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 2005 does not exceed $218.4 million or its revenue requirement for Budget Year 2006 does not exceed $221.7 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 collect such Revenue Requirement. In order for the ISO to adjust the GMC charges to collect a Grid Management Charge revenue requirement for Budget Year 2005 that exceeds $218.4 million or Budget Year 2006 that exceeds $221.7 million, the ISO must submit an application to the 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 as of January 1, 2007. 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.

<u>Part E – Cost Allocation</u>

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. Modesto Irrigation District (MID) is a Scheduling Coordinator and also is responsible for a portion of the GMC charges payable by another Scheduling Coordinator, Pacific Gas and Electric Company (PG&E) pursuant to a contract between them. MID and PG&E have agreed that MID shall pay the ISO directly $75,000 each month, in lieu of any payments to PG&E for its share of the GMC charges payable by PG&E and the ISO shall credit a portion of the amount received from MID to PG&E as an offset to PG&E's obligation for GMC charges. Any difference, positive or negative, between the amount credited to PG&E and the amount paid by MID to the ISO under this provision shall be reflected in the Operating and Capital Reserves Account. The payment arrangement described in this paragraph is subject to the conditions, and will be implemented pursuant to the procedures, set forth in the Offer of Partial Settlement accepted by the FERC in Docket Nos. ER04-115-000, et al. This arrangement shall not apply to MID's obligation for GMC charges as a Scheduling Coordinator, which shall be governed by the provisions of this Schedule 1 and the other applicable provisions of the ISO Tariff, except that in the event that MID accepts responsibility for scheduling any load currently scheduled by PG&E under SCID PGAB, the ISO will not charge any additional GMC at the tariffed GMC rate, but rather will attribute such schedules and load to the fixed $75,000.00 per month payment set forth above, provided that MID schedules such load under a new and separate SCID and the ISO shall not assess GMC charges to such SCID.

4. 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
High Voltage 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. Each Participating TO will charge for and collect the LVAC.

(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 shall be based on the principal balance in the high voltage TRBA as of September 30, which 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. For a Participating TO that is not a UDC, MSS or a Scheduling Coordinator serving End-Use Customers and that does not have Gross Load in its TO Tariff in accordance with Appendix F, Schedule 3, Section 9, the 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 Participating TO's over- or under-recovery shall be based on a partial year revenue requirement, calculated by multiplying the 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 Participating TO that is not a UDC or MSS Operator and that does not have Gross Load in its TO Tariff in accordance with Appendix F, Schedule 3, Section 9, then calculate the Participating TO's portion of the total Billed HVAC/TC in subsection (a) based on the ratio of the 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) FTR revenues shall be assigned to High Voltage or Low Voltage components based on the voltage of the path related to the FTR;

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

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

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.

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 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:

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

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 For installation 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

[not used]

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: $GOP_t = \dfrac{REDISP_{CONG_t}}{\sum_j QCharge_{jt} + \sum_j Export_{jt}}$

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 Δincbijt - 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 **EXPORTI_{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) <u>Regulation</u>. 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) <u>Spinning Reserve</u>. 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) <u>*Spinning Reserve*</u>. 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*

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

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

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

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:

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

$PFL_{s,h}$ 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

$$PREDISPATCH\_UPLIFT_{i,h,o} = 0 \;)$$

<u>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.</u>

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:

$$EXCESS\_COST_{i,h,o} = \left[\left(\sum_{1}^{k}\sum_{1}^{m} IIE\_ECON_{i,h,o,k,m} + \sum_{1}^{k}\sum_{1}^{m} IIE\_PREDISPATCH_{i,h,o,k,m} + \sum_{1}^{k}\sum_{1}^{m} RIE_{i,h,o,k,m}\right) * STLMT\_PRICE_{i,h,o} - BID\_COST_{i,h,o} - BID\_COST\_RIE_{i,h,o}\right] * PERF\_STAT_{i,h,o}$$

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 $VSSTCharge_{xjt}$ ($)

The lost opportunity cost Voltage Support user charge for Zone x for Trading Interval t for Scheduling Coordinator j.

G 3.10 $VSLTCharge_{xjm}$ ($)

The long-term charge for Voltage Support for month m for Zone x for Scheduling Coordinator j.

G 3.11 $BSEn_{ijt}$ ($)

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 $EnQBS_{ijt}$ (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 $EnBid_{ijt}$ ($/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 $BSSUP_{ijt}$ ($)

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 $BSRate_t$ ($/MWh)

The Black Start Energy payment user rate charged by the ISO to Scheduling Coordinators for Trading Interval t.

G 3.16 $QChargeBlackstart_{jt}$ (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: Date: Customer Number:	181 20-JUN-97 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 *w*ith 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

Estimated Interval =Next Actual - Previous Actual Interval

+ Previous Actual Interval

Number of Missing Intervals + 1

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 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 monthly changes in fuel prices using the proxy figure for natural gas prices posted on the ISO Home Page. 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 2.3 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 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 and other information the ISO reasonably requests to fulfill its obligation to validate forecast models and explain deviations.

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 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

Scheduling Coordinator Application

The information provided for this application will be treated as confidential information

PART A

SCHEDULING COORDINATOR APPLICATION FORM

This application is for approval as a Scheduling Coordinator ("SC") by the California Independent System Operator Corporation ("ISO") in accordance with the ISO Tariff.

I. Administrative Requirements

SC Applicant's Legal Name:

____

Address of principal place of business:

____

____

____

Authorized Representative: ____

Address: ____________________________________

____

Phone: ____________________________________

Fax: ____________________________________

E-mail: ____________________________________

Type of entity: ____

(Municipal utility, power marketer, investor owned utility, federal or state entity or other)

State of Incorporation or Partnership: _____________________

Proposed commencement date for service: _________________

II. Scheduling Coordinator Customer Information

2.1 The information required under Part C, the ISO Application File Template, must be provided for represented Scheduling Coordinator Metered Entities, which are Generators. The Scheduling Coordinator Applicant must submit all requested information prior to final certification, which must occur fourteen (14) days before the commencement of service.

2.2 Information for Scheduling Coordinator Metered Entities, which are End Users or Eligible Customers, must be kept in a standard business format based on generally accepted accounting principals. The ISO shall have the right to inspect and audit a Scheduling Coordinator's accounts and files relating to its Scheduling Coordinator Metered Entities after giving two Business Days notice in writing.

2.3 The Scheduling Coordinator Applicant must submit a list of all ISO Metered Entities, which it will represent.

III. Security Requirement

3.1 The Scheduling Coordinator Applicant will submit a credit application to apply for an Unsecured Credit Limit as set forth in the ISO Tariff and the ISO Credit Policy & Procedures Guide: (yes/no).

3.2 The Scheduling Coordinator Applicant will provide Financial Security in a form listed in Section 12.1.2 of the ISO Tariff: (yes/no).

Acceptable forms of Financial Security include:

(a) an irrevocable and unconditional letter of credit issued by a bank or financial institution that is reasonably acceptable to the ISO;

(b) an irrevocable and unconditional surety bond issued by an insurance company that is reasonably acceptable to the ISO;

(c) an unconditional and irrevocable guaranty issued by a company that is reasonably acceptable to the ISO;

(d) a cash deposit standing to the credit of the ISO in an interest-bearing escrow account maintained at a bank or financial institution that is reasonably acceptable to the ISO;

(e) a certificate of deposit in the name of the ISO issued by a bank or financial institution that is reasonably acceptable to the ISO;

(f) a payment bond certificate in the name of the ISO issued by a bank or financial institution that is reasonably acceptable to the ISO; or

(g) a prepayment to the ISO.

3.3 The Scheduling Coordinator Applicant must provide its bank account information before final certification. The Scheduling Coordinator Applicant's bank must be capable of performing Fed-Wire System transfers.

IV. Technical Requirements

4.1 Does the Scheduling Coordinator Applicant have the computer hardware, software and communication capabilities for interface compatibility with the ISO system for data transmission, for electronic data interchange (EDI) and for Fed-Wire System transfer accounts? (yes / no) If no, please submit a proposed completion date to be fully operational so that an ISO staff site visit can be arranged.

4.2 For Loads and Generating Units located within the ISO Controlled Grid, does the Scheduling Coordinator Applicant have any scheduling restrictions imposed by the parties they represent? (yes / no) If yes, provide full details on a separate sheet of paper.

4.3 Does the Scheduling Coordinator Applicant have adequate staffing to operate a Scheduling Coordinator's operational facility twenty-four (24) hours a day for 365 days a year? (yes / no). If no, please submit a proposed completion date to be fully operational so that an ISO staff site visit can be arranged.

V. Third Party Contractual Requirements

5.1 The Scheduling Coordinator Applicant confirms that all of its Scheduling Coordinator Customers which are located within the ISO Controlled Grid and which should execute agreements with the ISO have entered into or will enter into, prior to the certification of the Scheduling Coordinator Applicant, all required agreements with the ISO to enable them to meet the requirements of the ISO Tariff: (yes / no).

(a) Represented Generators have signed Participating Generator Agreements: (yes / no).

(b) Represented UDCs have signed UDC Operating Agreements and Meter Service Agreements: (yes / no).

(c) Represented ISO Metered Entities have signed Meter Service Agreements: (yes / no).

(d) Wholesale Customers it will represent have warranted to the Scheduling Coordinato Applicant that they are eligible for wholesale transmission service pursuant to the provisions of the FPA Section 212(h): (yes / no).

(e) Each End-Use Customer it will represent which requests Direct Access service has warranted to the Scheduling Coordinator Applicant that the End-Use Customer is eligible for such service: (yes / no).

5.2 The SCHEDULING COORDINATOR Applicant confirms that all of the parties which it represents as Scheduling Coordinator Customers have granted it all necessary agency authority, whether actual, implied or inherent, to enable the Scheduling Coordinator to perform all of its obligations under the ISO Tariff: (yes / no).

5.3 Notwithstanding 5.2, the Scheduling Coordinator confirms that it will have the primary responsibility, as the principal, for all Scheduling Coordinator payment obligations under the ISO Tariff : (yes / no).

VI. <u>Additional Information and Obligations</u>

6.1 The Scheduling Coordinator Applicant agrees to provide such further information to the ISO as the ISO may deem necessary to process the application and certify the Scheduling Coordinator Applicant as a Scheduling Coordinator now and on a continuing basis.

6.2 Subject to the ISO Tariff, the Scheduling Coordinator Applicant agrees to promptly report to the ISO within seven (7) Business Days or earlier any changes regarding the information provided by it referred to in the ISO Tariff and in the application with the exception of the security requirement data referred to in Part III of Part A in this Appendix which must be updated within five (5) Business Days. The Scheduling Coordinator shall be responsible if a failure to submit revised technical data more promptly extends the period during which schedules are rejected by the ISO.

6.3 The Scheduling Coordinator Applicant agrees to enclose herein the non-refundable application fee of $500 to cover the application processing costs, site visit and costs of providing ISO Tariff.

Please make check payable to:

The California Independent System Operator Corporation

6.4 Scheduling Coordinator Applicant agrees to promptly execute and return the Scheduling Coordinator Agreement, Meter Service Agreements, Interim Black Start Agreements, software licensing agreement, completed credit application, and/or Financial Security as applicable, and Fed-Wire System bank account number, after receiving its application approval letter from the ISO.

6.5 Final certification is contingent upon Scheduling Coordinator Applicant fulfilling all financial and technical requirements as referenced in the ISO Tariff (including Part C of this Appendix, the ISO Application File Template).

Scheduling Coordinator Applicant certifies by its signature on this Application Form that:

(1) all information it is submitting is correct and accurate; and that

(2) the Scheduling Coordinator Applicant has read and agrees to be bound by the ISO Tariff as may be in force or amended from time to time.

Name of Organization:

____

Scheduling Coordinator Applicant's Name (please print):

____

Scheduling Coordinator Applicant's Title:

____

Scheduling Coordinator Applicant's Signature:

____

State of ________________________}
ss
County of ______________________}

[SEAL]

Sworn and subscribed
before me this ____ day of
_________________,19___.

