**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

| | | |
|---|---|---|
| California Independent System Operator Corporation | ) | Docket No. ER04-____-000 |

# GRID MANAGEMENT CHARGE

## VOLUME VI OF IX

- Exhibit Numbers ISO-96 through ISO-176

October 31, 2003

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# Status Report: Grid Management Charge

**November 12, 2002**
Market Issues Forum

Ben T. Arikawa
Senior Financial Analyst
barikawa@caiso.com
(916) 608-5958

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# Topics

- Settlement Agreement in 2002 GMC Proceeding (ER02-250-000, *et.al.*), October 17, 2002
- GMC Information Filing, November 8, 2002
- 2004 GMC Reevaluation

# Settlement Agreement in 2002 GMC Proceeding

- Settles all issues except for issue related to Southwest Power Link
- Gross revenue requirement for 2002
  - Before application of reserve proceeds – $246 million
  - After application of reserve proceeds – $239.2 million

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# Settlement Agreement in 2002 GMC Proceeding (cont.)

- ISO withdraws assessment of ASREO on self-provided AS retroactive to January 1, 2002
  - $0.957 per MWh – January 1 through August 31, 2002
  - $1.048 per MWh – September 1 through October 31, 2002
  - $1.158 per MWh – November 1 through December 31, 2002
- Settlement allows use of some fines and penalties to offset costs to meet limits
- Refunds will be issued once Settlement is approved.

# Settlement Agreement in 2002 GMC Proceeding (cont.)

- For 2003
  - Limits gross revenue requirement
    - Before application of reserve proceeds to no more than $246 million
    - After application of reserve proceeds to no more than $239.2 million
  - Limits revenue requirement for each component
    - $138.6 million – CAS
    - $27.8 million – Congestion Management
    - $72.8 million - ASREO

# Settlement Agreement in 2002 GMC Proceeding (cont.)

- Incorporates certain details of Initial Decision
  - Stakeholder process for 2004 GMC reevaluation
  - Review of alternative proposals
- Greater Stakeholder access to Budget information
  - Settling Parties access to Budget documents and data
  - Stakeholder access to ISO Board to discuss Budget
- Consideration of structural changes due to MD02

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# Settlement Agreement in 2002 GMC Proceeding (cont.)

- Filed at FERC on October 17, 2002
  - Market notice issued concurrently
  - Posted at: http://www.caiso.com/pubinfo/FERC/filings/index.html
  - CPUC and FERC Staff filed comments supporting Settlement
  - Waiting for ALJ and FERC

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# GMC Information Filing

- Settlement Agreement allowed an informational filing for 2003 GMC and revenue requirement
- Filed at FERC November 8, 2002
- Meets all limits imposed by Settlement Agreement

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# GMC Information Filing (cont.)

- Gross Revenue Requirement
  - Before reserve proceeds - $245.9 million
  - After reserve proceeds - $237.6 million
- Components
  - CAS - $137.9 million ($0.569 per MWh)
  - Cong - $27.4 million ($0.320 per MWh)
  - ASREO – $72.3 million ($1.296 per MWh)

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# 2004 GMC Reevaluation

- August 29 – teleconference
- October 9 – meeting at ISO
  - Charter
  - FERC proceedings
  - Assignments
    - FERC Staff testimony on formula rate in ER01-313-000 *et.al.*
    - Ratemaking methods
    - Other ISO rates

# 2004 GMC Reevaluation (cont.)

- November 8 meeting
  - Presentations
    - Ziad – MD02
    - FERC Staff on formula rates
    - Ratemaking methods
    - Dr. Kirsch – MID rate design proposal
- December 9 meeting
  - Other proposals
    - CPUC/EOB

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# 2004 GMC Reevaluation (cont.)

- Meetings planned through May/June 2003
  - Everyone is welcome to attend
  - Debi Le Vine/Phil Leiber co-leads
- Product - redesigned GMC rate structure for 2004
- Rate structure to be used in Budget process for 2004 starting in June/July 2003

RE Data on deviations for MID proposal 12-04-02.txt

From: McGuffin, Mike
Sent: Wednesday, December 04, 2002 2:11 PM
To: Pritchard, Jan
Cc: Arikawa, Ben
Subject: RE: Data on deviations for MID proposal

Hi Jan,

We have deviation data for Imports, Exports, Generation, and Load, by SC, by 10 minute interval, by resource/location.

Let me know if this is the specificity you were looking for?

Mike McGuffin
Settlement Analyst
916-608-5753

-----Original Message-----
From: Arikawa, Ben
Sent: Wednesday, December 04, 2002 11:18 AM
To: McGuffin, Mike
Cc: Pritchard, Jan
Subject: Data on deviations for MID proposal

Mike,

Can you e-mail Jan Pritchard (janp@mid.org) at MID to give him a description of the different sets of deviation data that we have so that MID can give us their preferences? He will send it off to Laurence Kirsch for his opinion.

Please cc me so that I have a record of the exchange. Thanks.

Ben Arikawa
Senior Financial Analyst
California Independent System Operator
P.O. Box 639014
Folsom, CA 95763-9014

Voice: (916) 608-5958
fax: (916) 351-2259

email: barikawa@caiso.com

RE Data on deviations for MID proposal 12-05-02.txt
From: JAN PRITCHARD [janp@mid.org]
Sent: Thursday, December 05, 2002 7:01 AM
To: MMcGuffin@caiso.com
Cc: BArikawa@caiso.com
Subject: RE: Data on deviations for MID proposal

Hello Mike,

Thanks for the information. Ben is working to help assure that the data necessary to evaluate stakeholder rate-design proposals will be available when needed. I will forward your message to Dr. Kirsch and get back to both you and Ben as soon as possible.

Thanks again,

Jan

2BBYvx.370000000.9914

>>> "McGuffin, Mike" <MMcGuffin@caiso.com> 12/04/02 02:11PM >>>
Hi Jan,

We have deviation data for Imports, Exports, Generation, and Load, by SC, by
10 minute interval, by resource/location.

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RE Data on deviations for MID proposal 12-05-02.txt

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their preferences? He will send it off to Laurence Kirsch for his opinion.

Please cc me so that I have a record of the exchange. Thanks.

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fax: (916) 351-2259

email: barikawa@caiso.com

# 2004 GMC Stakeholder Process
Meeting 3
December 9, 2002
9:30 a.m. to 3:00 p.m.
California ISO
Room 101A – 1a

Conference Call-in Line:
(877) 661-1222 X178246

Materials will be distributed in advance of the meeting

I. Introductions / Announcements (Leiber)

II. Finalize Project Charter (timeline to be discussed at end of meeting) (Leiber)

III. Statements on desirable rate design elements by parties developing proposals: MID, CPUC/EOB, CAC, etc

IV. Briefing on ISO rate structure comparison (Arikawa)

V. Discussion of ISO List of Services (Arikawa)

- Additions/Divisions/Deletions to be submitted to ISO by 12/31/02.
- ISO to provide indicative costs for each service by early February 2003

VI. Discussion of Data Necessary (Arikawa)

- Distribute listing of anticipated data needs
- Additions to be submitted to ISO by 12/31/02.

VII. Confidentiality issues (Morrison)

VIII. MD02 Update (to be determined)

IX. Discussion of upcoming (January) meeting agenda and overview of remaining steps (Leiber)

## 2004 GMC Stakeholder Process

**Business Opportunity/Problem: [State the problem(s) the project will address in business terms. State the problem's impact to the business including the effects and costs (tangible, where possible]**

The California ISO ("ISO") needs to recover its start-up, capital, and operation and maintenance costs through the Grid Management Charge ("GMC"). The ISO believes that a complete reassessment of the GMC Rate Structure[1] is warranted at this time given past experiences with GMC ratemaking, and anticipated future changes. The Initial Decision by the Federal Energy Regulatory Commission ("FERC") Administrative Law Judge in the 2001 GMC proceeding directed the ISO "to undertake a comprehensive stakeholder review for the purpose of re-evaluation of the GMC structure in 2003" and "the ISO is directed to make a Section 205 filing upon completion of that re-evaluation process in 2003."[2]

An added challenge is the fact that the ISO is making significant changes to the current market design over the period of the MD02 effort [3](potentially extending from 2002-2006). The existing GMC rate structure needs to be re-evaluated to address stakeholder concerns in preparation of the 2004 GMC Rate setting process in the fall of 2003. Significant challenges in evaluating appropriate changes will be the lack of clarity regarding timing and composition of the MD02 and FERC Standard Market Design elements, and lack of data related to the effect of these changes on potential billing determinant volumes and costs.

### Goals/Objectives:

**Primary Goals/Objectives: [List in business terms the project's primary purpose and the high level results expected from its completion]**

The primary goal of the 2004 GMC Rate Design Project is through a comprehensive stakeholder process develop and implement a GMC rate methodology that best supports the new and still changing market design in a way that achieves equity between Market Participants and provides for the collection of the ISO's revenue requirement.

**The objectives of this effort are to design a rate structure that:**

- Have an open and equitable stakeholder process;
- Design a rate structure that is easy to administer (including reasonably cost effective, and benefits of change should outweight the costs) and understandable;
- **Develop a rate structure based on the principle of cost causation which charges** customers for the cost of services that they use/cause;
- Develop a rate structure that does not result in unmanageable adverse operational impacts;

[1] Rate Structure includes: determination of services provided (current and future), accumulation of overall costs, cost allocation, rate design (including billing determinants). While not the primary focus of this group, the overall level of ISO costs is of concern to ISO stakeholders, and consideration of a mechanism to adequately address this issue prospectively may be necessary.

[2] The intention of the direction is to work during 2003 for implementation of a new GMC structure in 2004.

[3] MD02 is being funded through the currently existing rate structure/budgets.

- Recover approved ISO costs in a stable, low risk manner without excess volatility, and
- Have the new rate structure filed with FERC by November 1, 2003, so that it can be effective January 1, 2004.
- Meet the terms of the 2002 GMC Settlement Agreement, which set forth issues to be covered in this 2004 GMC Stakeholder Process.

**Benefits: [List the key advantages of accomplishing the project. State in terms of tangible savings, wherever possible]**

Advantage of accomplishing this project include:

- A periodic review of the appropriateness of the ISO GMC structure.

From the ISO's perspective, advantage of accomplishing this project include:

- Development of better working relationships with Market Participants.
- Potential for reduced litigation at FERC related to future GMC filings.
- Possible better alignment of operational incentives with financial incentives affecting both the ISO and market participants.

**Scope: [Describe the boundaries of the project in terms of what it includes and what it does not include]**

Develop GMC rate structure to be effective January 1, 2004 that considers and evaluates various rate methodologies/structures, including but not limited to, the one currently in use, and the applicability of each proposal to the needs of impacted parties, including Market Participants and the ISO.

This effort will actively seek stakeholder participation in the development of the recommended solution. Feedback regarding disposition of all participation, including proposal status and comment review will be provided to all participants.

This effort will produce recommendation(s) that is given to the ISO. The ISO will include such recommendation(s) in the memorandum to the Board of Governors. The ISO Board of Governors will determine the 2004 GMC rate methodology to be filed by the ISO with FERC.

Excluded from the scope of this effort are issues related to the level or composition of the ISO budgets. However, ISO spending on various elements of the ISO's changing responsibilities related to MD02 and/or SMD may be considered as appropriate in the consideration of rate structure. Stakeholders recognize that integration of the ISO budget process and the rate structure is necessary to arrive at a November 1, 2003 filing that incorporates these elements.

**Product Deliverables: [The major elements of work that will be completed on the project. The set of specific, measurable, tangible, verifiable results expected from the completion of the project]**

- A project charter agreed to by all participants.

- Proposals from the Market Participants and the ISO regarding rate design options.
- A tool showing potential rates to aid in analysis of overall rate design proposals
- A rate design proposal for ISO Governing Board approval.

**Constraints: [List the factors that limit the project team's options (schedule, cost or scope/quality). Indicate which is the driving factor for the project; i.e. a predefined budget constrains scope and staffing]**

- Project due date is constrained by the FERC rate filing schedule (outside project control).
- Lack of clarity regarding ultimate MD02/SMD timeline and elements.
- Lack of data on the future effect of MD02/SMD market rules.
- Historical data on potential billing determinants and the level of granularity of cost/accounting records
- Finite team resources limit exploration and analysis of alternatives.

**Risks: [State the major exposures to possible delay, or failure in meeting the stated goals/objectives of the project]**

1. Time constraints of all parties due to the changes in market structure both by the ISO's MD02 and FERC's Standard Market Design Notice Of Proposed Rulemaking.
2. Inability to reach consensus on a rate design could result in extended litigation at FERC.
3. Lack of data regarding the effect of MD02 market changes and timing issues of MD02 could result in the adoption of a rate design that has significantly different impacts than anticipated.
4. Market instability due to regulatory risk and the potential for creditworthiness issues could divert team attention from this effort.

| | | |
|---|---|---|
| **ISO Project Leads:** | Debi Le Vine, Contracts; | Phil Leiber, Finance |
| **ISO Team Members:** | | |
| Jan Addy, Project Office; | Ben Arikawa, Finance; | Mike Epstein, Finance; |
| Don Fuller, Settlements; | Deane Lyon, OSAT; | Kevin Graves, Ops, Eng & Maintenance; |
| Mike McGuffin, Settlements; | Mike Peterson, OSAT; | Stephen Morrison, Legal & Regulatory; |
| David Withrow, Policy Office; | | Kyle Hoffman, Client Relations |
| **ISO Project Executive Sponsor:** | Bill Regan, CFO; | |

**Project Milestones: [If possible, list the key accomplishment points, required approvals, set dates.]**

1. Process Kickoff with Stakeholders — August 29, 2002
2. Develop and approve Project Charter
3. Develop and approve evaluation criteria for proposals
4. Proposals due from Market Participants and ISO
5. Proposal evaluation
6. Develop recommended solution
7. ISO provide update to MIF during process
8. ISO present to ISO Governing Board — May, 2003

**See following page for more detailed list of requirements**

# Project Completion Steps

January

- Finalize list of ISO services
- Distribute aggregate billing determinant data for use in proposal development

February

- ISO completes indicative/preliminary allocation of 2003 costs to proposed service list
- Stakeholders present initial conceptual proposals
- ISO presents its initial conceptual proposal

March

- Proposal evaluation
- ISO/Stakeholders present refined proposals with cost/billing determinant data
- Communicate status through MIF

April

- Proposal evaluation
- Customer impact analysis
- Development of consensus proposal?
- Communicate status through MIF

May

- Present design to ISO governing board for approval

June

- Commence settlement discussions regarding 2004 structure?
- Implementation of rate structure for use in 2004 budget development

July

- ISO Budgeting Commences

October

- Board approval of ISO 2004 budget

November

- File rate structure and budget/rate proposal at FERC

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# Briefing: Comparison of ISO Rate Structures

**December 9, 2002**
**2004 GMC Re-evaluation**

Ben T. Arikawa
Senior Financial Analyst

(916) 608-5958

# ISOs Compared

- Nine ISO
  - CAISO
  - ISO-NE (ISO-New England)
  - NY-ISO (New York ISO)
  - ERCOT (Electricity Reliability Council of Texas)
  - Ontario IMO (Independent Market Operator)
  - MISO (MidWest ISO)
  - Transmission Administrator of Alberta
  - Alberta Power Pool
  - PJM

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# Items Reviewed

- Number of categories
- Description of categories
- Size of "buckets"
- Rates
- Billing determinants
- Fixed or floating rates
- Independent or subsidizing categories
- Over/under collection
- Method of implementation
- Cost allocation method
- Status of unbundling effort
- Website address
- URL of rate filing

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# General Conclusions

- General comparisons difficult
- Number of categories
  - 1 (ERCOT, Ontario IMO, Alberta Power Pool)
  - 7 (PJM)
    - Could be described as 9 due to different rates for PJM East and West
- Size of "buckets"
  - As small as 1-3 percent (PJM Capacity Adequacy, Regulation and Frequency Response, Internal Energy Transactions, Capacity Resource and Obligation Management)

# General Conclusions (cont.)

- Rates
  - Mostly volumetric
  - Some demand, customer or transactions based
  - Mostly fixed, some floating
  - Typically independent
  - True-ups for over/under collection
- Method of implementation
  - Typically settlement
  - Rate filing – ERCOT

# General Conclusions (cont.)

- Cost allocation method
  - Annual process
  - Activity accounting system

# How Do Other ISOs Deal with SMD

- No explicit adjustments
  - PJM
- Explicit adjustments
  - ISO-NE
    - Retains rate components
    - Staged implementation of rate changes
      - January-June no change
      - July changes depending on date of SMD implementation

# Next Steps

- Developing contacts at other ISO rate departments
- Update table as more information is obtained

| Company | # Categories | Description of Categories | Further Description | Size of buckets | Rates (effective 1/1/2003 unless otherwise noted) |
|---|---|---|---|---|---|
| CAISO | 3 | Category 1. Control Area Services | | 58% of total | $0.569 per MWh |
| | | Category 2. Congestion Management | | 12% of total | $0.320 per MWh |
| | | Category 3. Ancillary Services and Real Time Energy Operations | | 30% of total. | $1.296 per MWh |
| NEISO | 3 | **Schedule 1** Scheduling, System Control and Dispatch | Includes scheduling service, provision of A/S. Processing requests for transmission service, coordination of transmission system operation, billing associated with transmission service, transmission system planning, administrative support for these. | Approximately 13% of total. | $0.05993 per kW-month |
| | | **Schedule 2** Energy Administration (EAS) | Includes dispatch service. Administer energy market and facilitate interchange transactions, bilateral transactions and generator bids. In summary: Generator dispatch, energy accounting, loss determination and allocation, billing preparation, administration of imbalance energy service, market power monitoring & mitigation, sanction activities, energy market assessments & reports, formulation of market rules, administer FTRs, ARRs. | Approximately 64% of total. | **A Rates- Effective 1/1 through 6/30**<br>TU Block 1 - $0.25330, Block 2 - $0.23027, Block 3 - $0.20725<br>VM Block 1 - $0.16862, Block 2 - $0.15329, Block 3 - $0.13796<br>**B Rates - Effective 7/1 unless SMD effective**<br>TU Block 1 - $0.39955, Block 2 - $0.36323, Block 3 - $0.32690<br>VM Block 1 - $0.26351, Block 2 - $0.23956, Block 3 - $0.21560<br>**C Rates - Effective with SMD**<br>Block 1 - $0.40049, Block 2 - $0.36408, Block 3 - $0.32767<br>VM Block 1 - $0.26641, Block 2 - $0.24219, Block 3 - $0.21797 |
| | | **Schedule 3** Reliability Administration (RAS) | Administer reliability markets, including Operating Reserve Markets, AGC/Regulation markets, ICAP settlement. Examples of functions performed: gen. dispatch associated with reliability markets; reliability markets accounting; billing preparation; generation emissions analysis; risk profile updates; resource adequacy reviews; regional reports/load forecasts/profiles (CELT, EIA, NERC); support of power supply, environmental, market reliability planning activities; market power monitoring, mitigation and assessment of reliability markets; formulation of additional reliability market rules. | Approximately 23% of total. | **A Rates- Effective 1/1 through 6/30**<br>$0.08367 per kW - month<br>**B Rates - Effective 7/1 unless SMD effective**<br>$0.09464 per kW - month<br>**C Rates - Effective with SMD**<br>$0.09480 per kW - month |
| NYISO | 2 services recovered over two billing determinants? | **Schedule 1** Scheduling, System Control and Dispatch; | Allocation of 85% of budgeted annual operating cost plus FERC fees to Loads and other withdrawals of Energy; allocation of remaining 15% to all injections supplying Energy into NYCA Locational-Based Marginal Price ("LBMP") Market. Rate set to equal $0.68 per MWh by use of rate stabilization component. A portion of rate, Market Services Tariff (MST) is set to recover startup costs. | OATT schedule 1: 94%<br>MST Schedule 1: 6% | **Effective 12/2002**<br>OATT $0.567233 per MWh<br>Startup $0.040298 per MWh<br>FERC Fee $0.030690 per MWh<br>Rate stabilization $0.000000 per MWh<br>**Total OATT $0.638221 per MWh**<br>Market Services Tariff $0.041779 per MWh<br>**Total Schedule 1 $0.6800000 per MWh** |
| ERCOT | 1 | ERCOT System Administration Fee | Fees and charges to Market Participants for use of the ERCOT scheduling, settlement, registration and other related systems and equipment. ERCOT has numerous other fees to recover costs of security screening, interconnection studies, map sales and copying. | | Requested effective 1/1/2003 - $0.33 per MWh |
| Ontario IMO | 1 | Usage fee based on allocated withdrawals (consumption plus exports) | Also annual participation fee of $1000-$8000 depending on activity level in MWh. Also, Market Evaluation Program deferral account to record all operation, maintenance and administration, and capital expenditures made in 2003 in respect of the development and implementation of the various elements of the Market Evaluation Program described in the 2003-2005 Business Plan. The IMO is configured to provide **six services**: • Directing operations • Assessment, compliance and current market development • Operating markets • Participant administration • Settlements • Customer services. "Not currently configured for major market evolution work." | Single service category | |



