/Zip Code: ______________________________
Email Address: ______________________________
Phone: ______________________________
Fax No: ______________________________

Name of Alternative
Representative: ______________________________
Title: ______________________________
Company: ______________________________
Address: ______________________________
City/State/Zip Code: ______________________________
Email Address: ______________________________
Phone: ______________________________
Fax No: ______________________________

Name of Primary
Representative: ______________________________

Title: ______________________________

Address: ______________________________

City/State/Zip Code: ______________________________

Email address: ______________________________

Phone: ______________________________

Fax: ______________________________

Name of Alternative
Representative: ______________________________

Title: ______________________________

Address: ______________________________

City/State/Zip Code: ______________________________

Email address: ______________________________

Phone: ______________________________

Fax: ______________________________

SCHEDULE 2

SETTLEMENT ACCOUNT

[Section 4.3]

CRR Entity Agent Account Information

Settlement Account No:

____

Title:

____

Sort Code:

____

Bank:

____

SCHEDULE 3

[Pro Rata Load Share per MSS Operator Represented by CRR Entity Agent]

[Section 4.4]

PART K. SETTLEMENT OF PREPAYMENTS BY OUT-OF-CONTROL AREA LOAD SERVING ENTITIES TO OBTAIN CRRS THROUGH THE CRR ALLOCATION PROCESS

The provisions below are included in this Appendix BB in order to enable the CAISO to: 1) settle any pre-payments made by an OCALSE that obtained CRRs through the CRR Allocation process for 2008 as required in Section 36.9 of this Appendix, and also, 2) in instances where the terms of the allocated CRRs were reduced prior to the start of MRTU re-settle any such amounts consistent with the reduced terms of the allocated CRRs.

11.2.5 Payment by Out-of-Control Area Load Serving Entity to Obtain CRRs Through the CRR Allocation Process.

11.2.5.1 Pursuant to Section 36.9, in addition to other requirements specified therein, an OCALSE will be eligible to participate in the CRR Allocation process if such entity has made a pre-payment to the CAISO and has met the requirements in Section 36.9. The prepayment amount shall equal the MW of CRR requested times the Wheeling Access Charge associated with the Scheduling Point corresponding to the CRR Sink times the number of hours in the period for each requested CRR MW amount. Except as provided in Section 39.9.2, such prepayment will be made three (3) Business Days in advance of the submission of CRR nominations for Monthly CRRs, Seasonal CRRs and Long Term CRRs to the CRR Allocation. Within thirty (30) days following the completion of the CRR Allocation process for Monthly CRRs, Seasonal CRRs and Long Term CRRs, the CAISO shall reimburse such OCALSE the amount of money pre-paid for any CRRs that were not allocated to the entity. To the extent that an OCALSE has prepaid Wheeling Access Charges, pursuant to Section 36.9 of this Appendix BB, for CRRs that have been reduced in term pursuant to Section 44.1, such Wheeling Access Charges shall be refunded to the OCALSE to reflect the reduction in term of the applicable CRRs.

11.2.5.3 Monthly Prepayment Option.

If the OCALSE qualified for the monthly prepayment option as specified in Section 36.9.2, the OCALSE shall make its payments consistent with the monthly prepayment schedule specified in the applicable Business Practice Manual.

PART L. CRR CONTINGENCY PLAN

Pursuant to the terms provided in this Part L of this Appendix, the CAISO shall: 1) reduce the terms of Seasonal CRRs and Long Term CRRs previously released through the annual CRR Allocation and Seasonal CRRs released through the CRR Auction to eliminate those months of their terms prior to when the CAISO will be operating under the MRTU Tariff as provided in Section 44.1; 2) resettle CRR Auction payments received or paid by the CAISO for positively or negatively valued CRRs, respectively, that were released through the annual CRR Auction as provided in Section 44.2; and 3) in the event that the CAISO cannot release Firm Transmission Rights through the FTR auction for the month of April or the month of May 2008, make FTRs available to eligible entities as further provided below in Section 44.2.

44 Reduction of CRR Terms and Resettlement of Reduced Term CRRs.

44.1 Reduction in Term of CRRs for 2008.

The terms of Seasonal CRRs released in the annual CRR Allocation or CRR Auction for 2008 and Long Term CRRs released in the annual CRR Allocation will be reduced to eliminate those months of their terms prior to the date on which the CAISO begins operations under the MRTU Tariff. For each CRR so reduced, the new term will begin at the start of the first hour of that CRR's time of use period in which the CAISO begins operations under the MRTU Tariff, and will end at that CRR's originally specified expiration. In the event that the CAISO begins operations under the MRTU Tariff after the originally specified expiration of a CRR, the term of that CRR will be reduced to zero.

44.2 Adjustment of the CRR Auction Settlement for CRRs with Reduced Terms.

For a CRR released in the CRR Auction for 2008 whose term is reduced pursuant to Section 44.1, the CAISO will calculate an adjustment to the CRR Auction Settlement by: 1) dividing the number of hours (on-peak or off-peak) that the term of the CRR was reduced by the number of hours (on-peak or off-peak) in the original term, and then 2) multiplying this ratio by the original CRR Auction Settlement amount for the CRR. To the extent that an adjustment to a CRR Auction Settlement is a positive amount, such amount will represent a payment due from the CAISO to the entity that received the CRR in the annual CRR Auction for 2008. To the extent that an adjustment to a CRR Auction Settlement is a negative amount, such adjustment shall represent a charge due to the CAISO from the entity who received the CRR in the CRR Auction for 2008.

44.2.1 Timing of Reduction, Resettlement and Invoicing.

44.2.1.1 Timing of Reduction and Resettlement Before CAISO Establishes Start-up Date for the MRTU Day-Ahead Market.

Commencing on April 1, 2008, and continuing until such time that the CAISO has announced the date on which it anticipates that it will begin operations under the MRTU Tariff through a CAISO Market Notice, the CAISO will, for each month during which the MRTU Tariff is not in effect: 1) for any CRRs released through the CRR Allocation and CRR Auction for 2008 that were originally scheduled to be in effect during that month, reduce the terms of such CRRs by one month as provided in Section 44.1, and 2) for any CRRs released through the CRR Auction for 2008 that were originally scheduled to be in effect during that month, adjust the CRR Auction Settlement as provided in Section 44.2. All adjustments to CRR Auction Settlements, as applicable, will apply to and will be netted for each CRR Holder that was originally awarded the CRRs in the first annual CRR Auction for 2008. The CAISO shall reflect any resulting payments or charges in a subsequent invoice per the ISO Payments Calendar as soon as practicable. To the extent that the CRR Auction resettlements as specified in this section are invoiced after the start of any month that has been eliminated from a CRR term, the CAISO will calculate and include interest in the invoiced Settlement adjustments, as set forth in Section 44.2.2. Interest on such adjustments will run from the first day of the applicable month until the day on which the invoice is issued.

44.2.1.2 Timing of Reduction and Resettlement After CAISO Establishes the Date on which it Will Begin Operations under the MRTU Tariff.

As of April 1, 2008, and after such time that the CAISO has through a CAISO Market Notice announced the anticipated date of on which it will begin operations under the MRTU Tariff, the CAISO shall determine the number of months that remain in 2008 prior to the announced start-up date and for which CRR term reduction and CRR Auction resettlement have not already been performed, and will perform the term reduction and CRR Auction resettlement for this time period as a whole in a one-time process. The CAISO shall reduce the terms of CRRs as provided in Section 44.1 and calculate CRR Auction resettlements as provided in Section 44.2 for the full remaining time period. These CRR Auction resettlements will be reflected in a subsequent invoice per the ISO Payments Calendar as soon as practicable after the date on which the CAISO announces the date on which it will begin operations under the MRTU Tariff. To the extent that the CRR Auction resettlements as specified in this section are invoiced after the start of any month that has been eliminated from a CRR term, the CAISO will calculate and include interest in the invoiced resettlement amounts, as set forth in Section 44.2.2. Interest on such adjustments will run from the first day of the applicable month until the day on which the invoice is issued.

44.2.2 Interest on Payments and Charges for Reduced Terms of CRRs Released Through the CRR Auction.

Interest on any adjustments to CRR Auction Settlements will be calculated at the rate specified in the regulations of FERC at 18 C.F.R. §35.19(a)(2)(iii). Interest on a positively valued CRR will represent interest owed to the entity to whom the affected CRR was originally released in the CRR Auction for 2008. Interest on a negatively valued CRR will represent interest due from the entity who obtained the CRR in the 2008 CRR Auction.

45 Firm Transmission Rights Additional Measures.

45.1 Backstop Measures.

In the event that the FTR auction for 2008-2009 cannot be completed in time to make FTRs available by April 1, 2008, the CAISO will offer entities who received FTRs in the previous FTR auction for April 2007 the opportunity to renew such FTRs for April 2008. Similarly, if the FTR auction for 2008-2009 also cannot be completed in time to make FTRs available for May 1, 2008, the CAISO will offer entities who received FTRs in the previous FTR auction for May 2007 the opportunity to renew such FTRs for May 2008. Before renewing such FTRs, however, the CAISO will calculate revised FTR maximum quantities for each applicable FTR transmission path based on the 99.5 percent availability criterion approved by the Commission in *California Independent System Operator Corp*., 88 FERC ¶ 61,156 (1999). In the event that the maximum FTR quantity for any applicable transmission path is determined to be less than the quantity of the FTRs released for that path for the April 2007 and May 2008 terms, parties who wish to renew their FTRs will be limited to a *pro rata* share of the revised quantity available for that path. Otherwise, parties will be permitted to renew up to 100 percent of their awarded FTRs for April 2007 and May 2007. Any available incremental capacity that is not nominated will be made available to through a manual auction conducted by the CAISO that will be based on submitted bids and a market clearing price.

45.2 Reduction of Terms of Firm Transmission Rights when MRTU Tariff is in Effect.

After the CAISO commences operations under the MRTU Tariff, for any FTRs that are still effect at such time, the CAISO shall reduce the terms of any FTRs that were released for any hours beginning at 12:00 a.m., on April 1, 2008 and ending at 11:00p.m., on March 31, 2009 p.m., for any month that the CAISO is operating under the MRTU Tariff. The CAISO shall also refund to the FTR Holders the Settlement amounts associated with the reduced terms of the FTRs proportionately. The CAISO shall reflect any resulting payments in a subsequent invoice per the ISO Payments Calendar as soon as practicable.

ISO TARIFF APPENDIX CC

For the purpose of enforcing Market Participant compliance with the forward reporting activities associated with resource adequacy and to enable the CAISO to assign Local Capacity Area Resource responsibility prior to the effective date of the CAISO Tariff as filed in FERC Docket No. ER06-615 and ER07-1257, the CAISO shall operate pursuant to this Appendix CC. This Appendix CC is included in the ISO Tariff to set forth temporary provisions that are based on tariff authority conditionally accepted in FERC Docket No. ER06-615 and as filed in Docket No. ER07-1257. These provisions enable the CAISO to: 1) require Load Serving Entities to elect between Reserving Sharing LSE and Modified Reserve Sharing LSE options; 2) define the information requirements for resource adequacy programs and the two Load Serving Entity options that must be provided to the CAISO; 3) require the submission from Load Serving Entities of monthly and annual Resource Adequacy Plans that set forth information, including identification of Local Capacity Area Resources; 4) determine the minimum amount of Local Capacity Area Resources needed in Local Capacity Areas and allocate responsibility to Load Serving Entities for such Local Capacity Area Resources; 5) require the registration of Use-Limited Resources and the submission of use plans by Use-Limited Resources; and 6) apply default resource counting protocols.

This Appendix CC, therefore, does not replace or supersede thoseat provisions contained in the ISO Tariff.

PART A – RESOURCE ADEQUACY

40 RESOURCE ADEQUACY DEMONSTRATION FOR ALL SCHEDULING COORDINATORS SCHEDULING DEMAND IN THE CAISO CONTROL AREA.

40.1 Applicability.

A Load Serving Entity, and its Scheduling Coordinator, shall be exempt from Section 40 of this appendix, if the metered peak Demand of the Load Serving Entity did not exceed one (1) MW during the twelve months preceding the last date on which the Load Serving Entity can make the election in Section 40.1.1 of this appendix for the 2008 Resource Adequacy Compliance Year. Section 40 of this appendix shall apply to all other Load Serving Entities and their respective Scheduling Coordinators. For purposes of Section 40 of this appendix, a Load Serving Entity shall not include any entity satisfying the terms of California Public Utilities Code Section 380(j)(3).

40.1.1 Election of Load Serving Entity Status.

By December 18, 2007, via e-mail to reliabilityrequirements@caiso.com, the Scheduling Coordinator for a Load Serving Entity, not exempt under Section 40.1 of this appendix, shall inform the CAISO whether each such LSE elects to be either: (i) a Reserve Sharing LSE or (ii) a Modified Reserve Sharing LSE for the 2008 Resource Adequacy Compliance Year. A Scheduling Coordinator for a Load-following MSS is not required to make an election under this Section. Scheduling Coordinators for Load-following MSSs are subject solely to Sections 40.2.4 and 40.3 of this appendix.

The CAISO may confirm with the CPUC, Local Regulatory Authority, or federal agency, as applicable, the accuracy of the election by the Scheduling Coordinator for any LSE under its respective jurisdiction, or, in the absence of any election by the Scheduling Coordinator, the desired election for any LSE under its jurisdiction. The determination of the CPUC, Local Regulatory Authority, or federal agency will be deemed binding by the CAISO on the Scheduling Coordinator and the LSE. If the Scheduling Coordinator and CPUC, Local Regulatory Authority, or federal agency, as appropriate, fails to make the election on behalf of an LSE in accordance with the Business Practice Manual, the LSE shall be deemed a Reserve Sharing LSE.

40.2 Information Requirements Regarding Resource Adequacy Programs.

40.2.1. Reserve Sharing LSEs.

40.2.1.1 Requirements for CPUC Load Serving Entities Electing Reserve Sharing LSE Status.

The information required by Section 40.2.1.1 of this appendix shall be provided to the CAISO as follows:

(a) The Scheduling Coordinator for a CPUC Load Serving Entity electing Reserve Sharing LSE status must provide the CAISO with all information or data to be provided to the CAISO as required by the CPUC and pursuant to the schedule adopted by the CPUC.

(b) Where the information or data provided to the CAISO under Section 40.2.1.1(a) of this appendix does not include Reserve Margin(s), then the provisions of Section 40.2.2.1(b) of this appendix shall apply.

(c) Where the information or data provided to the CAISO under Section 40.2.1.1(a) of this appendix does not include criteria for determining qualifying resource types and their Qualifying Capacity, then the provisions of Section 40.8 of this appendix shall apply.

(d) Where the information or data provided to the CAISO under Section 40.2.1.1(a) of this appendix does not include annual and monthly Demand Forecast requirements, then the provisions of Section 40.2.2.3 of this appendix shall apply.

(e) Where the information or data provided to the CAISO under Section 40.2.1.1(a) of this appendix does not include annual and monthly Resource Adequacy Plan requirements, then Section 40.2.2.4 of this appendix shall apply.

40.2.2 Requirements for Non-CPUC Load Serving Entities Electing Reserve Sharing LSE Status, Including Default Provisions for CPUC Load Serving Entities.

40.2.2.1 Reserve Margin.

The information required by Section 40.2.2.1 of this appendix shall be provided to the CAISO pursuant to the instructions set forth in a CAISO Market Notice within five (5) Business Days of the CAISO filing its statement certifying market readiness in accordance with Paragraph 1414 of 116 FERC ¶61,274 (2006).

(a) The Scheduling Coordinator for a Non-CPUC Load Serving Entity electing Reserve Sharing LSE status must provide the CAISO with the Reserve Margin(s) adopted by the appropriate Local Regulatory Authority or federal agency for use in the annual Resource Adequacy Plan and monthly Resource Adequacy Plans listed as a percentage of the Demand Forecasts developed in accordance with Section 40.2.2.3 of this appendix.

(b) For the Scheduling Coordinator for a Non-CPUC Load Serving Entity for which the appropriate Local Regulatory Authority or federal agency has not established a Reserve Margin(s) or a CPUC Load Serving Entity subject to Section 40.2.1.1(b) of this appendix that has elected Reserve Sharing LSE status, the Reserve Margin for each month shall be no less than 15% of the LSE's peak hourly Demand for the applicable month, as determined by the Demand Forecasts developed in accordance with Section 40.2.2.3 of this appendix.

40.2.2.2 Qualifying Capacity Criteria.

The information required by Section 40.2.2.2 of this appendix shall be provided to the CAISO pursuant to the instructions set forth in a CAISO Market Notice within five (5) Business Days of the CAISO filing its statement certifying market readiness in accordance with Paragraph 1414 of 116 FERC ¶61,274 (2006).

The Scheduling Coordinator for a Non-CPUC Load Serving Entity electing Reserve Sharing LSE status must provide the CAISO with a description of the criteria adopted by the Local Regulatory Authority or federal agency for determining qualifying resource types and the Qualifying Capacity from such resources and any modifications thereto as they are implemented from time to time. The Reserve Sharing LSE may elect to utilize the criteria set forth in Section 40.8 of this appendix.

40.2.2.3 Demand Forecasts.

The information required by Section 40.2.2.3 of this appendix shall be provided to the CAISO pursuant to the instructions set forth in a CAISO Market Notice within five (5) Business Days of the CAISO filing its statement certifying market readiness in accordance with Paragraph 1414 of 116 FERC ¶61,274 (2006).

The Scheduling Coordinator for a Non-CPUC Load Serving Entity or CPUC Load Serving Entity subject to Section 40.2.1.1(b) of this appendix electing Reserve Sharing LSE status must provide annual and monthly Demand Forecasts as part of the annual and monthly Resource Adequacy Plans under this appendix. The annual and monthly Demand Forecasts shall utilize the annual and monthly coincident peak Demand determinations provided by the California Energy Commission for such Load Serving Entity, which will be calculated from the Demand Forecast information submitted to the California Energy Commission by each Reserve Sharing LSE; or (ii) if the California Energy Commission does not produce coincident peak Demand Forecasts for the Load Serving Entity, the annual and monthly coincident peak Demand Forecasts produced by the CAISO for such Load Serving Entity in accordance with its Business Practice Manual. Scheduling Coordinators must provide data and information, as may be requested by the CAISO, necessary to develop or support the Demand Forecasts required by this Section.