Notary's Signature: ____

Please send application and required information to:

California Independent System Operator Corporation
c/o Schedule Coordinator Application Processing Office
151 Blue Ravine Road,
Folsom, CA 95630

Scheduling Coordinator Application PART B

Procedures for Changes or Additions to

Scheduling Coordinator's (SC's) Information

The Scheduling Coordinator must update, amend and / or correct the information originally submitted to the ISO during the Scheduling Coordinator application process using the format set forth in this Part and/or a revised Part C, the ISO Application File Template. The Scheduling Coordinator must submit all changes or additional information by first class postage paid mail to:

California Independent System Operator Corporation

c/o SC Application Processing Office

151 Blue Ravine Road

Folsom, CA 95630

The Scheduling Coordinator must notify the ISO of any change to the information that it has previously submitted to the ISO, or any additional information, at least three Business Days before the change will take effect.

The ISO will send a written acknowledgment of receipt of the Scheduling Coordinator's changes within three Business Days of receipt. The receipt shall be sent to the address on file with the ISO or the address specified in the notice of change received by the ISO.

Prior Information

____

____

____

New Information

____

____

____

Explanation and Reason for Change

____

____

Scheduling Coordinator Application PART C

ISO APPLICATION FILE TEMPLATE

The ISO Application File Template is an Excel template used to load resources into the ISO's database. There is also a customer help file created to work with a Microsoft Access Database which are used together to gather application information.

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.

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

[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

[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, and, if reasonably practicable, an informational assessment, as needed, of other affected owners' portions of the ISO Controlled Grid.

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 Interconnection Facilities, Network Upgrades and Distribution Upgrades

Part B Milestones

Part C Interconnection Details

Part D Security Arrangements Details

Part E Commercial Operation Date

Part F Addresses for Delivery of Notices and Billings

Part G Reliability Management System Agreement

Part H Interconnection Requirements for a Wind Generating Plant

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.

ISO TARIFF APPENDIX Z

Credit Policy and Procedures Guide

REVISION HISTORY

Revision No.	Date	Description
1.0	4/4/2003	Original Draft
2.0	8/13/2004	Second major revision – updated to include only the current credit policies and procedures.
3.0	5/6/2005	Third major revision – updated to include proposed credit policy changes.
4.0	3/6/2006	Fourth major revision – major restructuring and updating to support the new credit policy. Changes the method for determining a Market Participant's or FTR Bidder's unsecured credit limit from simply having an approved credit rating with one that bases unsecured credit as a percentage of Tangible Net Worth or Net Assets based on the type of entity and other quantitative and qualitative factors.
4.1	6/26/2006	Revision made to reflect necessary updates to the CPPG, in accordance with FERC's Notice of Extension of Time issued June 2, 2006, in Docket No. ER06-700-000. Revision to satisfy FERC Order Conditionally Accepting Tariff Revisions Governing Credit Policy issued May 12, 2006 115 FERC ¶ 61,170. Modifications included: • Deletion of Section A-1 describing the transition from the old "Approved Credit Rating Approach" and renumbering of the sections in Part A due to the passing of the transition period; • The addition of Unsecured Credit Limit calculation examples for Unrated Public/Private Corporations, Rated Governmental Entities and Unrated Governmental Entities; • Deletion of the reference to the ISO Board of Governor's ability to reduce the $250M cap on Unsecured Credit Limits; • Description of an alternative Estimated Aggregate Liability calculation method in Section C-2, Section C-3, Section C-3.1 and Appendix 1A.

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INTRODUCTION

All Market Participants and FTR Bidders requesting transmission services with the ISO will be subject to a financial review in accordance with the ISO standards for determining creditworthiness. Such review procedures are designed to protect Market Participants and FTR Bidders from undue exposure to default risk by other Market Participants and FTR Bidders.

This Credit Policy & Procedures Guide (CPPG) provides Market Participants and FTR Bidders further detailed information regarding credit-related provisions described in Section 12 of the ISO Tariff. By providing this information, the ISO hopes to provide Market Participants and FTR Bidders increased visibility into the standard, commercial credit review procedures that the ISO uses in evaluating a Market Participant's and FTR Bidder's ability to meet its financial obligations. Specifically, Market Participants and FTR Bidders will find in the CPPG:

- Information on the processes used to administer the credit policy;
- The methodology used to calculate Unsecured Credit Limits and Estimated Aggregate Liabilities;
- Acceptable forms of Financial Security and the associated processes for requesting, posting and administering Financial Security;
- Security requirements for FTR Bidders;
- Consequences for Market Participants' failure to meet their credit related obligations; and
- Other credit-related information.

Principles

The ISO's intent is to maintain the confidence of Market Participants and FTR Bidders in the ISO markets and to sustain the ISO's mission of ensuring an adequate supply of power at a reasonable cost, by equitably, consistently and strictly enforcing these credit procedures.

The ISO recognizes the importance to Market Participants and FTR Bidders that credit-related practices be transparent and comprehensive. The ISO will endeavor to maintain an accurate procedures guide that describes the methods used to conduct its credit analysis as well as other credit-related practices and administrative procedures on the ISO's Home Page.

Definitions

Any term defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Guide. In any instances where a definition in this document conflicts with a definition in the ISO Tariff, the ISO Tariff definition will prevail. Section number references refer to sections of the CPPG unless specifically stated otherwise.

The following table defines terms used throughout this document and their associated meanings:

TERM	DEFINITION
Affiliated Entities	Legally distinct business units that are Affiliates, as defined in the ISO Tariff.
Aggregate Credit Limit (ACL)	The sum of a Market Participant's or FTR Bidder's Unsecured Credit Limit and its Financial Security Amount, as provided for in Section 12 of the ISO Tariff.
Average Rating Default Probability (ARDP)	The sum of Credit Rating Default Probabilities divided by the total number of Credit Rating Default Probabilities used.
Business Association Identification Number (BAID)	An identification code used by the ISO to represent a Market Participant or a FTR Bidder. A Market Participant may have more than one BAID.
Credit Rating Default Probability	The 5 Year Median Default Probability based on a rating agency's credit rating as listed in the Credit Rating Default Probability table in Section A-2.2 of this CPPG.
FTR Bidder	An entity that submits a bis in an FTR auction conducted by the ISO in accordance with Section 36.4 of the ISO Tariff.
Collateral	See Financial Security.
Combined Default Probability (CDP)	A Market Participant's or FTR Bidder's blended probability of default based on credit agencies' Average Rating Default Probability and MKMV Default Probability according to rules established for different entity types.
Estimated Aggregate Liability (EAL)	The sum of a Market Participant's or FTR Bidder's known and reasonably estimated potential liabilities for a specified time period arising from charges described in the ISO Tariff, as provided for in Section 12 of the ISO Tariff.
Financial Security	Any of the types of financial instruments listed in Section 12 of the ISO Tariff that are posted by a Market Participant or FTR Bidder.
Financial Security Amount	The level of Financial Security posted in accordance with Section 12 of the ISO Tariff by a Market Participant or FTR Bidder.
Material Change in Financial Condition	A change in or potential threat to the financial condition of a Market Participant that increases the risk that the Market Participant will be unlikely to meet some or all of its financial obligations. The types of Material Change in Financial Condition include but are not limited to the following: (a) A credit agency downgrade; (b) Being placed on a credit watch list by a major rating agency; (c) A bankruptcy filing; (d) Insolvency; (e) The filing of a material lawsuit that could significantly adversely affect past, current or future financial results; or any change in the financial condition of the Market Participant which exceeds a five percent (5%) reduction in

	the Market Participant's tangible net worth for the Market Participant's preceding fiscal year, calculated in accordance with generally accepted accounting practices.
MKMV Default Probability	The Moody's KMV default probability determined in accordance with step 3 of Section A-2.2 of this CPPG.
Nationally Recognized Statistical Rating Organizations (NRSRO)	National credit rating agencies as designated by the U.S. Securities & Exchange Commission.
Net Assets (NA)	For governmental or not-for-profit entities, defined as total assets less total liabilities.
Rated Governmental Entity	A municipal utility or state or federal agency that holds an issuer, counterparty or underlying credit rating by a Nationally Recognized Statistical Rating Organization.
Rated Public/Private Corporation	An investor owned or privately held entity that holds an issuer, counterparty or underlying credit rating by a Nationally Recognized Statistical Rating Organization.
Scheduling Coordinator	An entity certified by the ISO for the purposes of undertaking the functions specified in Section 4.5.3 of the ISO Tariff.
Scheduling Coordinator Identification Number (SCID)	A unique number assigned to each Scheduling Coordinator by the ISO.
Tangible Net Worth (TNW)	Total Assets minus Intangibles (e.g., Good Will) minus Total Liabilities.
Unrated Governmental Entity	A municipal utility or state or federal agency that does not hold an issuer, counterparty or underlying credit rating by a Nationally Recognized Statistical Rating Organization.
Unrated Public/Private Corporation	An investor owned or privately held entity that does not hold an issuer, counterparty or underlying credit rating by a Nationally Recognized Statistical Rating Organization.
Unsecured Credit Limit (UCL)	The level of credit established for a Market Participant or a FTR Bidder that is not secured by any form of Financial Security, as provided for in Section 12 of the ISO Tariff.

Rules of Interpretation

Unless the context otherwise requires, if the provisions of this Guide and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Guide only to aid understanding.

A reference in this Guide to a given agreement, the ISO Guide 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.

The captions and headings in this Guide are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

A reference to a day or Trading Day is to a calendar day unless otherwise specified.

PART A: UNSECURED CREDIT

A-1. Credit Assessment Requirements

As provided in Section 12.1.1 of the ISO Tariff, an approved Application for Unsecured Credit must be on file with the ISO for those Market Participants and FTR Bidders seeking an Unsecured Credit Limit. A copy of the Application for Unsecured Credit can be found at the ISO Home Page. An Application for Unsecured Credit must only be filed once by a Market Participant or FTR Bidder. A Market Participant or FTR Bidder should subsequently inform the ISO of changes to contact or other relevant information contained in the Application.

As provided in Section 12.1 of the ISO Tariff, each Market Participant or FTR Bidder must secure its financial transactions with the ISO by maintaining an Unsecured Credit Limit (UCL) and/or by posting Financial Security. The combination of the UCL and the Financial Security Amount represents the Market Participant's or FTR Bidder's Aggregate Credit Limit (ACL). The ISO will periodically estimate a Market Participant's liabilities and will notify it in case its ACL needs to be increased through posting of additional Financial Security. It is the Market Participant's responsibility to maintain a sufficient ACL to meet all of their estimated financial obligations.

As provided in Sections 12.1.1, 12.1.5 and 12.4 of the ISO Tariff, each Market Participant and FTR Bidder requesting or having unsecured credit is required to submit to the ISO or its agent financial statements and other information related to the overall financial health of the Market Participant or FTR Bidder that will be used in determining the Market Participant's or and FTR Bidder's creditworthiness and ability to meet its financial obligations. Market Participants and FTR Bidders are responsible for the timely submission of their latest financial statements either directly or by indicating where the material can be located on their company website and/or on the U.S. Security Exchange Commission's website as well as other information that may be reasonably necessary for the ISO to conduct its evaluation. The ISO may also rely on financial reporting agencies and the financial press as part of the credit evaluation process.

As provided in Sections 12.1.1 and 12.1.2 of the ISO Tariff, as a result of the credit evaluation, a Market Participant or FTR Bidder may be denied an Unsecured Credit Limit with the ISO. Market Participants or FTR Bidders who have been denied an Unsecured Credit Limit may submit other forms of Financial Security acceptable to the ISO (see Part B) sufficient to cover their Estimated Aggregate Liabilities.

A-1.1. Financial Statements

As provided in Section 12.1.1 of the ISO Tariff, Market Participants and FTR Bidders requesting unsecured credit are required to provide financial statements so that a credit review can be completed.

Based on availability, the Market Participant or FTR Bidder must submit a financial statement for the most recent financial quarter, as well as audited financial statements for the most recent three fiscal years, or the period of existence of the Market Participant or FTR Bidder, if shorter, to the ISO or the ISO's designee. If audited financial statements are not available, financial statements, as described below, should be submitted, signed and attested to by an officer of the Market Participant or FTR Bidder as a fair representation of the financial condition of the Market Participant or FTR Bidder in accordance with generally accepted accounting principles.