DISCLAIMER: Some rate structures are complex and difficult to characterize/ summarize in a tabular format. See original documents.

| Company | Billing Determinants | Fixed or Floating Rates | Independent or Subsidizing Categorizes | Over/Under Collection | Method of Implementation | Cost Allocation | Status of unbundling effort (if applicable) | Website | Relevant/Current Rate Filing Documents |
|---|---|---|---|---|---|---|---|---|---|
| CAISO | Volumetric: Gross Control Area Load & Exports.<br>Volumetric: Net interzonal scheduled load.<br>Volumetric: Purchases & sales of A/S & RT energy. | Fixed (set in advance) | Independent | Over and under collection of funds will be used in a true-up mechanism for the next rate filing. Monies stay within their own categories. Quarterly rate adjustments | 2001 Rate Case, 2002 Settlement, 2003 Settlement. 2004: Section 205 rate case (or Settlement if possible.) | Annual process. Allocation percentages are developed for individual departments. | Extension of settlement agreement through 2003. Filings in 2003 as necessary to reflect MD02 changes. | www.caiso.com | |
| NEISO | Volumetric: Monthly network load and reserved capacity for point to point service.<br>Transaction units and volumetric measures: of costs for this bucket, 15% are allocated to transactions (TUs) and 85% to volumetric (VUs). Allocated per Settlement agreement. Blocked rate structure provides for declining costs for higher volumes. Special provisions for existing contracts.<br>Demand charge: 100% of costs allocated based on non-coincident peak load (with phase in period during which a portion of the costs are recovered based on peak load and icustomers non-coincident peak injections.) Fixed monthly fee for non-participant transmission customers. | Fixed (set in advance) | Independent | Over and under collection of monies will be use in a true-up mechanism for the next rate filing. Monies stay within their own categories. Within category 2, can be some cross subsidizing within the TU and VU split. | Unbundled structure implemented through settlement agreement (ER-01 316-000, 96-FERC P 61,261) scheduled to last from 2001-2003. 2003 rate case (Section 205) filed on 11/1/2002 to reflect necessary changes from SMD implementation in 2003. | Activity accounting system. Employees record time to departmental activities/tasks. Dept. Managers allocation activities/tasks to rate service categories. Also: ISO and NEPOOL have agreed that costs of SMD should not be amortized through rates until SMD service begins.but if SMD is late, contingency plan allows to recover SMD costs through existing rates. | Will reexamine applicability of current rate structure in light of operation of SMD in 2003 for changes in 2004. Significant effort spend for the 2003 rate filing to adapt existing 3 bucket rate structure to SMD. | www.iso-ne.com | www.iso-ne.com/FERC/filings/ISO_Tariff/ACT_filing_11-01-02.pdf |
| NYISO | 15 percent on imports MWh, 85 percent on load and exports MWh based on annual forecasts and historic market data to provide a relatively constant monthly rate. | Fixed (set in advance) | Independent | NYISO reserves right to adjust Schedule 1 to address changes to NYISO costs of operations and significant expenditures not known at the time the NYISO adopted its 2002 budget. | Schedule 1 rate implemented as a result of settlement in ER99-4235-000, et. al. effective Sept. 1, 2000. | Allocation of annual budget per agreement among New York Market Participants. Start-up costs (Jan-97 through Nov-99) are amortized monthly through December 2004. | Not Applicable - 2002 Budget allocated per agreement with New York Market Participants | www.nyiso.com | www.nyiso.com/markets/schedule/mkt_tariff_sched.html |
| ERCOT | | Fixed (set in advance) | Independent | | Rate filing with Texas PUC | | | www.ercot.com | www.ercot.com/Participants/2003feecase.htm |
| Ontario IMO | Usage fee of $1.06/MWh to be paid commencing January 1, 2003 by all wholesale customers or market participants on all energy withdrawn for use or sale in Ontario and on all export scheduled out of Ontario. | Fixed (set in advance) | Independent | Carry-forward of under/over collections to subsequent year revenue requirement. | | | | www.theimo.com | |

DISCLAIMER: Some rate structures are complex and difficult to characterize/ summarize in a tabular format. See original documents.

| Company | # Cate-gories | Description of Categories | Further Description | Size of buckets | Rates (effective 1/1/2003 unless otherwise noted) |
|---|---|---|---|---|---|
| Midwest ISO | 2+ | Schedule 1 Scheduling, Systems Control and Dispatch Service | **Schedule 1** is not a charge of the ISO, but of the control area operator providing the service. Single charge reflecting costs of all control area operators for providing this service. | Costs not recovered through schedule 1 are recovered through schedule 10. | |
| | | **Schedule 10** ISO Cost Recovery Adder | **Schedule 10** includes three parts. Part 1 is for transmission customers and owners. Part II is for those same entities that elect not to contract for bundled transmission service. Part III is for entities (independent transmission companies) who elect to contract for unbundled RTO services. Schedule 10 costs include start-up & development costs, operating costs, and tariff administration costs, and actual financing costs. Part III services include: Tariff Administration Services, Business Services, Reliability Services, Electronic Scheduling/Energy Losses, Operations Planning, Maintenance Coordination, Congestion Management, Market Monitoring | Schedule 10 costs capped at $0.15 per MWh through transition period (2011). Any excess costs ("deferred costs") are carried over between months, or amortized over 5 years at end of transition period. Part III services are charged based on costs incurred by MISO, allocated to services as follows: Tariff Administration Services 23.0%<br>Business Services 10.0%<br>Reliability Services 27.1%<br>Electronic Scheduling/Energy Losses 20.3%<br>Operations Planning 12.2%<br>Maintenance Coordination 3.7%<br>Congestion Management 2.8%<br>Market Monitoring 1.0% | |
| Transmission Administrator of Alberta (ESBI Alberta Ltd.) | | | | | |
| Alberta Power Pool | 1 | 1. Access Fee<br>2. Trading Fee | Functions mandated in the Province of Alberta's Electric Utilities Act:<br>· Power pool administration function (s. 11);<br>· System control function (s. 12);<br>· Market surveillance function (s. 9.1); and<br>· Transmission administration function, including ancillary services (s. 26). | 1. Access Fee: $250 per year.<br>2. Trading Fee: all other costs | |
| | | | · Scheduling service fee;<br>· Miscellaneous minor fees for banking;<br>· Control area services fee;<br>· Fees for ancillary services;<br>· Fees for congestion management;<br>· Fee for Regional Reliability Council, Regional Transmission Organization and security coordination;<br>· Study costs;<br>· Training course fees;<br>· Charges for statistical information and reports;<br>· Examination fee for becoming a trader on the exchange;<br>· Reconciliation fee per grid injection/exit point;<br>· Rule Book and other document fees; and<br>· Market information system fees.<br>· Rebilling/invoicing fee | | |



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|---|---|---|---|---|---|---|---|---|---|
| Midwest ISO | Volumetric, per MW, with on-peak and off-peak structure. | | | | | | | | |
| | **Schedule 10** includes three parts. Part 1 is for transmission customers and owners. Part II is for those same entities that elect not to contract for bundled transmission service. Part III is for entities who elect to contract for unbundled RTO services. Charges: Part 1: For transmission customers-- assessed on either: MW of reserved capacity, or network load. Part II: For Transmission owners: complicated formula based on peak usage. Part III: | Fixed (set in advance) | Independent | Schedule 10 charges are set based pm budgeted monthly costs and volume estimates, then trued-up based on actual MWhs and costs for the month . Schedule 10 has a cap of 15 cents/MWH for the transition period (ending February 28, 2010). Any participant leaving before end of transition period pays relative share of deferred costs. | Unknown | Unknown | Unknown | www.midwestiso.org | www.midwestiso.org/tariff/as_accepted/As_Accepted_Schedules_10-15-02.pdf |
| Transmission Administrator of Alberta (ESBI Alberta Ltd.) | | | | | Filing with regulator and decision by regulator. | | | www.ta-alberta.ca | www.ta-alberta.ca/cs/Rate_Schedules-Changes_Accepted.pdf |
| Alberta Power Pool | Purchase and sales of energy in MWh | Fixed | N/A | | | | | www.powerpool.ab.ca | |

FIN/ PRL10/3/03

DISCLAIMER: Some rate structures are complex and difficult to characterize/ summarize in a tabular format. See original documents.

| Company | # Cate-gories | Description of Categories | Further Description | Size of buckets | Rates (effective 1/1/2003 unless otherwise noted) |
|---|---|---|---|---|---|
| PJM | 7 | **Schedule 9-1** Control Area | Control Area Services includes costs of all PJM activities associated with preserving the reliability of the PJM and PJM West control areas and administering point to point transmission service and network integration transmission service. | 58% | varies from $0.24 to $0.41 per MWh of load (includes FERC fees)<br>varies from $0.22 to $0.38 |
| | | **Schedule 9-2** Capacity Adequacy | Capacity Adequacy Administration Service includes costs of administering or providing technical support for the Reliability Assurance Agreement and Reliability Assurance Agreement-West, including long term load forecasting, studies to establish reserve requirements and determination of each LSE's capacity obligations. | 1% | |
| | | **Schedule 9-3** Fixed Trans. Rights | Fixed Transmission Rights Administration Service includes the costs associated with administering the Fixed Transmission Rights ("FTRs") provided for under Attachment K to this Tariff, including, coordination of FTR bilateral trading, administration of FTR auctions, support of PJM's on-line, Internet-based eFTR tool, and analyses to determine what total combination of FTRs can be outstanding and accommodated by the PJM system at a given time. | 5% | $0.0366 per FTR MWh |
| | | **Schedule 9-4** Market Support | Market Support Service includes costs associated with supporting the operation of the PJM Interchange Energy Market and related functions, as described in Schedule 1 of the Operating Agreement and the Appendix to Attachment K to the Tariff, including, market modeling and scheduling functions, locational marginal pricing support, market settlements and billing, and market monitoring. | 30% | $0.0804 per MWh of generation<br>$0.0813 per MWh of load |
| | | **Schedule 9-5** Reg. and Freq. Response | Regulation and Frequency Response Administration Service includes the costs associated with administering the provision of Regulation and Frequency Response Service under Schedule 3 of the Tariff. PJM provides this service to Load Serving Entities and to generators that provide regulation in accordance with Schedule 3. | 2% | $0.4104 per MWh of regulation |
| | | **Schedule 9-6** Internal Energy Trans. | Internal Energy Transaction Administration Service includes the costs associated with the support of a PJM Internet-based ustomer interactive tool known as eSchedules. Through eSchedules, market participants may schedule bilateral wholesale transactions within the boundaries of the area comprised of the PJM West Region and PJM Control Area. | 1% | Service charge plus $2,000 signup fee |
| | | **Schedule 9-7** Capacity Resource and Obligation Management | Capacity Resource and Obligation Management Service includes the costs associated with (i) assuring that customers have arranged for sufficient generating capacity to meet their installed capacity obligations under the RAA and RAA-West; (ii) processing Network Integration Transmission Service; and (iii) administering the capacity credit market in the PJM Control Area and available capacity credit market in the PJM West Region. | 3% | East - $0.1952 per MW day of resource or obligation provided<br>Wast - $0.2512 per MW day of resource or obligation provided |
| | | **Schedule 9-8** Management Service Cost | Management Service Cost is not a separate service by PJM. Management Service Cost includes the costs of overhead and administrative activities performed by PJM which support PJM's provision of the services described in subsidiary Schedules 9-1 through 9-7 of this Schedule 9. Management Service Cost is to be allocated proportionally to directly assigned wages and salaries each year among such services. | | |

DISCLAIMER: Some rate structures are complex and difficult to characterize/ summarize in a tabular format. See original documents.

| Company | Billing Determinants | Fixed or Floating Rates | Independent or Subsidizing Categorizes | Over/Under Collection | Method of Implementation | Cost Allocation | Status of unbundling effort (if applicable) | Website | Relevant/Current Rate Filing Documents |
|---|---|---|---|---|---|---|---|---|---|
| PJM | Total hourly usage | varies monthly | Subsidizing (over/underages from | Schedule 9-8 Management Services Costs is used as a subsidizing account. | Unbundling implemented in PJM filing Oct. 29, 1999, ER00-298-000. Filing suspended and Settlement talks initiated. Settlement Agreement reach and certified by FERC July 31, 2000. | Allocation percentages specified in Tariff at the VP/Divisional level. Fixed until another 205 filing. | | www.pjm.com | www.pjm.com/committees/documents/fc/fc.html |
| | Proportional to regional non-coincident peak to overall PJM non-coincident peak | | | | | | | | |
| | FTR MW | | | | | | | | |
| | Total energy delivered + generation | | | | | | | | |
| | Regulation MWh | | | | | | | | |
| | Number of eSchedule users | | | | | | | | |
| | MW of available generation capacity | | | | | | | | |
| | Allocated to other Schedules | | | | | | | | |



DISCLAIMER: Some rate structures are complex and difficult to characterize/ summarize in a tabular format. See original documents.

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# Discussion of List of Data Requirements

**December 9, 2002**

**2004 GMC Re-evaluation**

Ben T. Arikawa
Senior Financial Analyst

(916) 608-5958

# Data Necessary for Rates

- Load (energy)
  - Gross, including behind the meter load
  - Net, without behind the meter load
  - Scheduled load
- Demand (instantaneous peak)
- Deviations from schedule (MID)
  - Peak
  - Absolute value over period
- Transmission flows (MID)

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# Data Necessary for Rates (cont.)

- Sales and Purchases of AS and RT energy
  - Peak demand
  - Flow (current Market Operations billing determinant)
- Number of SCs
- FTR MW
- Number of Transactions
  - To be used if a graduated customer charge is created
  - Transactions needs definition

# Data Necessary for Rates (cont.)

- Time Period
  - Twelve months
  - Final Settlements
  - October 2001 through September 2002

# Objectives

- Common data set for all participants to use
- Minimize burden on Settlements staff to query archived databases

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# Data Caveats

- Load means energy in ISO parlance
- Accuracy is a function of time interval
  - 10 minute Settlements data
  - 15 minute meter data
- Queries off archive server are ***slow***

# Next Steps

- Request feedback by December 31, 2002
  - Comments on list of data
  - Time interval to be used (10 minute, hourly)
  - Additional data required for development of participant proposals

**Preliminary Listing of Billing Determinant Data, Use and Source (12/05/2002 version)**

| | Data | Frequency | Period | Comments |
|---|---|---|---|---|
| 1. | Gross control area load (energy) | Hourly | Twelve months | Current billing determinant for Control Area Services. |
| 2. | Net control area load (energy) | Hourly | Twelve months | Not including behind the meter load |
| 3. | Scheduled load | Hourly | Twelve months | Use for scheduling charge if created |
| 4. | Maximum coincident demand, both gross and net | Monthly | Twelve months | Development of demand charge |
| 5. | Maximum non-coincident demand, both gross and net | Monthly | Twelve months | This is the sum of the maximum demand for each SC during the month plus (for gross) the sum of the connected loads for all behind-the-meter self-generation loads. Development of demand charge |
| 6. | Sum of the absolute value of maximum hourly SC deviations | Monthly | Twelve months | For MID proposal |
| 7. | Total of the absolute value of hourly SC deviations | Hourly | Twelve months | For MID proposal |
| 8. | Total transmission flows | Monthly | Twelve months | For use as billing determinant for transmission flows rate component of MID proposal. MID may be asked to define this billing determinant, if it is other than 1 or 2 above. |
| 9. | Sum of each SC's maximum purchases and sales of Ancillary Services, Supplemental Energy, and Imbalance Energy (both instructed and uninstructed) | Monthly | Twelve months | For development of demand charge for market operations |
| 10. | Total purchases and sales of Ancillary Services, Supplemental Energy, and Imbalance Energy (both instructed and uninstructed) | Monthly | Twelve months | For development of energy charge for market real time activity (same as current billing determinant) |
| 11. | Number of SCs | Monthly | Twelve months | For development of customer charge. |

Note: Parties should clearly note that the list of billing determinant data required may be altered as a result of the ongoing deliberations and developments in this process.

By: Ben Arikawa

Last updated: 12/05/2002

| | | | | |
|---|---|---|---|---|
| 12. | FTR MW | Annual | Twelve months | For development of FTR administration charge |
| 13. | Number of transactions by SC, which would include scheduled loads, purchases/sales of ancillary services, supplemental energy, and imbalance energy, inquiries, etc. Note: this information would only be made available to stakeholders aggregated across all SCs. | Monthly | Twelve months | For use in developing a graduated customer charge if one is desired -- SCs can be grouped in to several groups depending upon their size (maximum demand and/or number of transactions). The information that would be given out would be aggregated up to categories—Category A includes xx SCs, Category B includes yyy SCs, etc. where we would define the parameters of the various categories. |
| | | | | |

Note: Parties should clearly note that the list of billing determinant data required may be altered as a result of the ongoing deliberations and developments in this process.

By: Ben Arikawa
Last updated: 12/05/2002

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

101 FERC ¶ 61,266

Before Commissioners: Pat Wood, III, Chairman;
William L. Massey and Nora Mead Brownell.

California Independent System Operator Corporation

Docket Nos. ER02-1656-009
ER02-1656-010
ER02-1656-011

ORDER CLARIFYING THE CALIFORNIA MARKET REDESIGN IMPLEMENTATION SCHEDULE

(Issued November 27, 2002)

1. The California Independent System Operator Corporation (CAISO) filed a request for rehearing that included a request that the Commission clarify the California Market Redesign (MD02) implementation schedule.[1] In this order, we clarify the CAISO MD02 implementation schedule.[2] This order benefits customers by clarifying aspects of the October 11 Order, which will result in enhanced electricity reliability for California and help provide power at just and reasonable prices.

Background

2. In an order issued July 17, 2002[3] the Commission directed the CAISO to expedite implementation of Phase 2 of the MD02 proposal, including the creation of an integrated day-ahead market, ancillary services reforms, and hour-ahead and real-time reforms. We also directed the CAISO to file its proposal by October 21, 2002, for implementation by January 1, 2003.

---

[1]CAISO, Southern California Edison Company, Powerex Corp., Independent Energy Producers Association, Williams Energy Marketing and Trading Company, and Bonneville Power Administration filed Requests for Rehearing and/or Clarification of the October 11 Order. In this order we are addressing only the implementation of Phase 2 Lite and will address the remaining issues raised on rehearing in a later order.

[2]See California Independent System Operator Corporation, 101 FERC ¶ 61,061 (2002) (October 11 Order).

[3]See California Independent System Operator Corporation, 100 FERC ¶ 61,060 (2002) (July 17 Order).

3. At an August 2002 Technical Conference convened in San Francisco by Commission staff, the CAISO presented to stakeholders the reasons why it believed it could not implement the Phase 2 elements by the Commission-directed deadline of January 1, 2003. In addition stakeholders and the CAISO discussed various options for the MD02 implementation timeline. These options included (1) collapsing Phase 2 into Phase 3, to be implemented at the originally proposed Phase 3 deadline of Fall 2003, or (2) splitting Phase 2 through the implementation of a "Phase 2 Lite" by January 31, 2003, and implementing the remaining elements of Phase 2 concurrently with the elements of Phase 3.

4. "Phase 2 Lite" would implement a modified day-ahead market through (1) relaxation of the balanced schedule requirement for energy and congestion management bids; (2) elimination of the market separation rule; and (3) acceleration of the hour-ahead scheduling modifications the CAISO proposed. The rest of Phase 2 and all of Phase 3 would be implemented in Fall 2003, to include the full implementation of the forward integrated markets (energy, congestion management, ancillary services, unit commitment and a full network model) along with implementation of locational marginal pricing.

5. In the October 11 Order, the Commission found reasonable the proposal to implement "Phase 2 Lite," and directed its implementation by January 31, 2003. In light of a Phase 2 Lite implementation, the Order permitted the postponement of the remaining Phase 2 elements until implementation of Phase 3 in the Fall of 2003. In its November 8, 2002 Request for Rehearing of the October 11 Order, the CAISO states that the Commission should vacate its directive that Phase 2 Lite be implemented by January 31, 2003, and further argues that it could not implement Phase 2 Lite prior to Summer 2003. Southern California Edison Company urges the Commission to reconsider the implementation of Phase 2 Lite, stating that this approach would result in a waste of CAISO time and ratepayer resources and would lead to delays in implementing more important aspects of MD02.

Discussion

6. In its Request for Rehearing, the CAISO acknowledges that it had not examined thoroughly the feasibility of implementing Phase 2 Lite by January 31, 2003. It explains that "the October 11 Order [was] based on a record that was inaccurate and incomplete.