40.2.2.4 Annual and Monthly Resource Adequacy Plans.

The Scheduling Coordinator for a Non-CPUC Load Serving Entity or a CPUC Load Serving Entity subject to Section 40.2.1.1(b) electing Reserve Sharing LSE status must provide annual and monthly Resource Adequacy Plans for such Load Serving Entity. For 2008 Resource Adequacy Compliance Year, the annual Resource Adequacy Plan shall be submitted to the CAISO on January 31, 2008 in the form set forth on the CAISO Website. The initial monthly Resource Adequacy Plan under this appendix shall be submitted to the CAISO on the first Business Day after 30 calendar days from the date the CAISO files its statement certifying market readiness in accordance with Paragraph 1414 of 116 FERC ¶61,274 (2006) in the form set forth on the CAISO Website. Thereafter, monthly Resource Adequacy Plans shall be submitted to the CAISO by the last Business Day of the second month prior to the compliance month and in the form set forth on the CAISO Website. Prior to the requirement to submit monthly Resource Adequacy Plans to the CAISO in accordance with Section 40.2.2.4 of this appendix, monthly Resource Adequacy Plans must continue to be submitted in accordance with Section 40.2.2 of the ISO Tariff. The annual Resource Adequacy Plan must, at a minimum, set forth the Local Capacity Area Resources, if any, procured by the Load Serving Entity as described in Section 40.3 of this appendix. The monthly Resource Adequacy Plan should identify all resources, including Local Capacity Area Resources, the Load Serving Entity will rely upon to satisfy the applicable month's peak hour Demand of the Load Serving Entity as determined by the Demand Forecasts developed in accordance with Section 40.2.2.3 of this appendix and applicable Reserve Margin. Resource Adequacy Plans must utilize the Net Qualifying Capacity requirements of Section 40.5.2 of the ISO Tariff.

40.2.3 Modified Reserve Sharing LSEs.

40.2.3.1 Reserve Margin.

The information required by Section 40.2.3.1 of this appendix shall be provided to the CAISO within five (5) Business Days of the CAISO filing its statement certifying market readiness in accordance with Paragraph 1414 of 116 FERC ¶61,274 (2006).

(a) The Scheduling Coordinator for a Load Serving Entity electing Modified Reserve Sharing LSE status must provide the CAISO with the Reserve Margin(s) adopted by the CPUC, Local Regulatory Authority, or federal agency, as appropriate, for use in the annual Resource Adequacy Plan and monthly Resource Adequacy Plans listed as a percentage of the Demand Forecasts developed in accordance with Section 40.2.3.3 of this appendix.

(b) For the Scheduling Coordinator for a Load Serving Entity electing Modified Reserve Sharing LSE status for which the CPUC, Local Regulatory Authority, or federal agency, as appropriate, has not established a Reserve Margin, the Reserve Margin shall be no less than fifteen percent (15%) of the applicable month's peak hour Demand of the Load Serving Entity, as determined by the Demand Forecasts developed in accordance with Section 40.2.3.3 of this appendix.

40.2.3.2 Qualifying Capacity.

The information required by Section 40.2.3.2 of this appendix shall be provided to the CAISO pursuant to the instructions set forthi n a CAISO Market Notice within five (5) Business Days of the CAISO filing its statement certifying market readiness in accordance with Paragraph 1414 of 116 FERC ¶61,274 (2006).

The Scheduling Coordinator for a Load Serving Entity electing Modified Reserve Sharing LSE status must provide the CAISO with a description of the criteria for determining qualifying resource types and the Qualifying Capacity from such resources and any modifications thereto as they are implemented from time to time. The Modified Reserve Sharing LSE may elect to utilize the criteria set forth in Section 40.8 of this appendix.

40.2.3.3 Demand Forecasts.

(a) The Scheduling Coordinator for a Load Serving Entity electing Modified Reserve Sharing LSE status must provide annual and monthly Demand Forecasts as part of the annual and monthly Resource Adequacy Plans under this appendix. The annual and monthly Demand Forecasts shall utilize the annual and monthly coincident peak Demand determinations provided by the California Energy Commission for such Load Serving Entity, which will be calculated from Demand Forecast data submitted to the California Energy Commission by each Modified Reserve Sharing LSE; or (ii) if the California Energy Commission does not produce coincident peak Demand Forecasts for the Load Serving Entity, the annual and monthly coincident peak Demand Forecasts produced by the CAISO for such Load Serving Entity. Scheduling Coordinators must provide data and information, as may be requested by the CAISO, to develop or support the Demand Forecast required by this Section 40.2.3.3 of this appendix.

40.2.3.4 Annual and Monthly Resource Adequacy Plans.

The Scheduling Coordinator for a Load Serving Entity electing Modified Reserve Sharing LSE status must provide annual and monthly Resource Adequacy Plans. For 2008 Resource Adequacy Compliance Year, the annual Resource Adequacy Plan shall be submitted to the CAISO on January 31, 2008 in the form set forth on the CAISO Website. The monthly Resource Adequacy Plan shall be submitted to the CAISO on the first Business Day after 30 calendar days from the date the CAISO files its statement certifying market readiness in accordance with Paragraph 1414 of 116 FERC ¶61,274 (2006) in the form set forth on the CAISO Website. Thereafter, monthly Resource Adequacy Plans shall be submitted to the CAISO by the last Business Day of the second month prior to the compliance month and in the form set forth on the CAISO Website for each Modified Reserve Sharing LSE served by the Scheduling Coordinator. Prior to the requirement to submit monthly Resource Adequacy Plans to the CAISO in accordance with Section 40.2.3.4 of this appendix, monthly Resource Adequacy Plans must continue to be submitted in accordance with Section 40.2.2 of the ISO Tariff. The annual Resource Adequacy Plan must, at a minimum, set forth the Local Capacity Area Resources, if any, procured by the Modified Reserve Sharing LSE as described in Section 40.3 of this appendix. The monthly Resource Adequacy Plan must identify the resources the Modified Reserve Sharing LSE will rely upon to satisfy its forecasted monthly Demand and Reserve Margin as set forth in Section 40.2.3.1 of this appendix, for the relevant reporting period and must utilize the Net Qualifying Capacity requirements of Section 40.5.2 of the ISO Tariff.

40.2.4 Load-Following MSS.

A Scheduling Coordinator for a Load-following MSS must provide an annual Resource Adequacy Plan on January 31, 2008 for 2008 Resource Adequacy Compliance Year that sets forth, at a minimum, the Local Capacity Area Resources, if any, procured by the Load-following MSS as described in Section 40.3 of this appendix. The annual Resource Adequacy Plan shall utilize the annual coincident peak Demand determination provided by the California Energy Commission for such Load-following MSS using Demand Forecast data submitted to the California Energy Commission by the Load-following MSS, or, if the California Energy Commission does not produce coincident peak Demand Forecasts for the Load-following MSS, the annual coincident peak Demand Forecast produced by the CAISO for such Load-following MSS in accordance with its Business Practice Manual using Demand Forecast data submitted to the CAISO by the Load-following MSS.

40.3 Local Capacity Area Resource Requirements Applicable to Scheduling Coordinators for All Load Serving Entities.

40.3.1 Local Capacity Technical Study.

For 2008 Resource Adequacy Compliance Year, the CAISO's 2008 Local Capacity Technical Analysis, dated April 3, 2007, located at http://www.caiso.com/1bb5/1bb5ed3d46430.pdf on the CAISO Website shall constitute the Local Capacity Technical Study for purposes of Section 40 of this appendix. For the 2009 Resource Adequacy Compliance Year, on an annual basis, pursuant to the schedule set forth in the Business Practice Manual, the CAISO will, perform, and publish on the CAISO Website the Local Capacity Technical Study. The Local Capacity Technical Study shall identify Local Capacity Areas, determine the minimum amount of Local Capacity Area Resources in MW that must be available to the CAISO within each identified Local Capacity Area, and identify the Generating Units within each identified Local Capacity Area. The CAISO shall collaborate with the CPUC, Local Regulatory Authorities within the CAISO Control Area, federal agencies, and Market Participants to ensure that the Local Capacity Technical Study is performed in accordance with this Section 40.3 and to establish for inclusion in the Business Practice Manual other parameters and assumptions applicable to the Local Capacity Technical Study and a schedule that provides for: (i) reasonable time for review of a draft Local Capacity Technical Study, (ii) reasonable time for Participating TOs to propose operating solutions, and (iii) release of the final Local Capacity Technical Study no later than 120 days prior to the date annual Resource Adequacy Plans must be submitted.

40.3.1.1 Local Capacity Technical Study Criteria.

The Local Capacity Technical Study will determine the minimum amount of Local Capacity Area Resources needed to address the Contingencies identified in Section 40.3.1.2 of this appendix. In performing the Local Capacity Technical Study, the CAISO will apply those methods for resolving Contingencies considered appropriate for the performance level that corresponds to a particular studied Contingency, as provided in NERC Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0, as augmented by CAISO Reliability Criteria in accordance with the Transmission Control Agreement and Section 24.2.1 of Appendix EE. The CAISO Reliability Criteria shall include:

(1) Time Allowed for Manual Readjustment: This is the amount of time required for the operatior to take all actions necessary to prepare the system for the next contingency. This time should not be less than 30 minutes.

(2) No voltage collapse or dynamic instability shall be allowed for the Category D event-any B1-4 system readjusted (Common Mode) L-2, as listed in Section 40.3.1.2.

40.3.1.2 Local Capacity Technical Study Contingencies.

The Local Capacity Technical Study shall assess the following Contingencies:

Contingency Component(s)
NERC/WECC Performance Level A – No Contingencies
<u>NERC/WECC Performance Level B – Loss of a single element</u> 1. Generator (G-1) 2. Transmission Circuit (L-1) 3. Transformer (T-1) 4. Single Pole (dc) Line 5. G-1 system readjusted L-1
<u>NERC/WECC Performance Level C – Loss of two or more elements</u> 3. L-1 system readjusted G-1 3. G-1 system readjusted T-1 or T-1 system readjusted G-1 3. L-1 system readjusted T-1 or T-1 system readjusted L-1 3. G-1 system readjusted G-1 3. L-1 system readjusted L-1 4. Bipolar (dc) Line 5. Two circuits (Common Mode) L-2 9. SLG fault (stuck breaker or protection failure) for Bus section WECC-S3. Two generators (Common Mode) G-2
<u>D – Extreme event – loss of two or more elements</u> Any B1-4 system readjusted (Common Mode) L-2 All other extreme combinations D1-14.

40.3.2 Allocation of Local Capacity Area Resource Obligations.

The CAISO will allocate responsibility for Local Capacity Area Resources to Scheduling Coordinators for Load Serving Entities in the following sequential manner:

(a) The responsibility for the aggregate Local Capacity Area Resources required for all Local Capacity Areas within each TAC Area as determined by the Local Capacity Technical Study will be allocated to all Scheduling Coordinators for Load Serving Entities that serve Load in the TAC Area in accordance with the Load Serving Entity's proportionate share of the LSE's TAC Area Load at the time of the CAISO's annual coincident peak Demand set forth in the annual peak Demand Forecast for the next Resource Adequacy Compliance Year as determined by the California Energy Commission. Expressed as a formula, the allocation of Local Area Capacity Resource obligations will be as follows: (∑ Local Capacity Area MW in TAC Area from the Local Capacity Technical Study) * (LSE Demand in TAC Area at CAISO annual coincident peak Demand)/(Total TAC Area Demand at the time of CAISO annual coincident peak Demand). This will result in a MW responsibility for each Load Serving Entity for each TAC Area in which the LSE serves Load. The LSE may meet its MW responsibility, as assigned under this Section, for each TAC Area in which the LSE serves Load by procurement of that MW quantity in any Local Capacity Area in the TAC Area.

(b) For Scheduling Coordinators for Non-CPUC Load Serving Entities, the Local Capacity Area Resource obligation will be allocated based on Section 40.3.2(a) of this appendix.

(c) For Scheduling Coordinators for CPUC Load Serving Entities, the CAISO will allocate the Local Capacity Area Resource obligation based on an allocation methodology, if any, adopted by the CPUC. However, if the allocation methodology adopted by the CPUC does not fully allocate the total sum of each CPUC Load Serving Entity's proportionate share calculated under Section 40.3.2(a) of this appendix, the CAISO will allocate the difference to all Scheduling Coordinators for CPUC Load Serving Entities in accordance with their proportionate share calculated under 40.3.2(a) of this appendix. If the CPUC does not adopt an allocation methodology, the CAISO will allocate Local Capacity Area Resources to Scheduling Coordinators for CPUC Load Serving Entities based on Section 40.3.2(a) of this appendix.

Once the CAISO has allocated the total responsibility for Local Capacity Area Resources, the CAISO will inform the Scheduling Coordinator for each LSE of the LSE's specific allocated responsibility for Local Capacity Area Resources in each TAC Area in which the LSE serves Load.

40.3.3 Procurement of Local Capacity Area Resource Obligations by Load Serving Entities.

Nothing in Section 40 of this appendix obligates a Load Serving Entity to procure Local Capacity Area Resources to satisfy capacity requirements for each Local Capacity Area identified in the Local Capacity Technical Study. Scheduling Coordinators for Load Serving Entities may aggregate responsibilities for procurement of Local Capacity Area Resources. If a Load Serving Entity has procured Local Capacity Area Resources that satisfy generation capacity requirements for Local Capacity Areas, the Scheduling Coordinator for such Load Serving Entity shall include this information in its annual and monthly Resource Adequacy Plan(s).

40.4.7 Submission of Supply Plans.

(a) Scheduling Coordinators representing Resource Adequacy Resources supplying Resource Adequacy Capacity shall provide the CAISO with annual and monthly Supply Plans verifying their agreement to provide Resource Adequacy Capacity during the 2008 Resource Adequacy Compliance Year or relevant month, as applicable. For 2008 Resource Adequacy Compliance Year, an annual Supply Plan or certification that a previously submitted annual Supply Plan for 2008 Resource Adequacy Compliance Year has not changed shall be submitted to the CAISO on January 31, 2008 in the form set forth on the CAISO Website, and the initial monthly Supply Plan shall be submitted to the CAISO on the first Business Day after 30 calendar days from the date the CAISO files its statement certifying market readiness in accordance with Paragraph 1414 of 116 FERC ¶61,274 (2006). Thereafter, Supply Plans shall be submitted to the CAISO by the last Business Day of the second month prior to the compliance month. Prior to the requirement to submit Supply Plans to the CAISO in accordance with Section 40.4.7 of this appendix, monthly Supply Plans must be submitted in accordance with Section 40.6 of the ISO Tariff.

(b) The Supply Plan must be in the form of the template provided on the CAISO Website, which shall include an affirmative representation by the Scheduling Coordinator submitting the Supply Plan that the CAISO is entitled to rely on the accuracy of the information provided in the Supply Plan.

(c) The CAISO shall be entitled to take reasonable measures to validate the accuracy of the information submitted in Supply Plans under this Section of the appendix, including;

(1) Comparing a Resource Adequacy Resource's Resource Adequacy Capacity against the Resource Adequacy Resource's Net Qualifying Capacity, if applicable. To the extent the Resource Adequacy Capacity of a Resource Adequacy Resource included in a Supply Plan is greater than the Resource Adequacy Resource's Net Qualifying Capacity, the CAISO will notify the respective Scheduling Coordinators for the Resource Adequacy Resource and each Load Serving Entity that has included the Resource Adequacy Resource on its Resource Adequacy Plan that the Resource Adequacy Capacity

from the Resource Adequacy Resource shall be reduced to the Resource Adequacy Resource's Net Qualifying Capacity and that it will be considered a mismatch under Section 40.7 of this appendix. If the CAISO is not advised as to how the reduction in Resource Adequacy Capacity to conform with the Resource Adequacy Resource's Net Qualifying Capacity shall be allocated among each Load Serving Entity that included the Resource Adequacy Resource on its Resource Adequacy Plan, the CAISO will apply a pro rata reduction based on the Supply Plan.

(a) Disputes regarding the CAISO's determination of Net Qualifying Capacity shall be subject to Section 40.5.2 of the CAISO Tariff.

(b) The provisions of this Section shall not affect a Resource Adequacy Resource's Net Qualifying Capacity posted by the CAISO under Section 40.5.2 of the CAISO Tariff.

(2) Other errors or inaccuracies identified by the CAISO in a Supply Plan shall be treated as a mismatch under Section 40.7 of this appendix.

40.6.4 Additional Availability Requirements for Use-Limited Resources.

40.6.4.1 Registration of Use-Limited Resources.

Scheduling Coordinators for Use-Limited Resources, other than for hydroelectric Generating Units and Participating Load, including Pumping Load, must provide the CAISO an application in the form specified on the CAISO Website requesting registration of a specifically identified resource as a Use-Limited Resource. For any Use-Limited Resource that anticipates being included in an annual or monthly Resource Adequacy Plan and/or Supply Plan under this appendix, the registration shall be submitted by January 7, 2008. This application shall include specific operating data and supporting documentation including, but not limited to;

1) a detailed explanation of why the resource is subject to operating limitations;
2) historical data to show attainable MWhs for each 24-hour period during the preceding year, including, as applicable, environmental restrictions for NOx, SOx, or other factors; and
3) further data or other information as may be requested by the CAISO to understand the operating characteristics of the unit.

Within fifteen (15) Business Days after receipt of the application, the CAISO will respond to the Scheduling Coordinator as to whether or not the CAISO agrees that the facility is eligible to be a Use-Limited Resource. If the CAISO determines the facility is not a Use-Limited Resource, the Scheduling Coordinator may challenge that determination in accordance with the CAISO ADR Procedures.

40.6.4.2 Use Plan.

The Scheduling Coordinator shall provide for the 2008 Resource Adequacy Compliance Year a proposed annual use plan for each Use-Limited Resource that is a Resource Adequacy Resource. The proposed annual use plan will delineate on a month-by-month basis the total MWhs of Generation, total run hours, expected daily supply capability (if greater than four hours) and the daily Energy limit, operating constraints, and the timeframe for each constraint. The CAISO will have an opportunity to discuss the proposed annual use plan with the Scheduling Coordinator and suggest potential revisions to meet reliability needs of the system. The Scheduling Coordinator shall then submit its final annual use plan. Scheduling Coordinators for Use-Limited Resources must submit the proposed and final annual use plans in accordance with the schedule set forth in the Business Practice Manual. The Scheduling Coordinator will be able to update the projections made in the annual use plan in the monthly Resource Adequacy Plans. Hydroelectric Generating Units and Pumping Load will be able to update use plans intra-monthly as necessary to reflect evolving hydrological and meteorological conditions. The annual use plan must reflect the potential operation of the Use-Limited Resource at a level no less than the minimum criteria set forth by the Local Regulatory Authority for qualification of the resource.