The information should include, but is not limited to, the following:

a. If publicly traded:

   i. Annual and quarterly reports on Form 10-K and Form 10-Q, respectively

   ii. Form 8-K reports, if any

b. If privately held or governmentally owned:

   i. Management's Discussion & Analysis (if available)

   ii. Report of Independent Accountants (if available)

   iii. Financial Statements, including:

   - Balance Sheet
   - Income Statement
   - Statement of Cash Flows
   - Statement of Stockholder's Equity

   iv. Notes to Financial Statements

If the above information is available electronically on the Internet, the Market Participant or FTR Bidder may indicate in written or electronic communication where such statements are located for retrieval by the ISO or the ISO's designee.

A-1.2. Rating Agency Reports

Rating agency reports and credit ratings are utilized from those entities designated by the U.S. Securities & Exchange Commission - http://www.sec.gov/answers/nrsro.htm. The ratings utilized are to be long-term credit ratings for the entity as a whole, on a stand-alone basis without the benefit of third party credit support (also known as "issuer" or "underlying" ratings). Project financing ratings or insured bond ratings do not qualify, since such credit ratings are based on the availability of revenue streams or third-party funding available to bond holders but not necessarily available to trade creditors such as the suppliers to the ISO markets. Moreover, the ISO has been advised by the credit rating agencies that these projects or insured bond ratings cannot be considered as valid measures of an entity's ability to meet its non-bond obligations.

If a Market Participant or FTR Bidder has only a "senior long-term unsecured rating" instead of an issuer rating, the rating will be deemed acceptable; however, for the Unsecured Credit Limit calculation, the rating will be lowered by one rating level to account for the risk of obligations to the ISO having a lower claim priority.

If a Market Participant or FTR Bidder has only a "short-term rating" instead of an issuer rating, the ISO will utilize an equivalent long-term rating based on the highlighted rating in the following long- and short-term rating correlation table:

S&P		Moody's	
Short Term Rating	Equivalent Long Term Ratings	Short Term Rating	Equivalent Long Term Ratings
A-1+	AAA/AA+/**AA**/AA-/A+	P1	Aaa/Aa1/Aa2/**AA3**/A1/A2/A3
A-1	A+/**A**/A-	P2	A3/Baa1/**Baa2**/Baa3
A-2	A-/**BBB+**/BBB	P3	Baa3/Ba1/**Ba2**/Ba3
A-3	BBB/**BBB-**	NP	B1/B2/B3/Caa1/**Caa2**/ Caa3/Ca/C
B	BB+/**BB**/BB-		
C	B+ / B / B- / CCC+ / **CCC** / CCC- / CC / C		
D	**D**		

The highlighted rating represents a mid-range rating in the rating agencies' long- and short-term rating correlation table. Equivalent ratings from other rating agencies may also be considered. If the short-term rating is noted as being under a credit watch with negative implications, the ISO will use the lowest long-term equivalent rating in the range for its assessment.

Rating agency reports, particularly credit ratings, are reviewed and updated minimally on a quarterly basis for those Market Participants with an Unsecured Credit Limit. They are also reviewed as needed if questions arise as to changes to a Market Participant's financial health and/or credit standing. Additionally, credit rating agency reports of downgrade/upgrades are reviewed upon notice from a rating agency to determine if the Unsecured Credit Limit should be correspondingly decreased/increased.

A-1.3. Other Qualitative and Quantitative Credit Strength Indicators

As provided in Section 12.1.1 of the ISO Tariff, the ISO may rely on information gathered from financial reporting agencies, the general/financial/energy press, and provided by the Market Participant or FTR Bidder to assess an entity's overall financial health and its ability to meet its financial obligations. Information considered by the ISO in this process may include the qualitative factors noted in FERC's Policy Statement on Electric Creditworthiness[3]:

a) Applicant's history;
b) Nature of organization and operating environment;
c) Management;
d) Contractual obligations;

[3] "*Policy Statement on Credit Related Issues for Electric OATT Transmission Providers, Independent System Operators and Regional Transmission Organizations*" (*Order E-40, Docket PL05-3-000, November 19, 2004), at footnote 13.*

e) Governance policies;
f) Financial and accounting policies;
g) Risk management and credit policies;
h) Market risk including price exposures, credit exposures and operational exposures;
i) Event risk; and
j) The state or local regulatory environment.

Material negative information in these areas may result in a reduction of up to 100% in the Unsecured Credit Limit that would otherwise be granted based on the methodology described in Section A-2.2. A Market Participant or FTR Bidder, upon request, will be provided a written analysis as to how the provisions of Section A-2.2 were applied in setting its Unsecured Credit Limit.

Notwithstanding the considerations described above, Market Participants and FTR Bidders are obligated to provide the ISO timely information regarding any Material Change in Financial Condition, i.e., an adverse change that could affect its or one of its affiliated entities ability to pay its debt or meet its Financial Security obligations as they become due. Examples of Material Changes in Financial Condition may include but are not limited to:

a) Credit agency downgrades;
b) Being placed on a credit watch list by a major rating agency;
c) A bankruptcy filing;
d) Insolvency;
e) The filing of a material lawsuit that could significantly and adversely affect past, current or future financial results; or
f) Any change in the financial condition of the Market Participant or FTR Bidder that exceeds a five percent (5%) reduction in the Market Participant's or FTR Bidder's Tangible Net Worth or Net Assets for the Market Participant's or FTR Bidder's preceding fiscal year, calculated in accordance with generally accepted accounting practices.

A-2. Unsecured Credit Limit Calculation

See Section 12.1.1A, 12.1.1A.1, 12.1.1A.2 and 12.1.1A.3 of the ISO Tariff.

A-3. Unsecured Credit Limit Issues for Affiliated Entities

As provided in Section 12.1.1.1 of the ISO Tariff, if any Market Participant or FTR Bidder requesting or maintaining an Unsecured Credit Limit is affiliated with one or more other entities subject to the credit requirements of Section 12 of the ISO Tariff, the ISO may consider the overall creditworthiness and financial condition of such Affiliates when determining the applicable Unsecured Credit Limit. The ISO may determine that the maximum Unsecured Credit Limit calculated in accordance with Section A-2 of this document applies to the combined activity of such Affiliates.

A-4. Unsecured Credit Limit for a Local Publicly Owned Electric Utility

A Local Publicly Owned Electric Utility with a governing body having ratemaking authority that has submitted an application for an Unsecured Credit Limit shall be entitled to an Unsecured Credit Limit of one million dollars ($1,000,000) without regard to its Net Assets. Such Local Publicly Owned Electric Utility shall be entitled to request an Unsecured Credit Limit based on Net Assets as provided in Section 12.1.1 of the ISO Tariff in order to establish an Unsecured Credit Limit as the greater of one million dollars ($1,000,000) or the amount determined as provided in Section 12.1.1 of the ISO Tariff. A public entity that is not a Local Publicly Owned Electric Utility is not entitled to an Unsecured Credit Limit of one million dollars ($1,000,000) under this Section but may seek to establish an Unsecured Credit Limit as provided in Section 12.1.1 of the ISO

Tariff or any other provision of the ISO Tariff that may apply.

Public entities, including Local Publicly Owned Electric Utilities, that operate through a Joint Powers Agreement, or a similar agreement acceptable to the ISO with the same legal force and effect, shall be entitled to aggregate or assign their Unsecured Credit Limits subject to the following limitations and requirements. A public entity that is a party to a Joint Powers Agreement or similar agreement and that is also participating independently in the ISO's markets with an established Unsecured Credit Limit shall not be entitled to assign or aggregate any portion of its Unsecured Credit Limit that the public entity is using to support financial liabilities associated with its individual participation in the ISO's markets. A Local Publicly Owned Electric Utility that operates through a Joint Powers Agreement or similar agreement that desires to aggregate a portion of its Unsecured Credit Limit that is equal to or less than one million dollars ($1,000,000) with one or more other Local Publicly Owned Electric Utilities that operate through that Joint Powers Agreement or similar agreement or to assign a portion of its Unsecured Credit Limit that is equal to or less than one million dollars ($1,000,000) to the Joint Powers Authority shall be entitled to do so. A Local Publicly Owned Electric Utility that operates through a Joint Powers Agreement or similar agreement that desires to aggregate its Unsecured Credit Limit with one or more other Local Publicly Owned Electric Utilities that operate through that Joint Powers Agreement or similar agreement or to assign a portion of its Unsecured Credit Limit to the Joint Powers Authority that exceeds one million dollars ($1,000,000), and any public entity that is not a Local Publicly Owned Electric Utility that operates through a Joint Powers Agreement or similar agreement that desires to aggregate its Unsecured Credit Limit with one or more other Local Publicly Owned Electric Utilities that operate through that Joint Powers Agreement or similar agreement or to assign any portion of its Unsecured Credit Limit to the Joint Powers Authority, shall provide documentation that is acceptable to the ISO and that demonstrates the Local Publicly Owned Electric Utility or public entity will assume responsibility for the financial liabilities of the Joint Powers Agency associated with the assigned or aggregated portion of the Unsecured Credit Limit. Such documentation may include a guaranty or similar instrument acceptable to the ISO.

Unsecured Credit Limits established through this section or through Section 12.1.1 of the ISO Tariff shall be subject to the ISO's consideration of the same qualitative factors that apply to all other Market Participants and FTR Bidders as set forth in Section A-1.3 of the ISO Credit Policy & Procedures Guide, Appendix Z to the ISO Tariff, and accordingly, the ISO may adjust their Unsecured Credit Limits pursuant to Section 12.1.1 of the ISO Tariff.

A. 5 Unsecured Credit Limit for an Unrated Governmental Entity that Receives Appropriations from the Federal Government or a State Government

An Unrated Governmental Entity that receives appropriations from the federal government or a state government that has submitted an application for an Unsecured Credit Limit shall be entitled to an Unsecured Credit Limit of the lower of the cap of 250 million dollars ($250,000,000) or the amount appropriated by the federal or relevant state government for the purpose of procuring energy and energy-related products and services for the applicable fiscal year. The Unrated Governmental Entity seeking to establish an Unsecured Credit Limit pursuant to this section shall provide documentation establishing its annual appropriations. Unsecured Credit Limits established pursuant to this section or through Section 12.1.1 of the ISO Tariff shall be subject to the ISO's consideration of the same qualitative factors that apply to all other Market Participants and FTR Bidders as set forth in Section A-1.3 of the ISO Credit Policy & Procedures Guide, Appendix Z to the ISO Tariff, and accordingly, the ISO may adjust their Unsecured Credit Limits pursuant to Section 12.1.1 of the ISO Tariff.

PART B: APPROVED FORMS FINANCIAL SECURITY

In accordance with Section 12.1.2 of the ISO Tariff, a Market Participant or FTR Bidder, at its own expense, may submit one or more of the following forms of Financial Security to meet its posting requirement (pro-forma templates are located at http://www.caiso.com/docs/2005/06/14/200506141656326466.html):

- An irrevocable and unconditional letter of credit issued by a bank or financial institution that is reasonably acceptable to the ISO;

- An irrevocable and unconditional surety bond issued by an insurance company that is reasonably acceptable to the ISO;
- An unconditional guaranty issued by a company that is reasonably acceptable to the ISO;
- A cash deposit in an escrow account maintained at a bank or financial institution that is reasonably acceptable to the ISO;
- A certificate of deposit in the name of the ISO issued by a bank or financial institution that is reasonably acceptable to the ISO;
- A payment bond certificate issued by a bank or financial institution that is reasonably acceptable to the ISO; or
- A prepayment to the ISO.

The ISO will maintain standard agreement forms related to the above types of Financial Security. In accordance with Section 12.1.2.1 of the ISO Tariff, the ISO will evaluate non-standard agreement forms for these types of Financial Security on a case-by-case basis. For those Market Participants or FTR Bidders that propose the use of a non-standard agreement form, the form would be subject to review and approval by the ISO Finance and Legal Departments. A Market Participant or FTR Bidder will be required to justify any proposed departures from the standard agreement form. The ISO shall have ten (10) Business Days from receipt of such form of Financial Security to evaluate it and determine whether it will be approved as reasonably acceptable. Significant departures from the standard agreement forms may not be accepted. The request is deemed denied if the ISO does not respond within ten (10) Business Days. It should be noted that if the need to post additional Financial Security was prompted by an additional Financial Security request based upon the latest Estimated Aggregate Liability calculation, the review process does not defer the Market Participant's obligation to post.