The CAISO takes full responsibility for this."[4] Specifically, the CAISO argues that implementing Phase 2 Lite would require significant expenditure of funds and diversion of staff resources from Phases 2 and 3. The CAISO further argues that the Phase 2 Lite changes would be temporary "throwaway" modifications "that might only be in effect for a few months until [the temporary modifications are] replaced by the comprehensive IFM [Integrated Forward Market Design]."[5]

7. Our directives regarding the implementation schedule in the October 11 Order were based in large part on the assertion by the CAISO that it could implement Phase 2 Lite by January 31, 2003.[6] On rehearing, the CAISO contends that it has expended a "significant effort to examine the feasibility of Phase 2 Lite" and now maintains that it cannot implement Phase 2 Lite by January 31, 2003. Accordingly, we grant rehearing. We will no longer require the implementation of Phase 2 Lite by January 31, 2003, as previously directed in the October 11 Order.

8. We recognize the commitment of time and resources to undertake the market redesign and are committed to working with the CAISO and market participants.[7] To this end, we direct the CAISO to file a full implementation plan, including a detailed timeline with the sequential and concurrent nature of design elements, the software and vendors (once selected) to be used, and cost estimates for each element. This plan and its implementation should be robust enough to be compatible with the developing RTOs in the West. Specifically, we direct the CAISO to file an estimate of expenditures on hardware and software development necessary for implementation of MD02. The estimates should be based on vendor quotes and material costs for a system that can be upgraded or modified to reflect refinements necessary to interface with the systems of RTO West and WestConnect as they are developed.

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[4]CAISO Request for Rehearing, p 12.

[5]See Emergency Request for Rehearing and Motion for Clarification of the California Independent System Operator Corporation, November 8, 2002, p. 22.

[6]See 101 FERC at P. 83.

[7]We note that the Commission has scheduled a technical conference to be held on December 9, 2002 to facilitate continued discussions between the CAISO and stakeholders regarding the development of the remaining elements of the CAISO market redesign and to identify related implementation issues.

9. We direct the CAISO to update this plan on a monthly basis, indicating the progress made and the upcoming steps. This report shall be filed on the first Monday of each month, beginning with Monday, January 6, 2003.[8] In the first informational filing, the CAISO should explain (1) any alternative methods of developing the MD02 elements; (2) progress made in developing these elements; (3) actions that it will take to establish these elements; and (4) detailed breakdown of the total start-up costs. We may supplement these requirements in subsequent orders, as necessary, to facilitate our monitoring function.

The Commission orders:

The Commission hereby grants rehearing and clarifies the MD02 implementation schedule, and directs the CAISO to file monthly reports with the Commission, as discussed in the body of this order.

By the Commission.

( S E A L )

Linwood A. Watson, Jr.,
Deputy Secretary.

[8] We note that, on a monthly basis, the CAISO provides updates to its Board of Governors.

CALIFORNIA ISO

California Independent
System Operator

December 2, 2002

The Honorable Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

**Re: California Independent System Operator Corporation**
**Docket No. ER02-1656-000**

**Investigation of Wholesale Rates of Public Utility Sellers and Ancillary Services in the Western Systems Coordinating Council**
**Docket No. EL01-68-017**

Dear Secretary Salas:

Pursuant to the "Notice of Technical Conference" issued by the Federal Energy Regulatory Commission on November 8, 2002 in the captioned proceeding, the California Independent System Operator ("ISO") hereby submits its presentation for the December 9, 2002 technical conference.

The ISO notes that, due to computer problems, the ISO initially was able to file only the presentation portion of this filing electronically with the Commission. The ISO is now submitting a complete filing including the presentation, the instant transmittal letter and certificate of service. The ISO requests that the Commission accept this filing effective December 2, 2002.

Thank you for your assistance in this matter.

Respectfully submitted,

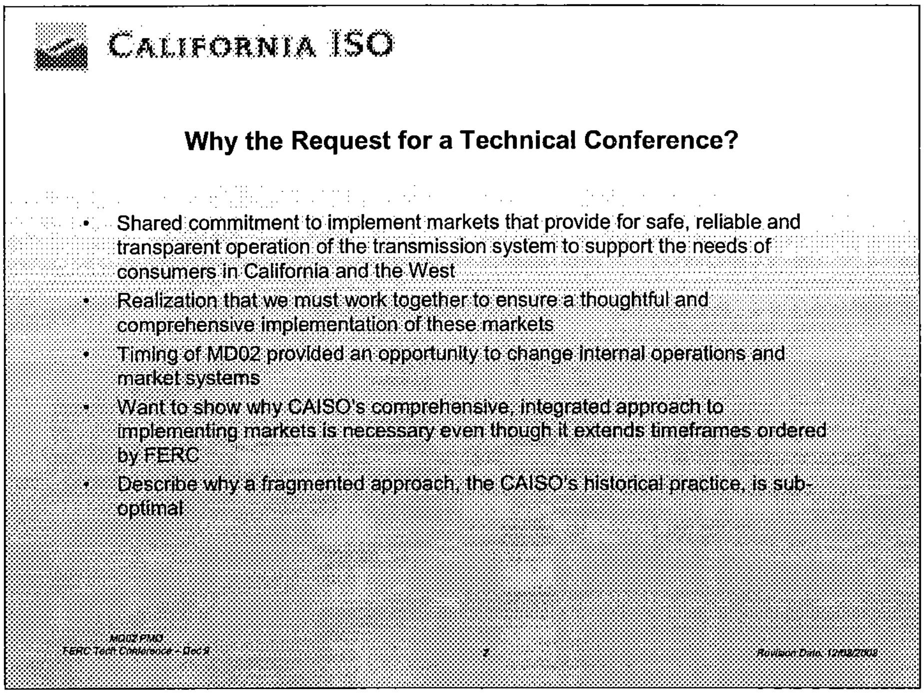
Anthony J. Ivancovich
Counsel for The California Independent
System Operator Corporation

CALIFORNIA ISO

# CAISO MD02 Implementation

## FERC Technical Conference

## December 9, 2002




The CAISO wants to make sure that FERC understands the context in which it is working and that the objectives of MD02 Implementation are aligned with what the Commission has put forth in the FERC's Market Design. In order to meet the objectives of both organizations, we need to look at the objectives in a comprehensive manner.

CALIFORNIA ISO

**The CAISO has initiated a comprehensive implementation approach**

- Instituted a disciplined, industry standard approach to the process
- Actively involved with four Stakeholder Working Groups created as an outcome of the August 2002 FERC Technical Conference
- Conducted three Joint Application Design sessions for Phase 1B with six planned for Phases 2 and 3
- CAISO's 'Fence and re-invest' strategy to re-architect system infrastructure

MQ02 PMO
FERC Tech Conference – Dec 9 3 Revision Date: 12/02/2002

The CAISO has undertaken a comprehensive approach to the design that needs to be carried into implementation. This approach is a fundamental change in the way that the CAISO looks at system development, a manner which employs sound business practices consistent with those found in a mature organization.

CALIFORNIA ISO

## Goals of Today's Presentation

- Communicate the comprehensive nature of what the CAISO is trying to do and the detrimental nature of fragmenting decisions and directives
- Work towards a comprehensive implementation approach for both FERC and CAISO
- Be conscious of timelines of stakeholders, FERC, CAISO, system development and western RTOs/ISOs
- Communicate the implications of FERC's decisions and timeframes for keeping the MD02 implementation moving forward

FERC admonished the CAISO to present a comprehensive market redesign plan rather than to continue a piecemeal approach. The CAISO delivered a comprehensive design. In order to realize the intended outcome of this directive, we need to make sure that both the Commission and CAISO can craft an implementation plan that gets us to a workable market that meets the needs of California and the West.

CALIFORNIA ISO

### Benefits of a Comprehensive Market Implementation

- Successful resolution to those market design problems under CAISO's control
- Cost-effective implementation of an infrastructure that is flexible and adjustable
- Faster implementation of a stable set of market rules
- Consistency with FERC's market design

MD02 PMO
FERC Tech Conference – Dec 9
5

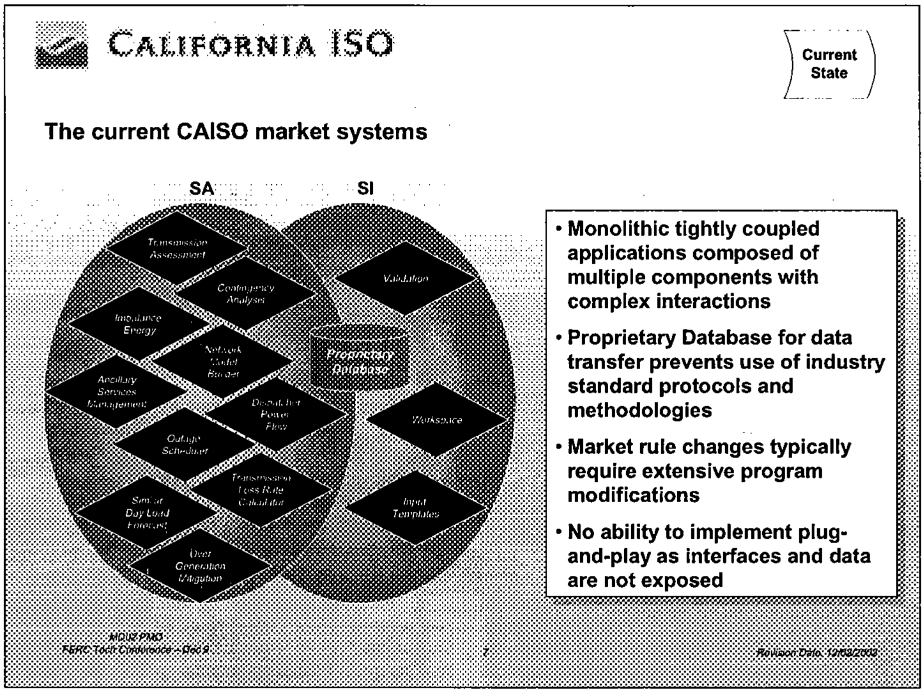
We understand what issues are critical to California and the wholesale market and have incorporated those in our design. It is better, and less expensive in the long run, if we plan and design to these issues now, rather than find out something doesn't work and to have to change it later. The underlying system changes are designed to allow adaptation to standard design elements as they evolve and to improve the wholesale electricity market in California.

CALIFORNIA ISO

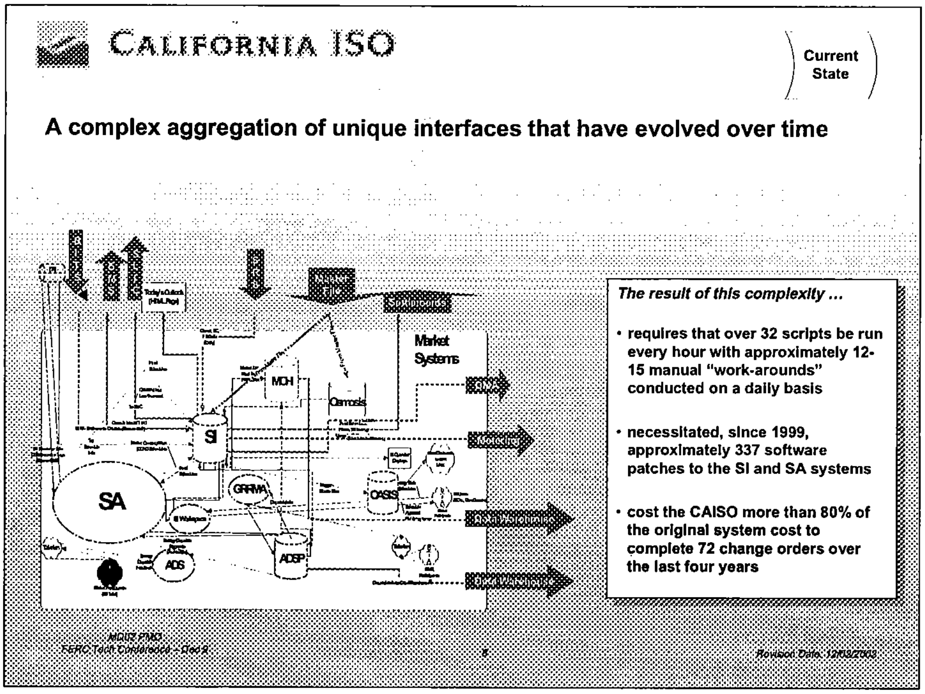
### Today's Presentation

- Provide a description of the current state of CAISO's systems
- Demonstrate how CAISO's proposed approach is aligned with FERC's market design
- Discuss how CAISO's proposed approach parallels industry standards
- Describe the key factors driving CAISO's proposed timelines
- Review the key FERC decision points in the timeline

We will show you what we are dealing with today and why it needs to change. How both market design elements and underlying infrastructure are consistent with the Commission's vision. What the CAISO is doing to assure its implementation strategy is consistent with prudent commercial practices and why we need to proceed at the pace that we are proposing.




Most of CAISO's current market functions reside in a black box we call our Scheduling Application (SA). This black box is welded to the Scheduling Infrastructure (SI) making it difficult to change, or add to, the existing functionality. The design of these systems is monolithic (that is the complex interdependent elements of the systems make changes to one element impact others, there is a high degree of shared data elements and interfaces and data interactions are not open.) Monolithic design, although not inherently poor, is intended for systems that will not undergo significant change. In general, the systems development industry has evolved away from monolithic design toward open and component type design principles to drive flexibility and economies in system development and operations.



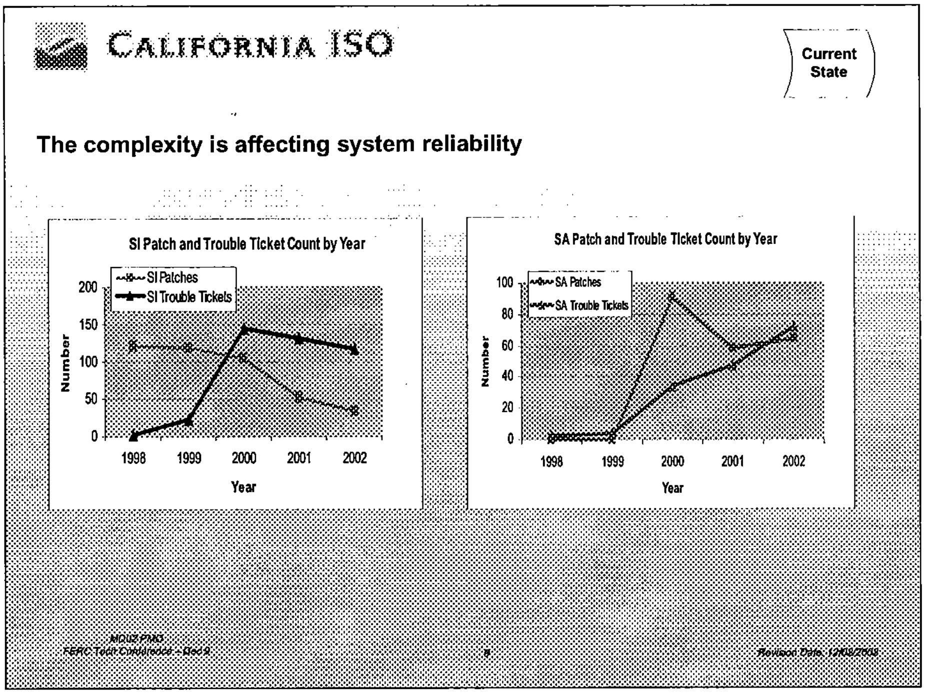

Although SI and SA are the foundation CAISO market systems, they are but part of a complex web of systems and interfaces required to run the CAISO markets.

The current design derives much of its unseemly complexity from accommodations and additions over the years to core market functionality. For example, in addition to core market functionality, GRMMA is used to track RMR dispatches, and OSMOSIS is for out of sequence and out of market energy. The market systems also include a complex set for interfaces to non market systems required to operate the CAISO such as EMS, settlements, metering and data warehouse to name but a few. The broad scope and high complexity of this set of systems makes changes to them risky and very difficult.

•The three main CAISO markets that use the SA for their operational functions are the: a) Day-ahead (DA), b) hour-ahead (HA) and c) RT markets. The SA system coordinates and consolidates all DA and HA energy schedules and optimizes AS bids and schedules into final schedules constrained by the CAISO grid reliability requirements. It also conducts the RT imbalance energy market by dispatching supplemental energy and AS resources in response to system imbalance energy (IE) requirements.

•Within these systems, over 32 scripts are run every hour with approximately 12-15 manual work-arounds (only within the market systems alone and doesn't include manual efforts in other departments such as settlements) conducted on a daily basis. This process is taxing and cumbersome and is making ongoing operations inefficient with an increased long term cost burden.

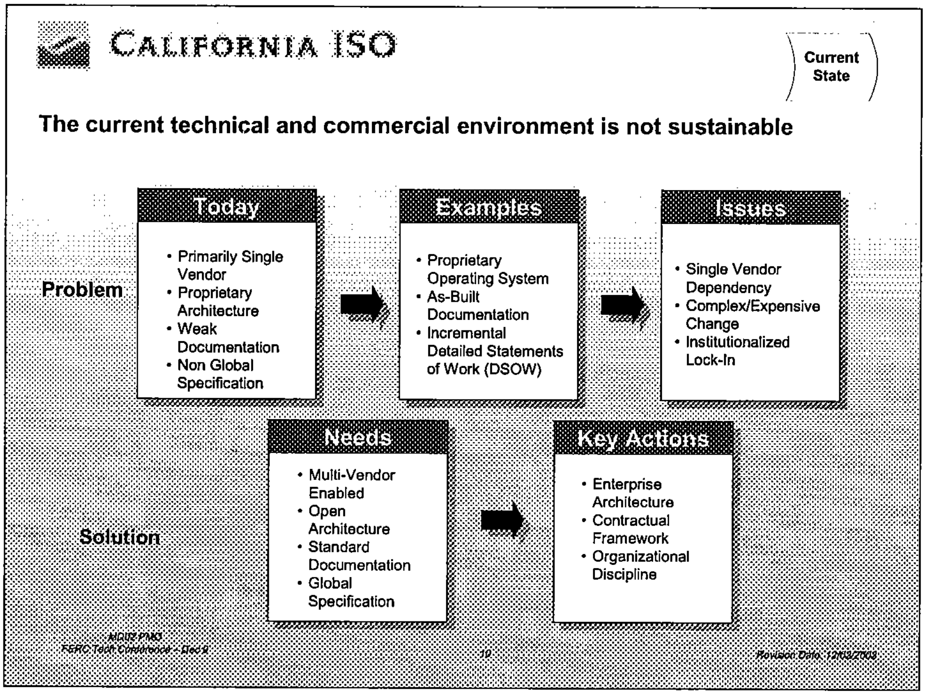
•Since 1999, approximately 337 software patches have been applied to the SI and SA systems. Software patches are used to fix problems and improve functionality as needed after the system has been delivered. In 2001 alone, there were over 141 trouble tickets associated with these two systems. Trouble tickets are created when system problems occur and the means for immediate resolution is not readily known. These trouble tickets resulted in system downtime averaging up to one hour per ticket.




CAISO's market systems since start-up have undergone significant incremental change (patches). Many of these patches include multiple updates to functionality. Concurrently over this time period, the CAISO systems have experienced a substantive numbers of trouble tickets. Each of these trouble incidences have impacted business operations (severity 1's and 2's). The most recent experience with trouble tickets in the SA system shows an alarming trend.

Although the cause and effect relationship of patches to trouble tickets is not one to one (i.e. some patches were to change functionality as a result of market rule changes) the primary trend of trouble tickets is increasing and most certainly the result of the added complexity resulting from the incremental changes to the SI and SA systems.

Continued incremental changes to these systems will undoubtedly continue these undesirable trends.




The current technical and commercial environment of the CAISO systems is not sustainable in the future. CAISO's primary system architecture is proprietary to a single vendor and inadequately documented. Specifications for changes to the systems since start up have primarily been incremental. This has resulted in the CASIO being dependent upon a single vendor. Changes to the current systems are complex and expensive. For all intents and purposes, the CAISO is "locked-in" into a technical environment and commercial framework which is not sustainable.

CAISO's approach to MD02 is to implement MD02 functionality upon a technical environment which is multi-vendor enabled, open and well documented. The foundation for this implementation is an open and flexible enterprise architecture implemented under a vendor contractual framework and process discipline consistent with good systems implementation practices.

