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 200*9* does not exceed $195 million, the ISO shall not be required to make a Section 205 filing to adjust the GMC charges calculated in accordance with this Schedule 1 to recover such Revenue Requirement. In order for the ISO to adjust the GMC charges to collect a Grid Management Charge Revenue Requirement for Budget Year 200*9* that exceeds $195 million, the ISO must submit an application to FERC under Section 205. In any event, the ISO shall submit a filing under Section 205 for approval of the GMC charges to be effective the earlier of January 1, 20***10*** or the effective date of amendments to the ISO Tariff implementing a new market design based on a nodal system of Congestion Management employing locational marginal pricing, such as the ISO's Market Redesign and Technology Upgrade ("MRTU"). In such filing, the ISO may revise the GMC rates set forth in this Schedule 1, but shall not be required to do so.

Periodic Financial Reports

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

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

ISO TARIFF APPENDIX F
Schedule 2
Other Charges

Voltage Support Service

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

Regulation Service

Regulation Obligation:

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

Regulation Rates:

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

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

Spinning Reserve Service

Spinning Reserve Obligation:

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

Spinning Reserve Rates:

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

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

Non-Spinning Reserve Service

Non-Spinning Reserve Obligation:

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

Non-Spinning Reserve Rates:

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

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

Replacement Reserves

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

Black Start Capability

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

Imbalance Energy Charges

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

Replacement Reserve Charge

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

Unaccounted for Energy

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

Transmission Losses Imbalance Charges

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

Access Charges

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

Usage Charges

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

Default Usage Charge

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

Grid Operations Charge for Intra-Zonal Congestion

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

Wheeling Access Charges

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

Charge for Failure to Conform to Dispatch Instructions

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

Reliability Must-Run Charge

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

FERC Annual Charge Recovery Rate

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

ISO TARIFF APPENDIX F
Schedule 3
Access Charge

1. Objectives and Definitions

1.1 Objectives

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

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

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

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

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

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

1.2 Definitions

(a) Master Definition Supplement

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

(b) Special Definitions for this Appendix

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

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

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

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

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

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

3. TAC Areas.

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

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

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

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

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

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

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

4. Transition Date

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

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

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

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

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

5. Determination of the Access Charge.

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

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

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

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

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

$$HVAC = HVAC_A + HVAC_I$$

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

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

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

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

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

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

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

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

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

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

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

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

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

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

6. High Voltage Transmission Revenue Requirement.

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

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

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

7. Limitation

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

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

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

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

8. Updates to High Voltage Access Charges.

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

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

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

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

8.4

9. Approval of Updated High Voltage Revenue Requirements

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

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

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

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

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

(b)

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

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

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

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

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

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

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

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

12.1 Division of Costs:

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

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

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

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

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

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

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

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

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

(e) Division of the TRBAA between HVTRR and LVTRR

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

ISO TARIFF APPENDIX F
Schedule 4

Participating Intermittent Resources Forecasting Fee

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

Participating Intermittent Resources Process Fee

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

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

Participating Intermittent Resources Export Fee

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

Participating Intermittent Resources Export Fee per Participating Intermittent Resource =

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

ISO TARIFF APPENDIX F

SCHEDULE 5

STATION POWER CHARGES

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

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

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

ISO TARIFF APPENDIX F
Schedule 6

TCPM SCHEDULES

Monthly TCPM Charge

The Monthly TCPM Charge shall be calculated by multiplying the monthly shaping factors by the target annual capacity price ($77.89/kW-yr).

Monthly Shaping Factors

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

Availability

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

AVAILABILITY FACTOR TABLE

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

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

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

Calculation of the Monthly PER

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

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

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

NP-15

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

SP-15

Weekday January through June

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

Saturday January through June

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

Sunday January through June

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

Weekday July through December

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

Saturday July through December

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

Sunday July through December

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

ISO TARIFF APPENDIX G

Must-Run Agreements

To be filed upon settlement

ISO TARIFF APPENDIX H

Methodology for Developing the Weighted Average Rate for Wheeling Service

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

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

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

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 Forinstallation Of Self-Contained A-Base Watt-hour Meters

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

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

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

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

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

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

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

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

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

Part B

PARTICIPATING SELLERS METER STANDARDS AND CAPABILITIES

ISO TARIFF APPENDIX K

Ancillary Service Requirements Protocol

ISO TARIFF APPENDIX K

Ancillary Service Requirements Protocol

PART A

CERTIFICATION FOR REGULATION

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

A 1.1 Operating Characteristics

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

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

A 1.2 Technical Requirements

A 1.2.1 Control

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

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

A 1.2.2 Monitoring:

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

A 1.2.2.1 actual power output (MW);

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

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

A 1.2.3 **Voice Communications:**

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

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

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

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

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

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

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

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

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

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

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

A 10.1 confirmation of control communication path performance;

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

A 10.3 confirmation of the Generating Unit control performance; and

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

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

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

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

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

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

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

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

OF THE ASRP OR THE ISO TARIFF.