The standard that the ISO will use in establishing reasonable acceptability for issuing banks, financial institutions or insurance companies is that the institution have and maintain a minimum corporate debt rating of an "A-" by S&P, "A3" by Moody's, "A-" by Duff & Phelps, "A-" by Fitch or an equivalent short-term debt rating by any of these agencies.

In those cases where a Market Participant or FTR Bidder is a subsidiary or affiliate of another entity and would like to utilize the consolidated financial statements and other relevant information of that entity for obtaining credit, a signed corporate guaranty is required. A guarantor would be considered reasonably acceptable and a corresponding Financial Security Amount would be set based on the guarantor's credit evaluation according to the same procedures that a Market Participant or FTR Bidder would undergo as described in Section A-1.

Cash deposits held in escrow will be maintained in an interest bearing account. Interest will accrue to the Market Participant's or FTR Bidder's benefit and will be added to the Market Participant's or FTR Bidder's prepayment account on a monthly basis. Should a Market Participant or FTR Bidder become delinquent in payments, the Market Participant's or FTR Bidder's outstanding account balance will be satisfied using deposited funds. The Market Participant or FTR Bidder must take care to replenish used funds to ensure that it maintains a suitable level of cash to meet future financial obligations.

The ISO Tariff also permits Market Participants to make a prepayment of an upcoming bill due to the ISO. A prepayment may be used as a form of Financial Security. Prepayments to the ISO will be held in an interest-bearing account or another investment acceptable to the Market Participant and the ISO, and interest on the investment will accrue at the rate as provided for in the investment. Interest will accrue to the Market Participant's benefit and will be added to the Market Participant's prepayment account on a monthly basis. Due to the additional administrative effort involved in tracking and posting interest on such prepayments, the use of this option is not encouraged.

As provided in Section 12.1.2.3 of the ISO Tariff, the ISO shall not be held liable for any losses of funds held and invested by the ISO on the Market Participant's or FTR Bidder's behalf. Market Participants and FTR Bidders agree to bear any risk of loss of principal and/or interest of such funds. Funds will only be invested in bank accounts, high-quality money market funds or U.S. Government securities according to the ISO investment policy, unless otherwise agreed to by the Market Participant or FTR Bidder and the ISO.

In accordance with Section 12.1.2.2 of the ISO Tariff, each Market Participant or FTR Bidder shall ensure that the financial instruments it uses for the purpose of providing Financial Security will not expire and thereby cause the Market Participant's or FTR Bidder's Aggregate Credit Limit to fall below the Market Participant's or FTR Bidder's Estimated Aggregate Liability. The ISO will treat a financial instrument that does not have an automatic renewal provision and that is not renewed or replaced within seven (7) days of its date of expiration as being out of compliance with the standards for Financial Security and will deem the value of such financial instrument to be zero, and will draw upon such Financial Security prior to its stated expiration if deemed necessary by the ISO.

PART C: ESTIMATED AGGREGATE LIABILITY CALCULATION

This section describes the approach used by the ISO to determine the Financial Security posting requirements for Market Participants. Different approaches are used for new Market Participants (those without experience data with the ISO or who have been previously inactive) and for Market Participants with such data.

C-1. New Market Participants

A new Market Participant (or a Market Participant that has previously been inactive) is required to post an initial Financial Security Amount to cover a minimum of 14 days of estimated obligations as well as additional Financial Security as obligations are incurred.

This posting requirement is based on anticipated scheduling/trading practices and overall volumes. The ISO has prepared a simple template (Appendix 2) that may be used to determine an initial posting requirement. The template is an Excel worksheet located at the New Market Participant Security Calculation link http://www.caiso.com/docs/2005/06/14/200506141656326466.html.

The ISO will monitor a Market Participant's ongoing security requirement by comparing actual obligations against the estimated obligations to determine if an additional Financial Security Amount is required using the method described in Section C.2. This approach permits a Market Participant to increase its Financial Security Amount as often as weekly until the time elapsed from initial participation equals the length of the ISO payment cycle. At that time, the Financial Security Amount should be sufficient to cover 102 days transactions on an ongoing basis (The "Level Posting Period", as described in the subsequent section).

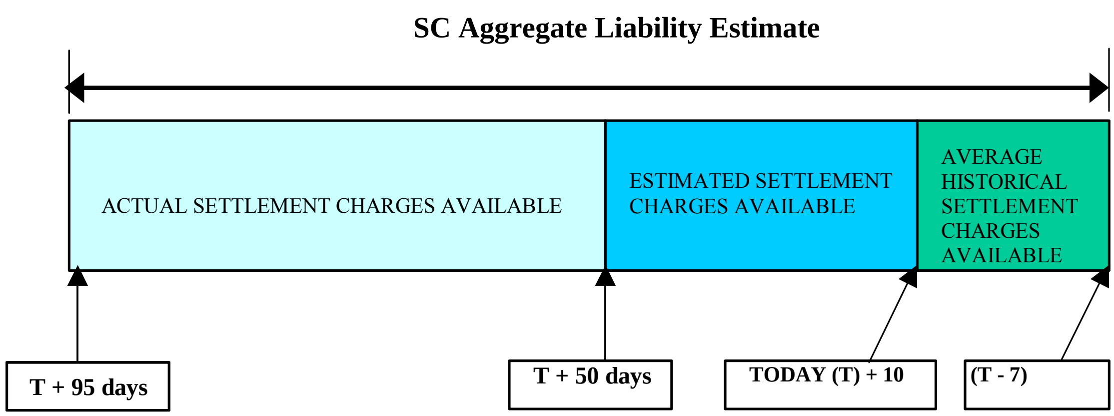
C-2. Other Market Participants - Scheduling Coordinator Aggregate Liability Estimate (SCALE) and Estimated Aggregate Liability (EAL) Overview

The Scheduling Coordinator Aggregate Liability Estimate (SCALE) application or an alternative method is used to calculate a Market Participant's Estimated Aggregate Liability, which is the estimate of unpaid obligations for a specified time period arising from charges described in the ISO Tariff.

The sum of a Market Participant's Unsecured Credit Limit and its Financial Security Amount is intended to provide coverage of not less than 100% of its Estimated Aggregate Liability. For a Market Participant that must post Financial Security because its Unsecured Credit Limit is not equal to or greater than its Estimated Aggregate Liability, the figures generated in determining the Estimated Aggregate Liability are normally the basis for determining each Market Participant's Financial Security posting requirement.

At any given time, the number of trade days of unpaid obligations to the ISO, based on the preliminary payment calendar, will be from 60-95 days, depending on the date of the last cash settlement. To avoid frequent changes to Financial Security posting requirements during the month and to allow a sufficient cushion of coverage given the allowed five day response time for Market Participants to post additional Financial Security, a "Level Posting Period" equal to 102 days is used as the basis for all Financial Security posting requirements.

The charges contributing to the Estimated Aggregate Liability are all charges outlined in the ISO Tariff. The Estimated Aggregate Liability calculation incorporates outstanding obligations, actual settlement charges, estimated settlement charges (calculated ten days after the trade date), and average historical settlement charges. The illustration below provides a representative example of what periods the different settlement charges cover in the Estimated Aggregate Liability calculation.



NOTE: The *Average Historical Settlement Charges Available* could vary between seven (7) to fourteen (14) days.

Level Posting Period EALs are calculated as follows:

1. Aggregate all outstanding, actual settlement, predictive settlement and average historical predictive obligations through a specified calendar date. For example, if the EAL analysis was conducted on 8/1/2005, the Level Posting Period would begin on June 1, 2005 and end on August 13, 2005. The following obligations would be included in the analysis:

   - Outstanding AR/AP Obligations – Any open AR/AP balances, excluding balances covered by bankruptcies.
   - Final Invoice Obligation – Those obligations not paid on the preliminary invoice.
   - Actual Settlement Obligations – June 1, 2005 to June 9, 2005.
   - Predictive Settlement Obligations – June 10, 2005 through July 25, 2005.
   - Predictive Monthly Settlement Obligations - June 1, 2005 through July 25, 2005. For month-end Charge Types, daily amounts will be calculated to reflect those amounts as they are accrued.
   - Forecasted Settlement Obligations – July 26, 2005 through August 13, 2005 based on the average predictive settlement obligations from July 11, 2005 through July 25, 2005.

2. Calculate the daily average obligation by dividing the aggregate obligations calculated in step 1 above by the total number of days between June 1, 2005 and August 13, 2005.
3. Multiply the daily average obligation calculated in step 2 above by the level posting period days (i.e., 102 days).

Level Posting Period Days – The maximum number of days outstanding for the calendar year, based on the preliminary payment calendar, plus seven days for administrative purposes; currently set at 102 days.

Predictive Settlement Obligations – The obligations calculated by the settlement system using estimated generation, load and intertie MWhs (see Appendix 1 for a description of the MWh estimation process).

For a Market Participant that maintains multiple BAID numbers, the Estimated Aggregate Liability of the Market Participant as a legal entity will be calculated by summing the Estimated Aggregate Liabilities for all such BAID numbers and comparing the sum of the Estimated Aggregate Liabilities to the Aggregate Credit Limit of the Market Participant.

C-3. Adjustments to SCALE and Use of other ISO Data to Generate Estimated Aggregate Liability

The SCALE application provides liability estimates for Market Participants that, from an aggregate perspective as well as for most individual Market Participants, are the best liability estimates available to the ISO. Prior to the use of this approach, the ISO used a mechanical projection of available settlements data over the "blind spot" for each participant for which settlements data was not yet available. That approach did not consider changes in activity levels, or most changes in market prices.

Despite the significant improvement in accuracy from the use of the SCALE approach, there are times at which the ISO or a Market Participant observes that the SCALE application may be producing a liability estimate that appears to be inaccurate. The ISO has noted this situation when certain market parameters change such as the introduction of new market charges during Phase 1B of MRTU in 2004and during the C1 Control Area Footprint change in December 2005. In such instances, the ISO will attempt to revise the SCALE algorithms to appropriately reflect such changes, and may make manual adjustments to the SCALE results to reflect known issues. Alternatively, as a result of these or other causes, the SCALE application may also be considered to be temporarily inoperative by the ISO, and another approach to calculating liabilities must be used. This approach may also be used when:

- It becomes necessary to monitor the liabilities of a Market Participant on a more frequent basis than the SCALE application provides for;
- The ISO has determined that SCALE is not producing accurate Estimated Aggregate Liabilities for one or more Market Participants; or
- In situations that arise that the automated SCALE application cannot readily accommodate, e.g., a Market Participant bankruptcy where new BAIDs are established. In such a case, the previous activity levels in the "old" BAIDs may be representative of ongoing activities levels, but this data is not readily accessible to the SCALE application to estimate liabilities for the new post-bankruptcy BAIDs.

Market Participants may also recommend changes to the liability estimates produced by the SCALE application or an alternative ISO calculation through the dispute procedures noted in Part E.

C-3.1 Calculation of Estimated Aggregate Liability Using Available Settlements Data

If the ISO determines that the SCALE application is inoperative or producing liability estimates that are of questionable accuracy, the ISO will use an alternate approach to calculate Estimated Aggregate Liabilities for Market Participants. This backup approach will rely on available settlements data.

As noted in Section C-2, the Estimated Aggregate Liability amount consists of those trade days for which actual settlement charges are available and trade days for which actual settlements charges are not yet available. This alternative approach relies on a different method for estimating charges for the trade days for which actual settlements data is not available. Specifically, estimated charges for these trade dates are estimated based on average daily charges for trade dates for which settlements data is available.

The alternative EAL method differs from the SCALE method only in the manner it estimates data to represent liability for the “blind spot” in the payment calendar. It captures the same “actual” data as in the SCALE approach, specifically:

- Outstanding AR/AP Obligations – Any open AR/AP balances, excluding balances covered by bankruptcies.
- Final Invoice Obligation – Those obligations not paid on the preliminary invoice.
- Actual Settlement Obligations – Preliminary Settlements obligations up to the date of the latest Preliminary Statement.

The 102-day Level Posting Period is utilized in both SCALE and the alternative EAL approach. Depending on when the latest Preliminary and Final invoices were paid, there will be between about 8 and 40 days of unpaid actual Preliminary Statements. There can be an additional 20 to 30 days of unpaid Final statements as well, though those days are not counted toward the 102-day total because they are only incremental and are not representative of a complete day of activity.