40.7 Compliance.

The CAISO will evaluate whether each annual and monthly Resource Adequacy Plan submitted by a Scheduling Coordinator on behalf of a Load Serving Entity under this appendix (including for 2008 each monthly Resource Adequacy Plan submitted pursuant to Sections 40.2.2 of the CAISO Tariff) demonstrates Resource Adequacy Capacity sufficient to satisfy the Load Serving Entity's (i) allocated responsibility for Local Capacity Area Resources under Section 40.3.2 of this appendix and (ii) applicable Demand and Reserve Margin requirements. In the case of an annual Reserve Margin requirement for 2008, the CAISO will also evaluate the annual Resource Adequacy Plan submitted under Section 40.2.1. If the CAISO determines that a Resource Adequacy Plan does not demonstrate Local Capacity Area Resources sufficient to meet its allocated responsibility under Section 40.3.2 of this appendix, compliance with applicable Demand and Reserve Margin requirements, or compliance with any other resource adequacy requirement in this appendix or adopted by the CPUC, Local Regulatory

Authority, or federal agency, as applicable, the CAISO will notify the relevant Scheduling Coordinator, CPUC, Local Regulatory Authority, or federal agency with jurisdiction over the relevant Load Serving Entity, or in the case of a mismatch between Resource Adequacy Plan(s) and Supply Plan(s), the relevant Scheduling Coordinators, in an attempt to resolve any deficiency. The notification will include the reasons the CAISO believes a deficiency exists. If the deficiency relates to the demonstration of Local Capacity Area Resources in a Load Serving Entity's annual Resource Adequacy Plan, and the CAISO does not provide a written notice of resolution of the deficiency, the Scheduling Coordinator for the Load Serving Entity may demonstrate that the identified deficiency is cured by submitting a revised annual Resource Adequacy Plan within sixty (60) days after the annual Resource Adequacy Plan is due under Sections 40.2.3.4, 40.2.2.4 and 40.2.4 of this appendix. For all other identified deficiencies, at least ten (10) days prior the effective month of the relevant Resource Adequacy Plan, the Scheduling Coordinator for the Load Serving Entity shall (i) demonstrate that the identified deficiency is cured by submitting a revised Resource Adequacy Plan or (ii) advise the CAISO that the CPUC, Local Regulatory Authority, or federal agency, as appropriate, has determined that no deficiency exists. In the case of a mismatch between Resource Adequacy Plan(s) and Supply Plan(s), if resolved, the relevant Scheduling Coordinator(s) must provide the CAISO with revised Resource Adequacy Plan(s) or Supply Plans, as applicable, at least ten (10) days prior to the effective month. If the CAISO is not advised that the deficiency or mismatch is resolved at least ten (10) days prior to the effective month, the CAISO will use the information contained in the Supply Plan to set the obligations of Resource Adequacy Resources under Section 40 of this appendix.

40.8 CAISO Default Qualifying Capacity Criteria.

40.8.1 Applicability.

The criteria in Section 40.8 of this appendix shall apply only: (i) where the CPUC or Local Regulatory Authority has not established and provided to the CAISO criteria to determine the types of resources that may be eligible to provide Qualifying Capacity and for calculating Qualifying Capacity for such eligible resource types and (ii) until the CAISO has been notified in writing by the CPUC of its intent to overturn, reject or fundamentally modify the capacity-based framework in CPUC Decisions 04-01-050 (Jan. 10, 2004), 04-10-035 (Oct. 28, 2004), and 05-10-042 (Oct. 31, 2005). The types of resources specified in Section 40.8.1 of this appendix will be eligible to provide Qualifying Capacity to the extent they meet the criteria for each type of resource set forth in Section 40.8.1 of this appendix.

40.8.1.2 Nuclear and Thermal.

Nuclear and thermal Generating Units, other than Qualifying Facilities with effective contracts under the Public Utility Regulatory Policies Act addressed in Section 40.8.1.8 of this appendix below, must be a Participating Generator or a System Unit. The Qualifying Capacity of nuclear and thermal units, other than Qualifying Facilities addressed in Section 40.8.1.8 of this appendix, will be based on net dependable capacity defined by NERC Generating Availability Data System information.

40.8.1.3 Hydro.

Hydroelectric Generating Units, other than Qualifying Facilities with contracts under the Public Utility Regulatory Policies Act, must be either Participating Generators or System Units. The Qualifying Capacity of a pond or Pumped-Storage Hydro Unit, other than a QF, will be determined based on net dependable capacity defined by NERC GADS minus variable head derate based on an average dry year reservoir level. The Qualifying Capacity of a pond or Pumped-Storage Hydro Unit that is a QF will be determined based on historic performance during the hours of noon to 6:00 p.m., using a three-year rolling average.

The Qualifying Capacity of all run-of-river hydro units, including Qualifying Facilities, will be based on net dependable capacity defined by NERC GADS minus an average dry year conveyance flow, stream flow, or canal head derate. As used in this section, average dry year reflects a one-in-five year dry hydro scenario (for example, using the 4th driest year from the last 20 years on record).

40.8.1.4 Unit-Specific Contracts.

Unit-specific contracts with Participating Generators or System Units will qualify as Resource Adequacy Capacity subject to the verification that the total MW quantity of all contracts from a specific unit do not exceed the total Net Qualifying Capacity (MW) consistent with the Net Qualifying Capacity determination for that unit.

40.8.1.5 Contracts with Liquidated Damage Provisions.

Firm Energy contracts with liquidated damages provisions, as generally reflected in Service Schedule C of the Western Systems Power Pool Agreement or the Firm LD product of the Edison Electric Institute pro forma agreement, or any other similar firm Energy contract that does not require the seller to source the Energy from a particular unit, and specifies a delivery point internal to the CAISO Control Area entered into before October 27, 2005 shall be eligible to count as Qualifying Capacity until the end of 2008. A Scheduling Coordinator, however, cannot have more than 25% of its portfolio of Qualifying Capacity met by contracts with liquidated damage provisions for 2008.

40.8.1.6 Wind and Solar.

As used in this Section, wind units are those wind Generating Units without backup sources of Generation and solar units are those solar Generating Units without backup sources of Generation. Wind and solar units, other than Qualifying Facilities with effective contracts under the Public Utility Regulatory Policies Act, must be Participating Intermittent Resources or subject to availability provisions of Section 40.6.4.3.4 upon that section's effective date.

The Qualifying Capacity of all wind or solar units, including Qualifying Facilities, for each month will be based on their monthly historic performance during that same month during the hours of noon to 6:00 p.m., using a three-year rolling average. For wind or solar units with less than three years operating history, all months for which there is no historic performance data will utilize the monthly average production factor of all units (wind or solar, as applicable) within the TAC Area in which the Generating Unit is located.

40.8.1.7 Geothermal.

Geothermal Generating Units, other than Qualifying Facilities addressed in Section 40.8.1.8 of this appendix, must be Participating Generators or System Units. The Qualifying Capacity of geothermal units, other than Qualifying Facilities addressed in Section 40.8.1.8 of this appendix, will be based on NERC GADS net dependable capacity minus a derate for steam field degradation.

40.8.1.8 Treatment of Qualifying Capacity for Qualifying Facilities.

Qualifying Facilities must be subject to an effective Participating Generator Agreement or QF Participating Generator Agreement or must be System Units, unless they have a PURPA contract. Except for hydro, wind, and solar Qualifying Facilities addressed pursuant to Sections 40.8.1.3 and 40.8.1.6 of this appendix, the Qualifying Capacity of Qualifying Facilities under PURPA contracts, will be based on historic monthly Generation output during the hours of noon to 6:00 p.m. (net of Self-provided Load) during a three-year rolling average.

40.8.1.9 Participating Loads.

The Qualifying Capacity of Participating Loads shall be the average reduction in Demand over a three-year period on a per Dispatch basis or, if the Participating Load does not have three years of performance history, based on comparable evaluation data using similar programs. Participating Loads must be available at least 48 hours, and if the Participating Loads can only be dispatched for a maximum of two hours per event, then only 0.89 percent of a Scheduling Coordinator’s portfolio may be made up of such Loads.

40.8.1.10 Jointly-Owned Facilities.

A jointly-owned facility must be either a Participating Generator or a System Unit. The Qualifying Capacity for the entire facility will be determined based on the type of resource as described elsewhere in this Section 40.8.1 of this appendix. In addition, the Scheduling Coordinator must provide the CAISO with a demonstration of its entitlement to the output of the jointly-owned facility's Qualified Capacity and an explanation of how that entitlement may change if the facility's output is restricted.

40.8.1.11 Facilities under Construction.

The Qualifying Capacity for facilities under construction will be determined based on the type of resource as described elsewhere in Section 40.8 of this appendix. In addition, the facility must have been in commercial operation for no less than one month to be eligible to be included as a Resource Adequacy Resource in a Scheduling Coordinator's monthly Resource Adequacy Plan.

40.8.1.12 System Resources.

40.8.1.12.1 Dynamic System Resources.

Dynamic System Resources shall be treated similar to resources within the CAISO Control Area, except with respect to the deliverability screen under Section 40.5.2.1 of the CAISO Tariff. However, eligibility as a Resource Adequacy Resource is contingent upon a showing by the Scheduling Coordinator that the Dynamic System Resource has secured transmission through any intervening Control Areas for the Operating Hours that cannot be curtailed for economic reasons or bumped by higher priority transmission and that the Load Serving Entity for which the Scheduling Coordinator is submitting Demand Bids has an allocation of import capacity at the import Scheduling Point under Section 40.5.2.2 of the CAISO Tariff that is not less than the Resource Adequacy Capacity provided by the Dynamic System Resource.

40.8.1.12.2 Non-Dynamic System Resources.

For Non-Dynamic System Resources, the Scheduling Coordinator must demonstrate that the Load Serving Entity for which the Scheduling Coordinator is scheduling Demand has an allocation of import capacity at the import Scheduling Point under Section 40.5.2.2 of the CAISO Tariff that is not less than the Resource Adequacy Capacity from the Non-Dynamic System Resource. The Scheduling Coordinator must also demonstrate that the Non-Dynamic System Resource is covered by Operating Reserves, unless unit contingent, in the sending Control Area. Eligibility as Resource Adequacy Capacity is contingent upon a showing by the Scheduling Coordinator of the System Resource that it has secured transmission through any intervening Control Areas for the Operating Hours that cannot be curtailed for economic reasons or bumped by higher priority transmission. With respect to Non-Dynamic System Resources, any inter-temporal constraints, such as multi-hour run blocks, must be explicitly identified in the monthly Resource Adequacy Plan, and no constraints may be imposed beyond those explicitly stated in the plan.

PART B - DEFINITIONS

Unless defined in this Appendix CC or the context otherwise requires, all capitalized terms and expressions used in this Appendix CC shall have the meaning as defined in the Master Definitions Supplement in Appendix A. The following capitalized terms and expressions used in this Appendix CC shall have the meanings set forth below unless otherwise stated or the context otherwise requires. If two or more capitalized terms are used together in a manner not uniquely defined in Appendix A or this Appendix CC, the meanings of each defined term apply.

CPUC Load Serving Entity	Any entity serving retail Load in the CAISO Control Area under the jurisdiction of the CPUC, including an electrical corporation under section 218 of the California Public Utilities Code, an electric service provider under section 218.3 of the California Public Utilities Code, and a community choice aggregator under section 331.1 of the California Public Utilities Code.
Dynamic Resource-Specific System Resource	A Dynamic System Resource that is a specific generation resource outside the CAISO Control Area.
Firm Liquidated Damages Contract	A contract utilizing or consistent with Service Schedule C of the Western Systems Power Pool Agreement or the Firm Liquidated Damages product of the Edison Electric Institute pro forma agreement, or any other similar firm Energy contract that does not require the seller to source the Energy from a particular unit, and specifies a delivery point internal to the CAISO Control Area.
Load Serving Entity (LSE)	Any entity (or the duly designated agent of such an entity, including, e.g. a Scheduling Coordinator), including a load aggregator or power marketer, that (a) (i) serves End Users within the CAISO Control Area and (ii) has been granted authority or has an obligation pursuant to California state or local law, regulation, or franchise to sell electric energy to End Users located within the CAISO Control Area; (b) is a federal power marketing authority that serves End Users; or (c) is the State Water Resources Development System commonly known as the State Water Project of the California Department of Water Resources.

Local Capacity Area	Transmission constrained area as defined in the study referenced in Section 40.3.1 of Appendix CC.
Local Capacity Area Resources	Resource Adequacy Capacity from a Generating Unit listed in the technical study or Participating Load that is located within a Local Capacity Area capable of contributing toward the amount of capacity required in a particular Local Capacity Area.
Local Capacity Technical Study	The study performed by the CAISO pursuant to Section 40.3.
Modified Reserve Sharing LSE	A Load Serving Entity whose Scheduling Coordinator has informed the CAISO in accordance with Section 40.1 of its election to be a Modified Reserve Sharing LSE.
Non-CPUC Load Serving Entity	Any entity serving retail Demand in the CAISO Control Area not within the jurisdiction of the CPUC, including (i) a local publicly owned electric utility under section 9604 of the California Public Utilities Code and (ii) any federal entities, including but not limited to federal power marketing authorities, that serve retail Load.
Non-Dynamic Resource-Specific System Resource	A Non-Dynamic System Resource that is a specific generation resource outside the CAISO Control Area.
Pumped-Storage Hydro Unit	A hydroelectric dam with the capability to produce electricity and the ability to pump water between reservoirs at different elevations to store such water for the production of electricity.
Pumping Load	A hydro pumping resource that is capable of responding to Dispatch Instructions by ceasing to pump.
Reserve Margin	The amount of Resource Adequacy Capacity that a Scheduling Coordinator is required to maintain in accordance with Section 40.
Reserve Sharing LSE	A Load Serving Entity whose Scheduling Coordinator has informed the CAISO in accordance with Section 40.1 of its election to be a Reserve Sharing LSE.
Resource Adequacy Compliance Year	A calendar year from January 1 through December 31.
Resource-Specific System Resource	A Dynamic or Non-Dynamic Resource-Specific System Resource.
Use-Limited Resource	A resource that, due to design considerations, environmental restrictions on operations, cyclical requirements, such as the need to recharge or refill, or other non-economic reasons, is unable to operate continuously on a daily basis, but is able to operate for a minimum set of consecutive Trading Hours each Trading Day.

ISO TARIFF APPENDIX DD

SMALL GENERATOR
INTERCONNECTION AGREEMENT (SGIA)

SMALL GENERATOR
INTERCONNECTION AGREEMENT (SGIA)

(For Generating Facilities No Larger Than 20 MW)

Small Generator Interconnection Agreement

This Small Generator Interconnection Agreement ("Agreement") is made and entered into this ________ day of ________________, 20__, by ____ ("Participating TO"), the California Independent System Operator Corporation, a California nonprofit public benefit corporation organized and existing under the laws of the State of California ("ISO") and

____

("Interconnection Customer") each hereinafter sometimes referred to individually as "Party" or referred to collectively as the "Parties."

Participating TO Information

Participating TO: ____
Attention: ____
Address: ____
City: ________________________________ State: ______________ Zip: ______
Phone: ________________ Fax: _________________

ISO Information

Attention: Phil Pettingill
151 Blue Ravine Road
Folsom, CA 95630
Phone: 916-351-4400 Fax: __________________

Interconnection Customer Information

Interconnection Customer: ____
Attention: ____
Address: ____
City: ________________________________ State: ______________ Zip: ______
Phone: ________________ Fax: _________________

Interconnection Customer Application No: _____________

In consideration of the mutual covenants set forth herein, the Parties agree as follows:

Article 1. Scope and Limitations of Agreement

1.1 This Agreement shall be used for all Interconnection Requests submitted under the Small Generator Interconnection Procedures (SGIP) except for those submitted under the 10 kW Inverter Process contained in SGIP Attachment 5.

1.2 This Agreement governs the terms and conditions under which the Interconnection Customer's Small Generating Facility will interconnect with, and operate in parallel with, the Participating TO's Transmission System.

1.3 This Agreement does not constitute an agreement to purchase or deliver the Interconnection Customer's power. The purchase or delivery of power and other services that the Interconnection Customer may require will be covered under separate agreements, if any. The Interconnection Customer will be responsible for separately making all necessary arrangements (including scheduling) for delivery of electricity in accordance with the ISO Tariff.

1.4 Nothing in this Agreement is intended to affect any other agreement between or among the Parties.

1.5 Responsibilities of the Parties

1.5.1 The Parties shall perform all obligations of this Agreement in accordance with all Applicable Laws and Regulations, Operating Requirements, and Good Utility Practice. The Parties shall use the Standard Large Generator Interconnection Agreement (ISO Tariff Appendix V) to interpret the responsibilities of the Parties under this Agreement.

1.5.2 The Interconnection Customer shall construct, interconnect, operate and maintain its Small Generating Facility and construct, operate, and maintain its Interconnection Facilities in accordance with the applicable manufacturer's recommended maintenance schedule, and in accordance with this Agreement, and with Good Utility Practice.

1.5.3 The Participating TO shall construct, operate, and maintain its Interconnection Facilities and Upgrades in accordance with this Agreement, and with Good Utility Practice. The ISO and the Participating TO shall cause the Participating TO's Transmission System to be operated and controlled in a safe and reliable manner and in accordance with this Agreement.

1.5.4 The Interconnection Customer agrees to construct its facilities or systems in accordance with applicable specifications that meet or exceed those provided by the National Electrical Safety Code, the American National Standards Institute, IEEE, Underwriter's Laboratory, and Operating Requirements in effect at the time of construction and other applicable national and state codes and standards. The Interconnection Customer agrees to design, install, maintain, and operate its Small Generating Facility so as to reasonably minimize the likelihood of a disturbance adversely affecting or impairing the system or equipment of the Participating TO and any Affected Systems. The Interconnection Customer shall comply with the Participating TO's Interconnection Handbook. In the event of a conflict between the terms of this Agreement and the terms of the Participating TO's Interconnection Handbook, the terms in this Agreement shall govern.

1.5.5 Each Party shall operate, maintain, repair, and inspect, and shall be fully responsible for the facilities that it now or subsequently may own unless otherwise specified in the Attachments to this Agreement. Each Party shall be responsible for the safe installation, maintenance, repair and condition of their respective lines and appurtenances on their respective sides of the point of change of ownership. The Participating TO and the Interconnection Customer, as appropriate, shall provide Interconnection Facilities that adequately protect the ISO Controlled Grid, the Participating TO's electric system, the Participating TO's personnel, and other persons from damage and injury. The allocation of responsibility for the design, installation, operation, maintenance and ownership of Interconnection Facilities shall be delineated in the Attachments to this Agreement.

1.5.6 The Participating TO and the ISO shall coordinate with Affected Systems to support the interconnection.

1.5.7 The Interconnection Customer shall execute the Reliability Management System Agreement of the Western Electricity Coordinating Council prior to parallel operation of the Small Generating Facility. The Reliability Management System Agreement is provided as Attachment 8 to this Agreement.

1.6 Parallel Operation Obligations

Once the Small Generating Facility has been authorized to commence parallel operation, the Interconnection Customer shall abide by all rules and procedures pertaining to the parallel operation of the Small Generating Facility in the ISO Control Area, including, but not limited to; 1) the rules and procedures concerning the operation of generation set forth in the ISO Tariff for the ISO Controlled Grid and; 2) the Operating Requirements set forth in Attachment 5 of this Agreement.