PART B

CERTIFICATION FOR SPINNING RESERVE

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

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

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

B 1.2.1 5% drop;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

PART C

CERTIFICATION FOR NON-SPINNING RESERVE

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

C 14.1 confirmation of control communication path performance;

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

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

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

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

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

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

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

PART D

CERTIFICATION FOR REPLACEMENT RESERVE

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

D 14.1 confirmation of control communication path performance;

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

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

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

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

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

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

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

PART E

CERTIFICATION FOR VOLTAGE SUPPORT

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

E 13.1 confirmation of control communication path performance;

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

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

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

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

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

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

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

PART F

CERTIFICATION FOR BLACK START

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

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

F 2.1 identification of the Generating Unit including Location Code;

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

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

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

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

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

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

F 3.1 acceptance of the proposal as presented;

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

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

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

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

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

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

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

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

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

F 10.1 confirmation of control communication path performance;

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

F 10.3 confirmation of the Generating Unit performance; and

F 10.4 simulation of a Black Start event.

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

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

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

ISO TARIFF APPENDIX L

Methodology to Assess Available Transfer Capability

METHODOLOGY TO ASSESS AVAILABLE TRANSFER CAPABILITY

L.1 Description of Terms
The following descriptions augment existing definitions found in Appendix A "Master Definitions Supplement."

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

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

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

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

L.1.4 Existing Transmission Commitments (ETC) include Existing Contracts, and as appropriate, Firm Transmission Rights, and Transmission Ownership Rights. The ISO reserves transmission capacity for each ETC based on instructions the responsible Participating TO submits to the ISO as to the amount of firm transmission capacity that should be reserved on each branch group for each hour of the Trading Day in accordance with Sections 4.2.1 and 16 of the ISO Tariff. The types of instructions the ISO receives from the Participating TO generally fall into three basic categories:

- The ETC reservation is a fixed percentage of the TTC on a line, which decreases as the TTC is derated (ex. TTC = 300 MW, ETC fixed percentage = 2%, ETC = 6 MWs. TTC derated to 200 MWs, ETC = 4 MWs);

- The ETC reservation is a fixed amount of capacity, which decreases if the line's TTC is derated below the reservation level (ex. ETC = 80 MWs, TTC declines to 60 MW, ETC = OTC or 60 MWs; or

- The ETC reservation is an algorithm that changes at various levels of TTC for the line (ex. Intertie TTC = 3,000 MWs, when line is operating greater than 2,000 MWs to full capacity ETC = 400 MWs, when capacity is below 2000 MWs ETC = OTC/2000* ETC).

Existing Contract capacity reservations remain reserved during the Day-Ahead and Hour-Ahead ISO markets. To the extent that the reservations are unused, they are released in real-time operations for use in the Real-Time Market.

Transmissions Ownership Rights capacity reservations remain reserved during the Day-Ahead and Hour-Ahead ISO markets, as well as through real-time operations. This capacity is under the control of the Participating TO and is not released to the ISO for use in the markets.

L.1.5 **ETC Reservations Calculator (ETCC)** exists as an SI (Scheduling Infrastructure) application. The ETCC identifies the amount of firm transmission capacity reserved (in MW) for each ETC rights holders on each branch group for each hour of the Trading Day.

- **CONG Calculated ETC Reservations**. In addition, the total amount of capacity reserved for firm ETC rights on each branch group is calculated within the ISO's Congestion Management system (CONG). CONG sums the transmission capacity reservation across all contract reference numbers (CRN) for each branch group to determine the total amount of ETC reservation on each branch group.

- **ISO Updates to ETC Reservations Table.** The ISO updates the ETC reservations table (if required) prior to running the Day-Ahead and Hour-Ahead Markets. The amount of transmission capacity reservation for ETC rights is determined based on the OTC of each branch group and in accordance with the curtailment procedures stipulated in the existing agreements and provided to the ISO by the responsible Participating TO.

- **Market Notification.** The information is made available to all SCs who have ETC scheduling capacities in advance of the Day-Ahead Preferred, Day-Ahead Revised Preferred, and Hour-Ahead Markets. This information is posted on the Open Access Same-Time Information System (OASIS).

- For further information, see ISO Operating Procedure M-423, Scheduling and Use of Existing Transmission Contract Rights and Transmission Ownership Rights, which is publicly available on the CAISO Website at http://www.caiso.com/docs/2002/03/14/2002031412575719815.pdf.