The remainder of days in the 102-day Level Posting Period for which unpaid Preliminary Statements are not available must be estimated. The estimate is derived by taking a daily average of published, actual charges and multiplying by the number of remaining days in the Level Posting Period. The daily average is based on all outstanding unpaid Preliminary and Final activity and an additional amount of days (as described subsequently) of historical Final Statement activity. Due to the difficulty and pitfalls of gauging “blind spot” activity on historical statements, three methods will be utilized, varying only by the number of historical months used in the derivation of daily-average amounts.

The three methods will use the same outstanding charges (i.e., available Preliminary and Final activity) but will also consider a total of either one, two, or twelve months of historical data. The process of estimation is a relatively simple one, though each Market Participant’s activity must be separated into Daily Market, Monthly Market, and GMC activity and estimated separately due to the difference in charge frequency. Appendix 1A contains additional details and an example calculation.

Once a daily average amount is derived for each market type and for each EAL method, they will be grouped by method and multiplied by the number of days remaining to fill the 102-day Level Posting Period. Thus, three Level Posting Period Estimated Aggregate Liability calculations will result. FERC Fees and other outstanding AR/AP balances will be added to each figure and the sum for each method will be divided by 0.9 in order to account for the ISO’s stated policy for Financial Security of not more than a 90% utilization rate. Any shortfall between the 90%

utilization amount of the EAL and the posted Financial Security will be considered as a potential request for additional Financial Security.

Any Market Participant that would tentatively be required to post additional Financial Security based on the Estimated Aggregate Liability calculation using any of these three methods is flagged for additional review. ISO staff will review the preliminary liability estimates resulting from the use of 12 months, 2 months and 1 months of historical settlements data. Such information is reviewed in a numeric and graphical format. ISO staff aims to select the method that best represents Market Participant activity for which settlements data is not yet available. If ISO staff determines that the Estimated Aggregate Liability for the Market Participant exceeds 90% of the Market Participant's Aggregate Credit Limit, the ISO will request additional Financial Security and will provide the supporting calculation used for the Estimate Aggregate Liability amount.

C-4. Special Circumstances

The ISO's goal is to ensure that active as well as inactive Market Participants (to the extent they are not covered by their Unsecured Credit Limits) post adequate Financial Security to cover all known and reasonably estimated potential liabilities. Various charges and collateral issues sometimes arise which require special consideration.

The ISO intends to include the following charges in the Estimated Aggregate Liability calculation, if and when such data is available, and will require Market Participants to post Financial Security accordingly. The ISO's planned Settlement and Market Clearing system upgrade is scheduled for implementation in November 2007, at which time improved data for certain of these transactions is anticipated to be available.

- **Daily Adjustments and Disputes** – Charges associated with daily adjustments and disputes that are regularly calculated by the settlement system will be included in the liability estimation calculations as the charges are calculated. There should generally be no need to attempt to forecast these amounts since they are typically relatively small and usually affect many Market Participants.

- **Refund Orders** – The ISO will assess its ability to reasonably calculate the charges associated with a refund before the ISO's settlement system is rerun. If the ISO can reasonably apportion the refund to specific Market Participants, it will include the amounts in the liability estimation process and request security accordingly. If the ISO deems that complexities of a refund order preclude it from reasonably assessing the liabilities, it will not make a security request until the refund is processed through the settlement system. However, the ISO will make available an aggregate forecast of the refund liabilities, if at all possible, to Market Participants for informational purposes only.

- **Good Faith Negotiations** – In general, Good Faith Negotiations (GFN) tend to affect the transactions of an individual Market Participant, which in turn may affect a few or many other Market Participants. Transactions associated with GFNs will be handled in the same manner as transactions associated with Refund Orders.

Other special circumstances include:

- **Debtor/Creditor Market Participants leaving the market or incurring substantial activity level changes** – Those Market Participants that are exiting the ISO markets, or that have changed their business practices resulting in substantially reduced participation in the ISO markets, will be required to maintain a Financial Security Amount at least equal to five percent (5%) of the absolute value of the peak monthly net charges from their beginning participation date to their last participation date or the date the substantial change occurred. The ISO will use this Financial Security posting requirement as a base amount and reserves the right to increase or decrease the base amount depending on the number of settlement reruns in the queue and the estimated value of those settlement reruns. The five percent (5%) residual Financial Security posting will be retained for a period of one year, unless specific circumstances warrant a change in this retention period (e.g., pending FERC ordered adjustments).

- **Past due amounts owed to SCs are not considered part of an SC's security posting**. This treatment is necessary if the ISO is to maintain the integrity of the overall settlement system, which requires that each month be settled separately. Each trade month consists of creditors and debtors whose receivables and obligations vary over time. To the extent that amounts owed to an SC related to defaults in previous months are included in the liability estimation calculation and permitted to reduce that SC's current posting requirements, the ISO will have no means to enforce the payment obligation of that SC to pay current invoices rather than refuse payment in an attempt to recoup previous past-due amounts owed to them.

C-5. Estimated Aggregate Liability Review

As provided in Section 12.4 of the ISO Tariff, Estimated Aggregate Liabilityis used to determine Financial Security posting requirements and is to be used as the basis for additional Financial Security requests, particularly when a Market Participant's calculated liability estimate exceeds 90% of its Estimated Aggregate Liability.

A Market Participant has five (5) business days to review the request for additional Financial Security and submit proposed changes that must be agreed to by the ISO. Within the five (5) business days, the Market Participant must either demonstrate to the ISO's satisfaction that the ISO's Financial Security request is all or partially unnecessary, or post the required Financial Security Amount calculated by the ISO. If the ISO and Market Participant are unable to agree on the appropriate level of Financial Security during the five (5) business day review period, the Market Participant must post the additional Financial Security and continue the dispute procedure as described in Part E. Any excess Financial Security amounts will be returned to the Market Participant if the dispute process finds in favor of the Market Participant.

C-6. Financial Security Posting Requirements

This section describes the process for determining when additional Financial Security is required and how the request for additional Financial Security is communicated to the Market Participant.

C-6.1. Financial Security Requests

As described above, to the extent a Market Participant's Unsecured Credit Limit is less than its Estimated Aggregate Liability, the Market Participant must post a Financial Security Amount. The determination of a required/recommended Financial Security Amount is based on a Market Participant's most recent ISO Estimated Aggregate Liability calculation. The ISO recommends that each Market Participant maintain an Aggregate Credit Limit such that its Estimated Aggregate Liability does not exceed 90% of its Aggregate Credit Limit. The calculation is as follows:

Recommended Aggregate Credit Limit = (Estimated Aggregate Liability) / (0.90)

The 90% level is specified in the ISO Tariff and is used as the basis for the Financial Security Amount recommended by the ISO. A Market Participant must provide an additional Financial Security Amount when its obligations reach 100 percent of its Aggregate Credit Limit. However, the ISO recommends providing additional Financial Security at the 90% level, because when a

Market Participant's Estimated Aggregate Liability exceeds 100% of its Aggregate Credit Limit, the ISO may be required to impose enforcement actions.

The Estimated Aggregate Liability calculated by the ISO for a Market Participant may fluctuate, and at times this may result in swings in Financial Security posting requirements. To the extent that the Estimated Aggregate Liability exceeds the Aggregate Credit Limit at any time, a Market Participant may be subject to enforcement actions including not being entitled to submit a schedule to the ISO. Thus, the ISO recommends that Market Participants maintain a margin of Aggregate Credit Limit above their maximum anticipated Estimated Aggregate Liability.

The Estimated Aggregate Liability is updated weekly for each Market Participant and is used to determine if additional Financial Security needs to be posted. Based on a Market Participant's Aggregate Credit Limit utilization level (which is the EAL divided by Aggregate Credit Limit), the following actions will be taken at each level listed:

Aggregate Credit Limit Utilization %	**Action**
< 50%.	No notice or action taken.
≥50% and < 70%	Market Participant notified for information only.
≥70% and < 90%	Market Participant notified of a *recommended* security increase. The ISO recommends, but does not require, that an additional posting is made to maintain the SCALE at or below 70%.
≥90%	The ISO *requests* that a Market Participant increase the posting amount within five business days so that the security utilization does not exceed 90 percent. If the Market Participant takes no action in response to the recommendation to post additional security, upon reaching 100 percent security utilization, they will be subject to the enforcement provisions of the ISO Tariff as described in Section D, Enforcement, including potential rejection of schedules.

C-6.2. Financial Security Requests Communication

Each week the ISO Finance calculates each Market Participant's Estimated Aggregate Liability and notifies the ISO's customer service representatives of the Estimated Aggregate Liability amount and any recommended increases in the Market Participant's Financial Security Amount. These communications contain specific information regarding the amount each Market Participant needs to post Financial Security in order to maintain the recommended 90% ratio described above as well as the minimum amount needed so that the Market Participant's Estimated Aggregate Liability does not exceed its Aggregate Credit Limit.

The ISO customer service representative is to contact any Market Participant for which an increase in Financial Security is recommended or required within one (1) business day.

The customer service representative should copy ISO Finance on all security related client correspondence. The ISO customer service representatives will communicate with the ISO Finance and Market Participants to address questions related to the request.

A required increase in the Financial Security Amount is to be resolved within five (5) business days. Each Market Participant not in compliance with the requirement that its Estimated Aggregate Liability be less than its Aggregate Credit Limit is subject to enforcement procedures as described in Part D.

C-6.3. FTR Auction Financial Security Requirements

The credit requirements related to participation in the ISO's annual Firm Transmission Rights (FTR) are the same as those for other market obligations. Auction requirements are set forth in the FTR Bidders Manual published annually by the ISO. A FTR Bidder's ACL must be sufficient to not only cover ongoing estimated liabilities but also the liabilities resulting from potential winning bids. Each FTR Bidder may choose to designate a portion of their UCL and/or posted Financial Security specifically for the FTR auction by notifying the ISO of the FTR Bidder's intent. Alternatively, the FTR Bidder may choose to post additional Financial Security solely to cover their participation in the FTR auction by notifying the ISO of the purpose for the additional Financial Security.

PART D. ENFORCEMENT

Following the date on which a Market Participant commences trading, if a Market Participant's Estimated Aggregate Liability, as calculated by the ISO, at any time exceeds its Aggregate Credit Limit, the ISO may take any or all of the following actions in accordance with Section 12.5 of the ISO Tariff:

(a) The ISO may withhold a pending payment distribution.

(b) The ISO may limit trading, which may include rejection of Schedules and/or limiting other ISO market activity. In such case, the ISO shall notify the Market Participant of its action and the Market Participant shall not be entitled to submit further Schedules to the ISO until the Market Participant posts an additional Financial Security Amount that is sufficient to ensure that the Market Participant's Aggregate Credit Limit is at least equal to its Estimated Aggregate Liability.

(c) The ISO may require the Market Participant to post an additional Financial Security Amount in lieu of an Unsecured Credit Limit for a period of time.

(d) The ISO may restrict, suspend, or terminate a Market Participant's Service Agreement.

In addition, the ISO may restrict or suspend a Market Participant's right to schedule or require the Market Participant to increase its Financial Security Amount if at any time such Market Participant's potential additional liability for Imbalance Energy and other ISO charges is determined by the ISO to be excessive by comparison with the likely cost of the amount of Energy scheduled by the Market Participant.

PART E. DISPUTE PROCEDURES

The ISO provides Market Participants the ability to dispute the Estimated Aggregate Liability calculated by the ISO and, as a result, the ISO may reduce or cancel a requested Financial Security adjustment. The following steps are required for a Market Participant to dispute a Financial Security request resulting from the ISO's calculation of Estimated Aggregate Liability:

1. Request by the Market Participant to review the ISO calculation.

2. Reasonable and compelling situation presented, as determined by the Market Participant's ISO client representative.

3. Documentation of facts and circumstances that evidence that the ISO's calculation of Estimated Aggregate Liability results in an excessive and unwarranted Financial Security posting requirement.

    a. Examples include:
        i. Issues related to non-recurring retroactive charges.

ii. Demonstrable changes in expected obligations as a result of physical changes (new capacity, loss of customers).
iii. Other issues.

b. Presentation of a reasonable alternative Estimated Aggregate Liability.
c.

4. Approval by the ISO Manager and/or Director of Customer Services and Industry Affairs and approval by the ISO Treasurer.