1.7 Metering

The Interconnection Customer shall be responsible for the reasonable and necessary cost for the purchase, installation, operation, maintenance, testing, repair, and replacement of metering and data acquisition equipment specified in Attachments 2 and 3 of this Agreement. The Interconnection Customer's metering (and data acquisition, as required) equipment shall conform to applicable industry rules and Operating Requirements.

1.8 Reactive Power

1.8.1 The Interconnection Customer shall design its Small Generating Facility to maintain a composite power delivery at continuous rated power output at the terminals of each generating unit at a power factor within the range of 0.95 leading to 0.90 lagging, unless the ISO has established different requirements that apply to all similarly situated generators in the ISO Control Area on a comparable basis. The requirements of this paragraph shall not apply to wind generators and the requirements of Attachment 7 shall apply instead.

1.8.2 Payment to the Interconnection Customer for reactive power that the Small Generating Facility provides or absorbs when the ISO requests the Interconnection Customer to operate its Small Generating Facility outside the range specified in article 1.8.1 will be made by the ISO in accordance with the applicable provisions of the ISO Tariff.

1.9 Capitalized terms used herein shall have the meanings specified in the Glossary of Terms in Attachment 1 or the body of this Agreement.

Article 2. Inspection, Testing, Authorization, and Right of Access

2.1 Equipment Testing and Inspection

2.1.1 The Interconnection Customer shall test and inspect its Small Generating Facility and Interconnection Facilities prior to interconnection. The Interconnection Customer shall notify the Participating TO and the ISO of such activities no fewer than five Business Days (or as may be agreed to by the Parties) prior to such testing and inspection. Testing and inspection shall occur on a Business Day. The Participating TO and the ISO may, at their own expense, send qualified personnel to the Small Generating Facility site to inspect the interconnection and observe the testing. The Interconnection Customer shall provide the Participating TO and the ISO a written test report when such testing and inspection is completed.

2.1.2 The Participating TO and the ISO shall provide the Interconnection Customer written acknowledgment that they have received the Interconnection Customer's written test report. Such written acknowledgment shall not be deemed to be or construed as any representation, assurance, guarantee, or warranty by the Participating TO or the ISO of the safety, durability, suitability, or reliability of the Small Generating Facility or any associated control, protective, and safety devices owned or controlled by the Interconnection Customer or the quality of power produced by the Small Generating Facility.

2.2 Authorization Required Prior to Parallel Operation

2.2.1 The Participating TO and the ISO shall use Reasonable Efforts to list applicable parallel operation requirements in Attachment 5 of this Agreement. Additionally, the Participating TO and the ISO shall notify the Interconnection Customer of any changes to these requirements as soon as they are known. The Participating TO and the ISO shall make Reasonable Efforts to cooperate with the Interconnection Customer in meeting requirements necessary for the Interconnection Customer to commence parallel operations by the in-service date.

2.2.2 The Interconnection Customer shall not operate its Small Generating Facility in parallel with the Participating TO's Transmission System without prior written authorization of the Participating TO. The Participating TO will provide such authorization to the Interconnection Customer and the ISO once the Participating TO receives notification that the Interconnection Customer has complied with all applicable parallel operation requirements. Such authorization shall not be unreasonably withheld, conditioned, or delayed.

2.3 Right of Access

2.3.1 Upon reasonable notice, the Participating TO and the ISO may send a qualified person to the premises of the Interconnection Customer at or immediately before the time the Small Generating Facility first produces energy to inspect the interconnection, and observe the commissioning of the Small Generating Facility (including any required testing), startup, and operation for a period of up to three Business Days after initial start-up of the unit. In addition, the Interconnection Customer shall notify the Participating TO and the ISO at least five Business Days prior to conducting any on-site verification testing of the Small Generating Facility.

2.3.2 Following the initial inspection process described above, at reasonable hours, and upon reasonable notice, or at any time without notice in the event of an emergency or hazardous condition, the Participating TO and the ISO shall have access to the Interconnection Customer's premises for any reasonable purpose in connection with the performance of the obligations imposed on it by this Agreement or if necessary to meet its legal obligation to provide service to its customers.

2.3.3 Each Party shall be responsible for its own costs associated with following this article.

Article 3. Effective Date, Term, Termination, and Disconnection

3.1 Effective Date
This Agreement shall become effective upon execution by the Parties subject to acceptance by FERC (if applicable), or if filed unexecuted, upon the date specified by the FERC. The Participating TO and the ISO shall promptly file this Agreement with the FERC upon execution, if required.

3.2 Term of Agreement
This Agreement shall become effective on the Effective Date and shall remain in effect for a period of ____ years from the Effective Date (term specified in individual agreements to be ten (10) years or such other longer period as the Interconnection Customer may request) and shall be automatically renewed for each successive one-year period thereafter, unless terminated earlier in accordance with article 3.3 of this Agreement.

3.3 Termination

No termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing with FERC of a notice of termination of this Agreement (if required), which notice has been accepted for filing by FERC.

3.3.1 The Interconnection Customer may terminate this Agreement at any time by giving the Participating TO and the ISO 20 Business Days written notice.

3.3.2 Any Party may terminate this Agreement after Default pursuant to article 7.6.

3.3.3 Upon termination of this Agreement, the Small Generating Facility will be disconnected from the ISO Controlled Grid. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this Agreement or such non-terminating Party otherwise is responsible for these costs under this Agreement.

3.3.4 The termination of this Agreement shall not relieve any Party of its liabilities and obligations, owed or continuing at the time of termination.

3.3.5 The provisions of this article shall survive termination or expiration of this Agreement.

3.4 Temporary Disconnection

Temporary disconnection of the Small Generating Facility or associated Interconnection Facilities shall continue only for so long as reasonably necessary under Good Utility Practice.

3.4.1 Emergency Conditions

"Emergency Condition" shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; (2) that, in the case of the ISO, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the ISO Controlled Grid or the electric systems of others to which the ISO Controlled Grid is directly connected; (3) that, in the case of the Participating TO, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Participating TO's Transmission System, the Participating TO's Interconnection Facilities, Distribution System, or the electric systems of others to which the Participating TO's electric system is directly connected; or (4) that, in the case of the Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Small Generating Facility or the Interconnection Customer's Interconnection Facilities. Under Emergency Conditions, the ISO or the Participating TO may immediately suspend interconnection service and temporarily disconnect the Small Generating Facility. The Participating TO or the ISO shall notify the Interconnection Customer promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Interconnection Customer's operation of the Small Generating Facility or the Interconnection Customer's Interconnection Facilities. The Interconnection Customer shall notify the Participating TO and the ISO promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the ISO Controlled Grid, the Participating TO's Interconnection Facilities, or any Affected Systems. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of the Interconnection Customer's or Participating TO's facilities and operations, its anticipated duration, and the necessary corrective action.

3.4.2 Routine Maintenance, Construction, and Repair

The Participating TO or the ISO may interrupt interconnection service or curtail the output of the Small Generating Facility and temporarily disconnect the Small Generating Facility from the ISO Controlled Grid when necessary for routine maintenance, construction, and repairs on the ISO Controlled Grid or the Participating TO's electric system. The Party scheduling the interruption shall provide the Interconnection Customer with five Business Days notice prior to such interruption. The Party scheduling the interruption shall use Reasonable Efforts to coordinate such reduction or temporary disconnection with the Interconnection Customer.

The Interconnection Customer shall update its planned maintenance schedules in accordance with the ISO Tariff. The ISO may request the Interconnection Customer to reschedule its maintenance as necessary to maintain the reliability of the ISO Controlled Grid in accordance with the ISO Tariff. Such planned maintenance schedules and updates and changes to such schedules shall be provided by the Interconnection Customer to the Participating TO concurrently with their submittal to the ISO.

3.4.3 Forced Outages

During any forced outage, the Participating TO or the ISO may suspend interconnection service to effect immediate repairs on the ISO Controlled Grid or the Participating TO's electric system. The Participating TO or the ISO shall use Reasonable Efforts to provide the Interconnection Customer with prior notice. If prior notice is not given, the Participating TO or the ISO shall, upon request, provide the Interconnection Customer written documentation after the fact explaining the circumstances of the disconnection. The Interconnection Customer shall notify ISO, as soon as practicable, of all forced outages or reductions of the Small Generating Facility in accordance with the ISO Tariff.

3.4.4 Adverse Operating Effects

The Participating TO or the ISO shall notify the Interconnection Customer as soon as practicable if, based on Good Utility Practice, operation of the Small Generating Facility may cause disruption or deterioration of service to other customers served from the same electric system, or if operating the Small Generating Facility could cause damage to the ISO Controlled Grid, the Participating TO's Transmission System or Affected Systems. Supporting documentation used to reach the decision to disconnect shall be provided to the Interconnection Customer upon request. If, after notice, the Interconnection Customer fails to remedy the adverse operating effect within a reasonable time, the Participating TO or the ISO may disconnect the Small Generating Facility. The Participating TO or the ISO shall provide the Interconnection Customer with five Business Day notice of such disconnection, unless the provisions of article 3.4.1 apply.

3.4.5 Modification of the Small Generating Facility

The Interconnection Customer must receive written authorization from the Participating TO and the ISO before making any change to the Small Generating Facility that may have a material impact on the safety or reliability of the ISO Controlled Grid or the Participating TO's electric system. Such authorization shall not be unreasonably withheld. Modifications shall be done in accordance with Good Utility Practice. If the Interconnection Customer makes such modification without the Participating TO's and the ISO's prior written authorization, the Participating TO or the ISO shall have the right to temporarily disconnect the Small Generating Facility.

3.4.6 Reconnection

The Parties shall cooperate with each other to restore the Small Generating Facility, Interconnection Facilities, the Participating TO's electric system, and the ISO Controlled Grid to their normal operating state as soon as reasonably practicable following a temporary disconnection.

Article 4. Cost Responsibility for Interconnection Facilities and Distribution Upgrades

4.1 Interconnection Facilities

4.1.1 The Interconnection Customer shall pay for the cost of the Interconnection Facilities itemized in Attachment 2 of this Agreement. The Participating TO shall provide a best estimate cost, including overheads, for the purchase and construction of its Interconnection Facilities and provide a detailed itemization of such costs. Costs associated with Interconnection Facilities may be shared with other entities that may benefit from such facilities by agreement of the Interconnection Customer, such other entities, the ISO, and the Participating TO.

4.1.2 The Interconnection Customer shall be responsible for its share of all reasonable expenses, including overheads, associated with (1) owning, operating, maintaining, repairing, and replacing its own Interconnection Facilities, and (2) operating, maintaining, repairing, and replacing the Participating TO's Interconnection Facilities.

4.2 Distribution Upgrades
The Participating TO shall design, procure, construct, install, and own the Distribution Upgrades described in Attachment 6 of this Agreement. If the Participating TO and the Interconnection Customer agree, the Interconnection Customer may construct Distribution Upgrades that are located on land owned by the Interconnection Customer. The actual cost of the Distribution Upgrades, including overheads, shall be directly assigned to the Interconnection Customer.

Article 5. Cost Responsibility for Network Upgrades

5.1 Applicability
No portion of this article 5 shall apply unless the interconnection of the Small Generating Facility requires Network Upgrades.

5.2 Network Upgrades
The Participating TO shall design, procure, construct, install, and own the Network Upgrades described in Attachment 6 of this Agreement. If the Participating TO and the Interconnection Customer agree, the Interconnection Customer may construct Network Upgrades that are located on land owned by the Interconnection Customer. Unless the Participating TO elects to pay for Network Upgrades, the actual cost of the Network Upgrades, including overheads, shall be borne initially by the Interconnection Customer.

5.3 Transmission Credits
No later than thirty (30) days prior to the Commercial Operation Date, the Interconnection Customer may make a one-time election by written notice to the ISO and the Participating TO to receive Firm Transmission Rights as defined in and as available under the ISO Tariff at the time of the election in accordance with the ISO Tariff, in lieu of a refund of the cost of Network Upgrades in accordance with Article 5.3.1.

5.3.1 Repayment of Amounts Advanced for Network Upgrades
Upon the Commercial Operation Date, the Interconnection Customer shall be entitled to a repayment, equal to the total amount paid to the Participating TO for the cost of Network Upgrades. Such amount shall include any tax gross-up or other tax-related payments associated with Network Upgrades not refunded to the Interconnection Customer, and shall be paid to the Interconnection Customer by the Participating TO on a dollar-for-dollar basis either through (1) direct payments made on a levelized basis over the five-year period

commencing on the Commercial Operation Date; or (2) any alternative payment schedule that is mutually agreeable to the Interconnection Customer and Participating TO, provided that such amount is paid within five (5) years from the Commercial Operation Date. Notwithstanding the foregoing, if this Agreement terminates within five (5) years from the Commercial Operation Date, the Participating TO's obligation to pay refunds to the Interconnection Customer shall cease as of the date of termination. Any repayment shall include interest calculated in accordance with the methodology set forth in FERC's regulations at 18 C.F.R. §35.19a(a)(2)(iii) from the date of any payment for Network Upgrades through the date on which the Interconnection Customer receives a repayment of such payment. Interest shall continue to accrue on the repayment obligation so long as this Agreement is in effect. The Interconnection Customer may assign such repayment rights to any person.

If the Small Generating Facility fails to achieve commercial operation, but it or another Generating Facility is later constructed and makes use of the Network Upgrades, the Participating TO shall at that time reimburse Interconnection Customer for the amounts advanced for the Network Upgrades. Before any such reimbursement can occur, the Interconnection Customer, or the entity that ultimately constructs the Generating Facility, if different, is responsible for identifying the entity to which reimbursement must be made.

5.3.2 Special Provisions for Affected Systems
The Interconnection Customer shall enter into an agreement with the owner of the Affected System and/or other affected owners of portions of the ISO Controlled Grid, as applicable, in accordance with the SGIP. Such agreement shall specify the terms governing payments to be made by the Interconnection Customer to the owner of the Affected System and/or other affected owners of portions of the ISO Controlled Grid. In no event shall the Participating TO be responsible for the repayment for any facilities that are not part of the Participating TO's Transmission System.

5.3.3 Rights Under Other Agreements
Notwithstanding any other provision of this Agreement, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that the Interconnection Customer shall be entitled to, now or in the future, under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades, including the right to obtain cash reimbursements or transmission credits for transmission service that is not associated with the Small Generating Facility.

Article 6. Billing, Payment, Milestones, and Financial Security

6.1 Billing and Payment Procedures and Final Accounting

6.1.1 The Participating TO shall bill the Interconnection Customer for the design, engineering, construction, and procurement costs of Interconnection Facilities and Upgrades contemplated by this Agreement on a monthly basis, or as otherwise agreed by the Parties. The Interconnection Customer shall pay each bill within 30 calendar days of receipt, or as otherwise agreed to by the Parties. Notwithstanding the foregoing, any invoices between the ISO and another Party shall be submitted and paid in accordance with the ISO Tariff.

6.1.2 Within three months of completing the construction and installation of the Participating TO's Interconnection Facilities and/or Upgrades described in the Attachments to this Agreement, the Participating TO shall provide the Interconnection Customer with a final accounting report of any difference between (1) the Interconnection Customer's cost responsibility for the actual cost of such facilities or Upgrades, and (2) the Interconnection Customer's previous aggregate payments to the Participating TO for such facilities or Upgrades. If the Interconnection Customer's cost responsibility exceeds its previous aggregate payments, the Participating TO shall invoice the Interconnection Customer for the amount due and the Interconnection Customer shall make payment to the Participating TO within 30 calendar days. If the Interconnection Customer's previous aggregate payments exceed its cost responsibility under this Agreement, the Participating TO shall refund to the Interconnection Customer an amount equal to the difference within 30 calendar days of the final accounting report.

6.2 Milestones
The Parties shall agree on milestones for which each Party is responsible and list them in Attachment 4 of this Agreement. A Party's obligations under this provision may be extended by agreement. If a Party anticipates that it will be unable to meet a milestone for any reason other than a Force Majeure Event, as defined in article 7.5.1, it shall immediately notify the other Parties of the reason(s) for not meeting the milestone and (1) propose the earliest reasonable alternate date by which it can attain this and future milestones, and (2) request appropriate amendments to Attachment 4. The Parties affected by the failure to meet a milestone shall not unreasonably withhold agreement to such an amendment unless (1) they will suffer significant uncompensated economic or operational harm from the delay, (2) attainment of the same milestone has previously been delayed, or (3) they have reason to believe that the delay in meeting the milestone is intentional or unwarranted notwithstanding the circumstances explained by the Party proposing the amendment.

6.3 Financial Security Arrangements
At least 20 Business Days prior to the commencement of the design, procurement, installation, or construction of a discrete portion of the Participating TO's Interconnection Facilities and Upgrades, the Interconnection Customer shall provide the Transmission Provider, at the Interconnection Customer's option, a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to the Participating TO and is consistent with the Uniform Commercial Code of the jurisdiction where the Point of Interconnection is located. Such security for payment shall be in an amount sufficient to cover the costs for constructing, designing, procuring, and installing the applicable portion of the Participating TO's Interconnection Facilities and Upgrades and shall be reduced on a dollar-for-dollar basis for payments made to the Participating TO under this Agreement during its term. In addition:

6.3.1 The guarantee must be made by an entity that meets the creditworthiness requirements of the Participating TO, and contain terms and conditions that guarantee payment of any amount that may be due from the Interconnection Customer, up to an agreed-to maximum amount.

6.3.2 The letter of credit or surety bond must be issued by a financial institution or insurer reasonably acceptable to the Participating TO and must specify a reasonable expiration date.

Article 7. Assignment, Liability, Indemnity, Force Majeure, Consequential Damages, and Default

7.1 Assignment
This Agreement may be assigned by any Party upon 15 Business Days prior written notice and opportunity to object by the other Parties; provided that:

7.1.1 Any Party may assign this Agreement without the consent of the other Parties to any affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement, provided that the Interconnection Customer promptly notifies the Participating TO and the ISO of any such assignment;

7.1.2 The Interconnection Customer shall have the right to assign this Agreement, without the consent of the Participating TO or the ISO, for collateral security purposes to aid in providing financing for the Small Generating Facility, provided that the Interconnection Customer will promptly notify the Participating TO and the ISO of any such assignment.

7.1.3 Any attempted assignment that violates this article is void and ineffective. Assignment shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. An assignee is responsible for meeting the same financial, credit, and insurance obligations as the Interconnection Customer. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

7.2 Limitation of Liability
Each Party's liability to the other Parties for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall any Party be liable to the other Parties for any indirect, special, consequential, or punitive damages, except as authorized by this Agreement.

7.3 Indemnity

7.3.1 This provision protects each Party from liability incurred to third parties as a result of carrying out the provisions of this Agreement. Liability under this provision is exempt from the general limitations on liability found in article 7.2.

7.3.2 The Parties shall at all times indemnify, defend, and hold the other Parties harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from another Party's action or failure to meet its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

7.3.3 If an indemnified Party is entitled to indemnification under this article as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under this article, to assume the defense of such claim, such indemnified Party may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

7.3.4 If an indemnifying Party is obligated to indemnify and hold any indemnified Party harmless under this article, the amount owing to the indemnified Party shall be the amount of such indemnified Party's actual loss, net of any insurance or other recovery.