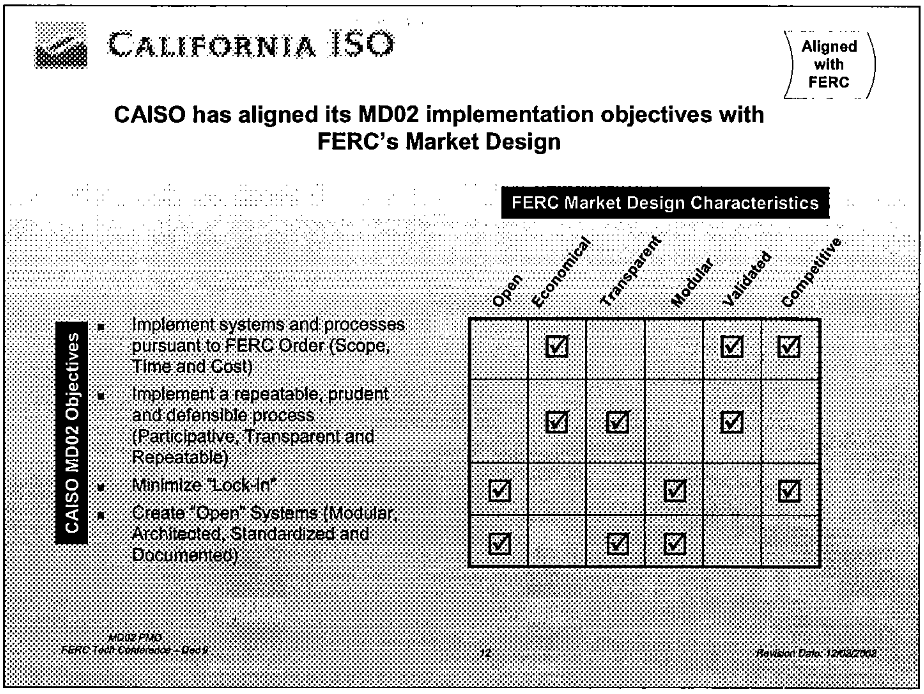
CALIFORNIA ISO

Aligned with FERC

**FERC's Market Design NOPR articulates a clear and prudent direction for ISO/RTO systems**

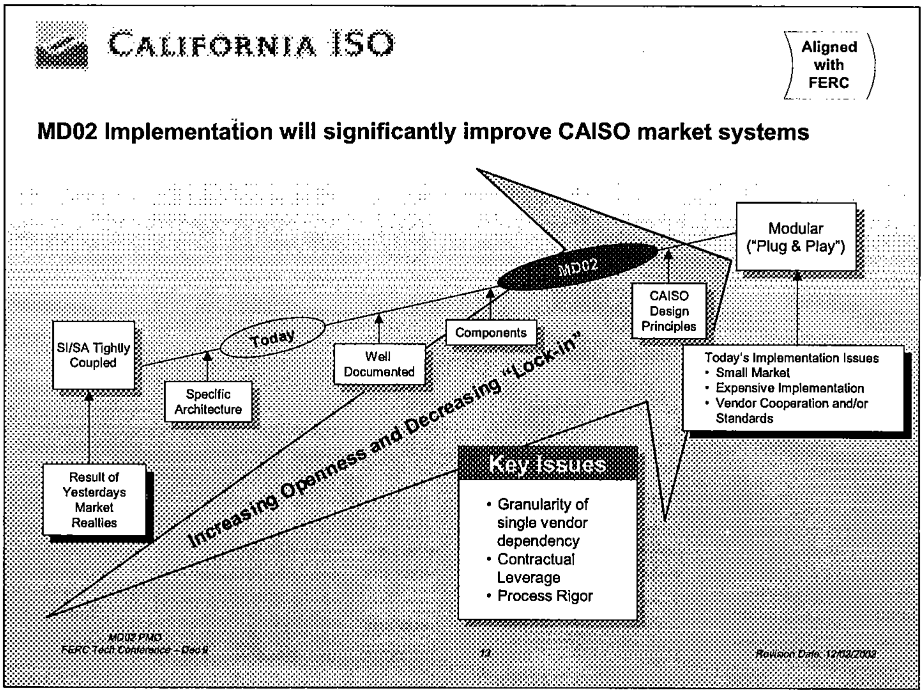
- **Open** - Avoid "Black Box" software
- **Economical** - Reduce implementation cost ("reinventing the wheel")
- **Transparent** – The ability to understand what the software does
- **Testable** – The ability to understand and compare performance
- **Modular** – The ability to change software modules without changing other software. ...Modularity requires standard interfaces
- **Validated** - Instill confidence in the software through robust testing and validation
- **Competitive** - The Commission's goal is to assure that the best software is available for use in the nation's wholesale markets. This can best be attained by promoting competition among vendors, in a way that assures that no vendor comes to "own" a market niche or impose barriers to entry by new software companies with innovative analytical approaches

FERC under the SMD NOPR has outlined a clear set of system objectives for ISO/RTO implementation. These objectives are consistent with best practices in the systems development industry. For the most part CAISO's current systems do not meet these objectives. This situation is one of the key drivers to migrate CAISO functioning market systems to new operating platforms.



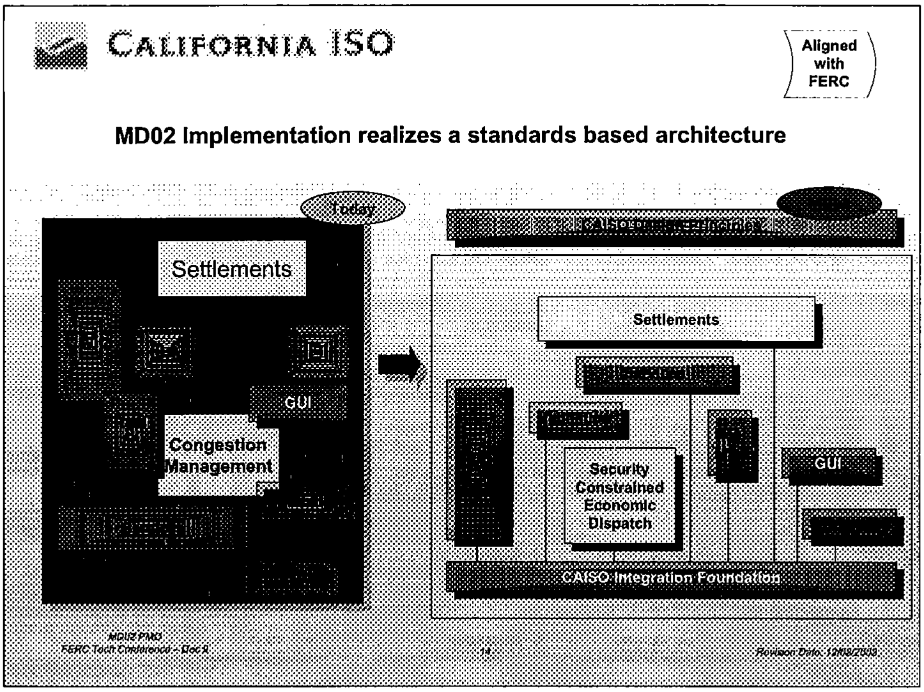

| CAISO MD02 Objectives | Open | Economical | Transparent | Modular | Validated | Competitive |
|---|---|---|---|---|---|---|
| Implement systems and processes pursuant to FERC Order (Scope, Time and Cost) | | ☑ | | | ☑ | ☑ |
| Implement a repeatable, prudent and defensible process (Participative, Transparent and Repeatable) | | ☑ | ☑ | | ☑ | |
| Minimize "Lock-In" | ☑ | | | ☑ | | ☑ |
| Create "Open" Systems (Modular, Architected, Standardized and Documented) | ☑ | | ☑ | ☑ | | |

The CAISO's objectives for the implementation of MD02 align closely with the objectives of SMD.




MD02 implementation as planned by the CAISO is aimed at significantly improving the foundation for CAISO's systems. MD02 will move the architecture of CAISO systems from the current tightly coupled specific architecture of the SI and SA systems to a well documented component based architecture consistent with the direction of FERC and good systems development practice.

Our plan and objective is the same as the Commission's, get to a point where we have an open and adaptable system within the context of a limited number of vendors. That is, be realistic about how open you need to be given that there are only a handful of suppliers and don't design beyond the scope of the market.




The primary enabler for driving the complexity out of the current CAISO systems is the use of a standard integration approach. Under such an approach, a common and "open" integration architecture will be utilized that integrates the various component elements of the CAISO systems.

The end point of this approach is an elimination of the complex and closed "black-box" characteristic of the current systems. After MD02 is implemented, integration of the specific components required to operate the CAISO markets will be accomplished through an open and common interface framework that supports flexibility and maintainability.

CALIFORNIA ISO

Approach

## MD02 Implementation Embraces Best Practices

- Commercially Accepted Methodology (Conform to IEEE Standard)
- Program Management Office
- System Development Life Cycle (SDLC)
  - Provides a common understanding of approach to systems development
    - Establishes a standard terminology
    - Maps project deliverables to roles and responsibilities
  - Repeatable process to gather and document business requirements
  - Standardized approach to system documentation (through process models and templates)
  - Identify points for measuring project performance and efficiency
  - Links directly to project methodology
- Information Services Industry Accepted (and common) Practices and Technologies
  - Use of standard technologies
    - ✓ Extensible Markup Language (XML)
    - ✓ Standard commercial data base
    - ✓ Common Information Model (CIM)
  - Adoption of an open system and standards approach
- CAISO Enterprise Architecture – Design Principles
  - Scalability, Openness, Reusability, Availability, Securability, Manageability ...

MD02 PMO
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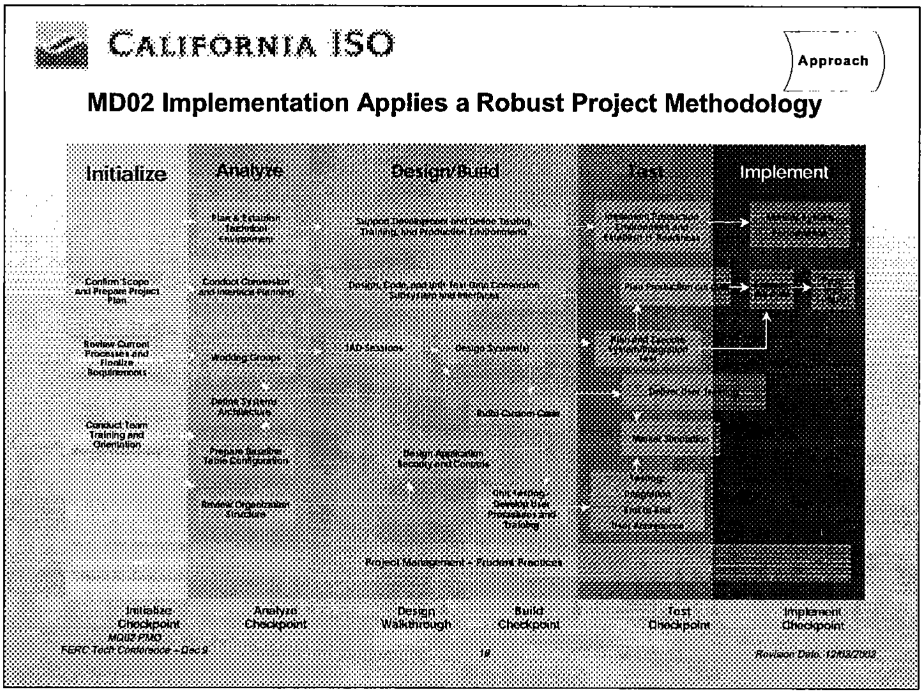
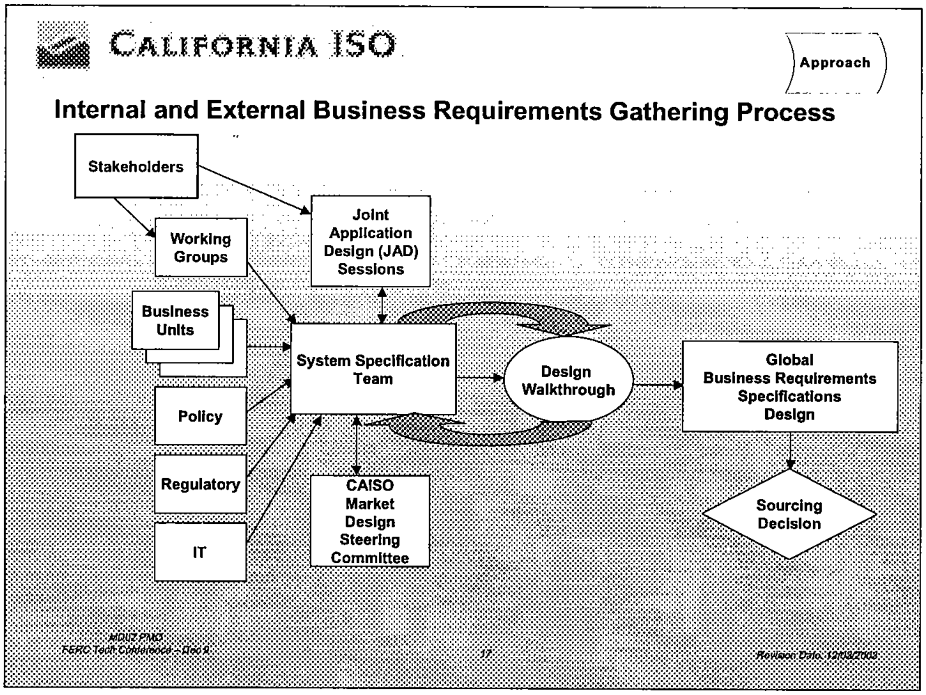
These represent the significant efforts that the CAISO has undertaken up to this point in the implementation phase of changing market functionality.




Software Requirements

- A methodology such as this is required to ensure quality
- Vendor control points
- Proper and prudent testing – unit, system, integration, end to end, user acceptance
- Adequate time for market simulation



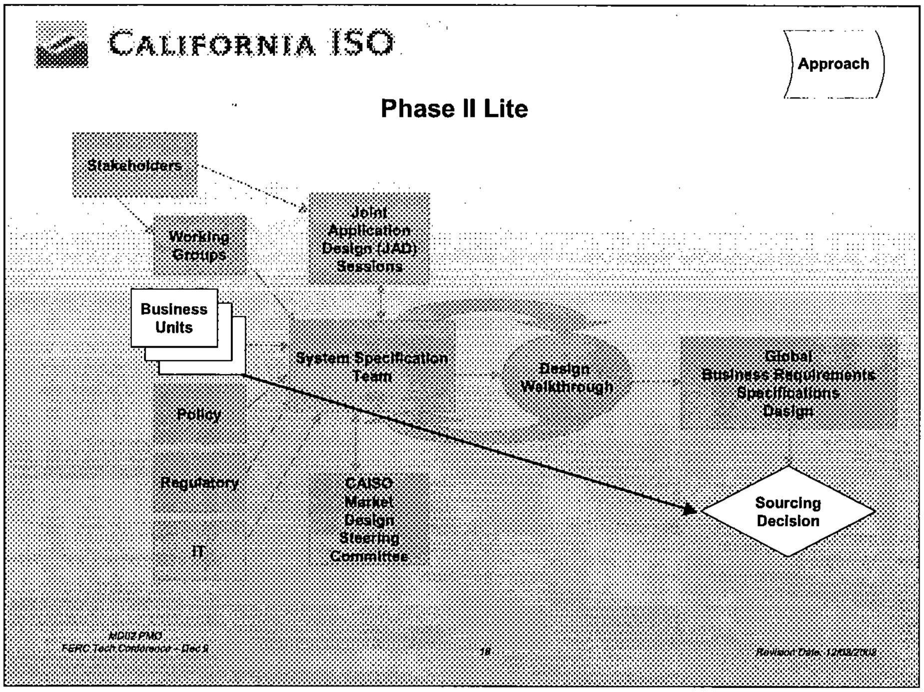

Describes the extensive stakeholder involvement through Working Groups (the what) and Joint Application Development (the how) process.

This business requirements gathering process needs to be done no matter how you source the solution.

Software Requirements

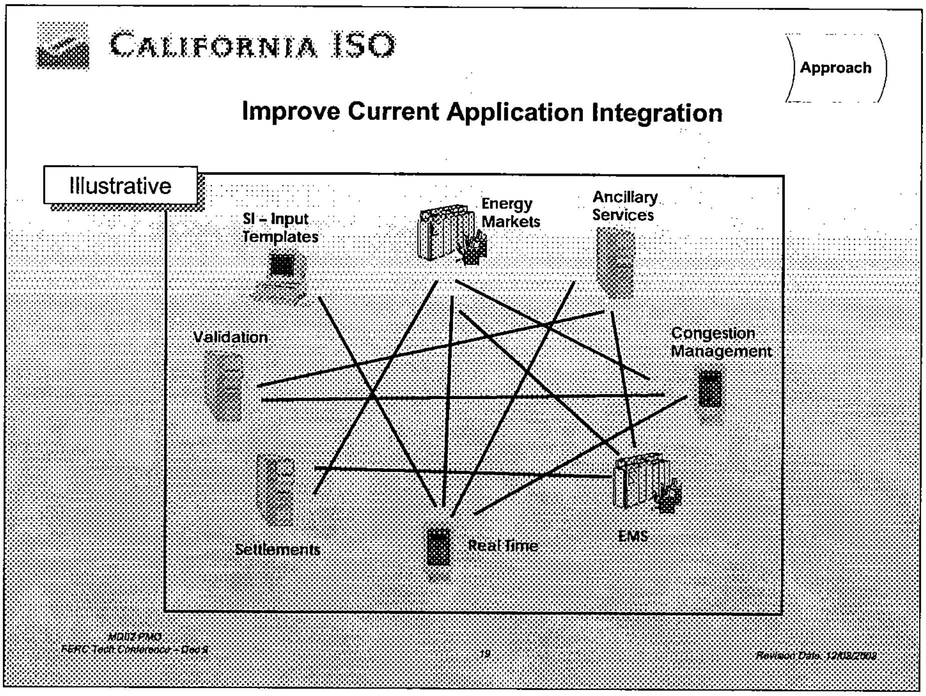
By fully engaging stakeholders and applying industry practices the final product will be more reliable and focused on the business needs.

While the Security Constrained Economic Dispatch for real-time imbalance energy did not receive significant stakeholder input in the conceptual design, significant rigor was added in developing the functional specifications. This included several joint application development (JAD) sessions with stakeholders, an iterative process within CAISO business units, a design walkthrough and the development of additional Tariff language to support the final design requirements prior to delivery to the vendor for coding (the actual software development). The result is that there is a well documented, broadly accepted market functionality that will be implemented by the CAISO pending successful development and testing phases.

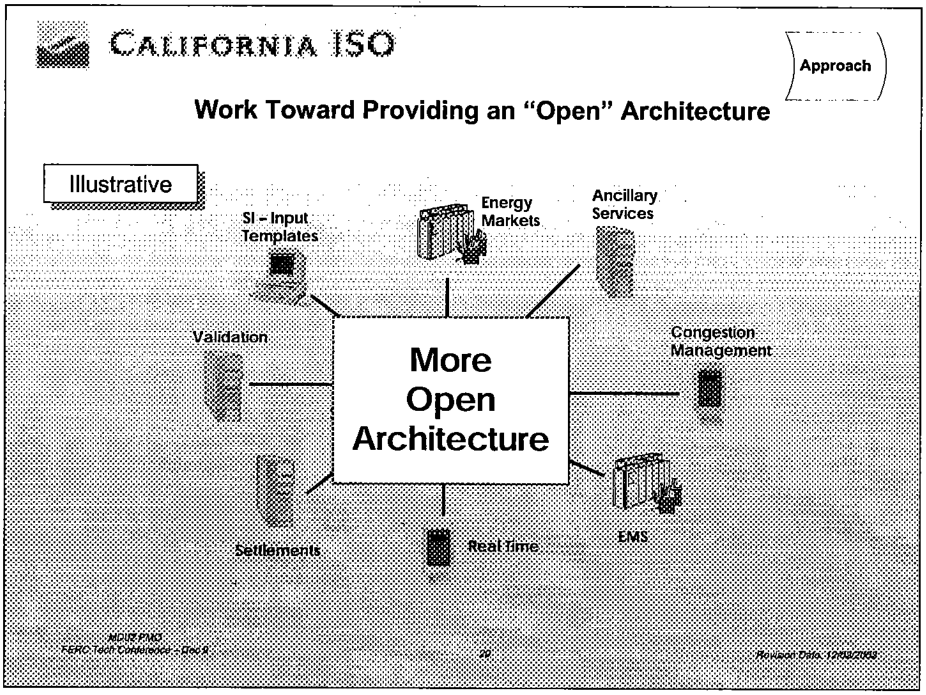



The Phase 2 "Lite" concept as originally proposed in the August FERC technical conference, was not considered in context of best practices for system development. As brought forward, it advanced directly from a business unit concept to a predestined sourcing decision. When the CAISO actually took a look at functional requirements and a reasoned approach, the implementation timeline increased substantially. When the requirements for both the market system and settlements changes were determined at a high level and adequate functional, integration and market testing were contemplated, it became apparent that to be implemented in a commercially prudent manner, it would require eight months or longer. This timeline is somewhat compressed as it did not contemplate significant stakeholder process in the design phase.

In addition to the extended implementation timeframe for adding Phase 2 "Lite" functionality on existing CAISO systems, the effort would have the undesirable impact of diverting scarce CAISO resources away from implementing the comprehensive MD02 Implementation changes. While MD02 Implementation activity would not cease, projected project timelines would invariably increase if critical resources were diverted to the Phase 2 "Lite" effort.