5. The ISO may decline to adjust the initial Estimated Aggregate Liability, as calculated using the SCALE application, if the Market Participant has had Financial Security shortfalls in the past 12 months (i.e., it has been shown that the Market Participant's Aggregate Credit Limit at times during the preceding 12 months has been insufficient to cover the Market Participant's Estimated Aggregate Liability).

In no such case shall an ISO request for increased Financial Security remain outstanding for more than five (5) business days. Either the above process is to be completed within five (5) business days from the date of the ISO request for additional Financial Security, or the Market Participant is to post additional Financial Security within the five (5) business days and continue this process, which may result in a return of posted Financial Security back to the Market Participant if the results of the dispute process are found to favor the Market Participant.

Factors for consideration in the event these procedures are utilized include:

Weighing the risk of using the lower figure to the potential detriment of market creditors if the Market Participant is under-secured and defaults, against the desire not to impose additional potentially unwarranted costs on a Market Participant.

Equity and consistency of treatment of Market Participants in the dispute procedure.

The evidentiary value of the information provided by the Market Participant's in the dispute procedure.

APPENDIX 1: Scheduling Coordinator Aggregate Liability Estimate Measurement File Development Process

INTRODUCTION

The following information provides background and an overview of the operation of the SCALE liability estimation process. This section focuses on the measurement file development process to develop proxies for missing meter data. This allows the ISO to use available operational to estimate current liabilities.

DEVELOPMENT PROCESS

Defined Terms

EMS Utility Distribution Control Area (UDC) Load – The ISO control area load MWhs aggregated at the PG&E, SCE and SDG&E level.

Generation Deviation Allocation Flag – The generation deviation allocation flag denotes which Market Participant load profiles are allocated generation deviation/Unaccounted for Energy (UFE) MWhs.

Load Profiles

Annual Load Profile – Load profile developed from actual meter MWhs for the period of Trade Date (T) + 50 to T+415.

Current Load Profile – Load profile developed from actual meter MWhs for period of T+50 to T+80.

Schedule Load Profile – Load profile developed from scheduled meter MWhs for the period of T+1 to T+49.

Seasonal Load Profile – Load profile developed from actual meter MWhs for the prior season.

Short-Term Schedule Load Profile - Load profile developed from scheduled meter MWhs for the period of T+1 to T+14.

Load Profile Adjustment Percentage – The load profile adjustment percentage is calculated as the percentage variance between actual metered load and allocated EMS UDC Load. This percentage is utilized to develop actual metered load, utilized by the settlement system, from allocated EMS UDC Load.

Meter Load to Scheduled Load Adjustment Percentage – The meter load to scheduled load adjustment percentage is calculated as the variance between actual meter load and scheduled load. The percentage is utilized to create representative meter load from scheduled load.

Off-Peak – This term represents the day of the week to which a load profile corresponds. The Off-Peak days of the week include: Saturday, Sunday and Holidays.

On-Peak –This term represents the day of the week to which a load profile corresponds. The On-Peak days of the week include: Monday, Tuesday, Wednesday, Thursday and Friday.

Other Adjustment Percentage – For a Market Participant whose load profiles and adjustment percentages do not reflect its load, the other adjustment percentage approach is utilized. This approach is only rarely used.

Use Meter Load to Scheduled Load Adjustment Percentage Flag – This flag identifies those calculated Market Participant load profiles that are subsequently adjusted by the meter load to scheduled load adjustment percentage.

Use Scheduled Load Flag – This flag identifies those Market Participants where utilization of scheduled load a proxy for metered load is appropriate.

Market Participant Liability Estimations

In 2003, the focus of the Scheduling Coordinator Aggregate Liability Estimation (SCALE) project was on the development of settlement statements seven days after the trade date using a system that is essentially a copy of the settlement system with missing load, generation and intertie data derived from a combination of meter, telemetry and estimated data from other systems. In order for the SCALE application to effectively and accurately calculate participant liabilities, three essential data inputs are needed: load, generation and intertie MWhs. It was determined that 75 to 80 percent of generation and intertie MWhs are derived from the ISO polled meter data stored in the ISO's Data Warehouse. However, the load MWhs were not available until 45 days after the trade date. Thus, the main focus of the SCALE project team's efforts to was on the estimation of load data. The analysis conducted produced the following findings:

1. Utilization of current actual meter load profiles, which are based on meter data that is 50 to 80 days old, to allocate EMS UDC Load, did not alone accurately reflect a Market Participant's current position in the market. For example, a Market Participant's load profile based on past data would not accurately reflect a situation where it has transferred its load/customers to another Market Participant.

2. Utilization of annual load profiles to allocate EMS UDC Load in many instances did not reflect load increases or decreases that appear over time. For example, since September 2001, certain Market Participants have acquired a substantial amount of load from other Market Participants, but the annual load profiles generated did not reflect this load shift.

3. Utilization of schedules to estimate system load and to derive participant liabilities did not reflect the actual daily system load or participant imbalances. This was mainly due to a Market Participant's ability to schedule whatever amount of load that it chooses. Analysis of Market Participant scheduling patterns has shown that many Market Participants' schedules are closely related to their actual metered quantities. However, Market Participant scheduling practices may not be consistent.

4. After conducting an analysis of the load estimation methodologies above, it was determined that all three methods should be combined to provide for a more accurate load estimate. The methodology, outlined below, includes the information gathered through the liability estimation process.

Additional areas that the SCALE team worked on were the estimation of the remaining 15 to 25 percent of missing generation and intertie MWhs. The team developed a methodology to estimate the remaining generation and intertie MWhs, and an explanation of the methodology is outlined below.

Load Estimation Methodology

As mentioned in the previous section, three approaches were considered to estimate load MWhs and each had significant shortcomings that precluded them from being utilized exclusively. By utilizing each of the methodologies in conjunction with each other, a proxy for metered load was developed that more closely represented each participant's position in the market. The following are the steps created to develop a Market Participant's load estimate.

1. **Develop Load Profiles** - Development of each Market Participant's "On-Peak" (Monday through Friday) and "Off-Peak" (Saturday, Sunday and Holidays) hourly load profiles by UDC area. The load profiles developed consist of:
   - Annual Load Profiles,
   - Seasonal Load Profiles,
   - Current Load Profiles,
   - Scheduled Load Profiles, and
   - Short-Term Scheduled Load Profiles.
2. **Select Load Profile** – Once the load profiles are developed for a given time period, the next step in the load estimation process is to determine which load profile (Annual, Seasonal, Current etc) most closely reflects a Market Participant's actual position in the market. For example, the EMS UDC Load from 12/16/2002 to 1/15/2003 is allocated to each of the load profiles listed above. Next, the allocated MWhs for each set of profiles is compared against the actual metered MWhs for the same time period 12/16/2002 to 1/15/2003. The load profile that best represents a Market Participant's actual meter MWhs is utilized for subsequent load allocations.
3. **Calculate / Select Load Profile Adjustment Percentages and Load Profile Application Flags** – The following adjustment percentages and load profile application flags, which are defined above, are calculated or selected to be utilized in subsequent calculations:
   - Load Profile Adjustment Percentage,
   - Meter Load to Scheduled Load Adjustment Percentage,
   - Other Adjustment Percentage,
   - Use Meter Load to Scheduled Load Adjustment Percentage Flag, and
   - Use Scheduled Load Flag.

   (note: the results of steps 1 thru 3 are utilized for a designated period, such as 30 days)

4. **Validate EMS UDC Load** – EMS UDC Load validation for each trade date is conducted to ensure that the data derived from EMS does not include significant outlier MWhs. The calculation includes comparing an historical EMS load profile (T+1 to T+50) to the current trade date load profile. Where the current load profile MWh does not meet the 15 percent tolerance level, the current EMS MWh value is adjusted to within tolerance.

5. **Allocate EMS UDC Load** – Next, the ISO will utilizes the selected load profile for determining the MP's hourly load to allocate EMS UDC Load. The following steps are required for the allocation of EMS UDC Load:
   i. The EMS UDC Load is allocated to MP's based on the following formula (all calculations are conducted on an hourly basis):
      - Where Use Schedule Load Flag = "True"; Scheduled Load * (1+Meter Load to Scheduled Load Adjustment Percentage)

- Where Use Schedule Load Flag = "False" and Use Meter Load to Scheduled Load Adjustment Percentage Flag = "True", EMS UDC Load * Selected Load Profile / 1000 * (1+ Load Profile Adjustment Percentage) * (1+ Other Adjustment Percentage) * (1+ Meter Load to Scheduled Load Adjustment Percentage),
- Else, EMS UDC Load * Selected Load Profile / 1000 * (1+ Load Profile Adjustment Percentage) * (1+ Other Adjustment Percentage)

ii. The value of Hourly EMS UDC Load * Selected Load Profile is divided by 1000 because the hourly load profile percentages derived are multiplied by 1000 for data representation purposes.

6. **Calculate Generation Deviation / Unaccounted for Energy (UFE) Quantity by UDC** - For each UDC, a Generation Deviation / UFE calculation is completed, which provides a residual amount of Load MWhs that are allocated to designated Market Participants on a *pro rata* basis. The purpose of the calculation and load MWh allocation is to minimize Charge Type 406 UFE charges. The UFE calculation is outlined in the settlement and billing protocols under CT 406. The allocation process is as follows (all calculations are conducted on an hourly basis):

   i. Where Generation Deviation Allocation Flag = "False", MP Load + (UDC UFE *MP Load / Total UDC Load where Generation Deviation Allocation Flag = "False").

7. **Load Distribution and Upload** – Upon deriving the load MWhs to be utilized in the settlement statement calculation, the MWhs are distributed to each Market Participant's valid resources IDs in the following manner and then uploaded into the SCALE application.

   i. Development of a list of valid metered and scheduled resources utilized by each MP over a given time period (T+1 to T+80).

   ii. Allocate the estimated load to the valid resources on a weighted basis by hour. For all resources that have both metered quantities and scheduled quantities, metered quantities will be utilized for weighting purposes. Resources that have scheduled quantities and no metered quantities are assumed to be recently utilized resources and scheduled quantities will be used for weighting purposes.

   iii. Allocate the resource quantities calculated above evenly across the six sub-hour interval levels for upload into the measurements table in the SCALE application.

Generation Estimation Methodology

As mentioned above, at T+7 approximately 15 to 25 percent of generation meter data is not available. The following is an explanation of the methodology utilized to develop a proxy for the missing generation meter data.

The ISO determined that the missing generation data consists of the following:

1. The ISO polled unit MWhs that were either not available at T+7 or were being worked on by the metering department at the time of the T+7 data push, and
2. Qualifying Facility (QF) unit and other non-polled unit MWhs.

The process for determining the remaining generation data is based on EMS and schedule data.

1. **Download T+7 Meter Data Acquisition System (MDAS) Generation Data** – For the trade date being worked on, all generation data available in the T+7 measurement table is downloaded for analysis purposes.
2. **Download Scheduled Generation Data** – From Market Operation's Scheduling Infrastructure (SI) database, download hourly scheduled generation by resource ID.
3. **Download Real Time (RT) Dispatch Data** – From Market Operation's SI database, download hourly real time dispatched data by resource ID.
4. **Download EMS Data from Plant Information (PI)** – A table has been developed from information provided by Market Operations that contains approximately 800 generation resource IDs mapped to the appropriate PI tags. Using the PI tags, generation unit hourly EMS MWhs are downloaded from PI.
5. **Download Actual Meter & Schedule Data** – From the Data Warehouse, download actual metered and scheduled quantities for a period of T+50 to T+80 for analysis purposes.
6. **Utilization of T+7 MDAS Generation Data** – Where T+7 MDAS generation data exists for a particular resource, even if the measurement quantity is zero, use this value. (Between 75 and 85 percent of all generation MWhs.)
7. **Utilization of EMS Generation Data** – Where MDAS data is not available and Dispatched Generation MWh >0 and EMS MWh >0, use EMS MWhs. (Approximately 18.75 percent of all generation MWhs.)
    a. Dispatched Generation MWh = Scheduled Generation MWh + RT Dispatched Generation MWh
    b. Where the EMS MWh * 1.15 is greater than the maximum generation capacity of the unit utilize the maximum generation capacity of the unit.
8. **Utilization of Dispatched/Scheduled Generation MWhs** – Where MDAS data is not available and Dispatched Generation MWh >0 and EMS MWh = 0, use Adjusted Dispatched / Scheduled Generation MWh. (Approximately 6.25 percent of all generation MWhs.)

    a. Adjusted Dispatched Generation MWh =
        i. For all Dispatched / Scheduled Generation MWhs >=1 MWh, Dispatched / Scheduled Generation MWhs* 1+(Hourly Metered vs. Scheduled Generation Variance Percentage)
    b. Resource Historical Metered vs. Scheduled Variance Percentage (T+50 to T+80) = (average hourly metered MWh – average hourly scheduled MWh) / average hourly scheduled MWh
9. **Upload the Developed MWhs to the SCALE Application** - Allocate the resource quantities calculated above evenly across the six sub-hour interval levels for upload into the measurements table in the SCALE application.