7.3.5 Promptly after receipt by an indemnified Party of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this article may apply, the indemnified Party shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

7.4 Consequential Damages

Other than as expressly provided for in this Agreement, no Party shall be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to another Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

7.5 Force Majeure

7.5.1 As used in this article, a Force Majeure Event shall mean "any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party’s control. A Force Majeure Event does not include an act of negligence or intentional wrongdoing by the Party claiming Force Majeure."

7.5.2 If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, the Party affected by the Force Majeure Event (Affected Party) shall promptly notify the other Parties, either in writing or via the telephone, of the existence of the Force Majeure Event. The notification must specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance. The Affected Party shall keep the other Parties informed on a continuing basis of developments relating to the Force Majeure Event until the event ends. The Affected Party will be entitled to suspend or modify its performance of obligations under this Agreement (other than the obligation to make payments) only to the extent that the effect of the Force Majeure Event cannot be mitigated by the use of Reasonable Efforts. The Affected Party will use Reasonable Efforts to resume its performance as soon as possible.

7.6 Default

7.6.1 No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of a Force Majeure Event as defined in this Agreement or the result of an act or omission of another Party. Upon a Default, the affected non-defaulting Party(ies) shall give written notice of such Default to the defaulting Party. Except as provided in article 7.6.2, the defaulting Party shall have 60 calendar days from receipt of the Default notice within which to cure such Default; provided however, if such Default is not capable of cure within 60 calendar days, the defaulting Party shall commence such cure within 20 calendar days after notice and continuously and diligently complete such cure within six months from receipt of the Default notice; and, if cured within such time, the Default specified in such notice shall cease to exist.

7.6.2 If a Default is not cured as provided in this article, or if a Default is not capable of being cured within the period provided for herein, the affected non-defaulting Party(ies) shall have the right to terminate this Agreement by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not such Party(ies) terminates this Agreement, to recover from the defaulting Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this article will survive termination of this Agreement.

Article 8. Insurance

8.1 The Interconnection Customer shall, at its own expense, maintain in force general liability insurance without any exclusion for liabilities related to the interconnection undertaken pursuant to this Agreement. The amount of such insurance shall be sufficient to insure against all reasonably foreseeable direct liabilities given the size and nature of the generating equipment being interconnected, the interconnection itself, and the characteristics of the system to which the interconnection is made. The Interconnection Customer shall obtain additional insurance only if necessary as a function of owning and operating a generating facility. Such insurance shall be obtained from an insurance provider authorized to do business in the State where the interconnection is located. Certification that such insurance is in effect shall be provided upon request of the Participating TO or ISO, except that the Interconnection Customer shall show proof of insurance to the Participating TO and ISO no later than ten Business Days prior to the anticipated Commercial Operation Date. If the Interconnection Customer is of sufficient credit-worthiness, it may propose to self-insure for such liabilities, and such a proposal shall not be unreasonably rejected.

8.2 The Participating TO agrees to maintain general liability insurance or self-insurance consistent with the Participating TO's commercial practice. Such insurance or self-insurance shall not exclude coverage for the Participating TO's liabilities undertaken pursuant to this Agreement.

8.3 The ISO agrees to maintain general liability insurance or self-insurance consistent with the ISO's commercial practice. Such insurance shall not exclude coverage for the ISO's liabilities undertaken pursuant to this Agreement.

8.4 The Parties further agree to notify each other whenever an accident or incident occurs resulting in any injuries or damages that are included within the scope of coverage of such insurance, whether or not such coverage is sought.

Article 9. Confidentiality

9.1 Confidential Information shall mean any confidential and/or proprietary information provided by one Party to another Party that is clearly marked or otherwise designated "Confidential." For purposes of this Agreement all design, operating specifications, and metering data provided by the Interconnection Customer shall be deemed Confidential Information regardless of whether it is clearly marked or otherwise designated as such.

9.2 Confidential Information does not include information previously in the public domain, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Parties and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce this Agreement. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under this Agreement, or to fulfill legal or regulatory requirements.

9.2.1 Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Parties as it employs to protect its own Confidential Information.

9.2.2 Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

9.3 Notwithstanding anything in this article to the contrary, and pursuant to 18 CFR § 1b.20, if FERC, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this Agreement, the Party shall provide the requested information to FERC, within the time provided for in the request for information. In providing the information to FERC, the Party may, consistent with 18 CFR § 388.112, request that the information be treated as confidential and non-public by FERC and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Parties to this Agreement prior to the release of the Confidential Information to FERC. The Party shall notify the other Parties to this Agreement when it is notified by FERC that a request to release Confidential Information has been received by FERC, at which time any of the Parties may respond before such information would be made public, pursuant to 18 CFR § 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

Article 10. Disputes

All disputes arising out of or in connection with this Agreement whereby relief is sought by or from ISO shall be settled in accordance with the provisions of Article 13 of the ISO Tariff, except that references to the ISO Tariff in such Article 13 of the ISO Tariff shall be read as reference to this Agreement. Disputes arising out of or in connection with this Agreement not subject to provisions of Article 13 of the ISO Tariff shall be resolved as follows:

10.1 The Parties agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this article.

10.2 In the event of a dispute, either Party shall provide the other Party with a written Notice of Dispute. Such Notice shall describe in detail the nature of the dispute.

10.3 If the dispute has not been resolved within two Business Days after receipt of the Notice, either Party may contact FERC's Dispute Resolution Service (DRS) for assistance in resolving the dispute.

10.4 The DRS will assist the Parties in either resolving their dispute or in selecting an appropriate dispute resolution venue (e.g., mediation, settlement judge, early neutral evaluation, or technical expert) to assist the Parties in resolving their dispute. DRS can be reached at 1-877-337-2237 or via the internet at http://www.ferc.gov/legal/adr.asp.

10.5 Each Party agrees to conduct all negotiations in good faith and will be responsible forone-half of any costs paid to neutral third-parties.

10.6 If neither Party elects to seek assistance from the DRS, or if the attempted dispute resolution fails, then either Party may exercise whatever rights and remedies it may have in equity or law consistent with the terms of this Agreement.

Article 11. Taxes

11.1 The Parties agree to follow all applicable tax laws and regulations, consistent with FERC policy and Internal Revenue Service requirements.

11.2 Each Party shall cooperate with the other Parties to maintain the other Parties' tax status. Nothing in this Agreement is intended to adversely affect the Participating TO's tax exempt status with respect to the issuance of bonds including, but not limited to, local furnishing bonds.

Article 12. Miscellaneous

12.1 Governing Law, Regulatory Authority, and Rules
The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of ___________________ (where the Point of Interconnection is located), without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

12.2 Amendment
The Parties may amend this Agreement by a written instrument duly executed by all of the Parties, or under article 12.12 of this Agreement.

12.3 No Third-Party Beneficiaries
This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

12.4 Waiver

12.4.1 The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

12.4.2 Any waiver at any time by any Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or Default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Participating TO. Any waiver of this Agreement shall, if requested, be provided in writing.

12.5 Entire Agreement
This Agreement, including all Attachments, constitutes the entire agreement among the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between or among the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, any Party's compliance with its obligations under this Agreement.

12.6 Multiple Counterparts
This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

12.7 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership among the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, another Party.

12.8 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

12.9 Security Arrangements

Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. FERC expects all transmission providers, market participants, and interconnection customers interconnected to electric systems to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and, eventually, best practice recommendations from the electric reliability authority. All public utilities are expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

12.10 Environmental Releases

Each Party shall notify the other Parties, first orally and then in writing, of the release of any hazardous substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Small Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Parties. The notifying Party shall (1) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than 24 hours after such Party becomes aware of the occurrence, and (2) promptly furnish to the other Parties copies of any publicly available reports filed with any governmental authorities addressing such events.

12.11 Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Parties for the performance of such subcontractor.

12.11.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Parties for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Participating TO or the ISO be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

12.11.2 The obligations under this article will not be limited in any way by any limitation of subcontractor’s insurance.

12.12 Reservation of Rights

The ISO and Participating TO shall each have the right to make a unilateral filing with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Agreement under any applicable provision of the Federal Power Act and FERC's rules and regulations; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations, except to the extent that the Parties otherwise mutually agree as provided herein.

Article 13. Notices

13.1 General

Unless otherwise provided in this Agreement, any written notice, demand, or request required or authorized in connection with this Agreement ("Notice") shall be deemed properly given if delivered in person, delivered by recognized national courier service, or sent by first class mail, postage prepaid, to the person specified below:

If to the Interconnection Customer:
Interconnection Customer: ____
Attention: __________________________________
Address: ____
City: ________________________________ State:______________ Zip:_______
Phone: ________________ Fax: _________________

If to the Participating TO:
Participating TO: ____
Attention: __________________________________
Address: ____
City: ________________________________ State:______________ Zip:_______
Phone: ________________ Fax: _________________

If to the ISO:
California Independent System Operator
Attention: ____
151 Blue Ravine Road
Folsom, CA 95630
Phone: 916-351-4400 Fax: _______________

13.2 Billing and Payment

Billings and payments shall be sent to the addresses set out below:

Interconnection Customer: ____
Attention: __________________________________
Address: ____
City: ________________________________ State:______________ Zip:_______

Participating TO: ____
Attention: __________________________________
Address: ____
City: ________________________________ State:______________ Zip:_______

13.3 Alternative Forms of Notice

Any notice or request required or permitted to be given by any Party to the other Parties and not required by this Agreement to be given in writing may be so given by telephone, facsimile or e-mail to the telephone numbers and e-mail addresses set out below:

If to the Interconnection Customer:

Interconnection Customer: ____
Attention: ____________________________________
Address: ____
City: __________________________________ State:_______________ Zip:________
Phone: _________________ Fax: __________________

If to the Participating TO:

Participating TO: ____
Attention: ____________________________________
Address: ____
City: __________________________________ State:_______________ Zip:________
Phone: _________________ Fax: __________________

If to the ISO:

California Independent System Operator
Attention:__________________________
151 Blue Ravine Road
Folsom, CA 95630
Phone: 916-351-4400 Fax: ____________

13.4 Designated Operating Representative

The Parties may also designate operating representatives to conduct the communications which may be necessary or convenient for the administration of this Agreement. This person will also serve as the point of contact with respect to operations and maintenance of the Party's facilities.

Interconnection Customer's Operating Representative:

Interconnection Customer: ____
Attention: ____________________________________
Address: ____
City: __________________________________ State:_______________ Zip:________
Phone: _________________ Fax: __________________

Participating TO's Operating Representative:

Participating TO: ____
Attention: ____________________________________
Address: ____
City: __________________________________ State:_______________ Zip:________
Phone: _________________ Fax: __________________

ISO's Operating Representative

California Independent System Operator
Attention: _________________
151 Blue Ravine Road
Folsom, CA 95630
Phone: 916-351-4400 Fax: ___________________

13.5 Changes to the Notice Information
Any Party may change this information by giving five Business Days written notice to the other Parties prior to the effective date of the change.

Article 14. Signatures

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective duly authorized representatives.

For the California Independent System Operator

Name: ____

Title: ____

Date: ______________________________

For the Participating TO

Name: ____

Title: ____

Date: ______________________________

For the Interconnection Customer

Name: ____

Title: ____

Date: ______________________________

Attachment 1

Glossary of Terms

Affected System – An electric system other than the ISO Controlled Grid that may be affected by the proposed interconnection, including the Participating TO's electric system that is not part of the ISO Controlled Grid.

Applicable Laws and Regulations – All duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Business Day – Monday through Friday, excluding federal holidays and the day after Thanksgiving Day.

Commercial Operation Date – The date on which a Small Generating Facility commenced generating electricity for sale as agreed upon by the Participating TO and the Interconnection Customer.

Control Area – An electrical system or systems bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection. A Control Area must be certified by the applicable reliability council.

Default – The failure of a breaching Party to cure its breach under this Agreement.

Distribution System – Those non-ISO-controlled transmission and distribution facilities owned by the Participating TO.

Distribution Upgrades – The additions, modifications, and upgrades to the Participating TO's Distribution System. Distribution Upgrades do not include Interconnection Facilities.

Good Utility Practice – Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be any one of a number of the optimum practices, methods, or acts to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority – Any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the Interconnection Customer, ISO, Participating TO, or any Affiliate thereof.

Interconnection Facilities – The Participating TO's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Small Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Small Generating Facility to the Participating TO's Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades or Network Upgrades.

Interconnection Handbook – A handbook, developed by the Participating TO and posted on the Participating TO's web site or otherwise made available by the Participating TO, describing technical and operational requirements for wholesale generators and loads connected to the Participating TO's

Transmission System, as such handbook may be modified or superseded from time to time. The Participating TO's standards contained in the Interconnection Handbook shall be deemed consistent with Good Utility Practice and applicable reliability standards.

Interconnection Request – A request, in accordance with the ISO Tariff, to interconnect a new Small Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Small Generating Facility that is interconnected with the ISO Controlled Grid.

ISO Controlled Grid – The system of transmission lines and associated facilities of the parties to the Transmission Control Agreement that have been placed under the ISO's Operational Control.

ISO Tariff – The ISO's tariff, as filed with FERC, and as amended or supplemented from time to time, or any successor tariff.

Material Modification – A modification that has a material impact on the cost or timing of any Interconnection Request or any other valid interconnection request with a later queue priority date.

Network Upgrades – Additions, modifications, and upgrades to the Participating TO's Transmission System required at or beyond the point at which the Small Generating Facility interconnects with the ISO Controlled Grid to accommodate the interconnection of the Small Generating Facility with the ISO Controlled Grid. Network Upgrades do not include Distribution Upgrades.

Operational Control – The rights of the ISO under the Transmission Control Agreement and the ISO Tariff to direct the parties to the Transmission Control Agreement how to operate their transmission lines and facilities and other electric plant affecting the reliability of those lines and facilities for the purpose of affording comparable non-discriminatory transmission access and meeting applicable reliability criteria.

Operating Requirements – Any operating and technical requirements that may be applicable due to the ISO, Western Electricity Coordinating Council, Control Area, or the Participating TO's requirements, including those set forth in this Agreement.

Party or Parties – The Participating TO, ISO, Interconnection Customer or the applicable combination of the above.

Point of Interconnection – The point where the Interconnection Facilities connect with the Participating TO's Transmission System.

Reasonable Efforts – With respect to an action required to be attempted or taken by a Party under this Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Small Generating Facility – The Interconnection Customer's device for the production of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Transmission Control Agreement – ISO FERC Electric Tariff No. 7.

Transmission System – The facilities owned and operated by the Participating TO and that have been placed under the ISO's Operational Control, which facilities form part of the ISO Controlled Grid.

Upgrades – The required additions and modifications to the Participating TO's Transmission System and Distribution System at or beyond the Point of Interconnection. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

Attachment 2

Description and Costs of the Small Generating Facility, Interconnection Facilities, and Metering Equipment

Equipment, including the Small Generating Facility, Interconnection Facilities, and metering equipment shall be itemized and identified as being owned by the Interconnection Customer or the Participating TO. The Participating TO will provide a best estimate itemized cost, including overheads, of its Interconnection Facilities and metering equipment, and a best estimate itemized cost of the annual operation and maintenance expenses associated with its Interconnection Facilities and metering equipment.

Attachment 3

One-line Diagram Depicting the Small Generating Facility, Interconnection Facilities, Metering Equipment, and Upgrades

Attachment 4

Milestones

In-Service Date:____________________

Critical milestones and responsibility as agreed to by the Parties:

	Milestone/Date	Responsible Party
(1)	______________________________	________________
(2)	______________________________	________________
(3)	______________________________	________________
(4)	______________________________	________________
(5)	______________________________	________________
(6)	______________________________	________________
(7)	______________________________	________________
(8)	______________________________	________________
(9)	______________________________	________________
(10)	______________________________	________________

Agreed to by:

For the ISO_______________________________________ Date________________

For the Participating TO_____________________________ Date________________

For the Interconnection Customer__________________________ Date________________

Attachment 5

Additional Operating Requirements for the ISO Controlled Grid and Affected Systems Needed to Support the Interconnection Customer's Needs

The Participating TO and the ISO shall also provide requirements that must be met by the Interconnection Customer prior to initiating parallel operation with the ISO Controlled Grid.

Attachment 6

Participating TO's Description of its Upgrades and Best Estimate of Upgrade Costs

The Participating TO shall describe Upgrades and provide an itemized best estimate of the cost, including overheads, of the Upgrades and annual operation and maintenance expenses associated with such Upgrades. The Participating TO shall functionalize Upgrade costs and annual expenses as either transmission or distribution related.

Attachment 7

INTERCONNECTION REQUIREMENTS FOR A WIND GENERATING PLANT

Attachment 7 sets forth requirements and provisions specific to a wind generating plant. All other requirements of this Agreement continue to apply to wind generating plant interconnections.

A. Technical Standards Applicable to a Wind Generating Plant

i. Low Voltage Ride-Through (LVRT) Capability

A wind generating plant shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the standard below. The LVRT standard provides for a transition period standard and a post-transition period standard.

Transition Period LVRT Standard

The transition period standard applies to wind generating plants that have either: (i) interconnection agreements signed and filed with FERC, filed with FERC in unexecuted form, or filed with FERC as non-conforming agreements between January 1, 2006 and December 31, 2006, with a scheduled in-service date no later than December 31, 2007, or (ii) wind generating turbines subject to a wind turbine procurement contract executed prior to December 31, 2005, for delivery through 2007.

6. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the Participating TO. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles at a voltage as low as 0.15 p.u., as measured at the high side of the wind generating plant step-up transformer (i.e. the transformer that steps the voltage up to the transmission interconnection voltage or "GSU"), after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system.
7. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU or to faults that would result in a voltage lower than 0.15 per unit on the high side of the GSU serving the facility.
8. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.
9. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator, etc.) within the wind generating plant or by a combination of generator performance and additional equipment.
10. Existing individual generator units that are, or have been, interconnected to the network at the same location at the effective date of the Attachment 7 LVRT Standard are exempt from meeting the Attachment 7 LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Attachment 7 LVRT Standard.