Due to the way that the current systems evolved, we are required to establish a multitude of point to point connections from one application to another to tie critical functionality together.




•CAISO Enterprise Architecture – Design Principles

–Scalability, Openness, Reusability, Availability, Securability, Manageability

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Timeline

## MD02 Implementation Schedule is Driven by Key Factors

- MD02 system implementation is primarily "brown field"
- Adequate time for Testing and Market Simulation is critical for both CAISO systems and market participants
- Addition of new market functions requires integration of new interfaces and migration of retained interfaces
- Many elements have predecessor requirements that create scheduling dependencies (i.e., Congestion Revenue Rights are dependant on implementation of the Full Network Model portion of Locational Marginal Pricing)
- Aggressive acceleration of implementation will precipitate implementation trade offs
- Many new market functions will be implemented on new platforms

**The MD02 Implementation provides for a totally new market structure for California. Within this context, planned timeframes are aggressive.**

MD02 PMO
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•MD02 system implementation is primarily "brown field" requiring CAISO staff to both support MD02 development and testing while sustaining current operations

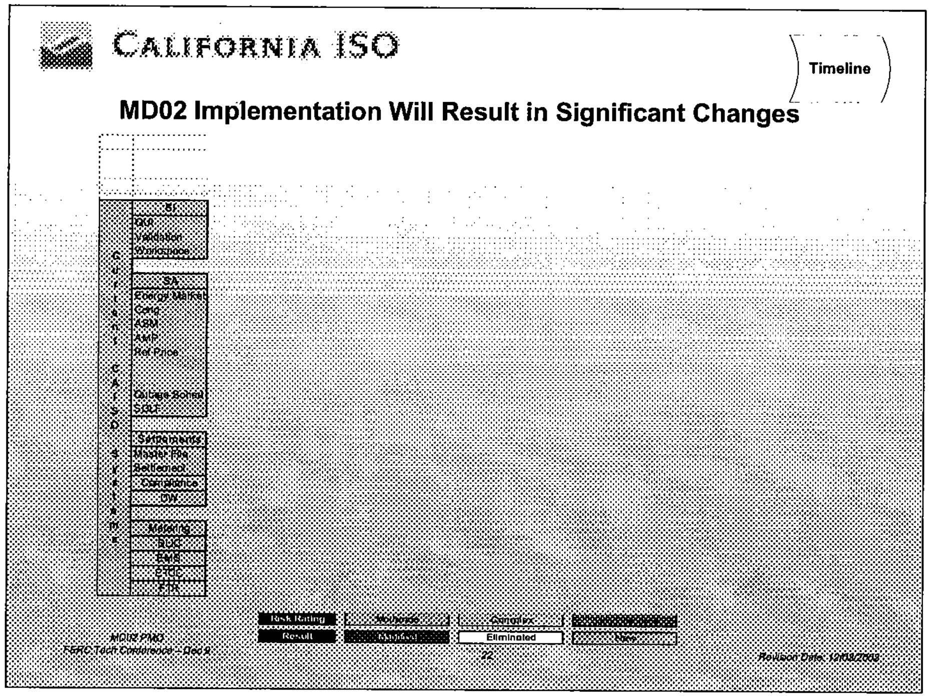
•The degree of market change will necessitate appropriate time for market simulation to support market participant needs

•Development of new market functions requires significant modification to already complex system components. Development time lines are highly dependent on limited vendor and CAISO staff expertise reducing the opportunity for parallel development across multiple system functions

•Many elements have predecessor requirements which create scheduling dependencies (i.e. Outage Notification)

•Imprudently accelerating implementation will precipitate implementation trade offs which may compromise quality and jeopardize efforts to minimize on going cost of operations

•Many new market functions will be implemented on new platforms which provide for improved operations. However implementing these new platforms requires robust testing and appropriate transition management activities




Above are the current components of the CAISO's current systems:

•Scheduling Infrastructure (SI)

•Scheduling Application (SA)

•Settlements

•Compliance

•Data Warehouse (DW)

•Metering

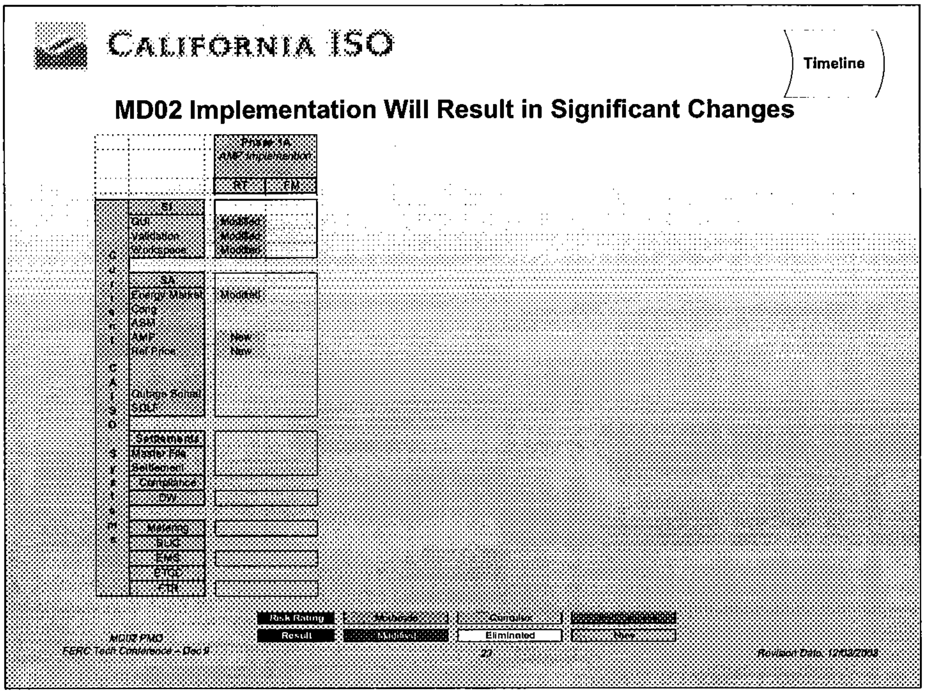
•Scheduling and Logging for ISO California (SLIC)

•Energy Management System (EMS)

•Existing Transmission Contract Calculator (ETCC)

•Firm Transmission Right (FTR)

The Legend denotes both a Risk Rating and the expected Result.




Work on Phase 1A began on July 17, 2002 and was successfully implemented on October 30, 2002.

New components include:

•Automatic Mitigation Procedure (AMP)

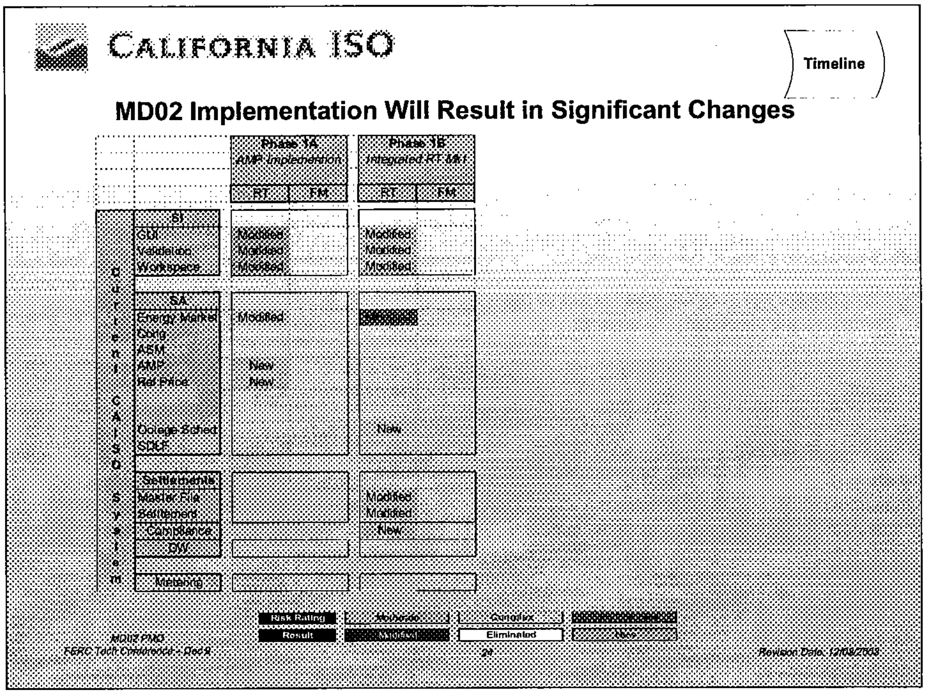
•Reference Price as calculated by an independent entity (Potomac Economics)

Using the legend, both projects are 1) new and 2) complex projects to implement.

The other components include:

Balancing Energy Ex-Post Price (BEEP) is an existing market system that was modified during Phase 1A

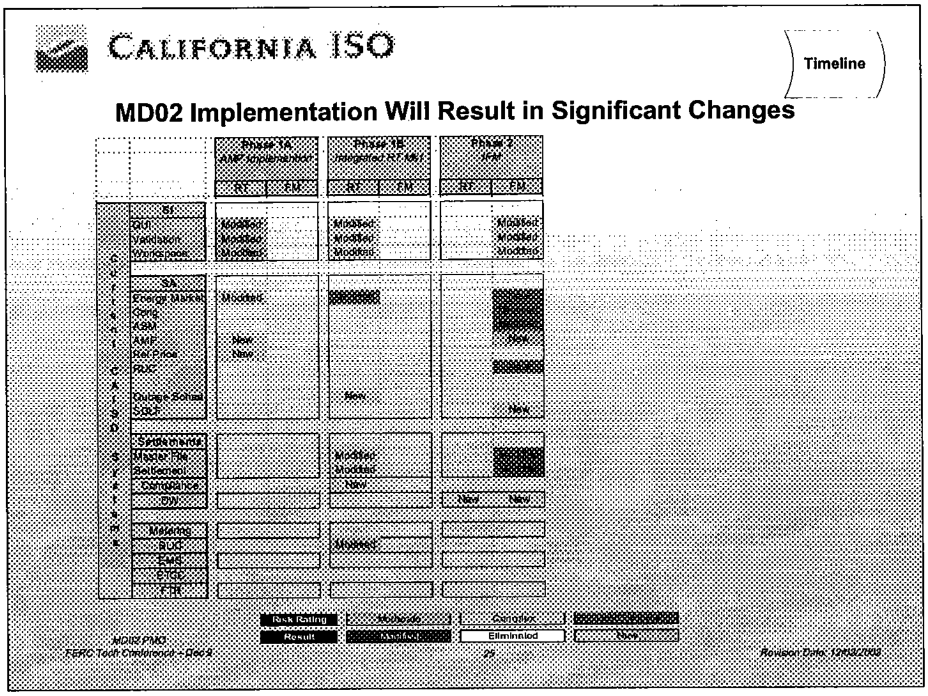
The Scheduling Infrastructure components were modified and moderately complex.



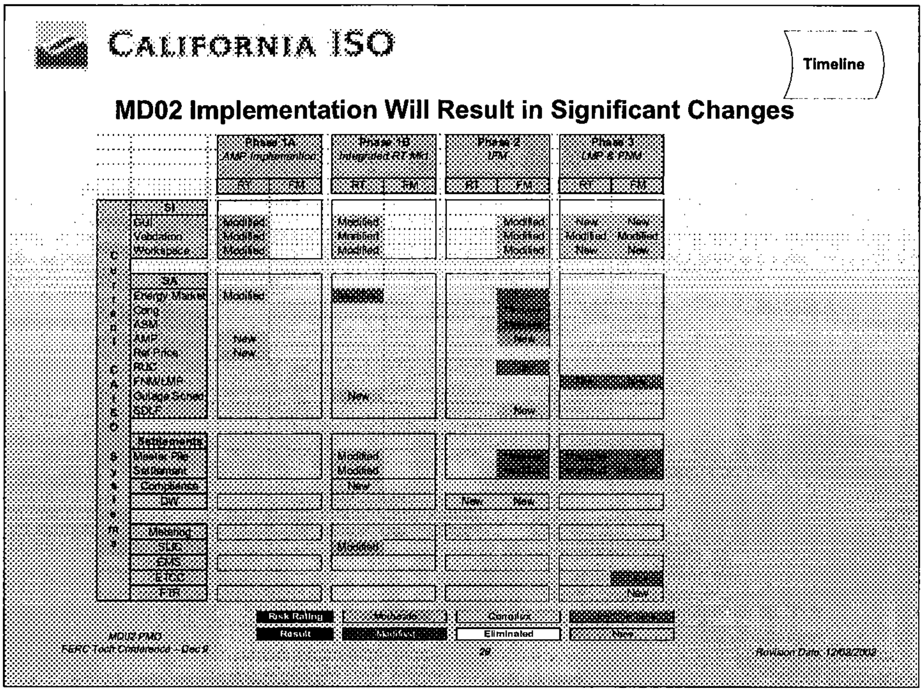

The CAISO is currently in the planning phase of of Phase 1B.

The BEEP (Imbalance Energy) modification is actually a migration to Security Constrained Economic Dispatch (SCED) on a new platform.

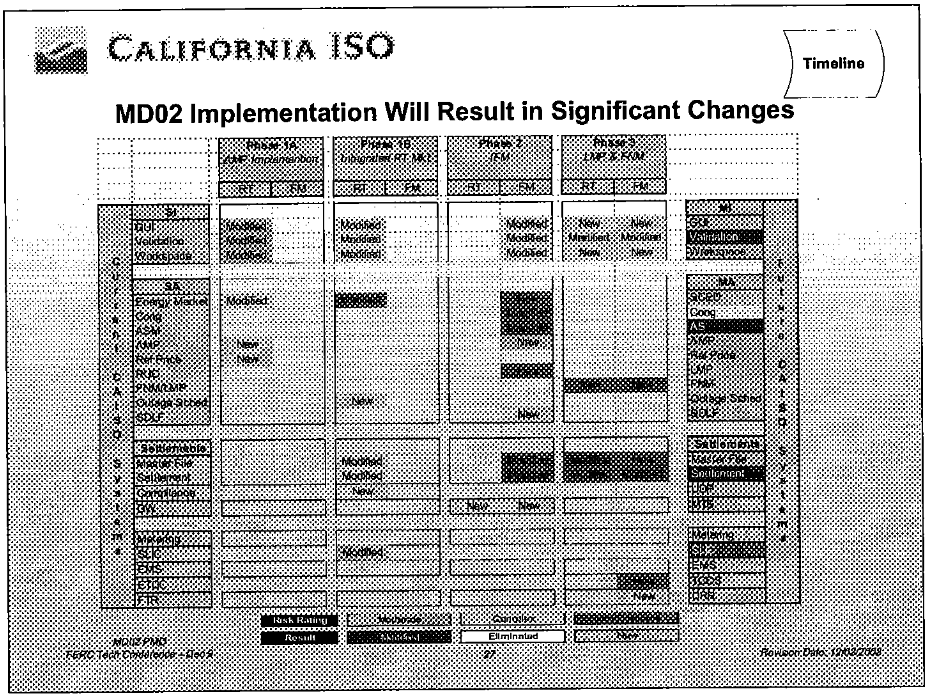
The outage scheduling functionality will allow the Scheduling Coordinator to update unit de-rates in real-time.




Phase 2 Forward Market (FM) modifications associated with energy, CONG (congestion) and ASM (ancillary service procurement) are the core changes that add a forward energy market to the CAISO and optimize its integration with congestion and ancillary services. The new AMP (Automatic Mitigation Procedure) functionality is adding mitigation to forward market bids. Significant changes are required in settlements and the master-file to accommodate the added market functionality. The MTS (market transaction system) moves historical transaction data off of the production system to a data warehouse.




Phase 3 adds Locational Marginal Pricing derived from a Full Network Model to the preceding changes in Phase 1 and Phase 2, and requires changes to the existing transmission contract calculation (ETCC) in the form of transmission allocation contract optimization system (TCOS). The basis for settlements changes again and at this point it is desirable to actually redesign the Masterfile architecture.




The new comprehensive market design is shown in the far right column as the ultimate outcome of MD02 Implementation.

•The market participant interface components (SI) will be completely revamped with improvements that benefit the market participants through an improved user interface (GUI) and CAISO system architecture through redesign table structures.

•Market applications (SA) will, by the end of the of the project, be completely revamped. SCED, FNM, LMP will have replaced or added to current market functionality and related market components will be pointed to new platforms and applied to new functionality (e.g.. AMP will be applied to forward markets)

•Settlement functionality will be significantly altered and the master file will be stand independent of the settlements system.

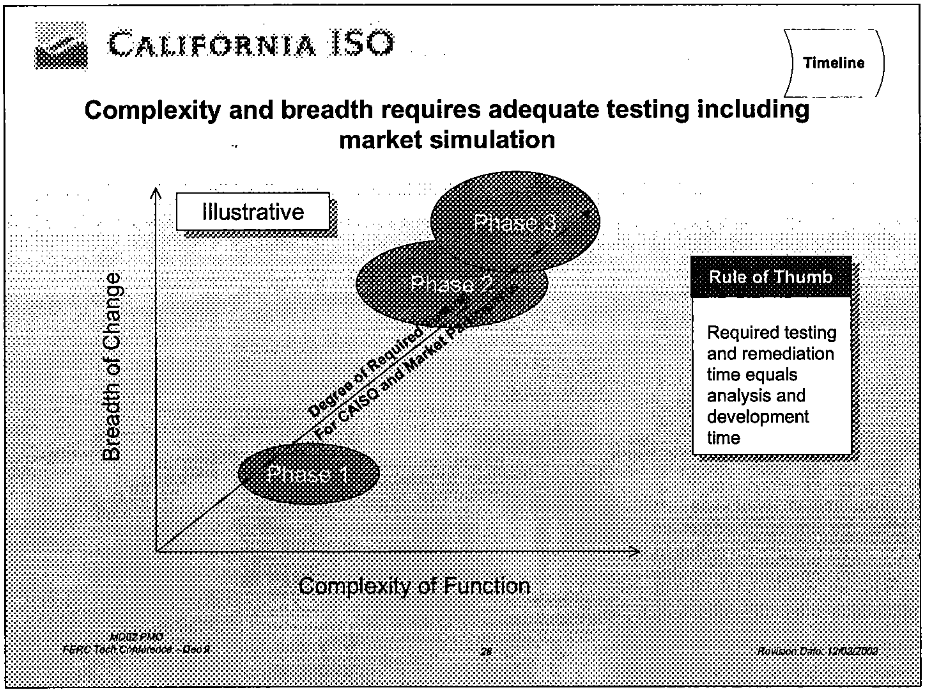
•The addition of the market transaction system (MTS) will provide a data warehouse for historical transaction data independent of the market production systems.

•While the metering and EMS functions will remain unchanged, interfaces with market, settlement and compliance systems will be updated to meet new standard integration protocols.

•The existing FTR functionality will be replaced with a CRR system to accommodate FNM and LMP functionality.

•TCOS is the method by which the CAISO assures that existing transmission contract rights (see slide 33) will be honored under the Full Network Model.

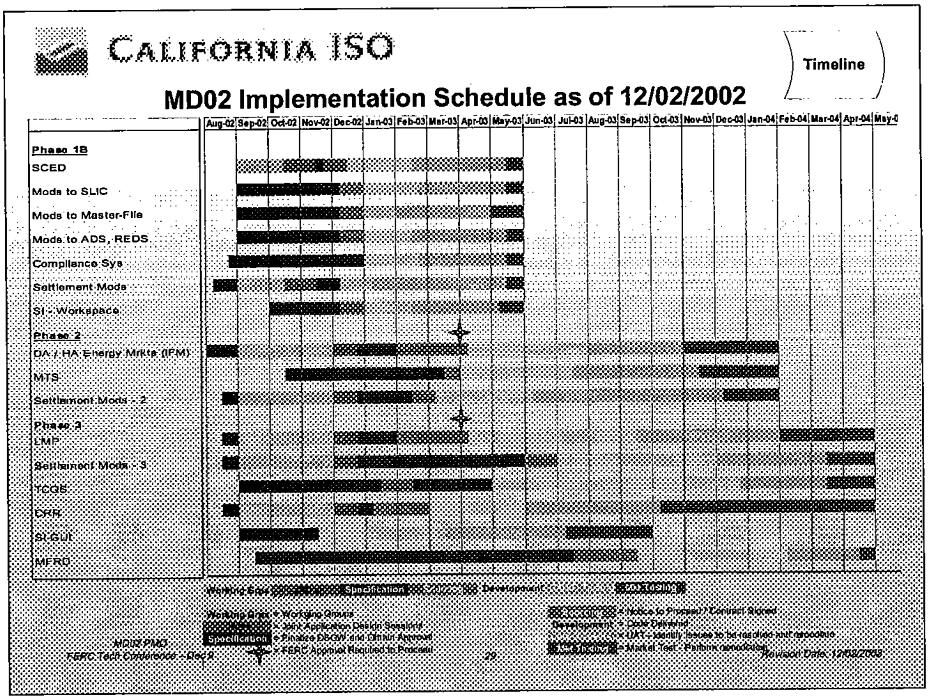
Overall, the MD02 Implementation is a highly complex project that affects every major system at the CAISO. The new market design must be viewed from a long term and comprehensive "end to end" perspective to ensure all the requirements of the new market are achieved.