Intertie/Intratie (TIE) Estimation Methodology

Currently, 75 to 80 percent of the TIE data is available from the ISO polled meters. The process for determining the remaining intertie MWhs is based on the utilization of EMS data and allocated load MWhs derived in the Load Estimation Methodology for various intraties.

1. **Download T+7 MDAS Intertie Data** – For the trade date being estimated, all TIE data available in the T+7 measurement table is downloaded for analysis purposes.
2. **Download EMS Data from PI** – A table has been developed from information provided by Market Operations that contains TIE resource IDs mapped to the appropriate PI tags. Using the PI tags, TIE hourly EMS MWhs are downloaded from PI.
3. **Utilization of T+7 MDAS Intertie Data** – Where T+7 MDAS TIE data exists, use MDAS data. (Approximately 84 percent of all TIE MWhs.)
4. **Utilization of EMS Intertie Data** – Where MDAS data is not available use the EMS data. (Approximately 13 percent of all TIE MWhs.)
5. **Utilization of Load Data** – For intratie IDs, utilize the amount calculated as load as the intratie MWhs where appropriate. (Approximately 3 percent of all TIE MWhs.)
6. **Upload the Developed MWhs to the SCALE Application** - Allocate the resource quantities calculated above evenly across the six sub-hour interval levels for upload into the measurements table in the SCALE application.

SCALE Data Development Conclusion

The above steps describe how missing meter MWh data is developed for an estimated T+7 settlement run. Further enhancements to this process may be forthcoming as the process is transitioned to a permanent software tool, planned for November 1, 2007 when the ISO's new Settlement and Market Clearing System (SaMC) is implemented.

APPENDIX 1A: ALTERNATIVE ESTIMATED AGGREGATE LIABILITY CALCULATION

To assist Market Participants in understanding and verifying the ISO's alternative EAL calculation, the following section provides additional details and an example calculation. As described in Section 3.1, the ISO initially evaluates a Market Participant's liability by deriving three estimates which vary only by the number of months used in derivation of the daily average liability amounts. ISO Staff review the preliminary estimates to determine which appears to be most representative of the likely actual liability, and may request additional collateral based on that estimate. A summary report detailing the alternative EAL calculation will be provided to any Maket Participant requested to post additional security, or at any time when requested by the Market Participant. The report will highlight only the method that is deemed by the ISO to be most representative of the Market Participant's liability, however all three methods are available upon request as well.

This Estimated Aggregate Liability (EAL) Report presents most of the details of the calculation, which should be verifiable by the Market Participant using published Settlements Statements. Adding all outstanding, unpaid, published Settlements activity to an estimate of the remaining liability in the 102-day period results in the Level Posting Period EAL.

For example, assume that the EAL is calculated on Friday, June 16, 2006. On this day there are 23 days of published Preliminary Statements along with 4 days of Final Statements for the month of April. All of this activity will be summed for April and will account for 23 days out of the required 102 days. The Preliminary Statement has been paid for March; therefore no days in March will be counted in the Level Posting Period. However, there are still incremental charges in March on Final Statements that have been invoiced but not paid, and therefore will be included in the liability amount.

Now an estimate must be derived for the remaining seven days of April, along with an additional 72 days that make up the Level Posting Period (23+7+72=102). The estimate is based on a calculated daily average amount for all Charge Types. For simplicity, the Charge Types are aggregated into three categories: Daily Market (Imbalance Energy, Ancillary Services, etc.), Monthly Market (Wheeling, Transmission, etc), and GMC. The following table entitled "**Charge Type Category List"** lists all Charge Types and their category designation.

The averages for all three categories will be calculated using the same time period, based on either one, two or twelve months of historical Settlements data. In the one-month method, the time-period for derivation of daily averages will include 23 days of April published data, 30 days of March published data (because the month is still open), and one additional month of previously paid Settlement activity, specifically the month of February. For purposes of our example, assume that all outstanding, published obligations net to a total of $7,000.

To derive a daily average amount for the category of 'Daily Market' charge types, sum all charge type amounts in this category (see attached table) from February 1 to April 23 and divide by 82 (28+31+23). Assume the result is $100 per day.

To derive the daily average of 'Monthly Market' charges, sum all charge type amounts in this category from February 1 to March 31. Due to the fact that these charge types accrue only on the last day of the month, there is no reason to consider the range of April 1 to April 23 at this time. Divide the amount by 60 days for the two-month period. Assume the result is $50 per day.

Lastly, derive the 'GMC' category charges in the same manner as the 'Monthly Market' charges and divide by 60. Assume the result is $25.

Now combine the results and calculate 102-day Liability.

Outstanding obligations: calculated above for the 23 days of April Prelims and 30 days of March Finals, includes 'Daily Market', 'Monthly Market' (incremental Final), and 'GMC' (incremental Final)

$ 7,000 *(23 days)*

'Daily Market' Estimate: 7 days in April, 31 days in May, 30 days in June, 11 days in July

$ 100 * (7+31+30+11) = $ **7,900** *(79 days)*

'Monthly Market' Estimate: 30 days in April, 31 days in May, 30 days in June, 11 days in July

$ 50 * (30+31+30+11) = **$ 5,100** (102 days)

'GMC' Estimate: 30 days in April, 31 days in May, 30 days in June, 11 days in July

$ 25 * (30+31+30+11) = **$ 2,550** (102 days)

Total 102-day Level Posting Period EAL:

$ 7,000 + $ 7,900 + $ 5,100 + $ 2,550

= $ 22,550

The other two methods are calculated in the same manner while adding additional months of historical Settlements data.

Charge Type Category List:

Frequency	Charge Type	Charge Type Description	Service Type
Daily	1	Day-Ahead Spinning Reserve due SC	Ancillary Services
Daily	2	Day-Ahead Non-Spinning Reserve due SC	Ancillary Services
Daily	3	Day-Ahead AGC/Regulation due SC	Ancillary Services
Daily	4	Day-Ahead Replacement Reserve due SC	Ancillary Services
Daily	5	Day-Ahead Regulation Up due SC	Ancillary Services
Daily	6	Day Ahead Regulation Down due SC	Ancillary Services
Daily	24	Dispatched Replacemnt Res (Bid-in) Capacity Withhold	Ancillary Services
Daily	51	Hour-Ahead Spinning Reserve due SC	Ancillary Services
Daily	52	Hour-Ahead Non-Spinning Reserve due SC	Ancillary Services
Daily	53	Hour-Ahead AGC/Regulation due SC	Ancillary Services
Daily	54	Hour-Ahead Replacement Reserve due SC	Ancillary Services
Daily	55	Hour Ahead AGC/Regulation Up due SC	Ancillary Services
Daily	56	Hour AHead AGC/Regulation Down due SC	Ancillary Services
Daily	61	Hour-Ahead RMR Preempted Spinning Reserve	RMR
Daily	62	Hour-Ahead RMR Preempted Non-Spinning Reserve	RMR
Daily	64	Hour-Ahead RMR Preempted Replacement Reserve	RMR
Daily	65	Hour-Ahead RMR Preempted Regulation Up	RMR
Daily	66	Hour-Ahead RMR Preempted Regulation Down	RMR
Daily	71	Real Time RMR Preempted Spin Reserve (DA Price)	RMR
Daily	72	Real Time RMR Preempted Non-Spin Reserve (DA Price)	RMR
Daily	74	Real Time RMR Preempted Replacement Reserve (DA Price)	RMR
Daily	75	Real Time RMR Preempted Regulation Up (DA Price)	RMR
Daily	76	Real Time RMR Preempted Regulation Down (DA Price)	RMR
Daily	81	Real Time RMR Preempted Spin Reserve (HA Price)	RMR
Daily	82	Real Time RMR Preempted Non-Spin Reserve (HA Price)	RMR
Daily	84	Real Time RMR Preempted Replacement Reserve (HA Price)	RMR
Daily	85	Real Time RMR Preempted Regulation Up (HA Price)	RMR
Daily	86	Real Time RMR Preempted Regulation Down (HA Price)	RMR
Daily	101	Day-Ahead Spinning Reserve due ISO	Ancillary Services
Daily	102	Day-Ahead Non-Spinning Reserve due ISO	Ancillary Services
Daily	103	Day-Ahead AGC/Regulation due ISO	Ancillary Services
Daily	111	Spinning Reserve due ISO	Ancillary Services
Daily	112	Non-spinning Reserve due ISo	Ancillary Services
Daily	114	Replacement Reserve due ISO	Ancillary Services
Daily	115	Regulation Up due ISO	Ancillary Services

Frequency	Charge Type	Charge Type Description	Service Type
Daily	116	Regulation Down due ISO	Ancillary Services
Daily	124	Dispatched Replace Res (Self-Prov.) Capacity Withhold	Ancillary Services
Daily	130	Insufficient Energy in Response to ISO Instructions	Misc
Daily	131	Reduct. in Avail. Cap. due to Uninst. Dev. due ISO	Misc
Daily	141	No Pay Charge - Spinning Reserve	No Pay
Daily	142	No Pay Charge - Non-Spinning Reserve	No Pay
Daily	144	No Pay Charge - Replacement Reserve	No Pay
Daily	145	No Pay Charge - Regulation Up	No Pay
Daily	146	No Pay Charge - Regulation Down	No Pay
Daily	151	Hour-Ahead Spinning Reserve due ISO	Ancillary Services
Daily	152	Hour-Ahead Non-Spinning Reserve due ISO	Ancillary Services
Daily	153	Hour-Ahead AGC/Regulation due ISO	Ancillary Services
Daily	201	Day-Ahead Intra-Zonal Congestion Incs/Decs Settlement	Congestion
Daily	202	Day-Ahead Intra-Zonal Congestion Charge Refund	Congestion
Daily	203	Day-Ahead Inter-Zonal Congestion Settlement due SC	Congestion
Daily	204	Day-Ahead Inter-Zonal Congestion Settlement due TO	Congestion
Daily	251	Hour-Ahead Intra-Zonal Congestion Settlement	Congestion
Daily	252	Hour-Ahead Intra-Zonal Congestion Charge Refund	Congestion
Daily	253	Hour-Ahead Inter-Zonal Congestion Settlement due SC	Congestion
Daily	254	Hour-Ahead Inter-Zonal Congestion Settlement due TO	Congestion
Daily	255	Hour-Ahead Inter-Zonal Congestion Debit to TOs	Congestion
Daily	256	Hour-Ahead Inter-Zonal Congestion Debit due SC	Congestion
Daily	271	Real-time Intra-zonal Congestion INC/DEC Settlement	Imbalance Energy
Daily	272	Real-time Above MCP Costs for Non-Market Dispatches	Excess Costs
Daily	301	Supplemental and A/S Energy	Reliability
Daily	303	Ex-Post Replacement Reserve due ISO (Dispatched)	Ancillary Services
Daily	304	Ex-Post Replacement Reserve due ISO (Undispatched)	Ancillary Services
Daily	353	Contracted Black Start due SC	Reliability
Daily	401	Instructed Energy	Imbalance Energy
Daily	402	Generation Deviation Settlement	Imbalance Energy
Daily	403	Load Deviation Settlement	Imbalance Energy
Daily	404	Export Deviation Settlement	Imbalance Energy
Daily	405	Import Deviation Settlement	Imbalance Energy
Daily	406	UFE Settlement	Imbalance Energy
Daily	407	Uninstructed Energy	Imbalance Energy
Daily	410	Unscheduled RMR Energy	Imbalance Energy
Daily	451	Real-Time Intra-Zonal Congestion Incs/Decs Settlement	Congestion
Daily	452	Real-Time Intra-Zonal Congestion Charge/Refund	Congestion