Post-transition Period LVRT Standard

All wind generating plants not covered by the transition period described above must meet the following requirements:

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the Participating TO. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the ISO Controlled Grid. A wind generating plant shall remain interconnected during such a fault on the ISO Controlled Grid for a voltage level as low as zero volts, as measured at the high voltage side of the wind GSU.
2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU.
3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.
4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator) within the wind generating plant or by a combination of generator performance and additional equipment.
5. Existing individual generator units that are, or have been, interconnected to the ISO Controlled Grid at the same location at the effective date of the Attachment 7 LVRT Standard are exempt from meeting the Attachment 7 LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Attachment 7 LVRT Standard.

ii. Power Factor Design Criteria (Reactive Power)

A wind generating plant shall operate within a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in this Agreement in order to maintain a specified voltage schedule, if the system impact study shows that such a requirement is necessary to ensure safety or reliability. The power factor range standard can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two, if agreed to by the Participating TO and ISO. The Interconnection Customer shall not disable power factor equipment while the wind plant is in operation. Wind plants shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the system impact study shows this to be required for system safety or reliability.

iii. Supervisory Control and Data Acquisition (SCADA) Capability

The wind plant shall provide SCADA capability to transmit data and receive instructions from the Participating TO and ISO to protect system reliability. The Participating TO and ISO and the wind plant Interconnection Customer shall determine what SCADA information is essential for the proposed wind plant, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area.

Attachment 8

Reliability Management System Agreement

RELIABILITY MANAGEMENT SYSTEM AGREEMENT
by and between
[TRANSMISSION OPERATOR]
and
[GENERATOR]

THIS RELIABILITY MANAGEMENT SYSTEM AGREEMENT (the "Agreement"), is entered into this ____ day of _____________, 2002, by and between ________________________ (the “Transmission Operator”) and ________________________ (the “Generator”).

WHEREAS, there is a need to maintain the reliability of the interconnected electric systems encompassed by the WSCC in a restructured and competitive electric utility industry;

WHEREAS, with the transition of the electric industry to a more competitive structure, it is desirable to have a uniform set of electric system operating rules within the Western Interconnection, applicable in a fair, comparable and non-discriminatory manner, with which all market participants comply; and

WHEREAS, the members of the WSCC, including the Transmission Operator, have determined that a contractual Reliability Management System provides a reasonable, currently available means of maintaining such reliability.

NOW, THEREFORE, in consideration of the mutual agreements contained herein, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Transmission Operator and the Generator agree as follows:

1. PURPOSE OF AGREEMENT

The purpose of this Agreement is to maintain the reliable operation of the Western Interconnection through the Generator’s commitment to comply with certain reliability standards.

2. DEFINITIONS

In addition to terms defined in the beginning of this Agreement and in the Recitals hereto, for purposes of this Agreement the following terms shall have the meanings set forth beside them below.

Control Area means an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the Western Interconnection.

FERC means the Federal Energy Regulatory Commission or a successor agency.

Member means any party to the WSCC Agreement.

Party means either the Generator or the Transmission Operator and

Parties means both of the Generator and the Transmission Operator.

Reliability Management System or **RMS** means the contractual reliability management program implemented through the WSCC Reliability Criteria Agreement, the WSCC RMS Agreement, this Agreement, and any similar contractual arrangement.

Western Interconnection means the area comprising those states and provinces, or portions thereof, in Western Canada, Northern Mexico and the Western United States in which Members of the WSCC operate synchronously connected transmission systems.

Working Day means Monday through Friday except for recognized legal holidays in the state in which any notice is received pursuant to Section 8.

WSCC means the Western Systems Coordinating Council or a successor entity.

WSCC Agreement means the Western Systems Coordinating Council Agreement dated March 20, 1967, as such may be amended from time to time.

WSCC Reliability Criteria Agreement means the Western Systems Coordinating Council Reliability Criteria Agreement dated June 18, 1999 among the WSCC and certain of its member transmission operators, as such may be amended from time to time.

WSCC RMS Agreement means an agreement between the WSCC and the Transmission Operator requiring the Transmission Operator to comply with the reliability criteria contained in the WSCC Reliability Criteria Agreement.

WSCC Staff means those employees of the WSCC, including personnel hired by the WSCC on a contract basis, designated as responsible for the administration of the RMS.

3. TERM AND TERMINATION

3.1 Term. This Agreement shall become effective [thirty (30) days after the date of issuance of a final FERC order accepting this Agreement for filing without requiring any changes to this Agreement unacceptable to either Party. Required changes to this Agreement shall be deemed unacceptable to a Party only if that Party provides notice to the other Party within fifteen (15) days of issuance of the applicable FERC order that such order is unacceptable].
[Note: if the interconnection agreement is not FERC jurisdictional, replace bracketed language with: [on the later of: (a) the date of execution; or (b) the effective date of the WSCC RMS Agreement.]]

3.2 Notice of Termination of WSCC RMS Agreement. The Transmission Operator shall give the Generator notice of any notice of termination of the WSCC RMS Agreement by the WSCC or by the Transmission Operator within fifteen (15) days of receipt by the WSCC or the Transmission Operator of such notice of termination.

3.3 Termination by the Generator. The Generator may terminate this Agreement as follows:
(a) following the termination of the WSCC RMS Agreement for any reason by the WSCC or by the Transmission Operator, provided such notice is provided within forty-five (45) days of the termination of the WSCC RMS Agreement;
(b) following the effective date of an amendment to the requirements of the WSCC Reliability Criteria Agreement that adversely affects the Generator, provided notice of such termination is given within forty-five (45) days of the date of issuance of a FERC order accepting such amendment for filing, provided further that the forty-five (45) day period within which notice of termination is required may be extended by the Generator for an additional forty-five (45) days if the Generator gives written notice to the Transmission Operator of such requested extension within the initial forty-five (45) day period; or
(c) for any reason on one year's written notice to the Transmission Operator and the WSCC.

3.4 Termination by the Transmission Operator. The Transmission Operator may terminate this Agreement on thirty (30) days' written notice following the termination of the WSCC RMS Agreement for any reason by the WSCC or by the Transmission Operator, provided such notice is provided within thirty (30) days of the termination of the WSCC RMS Agreement.

3.5 Mutual Agreement. This Agreement may be terminated at any time by the mutual agreement of the Transmission Operator and the Generator.

4. COMPLIANCE WITH AND AMENDMENT OF WSCC RELIABILITY CRITERIA

4.1 Compliance with Reliability Criteria. The Generator agrees to comply with the requirements of the WSCC Reliability Criteria Agreement, including the applicable WSCC reliability criteria contained in Section IV of Annex A thereof, and, in the event of failure to comply, agrees to be subject to the sanctions applicable to such failure. Each and all of the provisions of the WSCC Reliability Criteria Agreement are hereby incorporated by reference into this Agreement as though set forth fully herein, and the Generator shall for all purposes be considered a Participant, and shall be entitled to all of the rights and privileges and be subject to all of the obligations of a Participant, under and in connection with the WSCC Reliability Criteria Agreement, including but not limited to the rights, privileges and obligations set forth in Sections 5, 6 and 10 of the WSCC Reliability Criteria Agreement.

4.2 Modifications to WSCC Reliability Criteria Agreement. The Transmission Operator shall notify the Generator within fifteen (15) days of the receipt of notice from the WSCC of the initiation of any WSCC process to modify the WSCC Reliability Criteria Agreement. The WSCC RMS Agreement specifies that such process shall comply with the procedures, rules, and regulations then applicable to the WSCC for modifications to reliability criteria.

4.3 Notice of Modifications to WSCC Reliability Criteria Agreement. If, following the process specified in Section 4.2, any modification to the WSCC Reliability Criteria Agreement is to take effect, the Transmission Operator shall provide notice to the Generator at least forty-five (45) days before such modification is scheduled to take effect.

4.4 Effective Date. Any modification to the WSCC Reliability Criteria Agreement shall take effect on the date specified by FERC in an order accepting such modification for filing.

4.5 Transfer of Control or Sale of Generation Facilities. In any sale or transfer of control of any generation facilities subject to this Agreement, the Generator shall as a condition of such sale or transfer require the acquiring party or transferee with respect to the transferred facilities either to assume the obligations of the Generator with respect to this Agreement or to enter into an agreement with the Control Area Operator in substantially the form of this Agreement.

5. SANCTIONS

5.1 Payment of Monetary Sanctions. The Generator shall be responsible for payment directly to the WSCC of any monetary sanction assessed against the Generator pursuant to this Agreement and the WSCC Reliability Criteria Agreement. Any such payment shall be made pursuant to the procedures specified in the WSCC Reliability Criteria Agreement.

5.2 Publication. The Generator consents to the release by the WSCC of information related to the Generator's compliance with this Agreement only in accordance with the WSCC Reliability Criteria Agreement.

5.3 Reserved Rights. Nothing in the RMS or the WSCC Reliability Criteria Agreement shall affect the right of the Transmission Operator, subject to any necessary regulatory approval, to take such other measures to maintain reliability, including disconnection, which the Transmission Operator may otherwise be entitled to take.

6. THIRD PARTIES

Except for the rights and obligations between the WSCC and Generator specified in Sections 4 and 5, this Agreement creates contractual rights and obligations solely between the Parties. Nothing in this Agreement shall create, as between the Parties or with respect to the WSCC: (1) any obligation or liability whatsoever (other than as expressly provided in this Agreement), or (2) any duty or standard of care whatsoever. In addition, nothing in this Agreement shall create any duty, liability, or standard of care whatsoever as to any other party. Except for the rights, as a third-party beneficiary with respect to Sections 4 and 5, of the WSCC against Generator, no third party shall have any rights whatsoever with respect to enforcement of any provision of this Agreement. Transmission Operator and Generator expressly intend that the WSCC is a third-party beneficiary to this Agreement, and the WSCC shall have the right to seek to enforce against Generator any provisions of Sections 4 and 5, provided that specific performance shall be the sole remedy available to the WSCC pursuant to this Agreement, and Generator shall not be liable to the WSCC pursuant to this Agreement for damages of any kind whatsoever (other than the payment of sanctions to the WSCC, if so construed), whether direct, compensatory, special, indirect, consequential, or punitive.

7. REGULATORY APPROVALS

This Agreement shall be filed with FERC by the Transmission Operator under Section 205 of the Federal Power Act. In such filing, the Transmission Operator shall request that FERC accept this Agreement for filing without modification to become effective on the day after the date of a FERC order accepting this Agreement for filing. [This section shall be omitted for agreements not subject to FERC jurisdiction.]

8. NOTICES

Any notice, demand or request required or authorized by this Agreement to be given in writing to a Party shall be delivered by hand, courier or overnight delivery service, mailed by certified mail (return receipt requested) postage prepaid, faxed, or delivered by mutually agreed electronic means to such Party at the following address:

_______: ________________________________
____
____
____
Fax: ______________

_______: ________________________________
____
____
____
Fax: ______________

The designation of such person and/or address may be changed at any time by either Party upon receipt by the other of written notice. Such a notice served by mail shall be effective upon receipt. Notice transmitted by facsimile shall be effective upon receipt if received prior to 5:00 p.m. on a Working Day, and if not received prior to 5:00 p.m. on a Working Day, receipt shall be effective on the next Working Day.

9. APPLICABILITY

This Agreement (including all appendices hereto and, by reference, the WSCC Reliability Criteria Agreement) constitutes the entire understanding between the Parties hereto with respect to the subject matter hereof, supersedes any and all previous understandings between the Parties with respect to the subject matter hereof, and binds and inures to the benefit of the Parties and their successors.

10. AMENDMENT

No amendment of all or any part of this Agreement shall be valid unless it is reduced to writing and signed by both Parties hereto. The terms and conditions herein specified shall remain in effect throughout the term and shall not be subject to change through application to the FERC or other governmental body or authority, absent the agreement of the Parties.

11. INTERPRETATION

Interpretation and performance of this Agreement shall be in accordance with, and shall be controlled by, the laws of the State of ______________ but without giving effect to the provisions thereof relating to conflicts of law. Article and section headings are for convenience only and shall not affect the interpretation of this Agreement. References to articles, sections and appendices are, unless the context otherwise requires, references to articles, sections and appendices of this Agreement.

12. PROHIBITION ON ASSIGNMENT

This Agreement may not be assigned by either Party without the consent of the other Party, which consent shall not be unreasonably withheld; provided that the Generator may without the consent of the WSCC assign the obligations of the Generator pursuant to this Agreement to a transferee with respect to any obligations assumed by the transferee by virtue of Section 4.5 of this Agreement.

13. SEVERABILITY

If one or more provisions herein shall be invalid, illegal or unenforceable in any respect, it shall be given effect to the extent permitted by applicable law, and such invalidity, illegality or unenforceability shall not affect the validity of the other provisions of this Agreement.

14. COUNTERPARTS

This Agreement may be executed in counterparts and each shall have the same force and effect as an original.

IN WITNESS WHEREOF, the Transmission Operator and the Generator have each caused this Reliability Management System Agreement to be executed by their respective duly authorized officers as of the date first above written.

By: ____

Name:____

Title:____

By: ____

Name:____

Title:____

ISO TARIFF APPENDIX EE

Transmission Expansion and Planning Process

PART A. Transmission Expansion and Planning Process

24.1 Determination of Need for Proposed Transmission Projects.

A Participating TO, Market Participant, the CAISO, the CPUC, or CEC may propose a transmission system addition or upgrade, and the CAISO will determine, in accordance with this Section 24.1 of this Appendix EE, whether the transmission addition or upgrade is needed, where it will (1) promote economic efficiency, (2) maintain System Reliability, (3) satisfy the requirements of a Location Constrained Resource Interconnection Facility, or (4) maintain the simultaneous feasibility of allocated Long-Term CRRs. CAISO management can determine the need for transmission additions or upgrades with an estimated capital investment of less than $50 million without CAISO Governing Board approval. The determination of need by CAISO management for transmission additions or upgrades with an estimated capital cost of $50 million or more must be approved by the CAISO Governing Board.

24.1.1 Economically Driven Projects.

The determination that a transmission addition or upgrade is needed to promote economic efficiency shall be made in accordance with this Section 24 of this Appendix EE and the Business Practice Manual in any of the following ways:

(a) Where a Project Sponsor proposes a Merchant Transmission Facility and demonstrates to the CAISO the financial capability to pay the full cost of construction and operation of the Merchant Transmission Facility. The Merchant Transmission Facility must mitigate all operational concerns identified under Section 24.5 of this Appendix EE to the satisfaction of the CAISO, in consultation with the Participating TO(s) in whose PTO Service Territory the Merchant Transmission Facility will be located, and ensure the continuing feasibility of allocated Long Term CRRs over the length of their terms. To ensure that the Project Sponsor is financially able to pay the construction and operating costs of the Merchant Transmission Facility, and where the Participating TO is not the Project Sponsor and is to construct the Merchant Transmission Facility under Section 24.1 of this Appendix EE, the CAISO in cooperation with the Participating TO may require (1) a demonstration of creditworthiness (e.g., an appropriate credit rating), or (2) sufficient security in the form of an unconditional and irrevocable letter of credit or other similar security sufficient to meet its responsibilities and obligations for the full costs of the transmission addition or upgrade.

(b) Where a Project Sponsor, the CPUC, or CEC proposes a transmission addition or upgrade during the Request Window and the project is approved by the CAISO Governing Board, or a Participating TO proposes a transmission upgrade or addition to an existing transmission facility with an estimated capital cost of less than $50 million in accordance with the Study Plan and the project is included in the CAISO annual Transmission Plan. In determining whether to approve the project, the CAISO Governing Board or CAISO management, as applicable, shall consider the degree to which, if any, the benefits of the project outweigh the costs, in accordance with the procedures and using the technical studies set forth in the Business Practice Manual. The benefits of the project may include, but need not be limited to, a calculation of any reduction in production costs, Congestion costs, Transmission Losses, capacity or other electric supply costs resulting from improved access to cost-efficient resources, and environmental costs. The cost of the project must consider any estimated costs identified under Section 24.1.4 of this Appendix EE to maintain the simultaneous feasibility of allocated Long Term CRRs for the length of their term. The CAISO management or CAISO Governing Board, as appropriate, in determining whether to approve or recommend the project, shall also consider the comparative costs and benefits of viable alternatives to the proposed transmission upgrade or addition, including (1) other transmission additions or upgrades, or the effects of other transmission additions or upgrades proposed under Section 24.2 of this Appendix EE during the Transmission Planning Process cycle, (2) Demand-side management, (3) acceleration or expansion of any transmission upgrade or addition already approved by the CAISO Governing Board or included in any CAISO annual Transmission Plan, or (4) Generation.

(c) Where the CAISO proposes a transmission addition or upgrade during the CAISO's Transmission Planning Process and the project is approved by the CAISO Governing Board or included in the CAISO annual Transmission Plan, as appropriate. In determining whether to approve the CAISO proposed transmission addition or upgrade, the CAISO Governing Board and CAISO management shall apply the same factors set forth in Section 24.1.1(b) of this Appendix EE. If approved by the CAISO Governing Board or CAISO management, as appropriate, the CAISO will designate one or more of the Participating TOs with PTO Service Territories in which the terminus of the transmission addition or upgrade will be located to act as Project Sponsor.

Where two or more Participating TOs are designated as Project Sponsors, such CAISO designation will include the proportionate responsibility between or among Participating TOs to own, construct, and finance the transmission addition or upgrade. If a Participating TO refuses to act as a Project Sponsor under this Section 24.1.1(c) of this Appendix EE, the CAISO will first request other designated Participating TO(s) to assume the remainder or greater proportionate responsibility, and if no other Participating TO had been designated or is willing to increase its proportionate responsibility, the CAISO may solicit bids to finance, own, and construct the transmission addition or upgrade.

24.1.1.1 Information Requirements for Economic Transmission Projects.

The Project Sponsor and relevant Participating TOs shall provide any necessary assistance and information to the CAISO to enable the CAISO to determine that a transmission upgrade or addition is needed to promote economic efficiency, and will perform all studies required by the adopted Study Plan in a manner consistent with the Business Practice Manual. A Project Sponsor of an economically driven transmission upgrade or addition to promote economic efficiency under Section 24.1.1 of this Appendix EE shall also provide in its proposal a statement whether the proposed upgrade or addition will be a Merchant Transmission Facility.

24.1.2 Reliability Driven Projects.

The CAISO in coordination with each Participating TO with a PTO Service Territory will, consistent with the procedures set forth in the Business Practice Manual, identify the need for any transmission additions or upgrades required to ensure System Reliability consistent with all Applicable Reliability Criteria and CAISO Planning Standards. In making this determination, the CAISO, in coordination with each Participating TO with a PTO Service Territory and other Market Participants, shall consider lower cost alternatives to the construction of transmission additions or upgrades, such as acceleration or expansion of existing projects, Demand-side management, Remedial Action Schemes, appropriate Generation, interruptible Loads or reactive support. The CAISO shall direct each Participating TO with a PTO Service Area, as a registered Transmission Planner with NERC, to perform the necessary studies, based on the Unified Planning Assumptions and Study Plan as set forth in Section 24.2.3 of this Appendix EE and in accordance with the Business Practice Manual, to determine the facilities needed to meet all Applicable Reliability Criteria and CAISO Planning Standards. The Participating TO with a PTO Service Area shall provide the CAISO and other Market Participants with all information relating to the studies performed under this Section, subject to any limitation provided in Section 20.2 of the CAISO Tariff. The CAISO shall be free to propose any transmission upgrades or additions it deems necessary to ensure System Reliability consistent with Applicable Reliability Criteria and CAISO Planning Standards. The Participating TO with a PTO Service Territory in which the transmission upgrade or addition deemed needed under this Section 24.1.2 of this Appendix EE is to be located shall be the Project Sponsor, with the responsibility to construct, own and finance, and maintain such transmission upgrade or addition.