The scope of change and critical interdependencies between operating systems and market functionality require a robust testing regime.

There must be adequate time for comprehensive testing and Market Simulation for both the CAISO and market participants.

Testing is critical to the success of the new market.




The current implementation timelines deviate from dates originally contemplated by CAISO and implementation dates ordered by FERC. These timeframes reflect employing commercially prudent practices in system development that were not contemplated in previous MD02 filings with the Commission. Furthermore, they are subject to change based on variables such as vendor responses to RFPs and the change management process employed in system development.

FERC Decision Point Criteria:

Phase 2 – The CAISO requires conceptual design authorization from FERC to implement an optimized forward market that includes energy, ancillary services and congestion with accompanying settlement schema for allocation of charges substantially as initially filed. Additionally the CAISO expects to make a 205 filing on residual unit commitment and other issues that emerge as a result of additional stakeholder input from working groups and JAD sessions.

Phase 3 – As with Phase 3, the CAISO requires both conceptual design authorization on its proposed implementation of LMP and the design of CRRs, along with any subsequent design changes that emerge as a result of ongoing stakeholder working group issue resolution and design changes that come from JAD sessions.

Currently the CASIO anticipates making these 205 filings in January 2003. FERC would then have before it all of the material necessary to make a comprehensive decision on the required elements for the implementation of both Phase 2 and Phase 3. If a decision on both the conceptual design and subsequent 205 filings were to be rendered on or before March 31, 2003, the CAISO could maintain this projected implementation timeline. A FERC order in March that deviates significantly from the proposed design, or a ruling after that date is likely to extend the projected timeline.

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## Summary

- CAISO approach is comprehensive and and is consistent with FERC NOPR
- Fragmented decisions further complicate system development and significantly slows timeline for delivery
- Timeframe for MD02 Implementation is dependent on content and timing of FERC decisions



•Want to thank the FERC for putting on the Technical Conference and allowing the CAISO to present its current market systems, what the CAISO is moving towards and its timeline for completion.

•The CAISO understands the importance of working together with the FERC and Market Participants throughout the MD02 Implementation process.

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# Appendix

MD02 PMO
FERC Tech Conference – Dec 2
31
Revision Date: 12/03/2003

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Timeline

## MD02 Implementation Projects

| | Desctiption |
|---|---|
| **Phase 1B** | |
| SCED | Security Constrainted Economic Dispatch |
| Mods to SLIC | Modifications to System Logging |
| Mods to Master-File | Master File Modifications |
| Mods to ADS, REDS | Modifications to Dispatching Systems |
| Compliance Sys | Compliance System Modifications |
| Settlement Mods | Settlements Modifications |
| SI - Workspace | Workspace enhancement for "Openness" |
| **Phase 2** | |
| DA / HA Energy Mrkts (IFM) | Day Ahead/Hour Ahead - Integrated Forward Market |
| MTS | Market Transaction System |
| Settlement Mods - 2 | Settlements Modifications |
| **Phase 3** | |
| LMP | Locational Marginal Pricing |
| Settlement Mods - 3 | Settlements Modifications |
| TCGS | ETCDs |
| CRR | Congestion Revenue Rights |
| SI-GUI | SI Interface Modifications |
| MFRD | Master File Redesign |

MD02 PMO
FERC Tech Conference – Dec 9 32 Revision Date: 12/02/2003

Brief description of Project Names in the MD02 Implementation Schedule.

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## CAISO Existing Transmission Rights

Obligations Under Current Design Cause "Phantom Congestion"

- Rights Holders Assert that Physical Rights are Available in Real-time
- Currently Track 30 Separate Rights Holders on 19 (Bi-Directional) Branch Groups with over 25,000 MW of Obligations

Significant Impacts to Transmission Availability While Honoring ETCs on LMP

- Additional Rights need to be Modeled on Network
- Twice to Ten Times the Flow-Gates (Branch Groups) to Be Modeled Depending on Required Granularity
- System Effectively De-Rated by ETC Rights Prior to Calculating CRR and ATC Availability

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## Western Interconnection Activity

- **Seams Steering Group-Western Interconnection:**
  - January 8, 2003 Filing:
    - Codified Memorandum of Understanding
    - Identification of seams issues and plans for resolution
  - Working Groups:
    - Market Monitoring
    - Common Systems Interfaces
    - Transmission Planning
    - Congestion Management
    - Pricing Reciprocity
- **WestConnect Implementation Date: 2007/2008**
- **RTOWest Implementation Date: 2006**

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## Implement Enterprise Architecture Design Principles

| Tenet/Design Principle | SMD |
|---|---|
| **Modular** - Functionally partitioned into discrete, scalable, reusable modules consisting of isolated, self-contained functional elements | 352 - Modularity<br>358 - Standard Data Transfer |
| **Configurable** - the ability to reconfigure the component or service | 352 - Transparent<br>352 - Robust |
| **Customizable** - must be capable of being customized to business requirements | 352 - Transparent<br>352 - Robust |
| **Open** - allows programs to leverage commercially funded or developed technologies and thereby take increased advantage of competition | 352 - Transparent<br>353 - Open Process<br>358 - Best Modules from Vendor<br>354 - Common Data Model |
| **Abstract** - allow a service to leverage other services in a simplified manner while reducing cohesion | 352 - Transparent<br>354 - Common Data Model |
| **Loosely Coupled** - reduces the dependencies between other services including, but are not related to transactions, security, conversational state, and location | 352 - Modularity<br>357 - Vendor Competition |
| **Technologically neutral** - does not favor a specific platform or invocation mechanism | 352 - Scalability<br>356 - Keep pace with market<br>357 - Vendor Competition |
| **Encapsulated** - gathering together of related pieces of data and the operations performed on that data | 355 - Standardization<br>358 - Standard Data Transfer |
| **Secure** - the ability to provide security to an application and its data | 352 - Security |
| **Unique** - can be discovered and utilized by other applications | 354 - Common Data Model |
| **Instrumented** - enables the state and performance related metrics of services to be monitored and allows services to managed | 355 - Standardization<br>354 - Common Data Model |

MD02 PMO
FERC Tech Conference - Dec 9

*Modularity* encapsulates all of the principles of *Component Based Development* (CBD) and *Service Oriented Environments* (SOEs), two key features of the CAISO Application Architecture. CBD principles may be implemented in various technologies, but at the heart of CBD is the notion that if business services are designed as components, they are inherently reusable (as opposed to being designed for obsolescence).

*Configurability* describes the ability to reconfigure the component or service. Configurable components may be run in numerous physical topologies and be invoked in a number of manners. For example, a service will typically surface parameters related to how it connects to a database.

Applications must also be capable of being *customized* to business requirements. In the past, packaged applications often made a virtue of requiring that the business align its functions with the package. Today, this is recognized as inappropriate and usually impossible, because of the timescale of business change. Although numerous companies might use similar services, there will always be the need to implement business logic according to individual specifications.

An *open system* is a collection of interacting software, hardware, and human components that:

- •Is designed to satisfy stated needs
- •Has component interface specifications that are: Fully-defined, Available to the public and Maintained through group consensus
- •Is implemented such that its components conform to the interface specifications

*Abstraction* is "the expression of a quality apart from a particular object or specific embodiment." Abstraction is related to encapsulation: it is a mechanism for reducing complexity and increasing efficiency. Abstraction also tends to have the effect of reducing cohesion between services. Abstraction will often define a simplified interface that wraps a much more complex set of interfaces. For example, a complex set of relational tables in a Relational Database Management System (RDBMS) might be surfaced using a view; or the functionality of a messaging product might be surfaced using an abstracted interface. Abstractions allow a service to leverage other services in a simplified manner while reducing cohesion.

A *loosely coupled* system is one that reduces the dependencies between services. These dependencies include, but are not related to, transactions, security, conversational state, and location. The less context information that is shared between them, the more loosely coupled are the services.

Services that are *technologically neutral* do not favor a specific platform or invocation mechanism.

*Security* is about controlling access to a variety of resources, such as application components, data, and hardware.

*Encapsulation* is the gathering of related pieces of data together with the operations performed on that data. The essential characteristic of a service is this grouping of data and methods (operations) into a "black box" that only surfaces the service's business functionality. Thus, the interface to the service provides access to its business logic without the necessity for understanding the internals of the implementation. For example, it is irrelevant whether a data store is implemented in a database or in memory.

*Unique* services provide functionality that is not available from other services. Services should rely on other services as applicable for providing needed functionality. Common examples are services that in turn use the services of an RDBMS, Light Weight Directory Access Protocol (LDAP), or Domain Name Server (DNS). Services should also be designed with an understanding that they can and will be reused in any number of unforeseen manners.

Services must be *instrumented* to be globally manageable in order to provide reliable and maintainable solutions. As critical business functionality is accomplished by utilizing services, it is imperative that the services be proactively managed, just as hardware and network infrastructure are typically managed. As services are reused across system boundaries, this management functionality must also span system support groups.

**CERTIFICATE OF SERVICE**

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in the above-captioned docket.

Dated at Folsom, California, on this 2nd day of December, 2002.

____________________________________

Anthony J. Ivancovich

CALIFORNIA ISO

California Independent
System Operator

# Discussion of Preliminary List of ISO Services

**December 9, 2002**

**2004 GMC Re-evaluation**

Ben T. Arikawa
Senior Financial Analyst

(916) 608-5958

# Starting Point

- Draft RTO Functions – 2002/2001 FERC Accounting Workgroup (Attachment C-2 passed out on November 9)
- Straw man document
- Series of internal discussions
- Objectives
  - Create detailed statement of activities
  - Associate them with "Functions (Services)"

# Preliminary List of Services

- Twelve functions (services)
  - Real Time Grid Operations
  - Interchange Pre-Scheduling
  - Outage Coordination
  - Operations Engineering, Maintenance and Support
  - Grid Planning
  - Market Operations
  - Market Monitoring and compliance
  - Settlements, Billing, Credit Administration and Metering
  - Account Management Services and Training
  - ISO Contract Administration
  - Administrative and General
  - Startup Costs

# Preliminary List of Services (cont.)

- 50~100 activities associated with services

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# Further Discussion

- Overall questions about method
- Individual questions about services or activities

# Next Steps

- ISO may modify the list based on questions and comments
- ISO will provide mapping of cost centers to services once list is finalized
- Request feedback by December 31, 2002
  - Comments on the items in the list and their organization

| Preliminary List of Functions (Services) for ISO Rate Structure<br>Version 12/06/2002 | |
|---|---|
| **Service (Function)** | **Activities within proposed service (function)** |
| 1. Real-Time Grid Operations | Ancillary Services management:<br>• Dispatch of energy associated with Ancillary Services, including:<br>o Regulation<br>o Spin<br>o Non-spin<br>o Replacement reserve<br>o Black start<br>Monitoring of system conditions and dispatching to maintain reliability:<br>• Load and resource balancing<br>• Transmission line/path congestion management<br>• Voltage Control<br>• System emergency management<br>• Power flow studies and security analyses<br>Determination of resource adequacy<br>Coordinating Western Interconnection reliability with all WECC Reliability Coordinators<br>Integration and communication with other Control Areas:<br>• Interconnected switching operations<br>• Generation and transmission equipment outage coordination (in real time)<br>Interchange scheduling (in real time)<br>EMS and Telemetry management |

Originator: Ben Arikawa
Last updated: 12/06/2002
"Note: this listing of services and activities may be altered as a result of the ongoing deliberations and developments in this process."

| | |
|---|---|
| 2. Interchange Pre-Scheduling | Day-ahead/Hour-ahead scheduling<br>• ETAG (NERC-required electronic schedule tagging)<br>• Existing Transmission Contracts Calculator (ETCC) and scheduling<br>• New Firm Uses (NFU) scheduling<br>Reconciliation of schedules and interchange after-the-fact<br>NERC/WECC/CAISO Tariff required reporting<br>Weekly:<br>• Inadvertent Interchange report<br>• NERC reports (Inadvertent Interchange, ETAG)<br>• WECC "donut" report<br>Monthly:<br>• WECC Unscheduled Flow curtailment report<br>Quarterly:<br>• Quarterly California Energy Commission 1305 report<br>Annually:<br>• SDG&E DOE report<br>• FERC 714 report<br>• Report of Economic Operation |
| 3. Outage Coordination (other than real time) | Pre-planning of and preparation for generation and transmission outages<br>Generation and transmission equipment outage tracking and data/record keeping<br>On-site generation outage monitoring (SB-39 compliance)<br>Outage reporting (web site updates and regulatory agency reporting)<br>Supply of Generation and Transmission data for OASIS postings |

Originator: Ben Arikawa
Last updated: 12/06/2002
"Note: this listing of services and activities may be altered as a result of the ongoing deliberations and developments in this process."

<table>
<tr>
<td>4. Operations Engineering, Maintenance, and Support:</td>
<td>Transmission Maintenance:
<ul>
<li>Develop, monitor and enforce of transmission maintenance standards</li>
<li>Manage and oversee new generation interconnections, major capacity additions or upgrades and supporting Transmission Planning in project tracking.</li>
<li>Manage, analyze, prepare reports on system availability, reliability, and outage records.</li>
<li>Manage, audit, investigate, approving Transmission Maintenance Practices.</li>
<li>Manage, oversee, and approve the equipment ratings.</li>
</ul>
Operations Engineering:
<ul>
<li>Perform seasonal, annual, and, as necessary special analysis of transmission system performance and ratings.</li>
<li>Review, approve and provide specification on daily system configurations, emergency conditions, clearances and operational conditions.</li>
<li>Develop, prepare and update operating procedures.</li>
<li>Perform operational studies and system security analyses</li>
</ul>
Operations Support:
<ul>
<li>Manage the development, preparation and revision of all ISO Operating Procedures:
<ul>
<li>Transmission grid</li>
<li>Market Operations</li>
<li>Generation</li>
<li>Emergency</li>
</ul></li>
<li>Perform generating unit ancillary service certification and P-MAX testing</li>
<li>Manage UDC and Inter-Control Area Operating agreements</li>
<li>Manage dynamic energy scheduling agreements and interfaces</li>
<li>Manage required WECC Reliability Management System (RMS) and NERC</li>
<li>Maintain Compliance Program data collection, tracking, storage and reporting processes</li>
</ul></td>
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| | |
|---|---|
| 5. Grid Planning | Transmission Planning:<br>• Perform system transmission planning to ensure overall reliability<br>• Perform reserve requirement studies<br>• Perform Long-term (monthly, annual and longer) load forecasting<br>• Determine long term *transmission* resource adequacy<br>Regional Coordination:<br>• Coordinate participation in NERC, WECC, NAESB, ESC, and OSC<br>• Monitor and participate in resolving seams issues in the Western Interconnection<br>• Provide Control Area and interconnection mapping services to real time operations.<br>Determine long-term *generation* resource adequacy:<br>• Manage, develop, prepare, publish and participate in seasonal system load and generation assessments.<br>• Participate, guide, influence, and maintain records on environmentally constrained generation units.<br>• Determine dual fuel generator requirements<br>Determine Reliability Must-Run (“RMR”) contract requirements<br>Review Participating Transmission Owners (“PTOs”) Bulk Power Program and new generator or load interconnection studies |
| 6. Market Operations (A/S, RT & DA Energy, Transmission/Congestion) | Manage congestion (inter-zonal, LMP when implemented)<br>Manage transmission and generation schedules:<br>• Day and Hour Ahead schedules<br>• Day-Ahead market (under MD02)<br>• Determine schedule feasibility<br>Perform weekly, daily and hourly load forecasting<br>Determine market clearing prices (A/S and Energy)<br>Bid mitigation (real time and forward)<br>Maintenance of market information postings (transmission/market OASIS)<br>Unit commitment service under SMD<br>Mitigate market power in Day and Hour Ahead and Real Time markets<br>Development and management of demand response participation<br>Administer FTRs:<br>• Perform FTR auctions (Primary)<br>• Coordinate FTR bilateral trading (Secondary)<br>• Calculate and determine feasibility of FTR capacity |

Originator: Ben Arikawa
Last updated: 12/06/2002
"Note: this listing of services and activities may be altered as a result of the ongoing deliberations and developments in this process."

| | |
|---|---|
| 7. Marketing monitoring and compliance | Collect and analyze information on market behavior<br>Develop new market rules or changes to market rules in response to market behavior<br>Prepare and provide reports to regulatory authorities<br>Perform oversight and investigations |
| 8. Settlements, Billing, Credit Administration and Metering | Determine charges associated with:<br>• Transmission services<br>• Day-Ahead schedules and markets (A/S and Energy)<br>• Hour Ahead schedules and markets (A/S and Energy)<br>• Real time balancing energy market<br>• Congestion management<br>• Grid Management Charge<br>Manage settlement data<br>ETC administration<br>Prepare market and GMC invoices<br>Prepare special invoices for FERC fees, interest, etc.<br>Perform settlement statement reruns<br>Assist with market/settlements design and settlements training<br>Dispute resolution and monitoring<br>Credit and collateral management<br>• Manage collections and payments<br>• SC financial security analysis<br>Determination of losses and allocation<br>Metering and data management<br>• Collect and validate data from ISO polled meters<br>• Repository of data polled from ISO polled meters and data submitted by SCs<br>• Responsible for site inspection of metering sites<br>• Responsible for setting up RIG data bases and submitting data into EMS<br>• Push data to Settlement databases |
| | |

Originator: Ben Arikawa
Last updated: 12/06/2002
"Note: this listing of services and activities may be altered as a result of the ongoing deliberations and developments in this process."

| | |
|---|---|
| 9. Account Management Services and Training | Provide ISO Tariff, Systems, Market and Settlements guidance to customers<br>Communicate scheduled events to customers<br>Communicate Market information to customers<br>Develop training curriculum<br>Provide training to Market Participants (Settlements, System Infrastructure, Market Design)<br>Facilitate resolution of Market Participant issues |
| 10. ISO contract administration | Administer ISO contracts<br>Negotiate, manage, litigate contracts |
| 11. Administrative and General (not directly assigned elsewhere) | CEO<br>Finance and Accounting<br>Legal<br>HR<br>Regulatory policy and affairs<br>Information services<br>Strategic development<br>Communications |
| 12. Startup costs | Recover costs associated with Startup |

Originator: Ben Arikawa
Last updated: 12/06/2002
"Note: this listing of services and activities may be altered as a result of the ongoing deliberations and developments in this process."

From: Morrison, Stephen
Sent: Tuesday, December 10, 2002 12:15 PM
To: GMC WG
Subject: Statement on Information Availability

During the presentation on confidentiality issues at yesterday's meeting, one of the participants asked for a statement of the ISO's current policy on availability of information. The request came about as the participant recalled an earlier ISO Governing Board policy and made reference to its content.

The first Board Policy on In formation Availability was adopted on October 22, 1998. The participant's recollection that this policy intended to cause the publication of "all data older than 6 months" is inaccurate. A copy of the policy is attached for your information.

In any case the Policy was updated by the Board at it's meeting on November 29, 2001. A link to the current Policy is attached.

http://www.caiso.com/docs/09003a6080/12/57/09003a6080125719.pdf

Current practice regarding information availability is in accord with that policy, and no indication given yesterday derogates from that. The ISO remains committed to providing timely access to its information, "to the fullest extent practicable".

Stephen A S Morrison
Corporate Counsel
California ISO
(916) 608 7143

Navigant™
CONSULTING, INC.

MEMORANDUM

DATE: December 12, 2002

TO: Ben Arikawa
Phil Leiber

FROM: David B. Cohen

SUBJECT: DECEMBER 13TH 2002 BILLING DETERMINANT DATA CONFERENCE CALL

---

Here are my thoughts.

Non-Disclosure Agreement

Keep it simple. Stakeholder's agree not to disclose the "raw" data to anyone. Results from "illustrative" computations, prepared by Stakeholder's can be communicated with clients.

Format of Data

Historical billing determinant data will cover the period October 2001 through September 2002. Using this time period will:

1. Not include the four Southern Cities (Banning, Riverside, Azusa, Anaheim) joining the CAISO.
2. Will reflect SMUD in the CAISO through August 2002. (Adjustment Required to Remove)
3. Require adjustment to remove Self-Provided MWH of ASREO (Per the 2002 GMC Settlement Agreement).
4. Not reflect entities joining the CAISO as "Other Participants".

Adjustments to the billing data, to represent 2004, will need to be made once we have a set of historical billing determinant data. Please confirm.