Frequency	Charge Type	Charge Type Description	Service Type
Daily	481	Excess Cost for Instructed Energy	Imbalance Energy
Daily	485	Insufficient Response to AWE Instruction	Penalties
Daily	487	Allocation of Excess Cost for Instructed Energy	Imbalance Energy
Daily	499	Interest due SC	Misc
Daily	502	Generation Deviation Effective Price	Imbalance Energy
Daily	503	Load Deviation Effective Price	Imbalance Energy
Daily	505	Import Deviation Effective Price	Imbalance Energy
Daily	547	Uninstructed Deviation Penalty Charges Due ISO	Penalties
Daily	1003	Regulation Energy Payment Adjustment	Adjustments
Daily	1004	Over-Generation Payment Due SC	Reliability
Daily	1010	Neutrality Adjustment Charge/Refund	Imbalance Energy
Daily	1011	Ancillary Service Rational Buyer Adjustment	Ancillary Services
Daily	1012	RMR Preemption Revenue Allocation	RMR
Daily	1013	REPA Cash Neutrality Charge	Reliability
Daily	1030	No Pay Provision Market Refund	No Pay
Daily	1061	Distribution of Preempted Spinning Reserve	RMR
Daily	1062	Distribution of Preempted Non-Spinning Reserve	RMR
Daily	1064	Distribution of Preempted Replacement Reserve	RMR
Daily	1065	Distribution of Preempted Regulation Up	Ancillary Services
Daily	1066	Distribution of Preempted Regulation Down	Ancillary Services
Daily	1104	Over-Generation Payment Due ISO	Reliability
Daily	1210	Existing Contracts Cash Neutrality Charge/Refund	Misc
Daily	1277	Real-time Intra-zonal Congestion Charge/Refund	Imbalance Energy
Daily	1278	Alloc of AboveMCP Cost for Real-Time Non-Mkt Dsptch	Excess Costs
Daily	1303	Supplemental Reactive Energy due ISO	Reliability
Daily	1401	Imbalance Energy Offset	Imbalance Energy
Daily	1407	Deviation Penalty for Positive Uninstructed Deviation	Penalties
Daily	1470	Neutrality Charge for UDP Penalties	Penalties
Daily	1471	Excess Cost Neutrality Settlement	Excess Costs
Daily	1481	Excess Cost Allocation - Neutrality Adjustment	Excess Costs
Daily	1487	Energy Exchange Program Neutrality Adjustment	Adjustments
Daily	1680	Allocation of Bid Cost Recovery	Reliability
Daily	1999	Rounding Charge/Refund	Misc
Daily	2009	ISO/SC Distribution/Allocation	Misc
Daily	2010	Finance Charges	Misc
Daily	2020	Must Run due ISO	Misc
Daily	2407	Deviation Penalty for Negative Uninstructed Deviation	Penalties
Daily	2900	CONTINGENCY-Net Manual Market Invoice	Misc
Daily	4141	No Pay Settlement for Spin Capacity	No Pay
Daily	4142	No Pay Settlement for Non Spin Capacity	No Pay
Daily	4144	No Pay Settlement for Replacement Reserve Capacity	No Pay
Daily	4271	Reliability Excess Cost Settlement - Due SC	Imbalance Energy
Daily	4272	OOM Congestion Excess Cost Settlement - Due SC	Imbalance Energy
Daily	4401	Instructed Energy Settlement	Imbalance Energy

Frequency	Charge Type	Charge Type Description	Service Type
Daily	4406	Settlement of Unaccounted for Energy	Imbalance Energy
Daily	4407	Uninstructed Energy Settlement	Imbalance Energy
Daily	4410	Unscheduled RMR Energy	Imbalance Energy
Daily	4450	Transmission Loss Settlement	Imbalance Energy
Daily	4470	Negative Uninstructed Deviation Penalty	Penalties
Daily	4480	Positive Uninstructed Deviation Penalty	Penalties
Daily	4481	Settlement of Excess Cost - Due SC	Imbalance Energy
Daily	4487	Allocation of Excess Cost - Due ISO	Imbalance Energy
Daily	4660	Hrly Pre Dispatch Bid Cost Recovery Settlement	Excess Costs
Daily	4680	Settlement of Bid Cost Recovery	Excess Costs
Daily	4999	Neutrality Adjustment	Adjustments
Daily	5900	Shortfall Receipt	Misc
Daily	5910	Shortfall Allocation	Misc
Daily	5999	FERC Interest	Misc
Daily	6601	Communication Fees	Misc
Daily	6602	Training Fees	Misc
Daily	6603	Miscellaneous Fees	Misc
Daily	6604	OSAT Training Revenues	Misc
Daily	6605	Metering Training Revenues	Misc
Daily	6606	WSCC Revenues	Misc
Daily	6607	Detailed Wheeling Spreadsheet Fees	Misc
Daily	6608	Archived Settlement Statements Retrieval Fee	Misc
Daily	6609	Station Power Fee	Misc
Daily	6610	Station Power Fee Allocation	Misc
Daily	6611	Security Refund	Misc
Daily	6612	ISO Services for GCP	Misc
Daily	6616	FTR Auction	Misc
Daily	6701	Market Invoice	Misc
Daily	6702	GMC Invoice	Misc
Daily	6703	FERC Invoice	Misc
Monthly	7	Demand Relief Monthly Payment	Misc
Monthly	117	Demand Relief Monthly Charge	Misc
Monthly	302	Ex-Post Supplemental Reactive Power due TO	Reliability
Monthly	354	Wheeling Refund due TO	Wheeling
Monthly	372	High Voltage Access Charge due ISO	TAC
Monthly	374	High Voltage Access Revenue due PTO	TAC
Monthly	382	High Voltage Wheeling Charge due ISO	Wheeling
Monthly	383	Low Voltage Wheeling Charge due ISO	Wheeling
Monthly	384	High Voltage Wheeling Revenue due TO	Wheeling
Monthly	385	Low Voltage Wheeling Revenue due TO	Wheeling
Monthly	550	FERC Fees	FERC Fees
Monthly	591	Emissions Cost Recovery	Uplift Fees
Monthly	592	Start-Up Cost Recovery	Uplift Fees
Monthly	593	Emissions Cost Due Trustee	Uplift Fees
Monthly	594	Start-Up Costs Due Trustee	Uplift Fees
Monthly	595	Minimum Load Cost Allocation Due ISO	Reliability
Monthly	691	Emission Cost Payment	Uplift Fees

Frequency	Charge Type	Charge Type Description	Service Type
Monthly	692	Startup Cost Payment	Uplift Fees
Monthly	695	Minimum Load Cost Compensation Due SC	Reliability
Monthly	701	Forecasting Service Fee	Misc
Monthly	702	Forecasting Service Fee Allocation	Misc
Monthly	711	Intermittent Resources Net Deviations	Imbalance Energy
Monthly	721	Intermittent Resources Net Deviation Alloc Charge	Imbalance Energy
Monthly	731	Intermittent Resources Uninstructed Deviation	Imbalance Energy
Monthly	790	Market Transaction Bill Period Adjustment	Adjustments
Monthly	791	Grid Management Charge Bill Period Adjustment	Adjustments
Monthly	792	FERC Fee Bill Period Adjustment	Adjustments
Monthly	793	Transmission Access Charge Refund Bill Period Adj	Adjustments
Monthly	1001	Black start due BA	Reliability
Monthly	1101	Black Start Capacity due ISO	Reliability
Monthly	1120	Est. Summer Reliab. Contract Capacity Pymt/Charge	Reliability
Monthly	1121	Act. Summer Reliab. Contract Capacity Pymt/Charge	Reliability
Monthly	1302	Long Term Voltage Support Contract due ISO	Reliability
Monthly	1353	Black Start Energy due ISO	Reliability
Monthly	1591	EP Penalty Charge, due CAISO trustee	Penalties
Monthly	1592	EP Penalty Allocation Payment	Penalties
Monthly	1593	EP Penalty/Alloc for under/over	Penalties
Monthly	1691	MLCC Neutrality Allocation	Reliability
Monthly	1697	MLCC Tier 1 Allocation	Reliability
Monthly	1698	MLCC Reliability Service Cost Allocation	Reliability
Monthly	1699	MLCC Inter-Zonal Congestion Allocation	Reliability
Monthly	2999	Interest due SC	Misc
Monthly	3010	Termination Fee	Adjustments
Monthly	3020	Termination Fee	Adjustments
Monthly	3101	Black Start Capacity due BA	Reliability
Monthly	3302	Supplemental Reactive Energy due SC	Reliability
Monthly	3303	Long Term Voltage Support due BA	Reliability
Monthly	3351	Grid Management Charge Adjustment Charge/Refund	Adjustments
Monthly	3372	High Voltage Access Charge Adj - Due ISO	Adjustments
Monthly	3374	High Voltage Access Charge Adj - Due PTO	Adjustments
Monthly	3382	High Voltage Wheeling Access Charge Adj - Due ISO	Adjustments
Monthly	3383	Low Voltage Wheeling Access Charge Adj - Due ISO	Adjustments
Monthly	3384	High Voltage Wheeling Access Charge Adj - Due PTO	Adjustments
Monthly	3385	Low Voltage Wheeling Access Charge Adj - Due PTO	Adjustments
Monthly	3472	Demand Relief Energy Payment	Misc
Monthly	3473	Discretionary Load Curtailment Payment	Misc
Monthly	3482	Demand Relief Energy Charge	Misc
Monthly	3483	Discretionary Load Curtailment Charge	Misc

Frequency	Charge Type	Charge Type Description	Service Type
Monthly	3999	Interest and Penalty	Misc
Monthly	4695	Settlement of Minimum Load Cost Comp - Due SC	Reliability
GMC	4501	Core Reliability Services Non-Coincident Peak	GMC
GMC	4502	Core Reliability Services Non-Coincident Off-Peak	GMC
GMC	4503	Core Reliability Services Exports	GMC
GMC	4504	Core Reliability Svcs/Energy Trans Svcs Mojave	GMC
GMC	4505	Energy Transmission Services Net Energy	GMC
GMC	4506	Energy Transmission Services Deviations	GMC
GMC	4511	Forward Scheduling	GMC
GMC	4512	Forward Scheduling Inter-SC Trades	GMC
GMC	4513	Forward Scheduling Path 15 Inter SC Trades	GMC
GMC	4522	Congestion Management	GMC
GMC	4534	Market Usage Ancillary Services	GMC
GMC	4535	Market Usage Instructed energy	GMC
GMC	4536	Market Usage Uninstructed Energy	GMC
GMC	4575	Settlements, Metering, Client Relations	GMC

APPENDIX 2: Template for Determination of an Initial Financial Security Posting Amount

California ISO
Simplified Calculation of Initial Security Amount

Average Hourly Load	4.0	MWh	<------INPUT
Average Hourly Generation	5.4	MWh	<------INPUT
Total Daily Load / Generation	96.0		

	Billable MWh	Price	Total
Ancillary Services	5	$ 9.764	$ 47
FERC Fee	96	$ 0.038	$ 4
Grid Management Charge	165	$ 0.743	$ 123
Imbalance Energy	(25)	$ 44.233	$ (1,087)
Interzonal Congestion	40	$ 0.672	$ 27
Reliability / Minimum Load Cost Compensation	96	$ 0.765	$ 73
Reliability Must Run Generation	96	$ 0.004	$ 0
Uplift Charges	96	$ 0.042	$ 4
Wheeling Charges	96	$ 0.101	$ 10
Total Daily Charges / Daily Security Deposit			$ (800)
Level Period 102 day Security Deposit Posting Requirement			$ (81,579)

Assumptions:

MWh Percentages	
A/S % of Load	5.02%
Net Imbalance Energy Percentage	4.00%
Congestion % of Load	41.25%
Per MWh Costs	
Ancillary Services	$ 9.764
FERC Fee	$ 0.038
Grid Management Charge	$ 0.743
Imbalance Energy	$ 44.233
Interzonal Congestion	$ 0.672
Reliability / Minimum Load Cost Compensation	$ 0.765
Reliability Must Run Generation	$ 0.004
Uplift Charges	$ 0.042
Wheeling Charges	$ 0.101

Note:
Settlement calendar longest number of outstanding days is 95.
The ISO adds 7 days to the estimation to allow for administrative needs and communications to / from SC.