24.1.3. Location Constrained Resource Interconnection Facility Projects.

The CAISO, CPUC, CEC, a Participating TO or any other Market Participant may propose a transmission addition as a Location Constrained Resource Interconnection Facility. A proposal shall include the following information, to the extent available:

(a) Information showing that the proposal meets the requirements of Section 24.1.3.1 of this Appendix EE; and

(b) A description of the proposed facility, including the following information:

(1) Transmission studies demonstrating that the proposed facility satisfies Applicable Reliability Criteria and CAISO Planning Standards;

(2) Identification of the most feasible and cost-effective alternative transmission additions, which may include network upgrades, that would accomplish the objective of the proposal;

(3) A planning level cost estimate for the proposed facility and all proposed alternatives;

(4) An assessment of the potential for the future connection of further transmission additions that would convert the proposed facility into a network transmission facility, including conceptual plans;

(5) The estimated in-service date of the proposed facility; and

(6) A conceptual plan for connecting potential LCRIGs, if known, to the proposed facility.

24.1.3.1 Criteria for Qualification as a Location Constrained Resource Interconnection Facility.

(a) The CAISO shall conditionally approve a facility as a Location Constrained Resource Interconnection Facility if it determines that the facility is needed and all of the following requirements are met:

(1) The facility is to be constructed for the primary purpose of connecting to the CAISO Controlled Grid two or more Location Constrained Resource Interconnection Generators in an Energy Resource Area, and at least one of the Location Constrained Resource Interconnection Generators is to be owned by an entity(ies) that is not an Affiliate of the owner(s) of another Location Constrained Resource Interconnection Generator in that Energy Resource Area;

(2) The facility will be a High Voltage Transmission Facility;

(3) At the time of its in-service date, the facility will not be a network facility and would not be eligible for inclusion in a Participating TO's TRR other than as an LCRIF; and

(4) The facility meets Applicable Reliability Criteria and CAISO Planning Standards.

(b) The proponent of a facility that has been determined by the CAISO to meet the requirements of Section 24.1.3.1(a) of this Appendix EE shall provide the CAISO with information concerning the requirements of this subsection not less than ninety (90) days prior to the planned commencement of construction, and the facility shall qualify as a Location Constrained Resource Interconnection Facility if the CAISO determines that both of the following requirements are met:

(1) The addition of the capital cost of the facility to the High Voltage TRR of a Participating TO will not cause the aggregate of the net investment of all LCRIFs (net of the amount of the capital costs of LCRIFs to be recovered from LCRIGs pursuant to Section 26.6) included in the High Voltage TRRs of all Participating TOs to exceed fifteen percent (15%) of the aggregate of the net investment of all Participating TOs in all High Voltage Transmission Facilities reflected in their High Voltage TRRs (net of the amount of the capital costs of LCRIFs to be recovered from LCRIGs pursuant to Section 26.6) in effect at the time of the CAISO's evaluation of the facility); and

(2) Existing or prospective owners of LCRIGs have demonstrated their interest in connecting LCRIGs to the facility consistent with the requirements of Section 24.1.3.2 of this Appendix EE, which establishes the necessary demonstration of interest.

(c) Each Participating TO shall report annually to the CAISO the amount of its net investment in LCRIFs (net of the amount of the capital costs of LCRIFs to be recovered from LCRIGs pursuant to Section 26.6), the portion of the capital costs of LCRIFs credited to its TRR, and its net investment in High Voltage Transmission Facilities reflected in its High Voltage TRR (net of the amount of the capital costs of LCRIFs to be recovered from LCRIGs pursuant to Section 26.6), to enable the CAISO to make the determination required under Section 24.1.3.1(b)(1) of this Appendix EE.

24.1.3.2 Demonstration of Interest in a Location Constrained Resource Interconnection Facility.

A proponent of an LCRIF must demonstrate interest in the LCRIF equal to sixty percent (60%) or more of the capacity of the facility in the following manner:

(a) the proponent's demonstration must include a showing that LCRIGs that would connect to the facility and would have a combined capacity equal to at least twenty-five percent (25%) of the capacity of the facility have executed Large Generator Interconnection Agreements or Small Generator Interconnection Agreements, as applicable; and

(b) to the extent the showing pursuant to Section 24.1.3.2(a) of Appendix EE does not constitute sixty percent (60%) of the capacity of the LCRIF, the proponent's demonstration of the remainder of the required minimum level of interest must include a showing that additional LCRIGs:

(1) have obtained control over their site or paid a deposit to the CAISO in the amount of $250,000, which deposit shall be refundable if the LCRIF is not approved or is withdrawn by the proponent; and

(2) have demonstrated interest in the LCRIF by one of the following methods:

(i) executing a firm power sales agreement for the output of the LCRIG for a period of five years or longer; or

(ii) being in the CAISO's interconnection queue and paying a deposit to the CAISO equal to the sum of the minimum deposits required of an Interconnection Customer for all studies performed in accordance with the Large Generator Interconnection Procedures or Small Generator Interconnection Procedures, as applicable to the LCRIG, less the amount of any deposits actually paid by the LCRIG for such studies. The deposit shall be credited toward such study costs. If the LCRIF is not approved or is withdrawn by the proponent, any deposit paid under this provision shall be refundable to the extent it exceeds costs incurred by the CAISO for such studies; or

(iii) paying a deposit to the CAISO equal to five percent (5%) of the LCRIG's pro rata share of the capital costs of a proposed LCRIF. The deposit shall be credited toward study costs performed in connection with the Large Generator Interconnection Procedures or Small Generator Interconnection Procedures, whichever is applicable. If the LCRIF is not approved or is withdrawn by the proponent, any deposit paid under this provision shall be refundable to the extent it exceeds the costs incurred by the CAISO for such studies.

24.1.3.3 Coordination With Transmission Additions Proposed by Non-Participating TOs.

In the event that a facility proposed as an LCRIF would connect to LCRIGs in an Energy Resource Area that would also be connected by a transmission facility that is in existence or is proposed to be constructed by an entity that is not a Participating TO and that does not intend to place that facility under the Operational Control of the CAISO, the CAISO shall coordinate with the entity owning or proposing that transmission facility through any regional planning process to avoid the unnecessary construction of duplicative transmission additions to connect the same LCRIGs to the CAISO Controlled Grid.

24.1.3.4 Evaluation of Location Constrained Resource Interconnection Facilities.

In evaluating whether a proposed LCRIF that meets the requirements of Section 24.1.3.1 of this Appendix EE is needed, and for purposes of ranking and prioritizing LCRIF projects, the CAISO will consider the following factors:

(a) Whether, and if so, the extent to which, the facility meets or exceeds applicable CAISO Planning Standards, including standards that are Applicable Reliability Criteria.

(b) Whether, and if so, the extent to which, the facility has the capability and flexibility both to interconnect potential LCRIGs in the Energy Resource Area and to be converted in the future to a network transmission facility.

(c) Whether the projected cost of the facility is reasonable in light of its projected benefits, in comparison to the costs and benefits of other alternatives for connecting Generating Units or otherwise meeting a need identified in the CAISO Transmission Planning Process, including alternatives that are not LCRIFs. In making this determination, the CAISO shall take into account, among other factors, the following:

(1) The potential capacity of LCRIGs and the potential Energy that could be produced by LCRIGs in each Energy Resource Area;

(2) The capacity of LCRIGs in the CAISO's interconnection queue for each Energy Resource Area;

(3) The projected cost and in-service date of the facility in comparison with other transmission facilities that could connect LCRIGs to the CAISO Controlled Grid;

(4) Whether, and if so, the extent to which, the facility would provide additional reliability or economic benefits to the CAISO Controlled Grid; and

(5) Whether, and if so, the extent to which, the facility would create a risk of stranded costs.

24.1.4 Maintaining the Feasibility of Allocated Long Term CRRs.

The CAISO is obligated to ensure the continuing feasibility of Long Term CRRs that are allocated by the CAISO over the length of their terms. In furtherance of this requirement the CAISO shall, as part of its annual Transmission Planning Process cycle, test and evaluate the simultaneous feasibility of allocated Long Term CRRs, including, but not limited to, when acting on the following types of projects: (a) planned or proposed transmission projects; (b) Generating Unit or transmission retirements; (c) Generating Unit interconnections; and (d) the interconnection of new Load. Pursuant to such evaluations the CAISO shall identify the need for any transmission additions or upgrades required to ensure the continuing feasibility of allocated Long Term CRRs over the length of their terms. In assessing the need for transmission additions or upgrades to maintain the feasibility of allocated Long Term CRRs, the CAISO, in coordination with the Participating TOs and other Market Participants, shall consider lower cost alternatives to the construction of transmission additions or upgrades, such as acceleration or expansion of existing projects; Demand-side management; Remedial Action Schemes; constrained-on Generation; interruptible Loads; reactive support; or in cases where the infeasible Long Term CRRs involve a small magnitude of megawatts, ensuring against the risk of any potential revenue shortfall using the CRR Balancing Account and uplift mechanism in Section 11.2.4 of the CAISO Tariff. As part of the CAISO's Transmission Planning Process, the Participating TOs and Market Participants shall provide the necessary assistance and information to the CAISO to allow it to assess and identify transmission additions or upgrades that may be necessary under Section 24.1.4 of this Appendix EE. To the extent a transmission upgrade or addition is deemed needed to maintain the feasibility of allocated Long Term CRRs in accordance with this Section and included in the CAISO's annual Transmission Plan, the CAISO will designate the Participating TO(s) with a PTO Service Territory in which the transmission upgrade or addition is to be located as the Project Sponsor(s), responsible to construct, own and/or finance, and maintain such transmission upgrade or addition.

24.2 Transmission Planning and Coordination.

The CAISO shall perform the CAISO's Transmission Planning Process on an annual cycle in accordance with the terms of this CAISO Tariff, the Transmission Control Agreement, and the Business Practice Manual. The Transmission Planning Process shall, at a minimum:

(a) Coordinate and consolidate the transmission needs of the CAISO Control Area into a single plan, which will be assessed on the basis of maintaining the reliability of the CAISO Controlled Grid in accordance with Applicable Reliability Criteria and CAISO Planning Standards, in a manner that promotes the economic efficiency of the CAISO Controlled Grid and considers federal and state environmental and other policies affecting the provision of Energy.

(b) Reflect a planning horizon covering a minimum of ten (10) years that considers transmission enhancements and expansions, Demand Forecasts, Demand-side management, and capacity forecasts relating to generation technology type, additions and retirements, and such other factors as the CAISO determines are relevant.

(c) Seek to avoid unnecessary duplication of facilities and ensure the simultaneous feasibility of the CAISO Transmission Plan and the transmission plans of interconnected Control Areas, and otherwise coordinate with regional and sub-regional transmission planning processes and entities in accordance with Section 24.8 of this Appendix EE.

(d) Identify existing and projected limitations of the CAISO Controlled Grid's physical, economic or operational capability or performance and identify transmission upgrades and additions, including alternatives thereto, deemed needed in accordance with Section 24.1 of this Appendix EE to address the existing and projected limitations.

(e) Account for any effects on the CAISO Controlled Grid of the interconnection of Generating Units on the Distribution System under the Wholesale Distribution Access Tariffs of the Participating TOs, including an assessment of the deliverability of such Generating Units on a basis comparable to the Deliverability Assessment performed under Appendix U.

24.2.1 CAISO Planning Standards Committee.

The CAISO shall maintain a Planning Standards Committee, which shall be open to participation by all Market Participants, electric utility regulatory agencies within California, and other interested parties, to review, provide advice on, and propose modifications to CAISO Planning Standards for consideration by CAISO management and the CAISO Governing Board. The Planning Standards Committee shall meet, at a minimum, on an annual basis prior to publication of the draft Unified Planning Assumptions and Study Plan under Section 24.2.3 of this Appendix EE; however, additional meetings, web conferences, teleconferences may be scheduled as needed. Meetings of the Planning Standards Committee shall be noticed by Market Notice and such notice shall be posted to the CAISO Website. Teleconference capability will be made available for all meetings of the Planning Standards Committee. The CAISO Vice President of Planning and Infrastructure Development or his or her designee shall serve as chair of the Planning Standards Committee. All materials addressed at or relating to such meetings, including agendas, presentations, background papers, party comments, and minutes shall be posted to the CAISO Website. The chair of the Planning Standards Committee shall seek approval by the CAISO Governing Board of any modifications to the CAISO Planning Standards, as those CAISO Planning Standards exist as of the effective date of Section 24.2 of this Appendix EE, and must include in the report to the CAISO Governing Board a summary of the positions of parties with respect to the proposed modifications to the CAISO Planning Standards and the ground(s) for rejecting modifications, if any, proposed by Market Participants or other interested parties.

24.2.2 Request Window.

Market Participants may propose Economic Planning Studies and transmission upgrades or additions for inclusion in the annual Transmission Plan during a Request Window. The duration of the Request Window will be set forth in the Business Practice Manual and will occur in the year prior to the year in which the Transmission Plan is prepared. Proposals for Economic Planning Studies and transmission upgrades or additions must use the forms and satisfy the information and technical requirements set forth in the Business Practice Manual. Proposals for transmission additions or upgrades must be within or connect to the CAISO Control Area or CAISO Controlled Grid and proposals for Economic Planning Studies must be intended to promote competition or economic efficiency of serving Load within the CAISO Control Area, but may relate to Congestion relief or transmission capacity expansion outside the CAISO Control Area. The following proposals will only be considered in the Transmission Plan if proposed during the Request Window:

(a) Economic transmission upgrades or additions proposed under Section 24.1.1 of this Appendix EE, except for projects costing less than $50 million that are identified through Participating TO proposals provided pursuant to the Study Plan;

(b) Location Constrained Resource Interconnection Facilities under Section 24.1.3 of this Appendix EE not identified by the CAISO as part of Interconnection Studies performed under the LGIP set forth in Appendix U;

(c) Demand response programs that are proposed for inclusion in the base case or assumptions for the Transmission Plan or as alternatives to transmission additions or upgrades;

(d) Generation projects that are proposed as solutions to Congestion identified in previously published Economic Planning Studies, for inclusion in long-term planning studies, or as alternatives to transmission additions or upgrades; and

(e) Requests for Economic Planning Studies.

24.2.2.1 CAISO Assessment of Request Window Proposals.

Following the submittal of a proposal for a transmission addition or upgrade, Demand response program, or generation project during the Request Window in accordance with Section 24.2.2 of this Appendix EE, the CAISO will determine whether the proposal will be included in the Unified Planning Assumptions or Study Plan as appropriate. A proposal can only be included in the Unified Planning Assumptions or Study Plan upon the determination by the CAISO that:

(a) the proposal satisfies the information requirements for the particular type of project submitted as set forth in templates included in the Business Practice Manual;

(b) the proposal is not functionally duplicative of transmission upgrades or additions that have previously been approved by the CAISO; and

(c) the proposal, if a sub-regional or regional project that affects other interconnected Control Areas, has been reviewed by the appropriate sub-regional or regional planning entity, is not inconsistent with such sub-regional or regional planning entity's preferred solution or project, and has been determined to be appropriate for inclusion in the CAISO Study Plan, rather than, or in addition to, being included in or deferred to the planning process of the sub-regional or regional planning entity.

In accordance with the schedule and procedures set forth in the Business Practice Manual, the CAISO will notify the Market Participant submitting the proposal of any deficiencies in the proposal and provide the Market Participant an opportunity to correct the deficiencies. The failure to correct the deficiency precludes the proposal from inclusion in the Study Plan. The CAISO will notify the Market Participant submitting the proposal whether or not the proposal will be included in the Study Plan.

24.2.2.2 CAISO Assessment of Requests for Economic Planning Studies Received During the Request Window.

Following the submittal of a request for an Economic Planning Study during the Request Window in accordance with Section 24.2.2 of this Appendix EE, the CAISO will determine whether the request shall be designated as a High Priority Economic Planning Study for inclusion in the Unified Planning Assumptions and Study Plan. In making the determination, the CAISO will consider:

(a) Whether the requested Economic Planning Study seeks to address Congestion identified by the CAISO in the Congestion Data Summary published for the applicable Transmission Planning Process cycle and the magnitude, duration, and frequency of that Congestion;

(b) Whether the requested Economic Planning Study addresses delivery of Generation from Location Constrained Resource Interconnection Generators or network transmission facilities intended to access Generation from an Energy Resource Area (ERA) or similar resource area assigned a high priority by the CPUC or CEC;

(c) Whether the requested Economic Planning Study is intended to address Local Capacity Area Resource requirements; or

(d) Whether resource and Demand information indicates that Congestion described in the Economic Planning Study request is projected to increase over the planning horizon used in the Transmission Planning Process and the magnitude of that Congestion.

In accordance with the schedule and procedures set forth in the Business Practice Manual, the CAISO will post to the CAISO Website the list of selected High Priority Economic Planning Studies to be included in the draft Unified Planning Assumptions and Study Plan. The CAISO may assess requests for Economic Planning Studies individually or in combination where such requests may have common or complementary effects on the CAISO Controlled Grid. The CAISO will perform a maximum of five High Priority Economic Planning Studies; however, the CAISO retains discretion to perform greater than five High Priority Economic Planning Studies should stakeholder requests or patterns of Congestion or anticipated Congestion so warrant.

24.2.3 Additional Planning Information.

24.2.3.1 Information Provided by Participating TOs.

In addition to any information that must be provided to the CAISO under the NERC Reliability Standards for Modeling, Data and Analysis (NERC MOD Standards), Participating TOs shall provide the CAISO on an annual or periodic basis in accordance with the schedule and procedures and in the form required by the Business Practice Manual any information and data reasonably required by the CAISO to perform the Transmission Planning Process, including, but not limited to: (1) modeling data for power flow, including reactive power, short-circuit and stability analysis; (2) a description of the total Demand to be served from each substation, including a description of any Energy efficiency programs reflected in the total Demand; (3) the amount of any interruptible Loads included in the total Demand (including conditions under which an interruption can be implemented and any limitations on the duration and frequency of interruptions); (4), a description of Generating Units to be interconnected to the Distribution System of the Participating TO, including generation type and anticipated Commercial Operation Date; (5) detailed power system models of their transmission systems that reflect transmission system changes, including equipment replacement not requiring approval by the CAISO; (6) Distribution System modifications; (7) transmission network information, including line ratings, line length, conductor sizes and lengths, substation equipment ratings, circuits on common towers and with common rights-of-ways and cross-overs, special protection schemes, and protection setting information; and (8) Contingency lists.