**To start with, I recommend that the historical data be provided, in EXCEL spreadsheets, by a "masked" Identification Number for each SC for each of the individual billing determinants identified in Attachment 1. The Billing Determinant data should be provided incrementally, rather than waiting for all the data to be gathered.**

Existing Rate Design As A Base Line for Comparison

We need to have a "Base Line" of SC Invoices, showing billing units for a 12 month period. Once we have the billing units under the "current" three-bucket approach, the 2003 GMC rates can be applied. This will represent the Base Case or Existing Rate Design Level. The monthly billing unit data should be readily available from the Settlement Department before Christmas.

Attachment

## ATTACHMENT 1

### Preliminary Listing of Billing Determinant Data, Use and Source
### (12/05/2002 version)
### Discussion on December 13th at 10:00 am dial in # 1-877-661-1222 x 178246

| | Data | Frequency | Period | Comments |
|---|---|---|---|---|
| 1. | Gross control area load (energy) | Hourly | Twelve months | Current billing determinant for Control Area Services. |
| 2. | Net control area load (energy) | Hourly | Twelve months | Not including behind the meter load |
| 3. | Scheduled load | Hourly | Twelve months | Use for scheduling charge if created |
| 4. | Maximum coincident demand, both gross and net | Monthly | Twelve months | Development of demand charge |
| 5. | Maximum non-coincident demand, both gross and net | Monthly | Twelve months | This is the sum of the maximum demand for each SC during the month plus (for gross) the sum of the connected loads for all behind-the-meter self-generation loads. Development of demand charge |
| 6. | Sum of the absolute value of maximum hourly SC deviations | Monthly | Twelve months | For MID proposal |
| 7. | Total of the absolute value of hourly SC deviations | Hourly | Twelve months | For MID proposal |
| 8. | Total transmission flows | Monthly | Twelve months | For use as billing determinant for transmission flows rate component of MID proposal. MID may be asked to define this billing determinant, if it is other than 1 or 2 above. |
| 9. | Sum of each SC's maximum purchases and sales of Ancillary Services, Supplemental Energy, and Imbalance Energy (both instructed and uninstructed) | Monthly | Twelve months | For development of demand charge for market operations |

| | | | | |
|---|---|---|---|---|
| 10. | Total purchases and sales of Ancillary Services, Supplemental Energy, and Imbalance Energy (both instructed and uninstructed) | Monthly | Twelve months | For development of energy charge for market real time activity (same as current billing determinant) |
| 11. | Number of SCs | Monthly | Twelve months | For development of customer charge. |
| 12. | FTR MW | Annual | Twelve months | For development of FTR administration charge |
| 13. | Number of transactions by SC, which would include scheduled loads, purchases/sales of ancillary services, supplemental energy, and imbalance energy, inquiries, etc. Note: this information would only be made available to stakeholders aggregated across all SCs. | Monthly | Twelve months | For use in developing a graduated customer charge if one is desired – SCs can be grouped in to several groups depending upon their size (maximum demand and/or number of transactions). The information that would be given out would be aggregated up to categories—Category A includes xx SCs, Category B includes yyy SCs, etc. where we would define the parameters of the various categories. |
| | | | | |

From: Laurence Kirsch [ldkirsch@lrca.com]
Sent: Tuesday, December 17, 2002 1:36 PM
To: Arikawa, Ben; Pritchard, Jan; Ross Hemphill
Cc: Leiber, Phil; Morrison, Stephen; Neal, Sean
Subject: RE: Summarizing my discussion about MID's data requirements

Ben:

Please see the attached memorandum.

Laurence

-----Original Message-----
From: Arikawa, Ben [mailto:BArikawa@caiso.com]
Sent: Tue 12/17/2002 1:29 PM
To: Pritchard, Jan; Laurence Kirsch; Ross Hemphill
Cc: Leiber, Phil; Morrison, Stephen; Neal, Sean
Subject: Summarizing my discussion about MID's data requirements

Jan, Laurence and Ross,

Here are my notes concerning the data MID would like for development of its rate proposal. Please review, discuss amongst yourselves and let me know if this is what you want.

"Note: the attached documents are circulated by the sender solely for the express purpose of informing discussion. Therefore, none of the contents may be regarded by the reader as any form of offer, undertaking, policy, proposal or commitment by the sender, author or the California ISO."

Ben Arikawa
Senior Financial Analyst
California Independent System Operator
P.O. Box 639014
Folsom, CA 95763-9014

Voice: (916) 608-5958
fax: (916) 351-2259

email: barikawa@caiso.com

Summarizing my discussion about MID's data requirements 12-17-02.txt
From: Arikawa, Ben
Sent: Tuesday, December 17, 2002 11:30 AM
To: Pritchard, Jan; Kirsch, Laurence; Hemphill, Ross
Cc: Leiber, Phil; Morrison, Stephen; Neal, Sean
Subject: Summarizing my discussion about MID's data requirements

Jan, Laurence and Ross,

Here are my notes concerning the data MID would like for development o
f
its rate proposal. Please review, discuss amongst yourselves and let me know if this is what you want.

"Note: the attached documents are circulated by the sender solely for the express purpose of informing discussion. Therefore, none of the contents may be regarded by the reader as any form of offer, undertaking, policy, proposal or commitment by the sender, author or the California ISO."

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Folsom, CA 95763-9014

Voice: (916) 608-5958
fax: (916) 351-2259

email: barikawa@caiso.com

RE Summarizing my discussion about MID's data requirements 12-17-02a.txt
From: Arikawa, Ben
Sent: Tuesday, December 17, 2002 2:06 PM
To: 'Laurence Kirsch'; Arikawa, Ben; Pritchard, Jan; Ross Hemphill
Cc: Leiber, Phil; Morrison, Stephen; Neal, Sean
Subject: RE: Summarizing my discussion about MID's data requirements

Laurence,

Thanks for the quick response.

I think that #8 would be net control area load plus exports. I'll confirm and get you an answer.

-----Original Message-----
From: Laurence Kirsch [mailto:ldkirsch@lrca.com]
Sent: Tuesday, December 17, 2002 1:36 PM
To: Arikawa, Ben; Pritchard, Jan; Ross Hemphill
Cc: Leiber, Phil; Morrison, Stephen; Neal, Sean
Subject: RE: Summarizing my discussion about MID's data requirements

Ben:

Please see the attached memorandum.

Laurence

-----Original Message-----
From: Arikawa, Ben [mailto:BArikawa@caiso.com]
Sent: Tue 12/17/2002 1:29 PM
To: Pritchard, Jan; Laurence Kirsch; Ross Hemphill
Cc: Leiber, Phil; Morrison, Stephen; Neal, Sean
Subject: Summarizing my discussion about MID's data requirements

Jan, Laurence and Ross,

Here are my notes concerning the data MID would like for development of its rate proposal. Please review, discuss amongst yourselves and let me know if this is what you want.

"Note: the attached documents are circulated by the sender solely for the express purpose of informing discussion. Therefore, none of

the contents
may be regarded by the reader as any form of offer, undertaking, policy,
proposal or commitment by the sender, author or the California ISO."

Ben Arikawa
Senior Financial Analyst
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Voice: (916) 608-5958
fax: (916) 351-2259

email: barikawa@caiso.com

Data requirements revised including MID requirements 12-17-02b.txt
From: Arikawa, Ben
Sent: Tuesday, December 17, 2002 2:46 PM
To: Kirsch, Laurence; Hemphill, Ross; Pritchard, Jan
Cc: Leiber, Phil; Morrison, Stephen; Neal, Sean; McGuffin, Mike
Subject: Data requirements revised including MID requirements

Jan and Laurence,

Here is an edited version of the data requirements, where I added in Laurence's language for 6, 7 and 8. I added a sentence or two of explanation. I added "net" to absolute "net" uninstructed deviation since it is load deviations net of generation deviations in the same direction.

On 8, I think that net control area load fits Laurence's "Power withdrawals from the ISO-controlled grid (energy)." Net control area load is metered load plus exports. This does not include behind the meter load estimates. (Mike McGuffin will confirm if I am wrong in this assertion.)

Once we have confirmed all this, I'll email out a revised list of data

requirements along with Laurence's email.

Ben Arikawa
Senior Financial Analyst
California Independent System Operator
P.O. Box 639014
Folsom, CA 95763-9014

Voice: (916) 608-5958
fax: (916) 351-2259

email: barikawa@caiso.com

Memo on Cost of Service 12-19-02.txt

MessageFrom: Ross Hemphill [rchemphill@lrca.com]
Sent: Thursday, December 19, 2002 10:01 AM
To: Arikawa, Ben
Cc: Jan Pritchard; SMN@dwgp.com; Laurence Kirsch
Subject: Memo or Phil Leiber □9

Ben,

Attached is a memo regarding the GMC cost of service and ratemaking process for consideration and discussion.

Ross Hemphill

__________

Ross C. Hemphill, Ph.D.
Christensen Associates
Tel: 608-231-2266 (Ext. 168)
Fax: 608-231-1365

Website: www.LRCA.com

RE Memo on Cost of Service 12-19-02.txt

From: JAN PRITCHARD [janp@mid.org]
Sent: Thursday, December 19, 2002 11:57 AM
To: BArikawa@caiso.com
Cc: SMN@dwgp.com
Subject: RE: Memo on Cost of Service

Ben,

Yes. Please feel free to distribute Ross's memo to the GMC stakeholde
r
list.

Jan

2BBYvx.370000000.9914

>>> "Arikawa, Ben" <BArikawa@caiso.com> 12/19/02 11:33AM >>>
Jan,

I will be sending out a revised list of activities with some
attribution to
cost centers this afternoon along with a description of what we can do
with
all this. May I forward Ross's email with my email?

-----Original Message-----
From: Ross Hemphill [mailto:rchemphill@lrca.com]
Sent: Thursday, December 19, 2002 10:01 AM
To: Arikawa, Ben
Cc: Jan Pritchard; SMN@dwgp.com; Laurence Kirsch
Subject: Memo on Cost of Service

Ben,

Attached is a memo regarding the GMC cost of service and ratemaking
process
for consideration and discussion.

Ross Hemphill

---

Ross C. Hemphill, Ph.D.
Christensen Associates
Tel: 608-231-2266 (Ext. 168)
Fax: 608-231-1365

Website: www.LRCA.com <http://www.lrca.com/>

From: Arikawa, Ben
Sent: Thursday, December 19, 2002 12:33 PM
To: Hemphill, Ross
Cc: Pritchard, Jan; Kirsch, Laurence
Subject: November 8th GMC presentations

Ross,

Here are my presentations and materials from the November 8th GMC meeting. I'll send you the October 9th materials separately.

Ben Arikawa
Senior Financial Analyst
California Independent System Operator
P.O. Box 639014
Folsom, CA 95763-9014

Voice: (916) 608-5958
fax: (916) 351-2259

email: barikawa@caiso.com

October 9th presentation 12-19-02.txt

From: Arikawa, Ben
Sent: Thursday, December 19, 2002 12:36 PM
To: Hemphill, Ross
Cc: Pritchard, Jan; Kirsch, Laurence
Subject: October 9th presentation

Ross,

Here is the October 9th presentation that I gave. There were other documents, but none are directly relevant to rate issues.

Ben Arikawa
Senior Financial Analyst
California Independent System Operator
P.O. Box 639014
Folsom, CA 95763-9014

Voice: (916) 608-5958
fax: (916) 351-2259

email: barikawa@caiso.com

**From:** Morrison, Stephen
**Sent:** Thursday, December 19, 2002 6:24 PM
**To:** GMC WG
**Subject:** Draft NDA

To parties' counsel:

Attached is a redline draft Non Disclosure Agreement. The draft is the agreed upon NDA text from the settlement with a minimal number of changes.

While this NDA alone does not meet all of the requirements placed upon the ISO by its Tariff (particularly with regard to potential data sets which might refer to detailed market participant data) it is the principal instrument to permit the ISO to share the maximum amount of data. The ISO will review its need to issue Market Notices to permit it to release more specific data sets - should it deem that the data requests make that necessary.

As the objective is to create a secure area in which participants may more freely have access to ISO data, any suggestions as to how this draft might be improved are welcome. Please route such suggestions to me via your counsel.

Assuming general agreement on the text, we should aim to have executed versions being submitted to the ISO by the end of this week.

Stephen A S Morrison
**Corporate Counsel**
**California ISO**
(916) 608 7143

From: LISA WOLFE [LWOLFE@EOB.CA.GOV]
Sent: Friday, December 20, 2002 5:26 PM
To: GMCWG@caiso.com; SMorrison@caiso.com
Subject: Re: Draft NDA

Stephen,

One comment so far on the proposed NDA: Para. 5d - definition of GMC Rate Structure Project Stakeholder Process. The definition makes sense insofar as it harkens back to the Initial Decision in ER01-313 which is the genesis of this stakeholder effort. However, it does not capture the concept discussed at the third Stakeholder Meeting that there may be a need to continue Stakeholder efforts down the line as MD02/LMP continues to evolve. Essentially, the evolution of MD02 adds another dimension to reevaluation of GMC not entirely contemplated in the ID. Potentially, ISO data used to reevaluate GMC methodology would have ongoing usefulness if stakeholder efforts continue later to further address LMP implementation (and/or other issues that at this juncture are too speculative to really take into complete account in a thorough GMC rate methodology overhaul). As written, para 9 in conjunction with 5d would not allow continued use of ISO data for further consideration of GMC methodology.

The definition in 5d could be modified to account for potential continuation of the stakeholder process down the line. Or para 9 amended to allow Confidential Materials to be used towards ongoing GMC methodology evaluation by the Stakeholders. Or, of course, another NDA could be executed later if need be that agrees to use of confidential data including data that is the subject on the instant agreement.

Lisa

Lisa V. Wolfe
Staff Counsel
California Electricity Oversight Board
770 L Street, Suite 1250
Sacramento, CA 95814
phone: (916) 322-8601
fax: (916) 322-8591
email: lwolfe@eob.ca.gov

>>> "Morrison, Stephen" <SMorrison@caiso.com> 12/19/02 06:24PM >>>
To parties' counsel:

Attached is a redline draft Non Disclosure Agreement. The draft is the agreed upon NDA text from the settlement with a minimal number of changes.

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Assuming general agreement on the text, we should aim to have executed versions being submitted to the ISO by the end of this week.

<<Draft NDA.doc>>

Stephen A S Morrison
Corporate Counsel
California ISO
(916) 608 7143

From: LISA WOLFE [LWOLFE@EOB.CA.GOV]
Sent: Monday, December 23, 2002 5:36 PM
To: GMCWG@caiso.com; SMorrison@caiso.com
Subject: Re: Draft NDA

Stephen -

As a follow up to our conversation today re the draft NDA. The concern is summarized in the email below that was sent on Friday...basically, given uncertainties with MD02 implementation and the MD02 schedule, the need to consider GMC methodology may live beyond the FERC filing for the 2004 budget. Here are some draft language options:

Amend Section 5(d) by deleting "which will end with a filing with the Federal Energy Regulatory Commission (FERC) by the CAISO regarding a revised GMC.

OR

Amend

Section 9 so the second sentence reads :" Confidential Materials shall not be used except as necessary for stakeholder involvement in the ISO's GMC Rate Structure Project Stakeholder Process, and as may be necessary for ongoing consideration of GMC structure or rate methodology,...

The above wording avoids needing another NDA if it comes to that.

Another option would be a subsequent NDA to allow use of data for GMC stakeholder efforts that continue after the initial filing (if that happens). In that case, I would add the following language as sentence three to para. 9: "The Confidential Material that is the subject of this Agreement may be used as necessary for continuing review of the GMC structure and rate methodology subsequent to the GMC Rate Structure Project Stakeholder Process upon execution of another confidentiality agreement between the CAISO and the Stakeholders."

Lisa

Stephen,

One comment so far on the proposed NDA: Para. 5d - definition of GMC Rate Structure Project Stakeholder Process. The definition makes sense insofar as it harkens back to the Initial Decision in ER01-313 which is the genesis of this stakeholder effort. However, it does not capture the concept discussed at the third Stakeholder Meeting that there may be a need to continue Stakeholder efforts down the line as MD02/LMP continues to evolve. Essentially, the evolution of MD02 adds another dimension to reevaluation of GMC not entirely contemplated in the ID. Potentially, ISO data used to reevaluate GMC methodology would have ongoing usefulness if stakeholder efforts continue later to further address LMP implementation (and/or other issues that at this juncture are too speculative to really take into complete account in a thorough GMC rate methodology overhaul). As written, para 9 in conjunction with 5d would not allow continued use of ISO data for further consideration of GMC methodology.

The definition in 5d could be modified to account for potential continuation of the stakeholder process down the line. Or para 9 amended to allow Confidential Materials to be used towards ongoing GMC methodology evaluation by the Stakeholders. Or, of course, another NDA could be executed later if need be that agrees to use of confidential data including data that is the subject on the instant agreement.

Lisa

Lisa V. Wolfe
Staff Counsel
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770 L Street, Suite 1250
Sacramento, CA 95814
phone: (916) 322-8601
fax: (916) 322-8591
email: lwolfe@eob.ca.gov

>>> "Morrison, Stephen" <SMorrison@caiso.com> 12/19/02 06:24PM >>>
To parties' counsel:

Attached is a redline draft Non Disclosure Agreement. The draft is the agreed upon NDA text from the settlement with a minimal number of changes.

While this NDA alone does not meet all of the requirements placed upon the ISO by its Tariff (particularly with regard to potential data sets which might refer to detailed market participant data) it is the principal instrument to permit the ISO to share the maximum amount of data. The ISO will review its need to issue Market Notices to permit it to release more specific data sets - should it deem that the data requests make that necessary.

As the objective is to create a secure area in which participants may more freely have access to ISO data, any suggestions as to how this draft might be improved are welcome. Please route such suggestions to me via your counsel.

Assuming general agreement on the text, we should aim to have executed versions being submitted to the ISO by the end of this week.

<<Draft NDA.doc>>
Stephen A S Morrison
Corporate Counsel
California ISO
(916) 608 7143

CALIFORNIA ISO

# 2003 COST ALLOCATION MATRIX

November 8, 2002

# Table of Contents



## APPENDICES

A. 2003 Capital Projects

B. Operating Reserve Calculation

C. Cost Allocation Matrix

# I. OVERVIEW OF COST ALLOCATION PROCESS

This section provides an overview of the cost allocation matrix, a table which summarizes the California Independent System Operator's ("ISO") 2003 operating budget according to the three unbundled service categories:

- Control Area Services, abbreviated as "CAS"
- Congestion Management, abbreviated as "CONG"
- Ancillary Services and Real-Time Energy Operations (abbreviated as or "ASREO" or "Market Operations") The application of this charge to 50% of A/S self-provision is eliminated in 2003 (per the pending 2002 GMC Settlement.)

A description of the three categories follows in the next section, "ISO Unbundled Service Category Descriptions." The cost allocation matrix lists all ISO costs that are elements of the grid management charge, including operating costs and debt service, and the effect of the operating reserve.

The operating costs are organized according to "cost centers"[1] and are grouped according to categories called "Departmental Roll-Ups." For example, the following cost centers: "1521 Grid Planning", "1542 Outage Coordination", and "1543 Operations Engineering", are included in the "Operations Direct" Departmental Roll-up. The budgeted amounts for each cost center are either directly assigned to the three unbundled service categories or are allocated to the categories in the cost allocation matrix.

The ISO has continued to refine the cost-unbundling process since 2001, when the ISO implemented an unbundled Grid Management Charge. For that year, directors and managers from each cost center assigned their overall costs to the three unbundled service categories. Certain costs related to department overhead, overall corporate overhead, or services that benefit multiple departments and functions were allocated based overall operating costs or headcount. Beginning for budget year 2002, managers and directors of each cost center assign each expense line item within their cost center to the unbundled categories or a general category. This refinement provides an enhanced level of accuracy in the documentation of the allocation percentages for each cost center.

**Operating and Maintenance Budget Costs**

Cost centers are grouped according to "Direct" and "Indirect" Departmental Rollups. Cost centers that fall within a "Direct" Department Rollup are allocated by direct assignment. Cost centers that fall within an "Indirect" Department Rollup are allocated by based on the results of the direct assignments. Descriptions of the direct and indirect allocation methodologies are presented below:

Directly Assigned Costs:

Direct costs are those that are directly related to one or more of the three unbundled service categories. Each expense line item within the directly assigned cost center is allocated according to ratios provided by the cost center's manager or director. The costs are then totaled for each of the three unbundled service categories. The total for each unbundled service category within the cost center is then divided by the total amount budgeted for the cost center to arrive at the cost center's overall allocation percentages.

Managers and directors of cost centers with directly assigned costs also have the option to allocate a percentage of their overall costs to a "general" category. Costs in this category include those that support several aspects of the work done in their cost center. These costs are subsequently spread over the three unbundled service categories.

•

1 Cost centers are synonymous with departments All O&M costs are assigned to a cost center in the ISO's Oracle based accounting system.

The simplified example below shows how costs for "Cost Center X " are allocated to the three unbundled serve categories. Note that the factors are provided for each subcomponent of these expenses. For example, each staff person in a department is directly assigned to the unbundled categories.