L.1.6 **Transmission Reliability Margin (TRM)** is that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. TRM reserves sufficient transmission capacity from the Day-Ahead (DA) Market to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. This DA implementation avoids real time schedule curtailments that would otherwise be necessary due to:

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

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

The ISO does not use TRMs. The TRM value is set at zero.

L.1.7 Capacity Benefit Margin (CBM) is that amount of transmission transfer capability reserved by Load Serving Entities (LSEs) to ensure access to generation from interconnected systems to meet generation reliability requirements. In the DA Market, CBM may be used to provide reliable delivery of Energy to ISO Control Area Loads and to meet ISO responsibility for resource reliability requirements in real time. The purpose of this DA implementation is to avoid real time schedule curtailments and firm load interruptions that would otherwise be necessary. CBM may be used to reestablish Operating Reserves. CBM is not available for non-firm transmission in the ISO Control Area. CBM may be used only after:

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

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

CBM = (Demand + Reserves) - Resources

Where:

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

The ISO does not use CBMs. The CBM value is set at zero.

L.2 ATC Algorithm

A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. ATC is defined as the Total Transfer Capability (TTC), less the Transmission Reliability Margin (TRM) (which are set at a value of zero), less the sum of existing transmission commitments, current physical constraints, and retail customer service commitments. The ISO posts the ATC values in megawatts to OASIS in conjunction with the ISO Market closing events for the Day-Ahead, Hour-Ahead, and Real-Time markets.

ATC = OTC – (TRM + ETC + CBM)

or

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

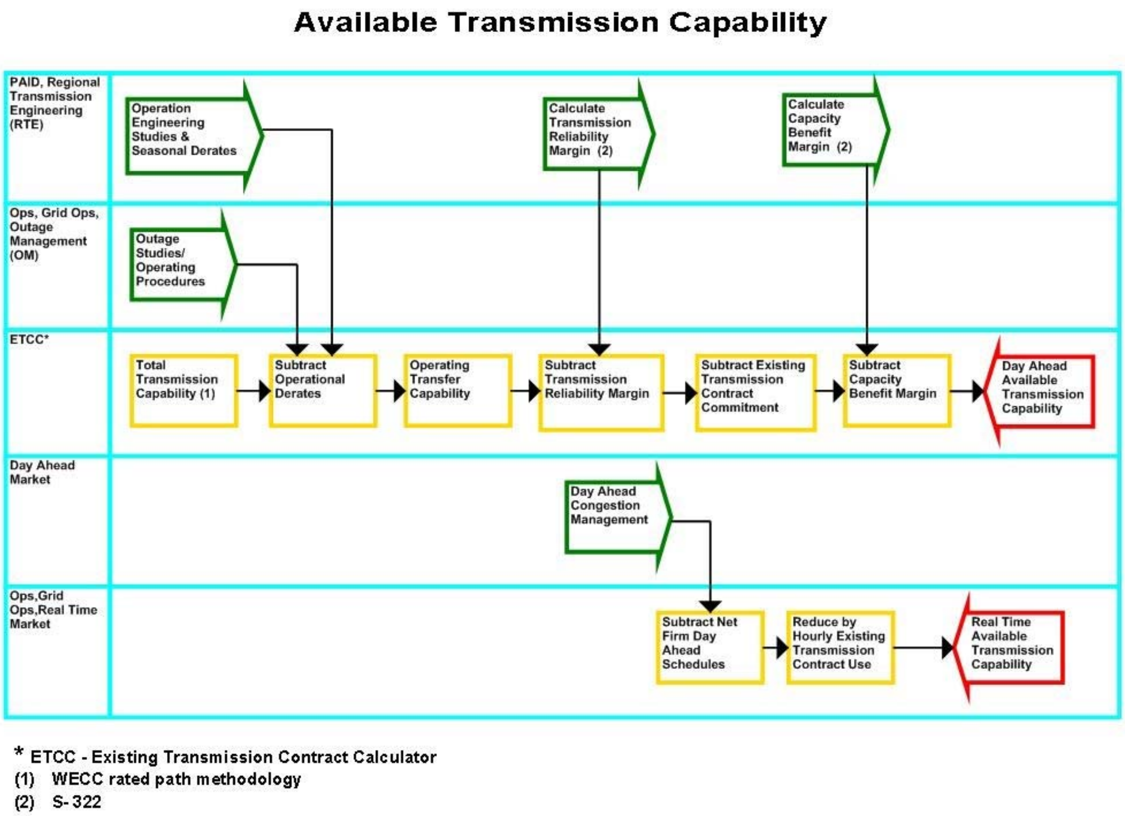
Where:

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

The specific data points used in the ATC calculation are each described in the following table.