24.2.3.2 Information Provided by Participating Generators.

In addition to any information that must be provided to the CAISO under the NERC Reliability Standards for Modeling, Data and Analysis (NERC MOD Standards), Participating Generators shall provide the CAISO on an annual or periodic basis in accordance with the schedule, procedures and in the form required by the Business Practice Manual any information and data reasonably required by the CAISO to perform the Transmission Planning Process, including, but not limited to (1) modeling data for short-circuit and stability analysis and (2) data, such as term, and status of any environmental or land use permits or agreements the expiration of which may affect that the operation of the Generating Unit.

24.2.3.3 Information Requested from Load Serving Entities.

In addition to any information that must be provided to the CAISO under the NERC Reliability Standards for Modeling, Data and Analysis (NERC MOD Standards), the CAISO shall solicit from Load Serving Entities through their Scheduling Coordinators information required by, or anticipated to be useful to, the CAISO in its performance of the Transmission Planning Process, including, but not limited to (1) long-term resource plans; (2) existing long-term contracts for resources and transmission service outside the CAISO Control Area; (3) resource capacity and Energy bid information received through requests for offers or similar solicitations; and (4) Demand Forecasts, including forecasted effect of Energy efficiency and Demand response programs.

24.2.3.4 Information Requested from Interconnected Control Areas, Sub-Regional Planning Groups and Electric Utility Regulatory Agencies.

In accordance with Section 24.8 of this Appendix EE, the CAISO shall obtain or solicit from interconnected Control Areas, regional and sub-regional planning groups within the WECC, the CPUC, the CEC, and Local Regulatory Authorities information required by, or anticipated to be useful to, the CAISO in its performance of the Transmission Planning Process, including, but not limited to (1) long-term transmission system plans; (2) long-term resource plans; (3) generation interconnection queue information; (4) Demand forecasts; and (5) any other data necessary for the development of power flow, short-circuit, and stability cases over the planning horizon of the CAISO Transmission Planning Process.

24.2.3.5 Obligation to Provide Updated Information.

If material changes to the information provided under Sections 24.2.3.1 and 24.2.3.2 of this Appendix EE occur during the annual Transmission Planning Process, the providers of the information must provide notice to the CAISO of the changes.

24.2.4 Unified Planning Assumptions and Study Plan.

24.2.4.1 Additional Projects and Data for Development of the Unified Planning Assumptions and Study Plan.

The CAISO will develop Unified Planning Assumptions and Study Plan using information and data received during the Request Window and under Section 24.2.3 of this Appendix EE. The CAISO will also use the following in the development of the Unified Planning Assumptions and Study Plan:

(1) WECC base cases for the relevant planning horizon;

(2) transmission upgrades and additions approved by the CAISO and scheduled to be energized within the planning horizon;

(3) Location Constrained Resource Interconnection Facilities conditionally approved under Section 24.1.3.1(a) of this Appendix EE;

(4) Network Upgrades identified pursuant to Section 25, Appendix U or Appendix W relating to the CAISO's Large Generator Interconnection Procedures and Appendix AA relating to the CAISO's Small Generator Interconnection Procedures;

(5) operational solutions validated by the CAISO to address Local Capacity Area Resource requirements;

(6) regulatory initiatives, as appropriate, including state regulatory agency initiated programs;

(7) Energy Resource Areas or similar resource areas identified as high priority by the CPUC or CEC; and

(8) results and analyses from Economic Planning Studies or other assessments that may have identified potentially needed transmission upgrades or additions performed in past CAISO Transmission Planning Process cycles.

24.2.4.2 General Scope of Unified Planning Assumptions and Study Plan.

The Unified Planning Assumptions and Study Plan shall, at a minimum, describe:

(a) the planning data and assumptions to be used, to the maximum extent possible, as a base case for each technical study to be performed in the Transmission Planning Process cycle, including, but not limited to, those related to Demand Forecasts and distribution, generation capacity additions and retirements, and transmission system modifications;

(b) a list of each technical study to be performed in the Transmission Planning Process cycle and a summary of the technical study's objective or purpose;

(c) a description of any modifications to the planning data and assumptions developed as the general base case in Section 24.2.4.2(a) of this Appendix EE made in each technical study performed in the Transmission Planning Process cycle;

(d) a description of the software tools, methodology and other criteria used in each technical study performed in the Transmission Planning Process cycle;

(e) the identification of any entities directed to perform a particular technical study or portions of a technical study;

(f) a proposed schedule for all stakeholder meetings to be held as part of the Transmission Planning Process cycle, and means for notification of any changes thereto, the location on the CAISO Website of information relating to the technical studies performed in the Transmission Planning Process cycle, and the name of a contact person at the CAISO for each technical study performed in the Transmission Planning Process cycle;

(g) a list and description of each Economic Planning Study studied by the CAISO as a High Priority Economic Planning Study under Section 24.9 of this Appendix EE; and

(h) to the maximum extent practicable, and where applicable, identify appropriate sensitivity analyses, including project or solution alternatives, to be performed as part of technical studies.

24.2.4.3 Preparation of Draft and Final Unified Planning Assumptions and Study Plan.

(a) Following review of relevant information, the CAISO will prepare and post on the CAISO Website a draft Unified Planning Assumptions and Study Plan. The CAISO will issue a Market Notice announcing the availability such draft, soliciting comments, and scheduling a stakeholder conference(s) as required by Section 24.2.4.3(c) of this Appendix EE.

(b) All comments from stakeholders on the draft Unified Planning Assumptions and Study Plan will be posted by the CAISO to the CAISO Website.

(c) Subsequent to the posting of the draft Unified Planning Assumptions and Study Plan, the CAISO will conduct a minimum of one stakeholder meeting open to Market Participants, electric utility regulatory agencies, and other interested parties to review, discuss, and recommend modifications to the draft Unified Planning Assumptions and Study Plan. Additional stakeholder meetings, web conferences, or teleconferences may be scheduled as needed. All stakeholder meetings, web conferences, or teleconferences shall be noticed by Market Notice and such notice shall be posted to the CAISO Website.

(d) Following the stakeholder conference(s) required by Section 24.2.4.2(c) of this Appendix EE, and under the schedule set forth in the Business Practice Manual, the CAISO will determine and publish to the CAISO Website the final Unified Planning Assumptions and Study Plan in accordance with the procedures set forth in the Business Practice Manual.

24.2.5 Development and Approval of Transmission Plan.

24.2.5.1 Technical Studies.

(a) In accordance with the Unified Planning Assumptions and Study Plan and the procedures and deadlines in the Business Practice Manual, the CAISO will perform, or direct the performance by third parties of, technical studies and other assessments necessary for the Transmission Plan and Transmission Planning Process, post the preliminary results on the CAISO Website, conduct a minimum of one stakeholder conference, and provide an opportunity for comments of the preliminary results. Additional stakeholder meetings, web conferences, or teleconferences may be scheduled as needed. All stakeholder meetings, web conferences, or teleconferences shall be noticed by Market Notice and such notice shall be posted to the CAISO Website.

(b) All technical studies, whether performed by the CAISO or third party under the direction of the CAISO, must utilize the Unified Planning Assumptions for the particular technical study to the maximum extent practical, and deviations from the Unified Planning Assumptions for the particular technical study must be documented in the preliminary and final results of each technical study. The CAISO will measure the results of the studies against NERC planning standards, WECC planning standards, and the CAISO Planning Standards, and other criteria established by the Business Practice Manual. After consideration of the comments received on the preliminary results, the CAISO will complete, or direct the completion of, the technical studies and post the final study results on the CAISO Website.

24.2.5.2 Development of Transmission Plan.

(a) In accordance with the schedule and procedures in the Business Practice Manual, the CAISO will post a draft Transmission Plan. The CAISO will subsequently conduct a stakeholder conference regarding the draft Transmission Plan and solicit comments, consistent with the timelines and procedures set forth in the Business Practice Manual. Additional stakeholder meetings, web conferences, or teleconferences may be scheduled as needed. All stakeholder meetings, web conferences, or teleconferences shall be noticed by Market Notice and such notice shall be posted to the CAISO Website. After consideration of comments, the CAISO will post a final Transmission Plan to the CAISO Website.

(b) The draft and final Transmission Plan may include, but is not limited to: (1) the results of technical studies performed under the Study Plan; (2) determinations, recommendations, and justifications for the need, according to Section 24.1 of this Appendix EE,for identified transmission upgrades and additions; (3) assessments of transmission upgrades and additions not proposed under Section 24.1 of this Appendix EE and for which need has not been formally determined by the CAISO Governing Board or management, as applicable, under Section 24.1 of this Appendix EE, but which have been identified by the CAISO as potential solutions to transmission needs studied during the Transmission Planning Process cycle; (3) results of Economic Planning Studies performed during the Transmission Planning Process cycle; and (4) an update on the status of transmission upgrades or additions previously approved by the CAISO, including identification of mitigation plans, if necessary, to address any potential delay in the anticipated completion of an approved transmission upgrade or addition.

(c) The Transmission Plan may not include the results of certain technical studies performed as part of the Transmission Planning Process cycle identified in the Unified Planning Assumptions and Study Plan that were scheduled for completion after publication of the Transmission Plan for the Transmission Planning Process cycle.

24.2.5.3 Approval by the CAISO Governing Board.

The CAISO will present the Transmission Plan to the CAISO Governing Board at the first meeting of the year following the year in which the Transmission Plan is prepared. The Transmission Plan will be considered final once it has been presented to the CAISO Governing Board and will be posted on the CAISO Website. Transmission upgrades and additions for which CAISO Governing Board approval is required may be presented to the CAISO Governing Board for approval separate from presentation of the Transmission Plan.

24.3 Obligation to Construct Transmission Projects Included in Transmission Plan.

A Participating TO that has a PTO Service Territory shall be obligated to construct all transmission additions and upgrades that are determined by the CAISO Governing Board or management, as applicable, to be needed in accordance with the requirements of Section 24 of this Appendix EE, not including conditional approvals and determinations of need under Section 24.1.3.1(a), and which: (1) are additions or upgrades to transmission facilities that are located within its PTO Service Territory, unless (a) it does not own the facility being upgraded or added and neither terminus of such facility is located within its PTO Service Territory or (b) it does not own the facility being upgraded or added and the Project Sponsor is a Participating TO that elects to construct the transmission upgrade; or (2) are additions to existing transmission facilities or upgrades to existing transmission facilities that it owns, that are part of the CAISO Controlled Grid, and that are located outside of its PTO Service Territory, unless the joint-ownership arrangement, if any, does not permit. A Participating TO's obligation to construct such transmission additions and upgrades shall be subject to: (1) its ability, after making a good faith effort, to obtain all necessary approvals and property rights under applicable federal, state, and local laws and (2) the presence of a cost recovery mechanism with cost responsibility assigned in accordance with Section 24.7 of the CAISO Tariff. The obligations of the Participating TO to construct such transmission additions or upgrades will not alter the rights of any entity to construct and expand transmission facilities as those rights would exist in the absence of a TO's obligations under this CAISO Tariff or as those rights may be conferred by the CAISO or may arise or exist pursuant to this CAISO Tariff.

24.4 Participating TO Study Obligation.

The Participating TO constructing or expanding facilities in accordance with Section 24.3 of this Appendix, will be directed by the CAISO to coordinate with the Project Sponsor or Participating TO(s) with PTO Service Territories in which the transmission upgrade or addition will be located, as appropriate, and other Market Participants to perform any study or studies necessary, including a Facility Study, to determine the appropriate facilities to be constructed in accordance with the CAISO Transmission Planning Process and the terms set forth in the TO Tariff.

24.5 Operational Review.

The CAISO will perform an operational review of all facilities studied as part of the CAISO Transmission Planning Process that are proposed to be connected to, or made part of, the CAISO Controlled Grid to ensure that the proposed facilities provide for acceptable operating flexibility and meet all its requirements for proper integration with the CAISO Controlled Grid. If the CAISO finds that such facilities do not provide for acceptable operating flexibility or do not adequately integrate with the CAISO Controlled Grid, the CAISO shall coordinate with the Project Sponsor and, if different, the Participating TO with the PTO Service Territory in which the facilities will be located to reassess and redesign the facilities required to be constructed. Transmission upgrades or additions that do not provide acceptable operating flexibility or do not adequately integrate with the CAISO Controlled Grid cannot be included in the CAISO Transmission Plan or approved by CAISO management or the CAISO Governing Board, as applicable.

24.6 State and Local Approval and Property Rights.

24.6.1 The Participating TO obligated to construct facilities under this Section 24 must make a good faith effort to obtain all approvals and property rights under applicable federal, state and local laws that are necessary to complete the construction of the required transmission additions or upgrades. This obligation includes the Participating TO's use of eminent domain authority, where provided by state law.

24.6.2 If the Participating TO cannot secure any such necessary approvals or property rights and consequently is unable to construct a transmission addition or upgrade found to be needed in accordance with Section 24.1 of this Appendix, it shall promptly notify the CAISO and the Project Sponsor, if any, and shall comply with its obligations under the TO Tariff to convene a technical meeting to evaluate alternative proposals. The CAISO shall take such action as it reasonably considers appropriate, in coordination with the Participating TO, the Project Sponsor, if any, and other affected Market Participants, to facilitate the development and evaluation of alternative proposals including, where possible, conferring on a third party the right to build the transmission addition or upgrade as set forth in Section 24.6.3 of this Appendix.

24.6.3 Where the conditions of Section 24.6.2 of this Appendix have been satisfied and it is possible for a third party to obtain all approvals and property rights under applicable federal, state and local laws that are necessary to complete the construction of transmission additions or upgrades required to be constructed in accordance with this CAISO Tariff (including the use of eminent domain authority, where provided by state law), the CAISO may confer on a third party the right to build the transmission addition or upgrade, which third party shall enter into the Transmission Control Agreement in relation to such transmission addition or upgrade.

24.7 WECC and Regional Coordination.

The Project Sponsor will have responsibility for completing any applicable WECC requirements and rating study requirements to ensure that a proposed transmission addition or upgrade meets regional planning requirements. The Project Sponsor may request the Participating TO to perform this coordination on behalf of the Project Sponsor at the Project Sponsor's expense.

24.8 Regional and Sub-Regional Planning Process.

The CAISO will be a member of the WECC and other applicable regional or sub-regional organizations and participate in WECC's operation and planning committees, and in other applicable regional and sub-regional coordinated planning processes.

24.8.1 Scope of Regional or Sub-Regional Planning Participation.

The details of the CAISO's participation in regional and sub-regional planning processes are set forth in the Business Practice Manual. At a minimum, the CAISO shall be required to:

(a) solicit the participation, whether through sub-regional planning groups or individually, of all interconnected Control Areas in the development of the Unified Planning Assumptions and Study Plan and in reviewing the results of technical studies performed as part of the CAISO's Transmission Planning Process in order to:

(1) coordinate, to the maximum extent practicable, planning assumptions, data and methodologies utilized by the CAISO, regional and sub-regional planning groups or interconnected Control Areas;

(2) ensure transmission expansion plans of the CAISO, regional and sub-regional planning groups or interconnected Control Areas are simultaneously feasible and seek to avoid duplication of facilities.

(b) coordinate with regional and sub-regional planning groups regarding the entity to perform requests for Economic Planning Studies or other Congestion related studies;

(c) transmit to applicable regional and sub-regional planning groups or interconnected Control Areas information on technical studies performed as part of the CAISO Transmission Planning Process;

(d) post on the CAISO Website links to the planning activities of applicable regional and sub-regional planning groups or interconnected Control Areas.

24.8.2 Limitation on Regional Activities.

Neither the CAISO nor any Participating TO nor any Market Participant shall take any position before the WECC or a regional organization that is inconsistent with a binding decision reached through an arbitration proceeding pursuant to Section 13 of the CAISO Tariff.

24.9 Economic Planning Studies.

24.9.1 Congestion Data Summary.

In accordance with the schedule and procedures set forth in the Business Practice Manual, the CAISO shall post on the CAISO Website a Congestion Data Summary.

24.9.2 High Priority Economic Planning Studies.

High Priority Economic Planning Studies shall be performed in accordance with the standards and procedures established in the Business Planning Manual. Market Participants may conduct Economic Planning Studies that have not been designated as High Priority Economic Planning Studies at their own expense and may submit such studies for consideration in the development of the Transmission Plan when the CAISO provides notice of the stakeholder meeting regarding technical study results pursuant to Section 24.2.5.2 of this Appendix EE.

PART B. – DEFINITIONS

CAISO Planning Standards	Reliability Criteria that: (1) address specifics not covered in the NERC and WECC planning standards; (2) provide interpretations of the NERC and WECC planning standards specific to the CAISO Controlled Grid; and (3) identify whether specific criteria should be adopted that are more stringent than the NERC and WECC planning standards.
CEC	The California Energy Commission or its successor.
Congestion Data Summary	A report issued by the CAISO on the schedule set forth in the Business Practice Manual that sets forth historic Congestion on the CAISO Controlled Grid.
Critical Energy Infrastructure Information (CEII)	Critical Energy Infrastructure Information shall have the meaning given the term in the regulations of FERC at 18 C.F.R. § 388.12, et seq.
Economic Planning Study	A study performed to provide a preliminary assessment of the potential cost effectiveness of mitigating specifically identified Congestion.
High Priority Economic Planning Study	An Economic Planning Study performed by the CAISO for inclusion in the Transmission Plan and for which the CAISO assumes cost responsibility.
Long Term Congestion Revenue Right (Long Term CRR)	A Congestion Revenue Right differentiated by season and time-of-use period (on-peak and off-peak) with a term of ten years.
Merchant Transmission Facility	A transmission facility or upgrade that is part of the CAISO Controlled Grid and whose costs are paid by a Project Sponsor that does not recover the cost of the transmission investment through the CAISO's Access Charge or WAC or other regulatory cost recovery mechanism.

NERC Reliability Standards for Modeling, Data and Analysis (NERC MOD Standards)	A set of NERC Reliability Standards applicable to the transmission planning process.
Planning Standards Committee	The committee appointed under Section 24.2.1.
Request Window	The period of time as set forth in the Business Practice Manual during which transmission additions or upgrades, requests for Economic Planning Studies, and other transmission related information is submitted to the CAISO in accordance with Section 24.2.2 of Appendix EE.
Study Plan	The plan to be developed pursuant to Section 24.4.3 of Appendix EE, which sets forth the technical studies to be performed during the annual Transmission Planning Process.
Transmission Plan	The report prepared by the CAISO on annual basis pursuant to Section 24 of Appendix EE, which documents the outcome of the Transmission Planning Process as defined in the Study Plan.
Transmission Planner	A designation by NERC regarding responsibility to perform specified transmission planning functions in accordance with the NERC Reliability Standards.
Transmission Planning Process	The process by which the CAISO assesses the CAISO Controlled Grid as set forth in Section 24 of Appendix EE.
Unified Planning Assumptions	The assumptions to be developed pursuant to Section 24.4.3 of Appendix EE and used, to the maximum extent possible, in performing technical studies identified in the Study Plan as part of the annual Transmission Planning Process.