ATC	ATC_BG_MW	Available Transfer Capacity, in MW, per Branch Group and Path direction.
Constrained Hour	CONSTRAINED_BG_FLG	Hourly Y/N flag for a specified Branch Group indicating whether the OTC is less than or equal to 25% of the TTC. This flag can be used to determine if the Branch Group is considered a Constrained Path in accordance with the FERC Definitions.
Constraints	CONSTRAINED_BG_MW	Hourly transmission Constraints, in MW, for a specific Branch Group and Path direction.
Counterflows	COUNTERFLOW_BG_MW	Hourly Interchange scheduled in the opposite direction over a specified Branch Group.
ETC Available	ETC_BG_AVAIL_MW	Capacity reserved on a specified Branch Group for Existing Transmission Contract owners. This value reflects the Existing Transmission Contract rights that have not been scheduled for use over a specified Branch Group and Path direction.
ETC Scheduled	ETC_BG_SCHD_MW	Total hourly Interchange Schedules using Existing Transmission Contracts over a specified Branch Group and Path direction.
FTR Scheduled	FTR_BG_SCHD_MW	Total hourly Interchange Schedules using Firm Transmission Rights over a specified Branch Group and Path direction.
AS Scheduled	OP_RSRV_BG_SCHD_MW	Ancillary Services scheduled, in MW, as imports over a specified Branch Group.
OTC	OTC_BG_MW	Hourly Operating Transfer Capacity of a specified Branch Group, per Path direction, with consideration given to known Constraints and operating limitations, as used in the Congestion Management System for a specified market.
TRM	TRM_BG_MW	Hourly Transmission Reliability Margin, in MW, of a specified Branch Group, per Path direction.
Spot Market Usage	TRNS_SPOT_MKT_USAGE_MW	Total hourly New Firm Use less quantities scheduled under Firm Transmission Rights for a specified Branch Group and path direction.
TTC	TTC_BG_MW	Hourly Total Transfer Capacity, in MW, of a specified Branch Group, per Path direction.

L.3 ATC Process Flowchart



L.4 TTC – OTC Determination
All transfer capabilities are developed to ensure that power flows are within their respective operating limits, both pre-Contingency and post-Contingency. Operating limits are developed based on thermal, voltage and stability concerns according to industry reliability criteria (WECC/NERC) for transmission paths. The process for developing TTC or OTC is the same with the exception of inclusion or exclusion of operating Constraints based on system conditions being studied. Accordingly, further description of the process to determine either OTC or TTC will refer only to TTC.

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

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

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

- **Thermal Limits** – Thermal limits establish the maximum amount of electric current that a transmission line or electrical facility can conduct over a specified time-period as established by the Transmission Owner.
- **Voltage Limits** – System voltages and changes in voltages must be maintained within the range of acceptable minimum and maximum limits to avoid a widespread collapse of system voltage.
- **Stability Limits** – The transmission network must be capable of surviving disturbances through the transient and dynamic time-periods (from milliseconds to several minutes, respectively) following the disturbance so as to avoid generator instability or uncontrolled, widespread interruption of electric supply to customers.

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

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

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

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

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

L.5 Developing a Power Flow Base-Case

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

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

L.5.3. Power Flow Base-Cases Selection Methodology

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

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

L.5.4 Update a Power Flow Base-Case

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

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

L.5.4.1 Outage Consideration

Unless detailed otherwise, the RTE considers modeling outages of:

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

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

L.5.4.2 Area Load Level

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

L.5.4.3 Modify Path Flows

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

L.5.4.4 Generation Level

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

L.5.4.5 Voltage Levels

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

L.6 Contingency Analysis

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

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

L.6.1 Operating Criteria and Study Standards

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

Pre-Contingency

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

Post-Contingency

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

The RTE models the following Contingencies:

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

L.6.2 Manual Contingency Analysis

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

L.6.3 Contingency Analysis Utilizing a Contingency Processor

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

L.6.4 Determination of Crucial Limitations

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

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

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

L.8 Limits for Contingency Limitations

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

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

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

ISO TARIFF APPENDIX M

Transmission Rights/Curtailment Instructions Template

TRANSMISSION RIGHTS/CURTAILMENT INSTRUCTIONS TEMPLATE

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

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

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

(o) Non-Emergency Curtailments

[If other than pro rata, attach spreadsheet for ISO to use in allocating curtailments to rights holders between the indicated Zones. Otherwise, indicate "pro rata" here.]

(p) Emergency Curtailments

[Describe special procedures/requirements here. Indicate "N/A" if none.]

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