***Step 1: Managers provide ratios for each line item.***

| Cost Center X | Total $s | | % CAS | %CONG | %ASREO | %General |
|---|---|---|---|---|---|---|
| Salaries | $100 | = | 25% | 25% | 25% | 25% |
| Travel | $100 | = | 25% | 25% | 50% | |

***Step 2:Budgeted costs are totaled for each unbundled service category.***

| Cost Center X | Total $s | | CAS $s | CONG $ | ASREO$ | General $s |
|---|---|---|---|---|---|---|
| Salaries | $100 | = | $25 | $25 | $25 | $25 |
| Travel | $100 | = | $25 | $25 | $50 | |
| Total | $200 | = | $50 | $50 | $75 | $25 |

***Step 3: Allocation percentages for general dollars are calculated.***

| Cost Center X | Total | | CAS | CONG | ASREO |
|---|---|---|---|---|---|
| Total amount: (Without General) | $175 | = | $50 | $50 | $75 |
| Allocation percentages (Without General) | 100% | = | 28.57% | 28.57% | 42.86% |

***Step 4: General dollars are allocated to the three unbundled service categories.***

General

CAS: $25 x 28.57% = $7.14
CONG: $25 x 28.57% = $7.14
ASREO: $25 x 42.86% = $10.71

| Cost Center X | Total $ | | CAS $ | CONG $ | ASREO $ |
|---|---|---|---|---|---|
| General Costs | $25 | ---> | $7.143 | $7.143 | $10.714 |

***Step 5: Costs are totaled for each unbundled service category.***

| Cost Center X | Total | | CAS | CONG | ASREO |
|---|---|---|---|---|---|
| Total Without General: | $175 | | $50 | $50 | $75 |
| General Costs | $25 | ---> | $7.143 | $7.143 | $10.714 |
| Total | $200 | = | $57.143 | $57.143 | $85.714 |

***Step 6: Allocation Percentages are computed for the cost center.***

| Cost Center X | Total | | CAS | CONG | ASREO |
|---|---|---|---|---|---|
| Total | $200 | = | $57.143 | $57.143 | $85.714 |

| | | | | | |
|---|---|---|---|---|---|
| Allocation percentages | 100% | = | 28.57% | 28.57% | 42.86% |

**Indirect Costs**

Cost centers that provide services that cannot be directly assigned to the unbundled service categories are allocated in a different manner. Allocation factors for these indirect costs are developed using five approaches:

- Allocated Based on Department Direct Costs: Cost centers that are directly related to specific departments are allocated based on those department's direct costs. For example, costs within the Indirect Operations Departmental Roll-up are allocated according to the Direct Operations Departmental Rollup allocation factors. Correspondingly, cost centers included in the Indirect Information Technology Departmental Rollup are allocated according to the Direct Information Technology Departmental Rollup.

- Allocated Based on Supervised Departments' Costs: Cost centers that are directly related to specific departments which the cost center supervises are allocated based on those departments' direct costs.

- Allocated based on Direct Operating Costs: – Cost centers which involve services that benefit multiple departments are allocated based on total direct operating costs of those departments. For example, cost center 1631, Legal & Regulatory, serves the entire company, and is thus allocated according to ratios of direct operating costs.

- Allocated Based on Labor Dollar Ratios: Cost centers which benefit multiple departments that are more closely related to employees than overall direct operating costs are allocated based on labor dollars ratios. For example, 1841, Human Resources, is allocated to the three unbundled services based on labor dollar ratios.

- Allocated based on Labor Dollar Ratios – Special: – Cost center 1441, Vendor Management, is allocated using a modified labor dollar ratio approach. The methodology for this is shown in the cost allocation matrix, and is described later in this document.

The cost centers and the allocation methodologies are listed in the table that follows, "Allocation Descriptive Detail". Note, however, that even these indirect cost centers may, and have, assigned individual costs directly to the unbundled service categories where appropriate.

Other costs or revenues which are elements of the ISO's overall revenue requirement include:

| | Allocated: |
|---|---|
| Interest revenues | Overall O&M allocation results |
| SC application & other fees | Overall O&M allocation results |
| WECC Security Coordination Reimbursement | 100% CAS |

**Capital Costs: Debt Service and Cash Funded Capital Expenditures**

The total budgeted debt service costs for 2003 (including the debt service coverage requirement of 25%) are $55 million, representing principal and interest payments related to earlier bond issuances in 1998 and 2000 of $337.5 million. As a result of ISO's expected inability to issue new debt in 2003 at reasonable interest rates due to a poor credit rating, $22 million for 2003 budgeted capital expenditures will be funded directly from the GMC.

The assignment/allocation methodology used to allocate the debt service and cash funded capital expenditures to the three unbundled service categories involved either directly assigning costs to the unbundled categories, where possible, or if not possible, allocation based on various methods. Additional details of this process and the proposed 2003 capital projects are provided in Section VI of this report.

**Revenue Credit/Deficiency**

In addition to 2003 costs, the 2003 revenue requirement includes prior year costs and adjustments resulting from the ISO's Financial & Capital Operating Reserves Account ("Operating Reserve"). The calculation of the Operating Reserve revenue credit or deficiency for each unbundled service category is shown in Section V of this report.

**Summary of Cost Allocation Results**

The attached cost allocation matrix summarizes these results and ratios that show the percentage of total ISO costs associated with the provision of each of the three unbundled services offered by the ISO. The budgeted 2003 allocation ratios developed are as listed below. These are net allocation factors, after the application of the 2002 revenue credit or deficiency from the Operating Reserve.

| | | |
|---|---|---|
| 1. | CAS | 58% |
| 2. | CONG | 11.5% |
| 3. | ASREO | 30.5% |

These ratios represent the portions of the ISO's overall Revenue Requirement for 2003 for each of the three unbundled service categories as follows (in thousands). The following page provides an overview of the total revenue requirement.

| | | |
|---|---|---|
| 1. | CAS | $137,857 |
| 2. | CONG | $27,400 |
| 3. | ASREO | $72,343 |
| | Total | $237,600 |

After determining the revenue requirement associated with each of the three unbundled categories, the volume forecasts for each category are developed. The billing determinants for each category are as follows:

| | | |
|---|---|---|
| 1. | CAS | Control Area Gross Load and Exports |
| 2. | CONG | Net scheduled Inter-Zonal flows per path, Excluding Existing Transmission Contracts |
| 3. | ASREO | Purchases and sales of Ancillary Services and Real Time Energy whether instructed or uninstructed.[2] |

The forecasted volumes of the billing determinant for each unbundled service category for 2003 are as follows (in thousands of MWhs):

| | | |
|---|---|---|
| 1. | CAS | 242,386 |
| 2. | CONG | 85,562 |
| 3. | ASREO | 55,809 |

Finally, a unit charge per MWh is developed to recover the costs for the three unbundled service categories by dividing the revenue requirement for each of the three categories by the associated billing determinant volumes. The unit charges for 2003 are as follows (in $ per MWh):

| | | |
|---|---|---|
| 1. | CAS | 0.569 |
| 2. | CONG | 0.320 |
| 3. | ASREO | 1.296 |

A description of the tasks and responsibilities of each cost center, the results of their allocations, and any commentary related to these allocations is provided below in the section entitled "Allocation Descriptive

2 An ISO compliance filing related to a FERC Order issued on October 9, in Docket ER02-1656-001, would include day-ahead market volumes here.

Detail." The cost allocation matrix and the descriptive text, which is included for each cost center, explains the methodology used for allocating all operating costs.

The overall revenue requirement for 2003 of $237.6 million, is calculated as follows: ($ in thousands):

| | |
|---|---|
| **Revenue Requirement ($ in '000)** | |
| **Operating & Maintenance Budget** | 171,783 |
| **Financing Budget:** | |
| Principal-Existing Debt | 35,300 |
| Interest-Existing Debt | 8,497 |
| Operating Reserve (25% of Principal & Interest) | 10,949 |
| Subtotal, Financing Collection | 54,746 |
| **Capital Project Funding (full CapEx Budget Funded)** | 22,000 |
| **Less: Expense Recovery Budget:** | |
| Interest Earnings | (1252) |
| SC Application & Training Fees | (120) |
| WECC Reimbursement/NERC Reimbursement | (1,256) |
| Subtotal, Expense Recovery Budget | (2,628) |
| Subtotal, Revenue Requirement before Revenue Credit | 245,857 |
| (Revenue Credit)/Deficiency From Operating Reserve | (8,257) |
| (12/31/2002 Reserve Balance varies by Service Category) | |
| **Total Revenue Requirement** | **237,600** |

## II. ALLOCATION METHOD SUMMARY

A description of the methods used to allocate specific operating and debt service costs to the three unbundled service categories follows. In this table, the cost centers are listed in the order in which they appear in the cost allocation matrix.

| | | |
|---|---|---|
| 1500 | Operations | |
| 1521 | Grid Planning | Direct Assignment |
| 1542 | Outage Coordination | Direct Assignment |
| 1543 | Loads and Resources | Direct Assignment |
| 1544 | Real-Time Scheduling | Direct Assignment |
| 1545 | Grid Operations | Direct Assignment |
| 1546 | Security Coordination | Direct Assignment |
| 1549 | Operations Training Group | Direct Assignment |
| 1554 | Special Projects Engineering | Direct Assignment |
| 1555 | Operations Support Group | Direct Assignment |
| 1558 | Transmission Maintenance | Direct Assignment |
| 1561 | Operations Engineering South (Previously Southern Area Engineering) | Direct Assignment |
| 1562 | Operations Engineering North (Previously Northern Area Engineering) | Direct Assignment |
| 1563 | Coordinated Operations | Direct Assignment |
| 1565 | Pre-Scheduling and Support | Direct Assignment |
| 1566 | Regional Coordination | Direct Assignment |
| 1559 | Operations Application Support | Direct Assignment |
| | | |
| 1500 | Operations – Indirect | |
| 1511 | VP - Grid Operations General | Department Direct costs |
| 1547 | Engineering and Maintenance | Supervised Department costs (1543, 1561, 1562, 1558) |
| 1548 | Operations Support and Training Group – General | Supervised Department costs (1549, 1555, 1559, 1563) |
| 1564 | Operations Scheduling | Supervised Department Costs (1544, 1542, 1565) |
| | | |
| 1700 | VP Market Services | |
| 1722 | Application Support | Direct Assignment |
| 1723 | Tariff and Contract Implementation | Direct Assignment |
| 1724 | BBS - PSS | Direct Assignment |
| 1725 | BBS - FSS | Direct Assignment |
| 1731 | Contracts and Special Projects | Direct Assignment |
| 1741 | Client Relations | Direct Assignment |

| | | |
|---|---|---|
| 1752 | Manager of Markets | Direct Assignment |
| 1753 | Market Application & Testing | Direct Assignment |
| 1755 | Market Support and Development | Direct Assignment |
| 1756 | Market Quality | Direct Assignment |
| 1757 | Market Integration | Direct Assignment |
| | | |
| 1700 | Market Services – Indirect | |
| 1711 | VP - Market Services | Department Direct costs |
| 1721 | Billing and Settlements | Supervised Department Costs (1722, 1723, 1724, 1725) |
| 1751 | Market Operations | Supervised Department Costs (1752, 1753, 1755, 1757) |
| | | |
| 1400 | Chief Information Officer | |
| 1411 | Chief Information Officer- General | Direct Operating costs |
| 1424 | Asset Management | Direct Assignment |
| 1441 | Outsourced Contracts | Labor Dollar Ratios - Special |
| 1432 | Computer Operations-General | Supervised Department Costs (1431, 1442, 1451) |
| 1431 | End User Support | Direct Operating costs |
| 1433 | Network Operations | Labor Dollar Ratios - Special |
| 1442 | Production Support | Direct Operating costs |
| 1451 | Information Security | Direct Operating costs |
| 1422 | Corp & Enterprise Apps-General | Supervised Department Costs (1466, 1468, 1469) |
| 1466 | Enterprise Apps | Direct Operating costs |
| 1468 | Corporate Application Support | Direct Operating costs |
| 1469 | Analytical & Reporting | Direct Operating costs |
| 1463 | Operations Applications General | Supervised Department Costs (1461, 1462, 1467, 1481) |
| 1461 | Control Systems | Direct Assignment |
| 1462 | Field Data Acquisition System (FDAS) | Direct Assignment |
| 1467 | Settlement Systems Services | Direct Assignment |
| 1481 | Markets and Scheduling | Direct Operating costs |
| 1471 | Infrastructure Engineering | Direct Operating costs |
| | | |
| 1600 | Legal - Direct | |
| 1641 | Market Analysis | Direct Assignment |
| 1661 | Compliance | Direct Assignment |
| 1662 | Data Quality Group | Direct Assignment |
| | | |

| | | |
|---|---|---|
| 1300 | Finance - Corporate Indirect | |
| 1311 | CFO - General | Supervised Department Costs (1321, 1331, 1351, 1361) |
| 1321 | Accounting | Direct Operating costs |
| 1331 | Treasury and Financial Planning | Direct Operating costs |
| 1351 | Facilities | Labor Dollar Ratios |
| 1361 | Office Administration | Labor Dollar Ratios |
| | | |
| 1600 | Legal: Chief Counsel – Indirect | |
| 1611 | General Counsel – General | Supervised Department Costs (1631, 1641, 1651, 1661, 1662) |
| 1631 | Legal and Regulatory | Direct Operating costs |
| | | |
| 1800 | VP Corporate and Strategic Development – Indirect- | |
| 1811 | VP Corporate and Strategic Devt. - General | Supervised Department costs (1821, 1831, 1841, 1851, 1861) |
| 1821 | Communications | Direct Operating costs |
| 1841 | Human Resources | Labor Dollar Ratios |
| 1831 | Strategic Development | Direct Operating costs |
| 1851 | Project Office | Direct Operating costs |
| 1861 | Regulatory Policy | Direct Operating costs |
| | | |
| 1100 | CEO / Corporate Indirect | |
| 1111 | CEO - General | Labor Dollar Ratios |
| 1651 | Board of Governors | Labor Dollar Ratios |
| 1241 | MD02 | Direct Assignment |

# III. UNBUNDLED SERVICE CATEGORY DESCRIPTIONS

A description of the three categories of services performed by the ISO is as follows:

1. **Control Area Operations (Grid Reliability):** This category is responsible for managing the Control Area and the ISO Controlled Grid to "keep the lights on," *i.e.*, ensure safe, reliable operation of the transmission grid and dispatch of bulk power supplies, including but not limited to:

   - performing operational studies;
   - system security analyses;
   - transmission maintenance standards;
   - system planning to ensure overall reliability;
   - integration with other Control Areas;
   - emergency management;
   - outage coordination;
   - transmission planning; and
   - scheduling generation, imports, exports, and wheeling in the Day-Ahead and Hour-Ahead of actual operations.
   - monitoring and use of ancillary services (both market and self-provided);

2. **Congestion Management** -This category is responsible for dealing with Congestion, which exists when power flowing on a transmission path exceeds the transmission path capacity. Congestion management is conducted by the ISO during the scheduling process and results in the economic rationing of transmission service in order to prevent congestion.

3. **Ancillary Services and Real-Time Energy Operations** This category is responsible for providing for ancillary service and energy related services, including, but not limited to: providing open and non-discriminatory access for market making activities for participants through Ancillary Services auctions and Energy balancing services, Posting of market information; Market surveillance and analysis; Settlement, billing, and metering related to these.

ISO costs not directly attributable to the above service categories are identified as "General" costs during the budgeting process. These "General" costs are later allocated to the above three GMC service categories using various approaches. If a cost can be directly assigned to the categories above, rather than allocated as a General cost, that is the preferable approach.

<u>Clarification regarding MD02</u>

MD02 will significantly change all aspects of the ISO's energy market structure, and will affect all of the above service categories. For 2004, the ISO expects to have a new GMC rate structure in place as a result of a recently commenced stakeholder process on the GMC. However, 2003 will be a transitional year where the above categories will be used. The various components of MD02 (and anticipated commencement dates) as they relate to the above categories are listed below:

**1. CAS**

- Determination of resource adequacy; (Phase III: assume late 2003 or beyond)
- Schedule feasibility; (Phase II: assume mid 2003)
- Real-time Load and Generation balancing (Phase IB: BEEP→Sec. Constrained Econ. Dispatch)

**2. CONG**

- Locational Marginal Pricing (LMP), and nodal vs. zonal calculations (Phase III: assume late 2003)

**3. ASREO:**

- Bid mitigation (Real Time: Phase I-Oct 2002, and Forward Energy Market: Phase II- assume mid 2003)
- Day-ahead energy market (Phase II: assume mid 2003)

# IV. COST CENTER (DEPARTMENT) DESCRIPTIONS

All ISO cost centers are listed and described in the following section of this report. For "Direct Assignment" cost centers, allocation results are listed.

## 1100 Chief Executive Officer

### 1111 CEO - General

**Description:**

The CEO oversees and directs all operations of the ISO and reports to the Board of Governors.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Labor Dollar Ratios

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### 1241 MD02

**Description:**

The MD02 cost center is responsible for the implementation of the corporate wide market redesign effort known as MD02. The project will span multiple years, from 2002 to 2004.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 32% | 33% | 35% |

---

### 1521 Grid Planning

**Description:**

The ISO Grid Planning Department is charged with reviewing the Participating Transmission Owners ("PTOs") Bulk Power Program (a five-year Program is filed with the ISO every year) and reviewing the studies the PTOs perform for connecting new generators or load to the ISO Controlled Grid. Either the ISO recommendations (if any) are implemented by the PTOs or the problem is resolved via dispute resolution processes.

Additionally, Grid Planning conducts studies to determine Reliability Must-Run ("RMR") contract requirements and dual fuel generator requirements, and provides support to Operating Engineering. Grid Planning has been involved in the preparation of the new ISO Reliability criteria, conducts several meetings per year with stakeholder groups, and is working toward common facility ratings (when feasible).

Additionally, Grid Planning leads or supports several Regional and National technical/engineering groups including the Western Electricity Coordinating Council ("WECC"), the Western Interconnection Coordination Forum, and the North American Electric Reliability Council ("NERC").

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 100% | 0% | 0% |

# 1300 Chief Financial Officer

## 1311 CFO - General

**Description:**

The Chief Financial Officer directly oversees the activities of the Accounting (Controller) , Treasury, and Financial Planning groups, and the Facilities and Office Administration functions. All of these are functions which support all ISO services.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Supervised Departments costs

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## 1321 Accounting

**Description:**

The ISO Accounting Department is comprised of four areas of responsibility. Each area performs specific functions that enable the department as a whole to provide the best possible financial accounting services to the ISO. Each area and a brief description of its functions is listed below.

1) Controllership/Accounting Administration:
   * Responsible for implementing internal control policies and procedures. This area acts as the umbrella for all other areas of the department.
2) General Accounting and Financial Reporting:
   * Responsible for preparing, analyzing and distributing financial and management reports to various internal and external users.
   * Responsible for coordinating the financial, operational, and settlements control, and other audits. These audits ensure that the ISO is in conformity with generally accepted accounting principles and is in compliance with certain established procedures.
   * Responsible for preparing and submitting various tax returns and other informational filings to federal, state, and local agencies.
   * Responsible for the integrity and maintenance of the general ledger and fixed assets systems. Tasks include reconciliations of accounts and bank statements, preparation and input of journal vouchers, and analyses of expenditures.
3) Cash and Credit:
   * Responsible for processing payments for goods and services where a valid purchase order was placed with the invoicing vendor as well as for those goods and services received by the ISO which were not ordered by purchase order, including the reimbursement of employee travel expenses.
   * Assists in the market settlement process by collecting and distributing cash to the market players. This responsibility includes the settlement process for GMC, market, FTR, FERC, SRA, emissions, start-up and other types.
   * Responsible for the receipt of monies, banking interfaces and general cashier operations.
4) Purchasing:
   * Responsible for obtaining products, services and travel for the ISO. Acts as authorized agent to create and distribute formal purchase orders to suppliers.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Direct Operating Costs

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## 1331 Financial Planning and Treasury

**Description:**

The Financial Planning and Treasury group is responsible for the following:
- Treasury and Cash Management;
- Insurance/ Risk Management;
- Debt administration;
- Budgeting/Financial Planning;
- Financial Administration of Capital Projects;
- Benchmarking;
- Contractor Administration;
- GMC/Rates/Unbundling; and
- Accounting System Support and Maintenance

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Direct Operating Costs

---

## 1351 Facilities

**Description:**

The Facilities Department is responsible for the physical building environment of the ISO. Its role is to provide and manage a safe, efficient, and comfortable work environment with a highly reliable building infrastructure that fosters teamwork and collaboration. This role can be broken down into several areas:

- Facilities Planning: The allocation of space to accommodate staff and staff changes along with the redesign, modifications, and furnishing of that space.
- Critical Systems: Providing and ensuring high-reliability infrastructure to accommodate Information technology equipment and operating systems housed in the computer rooms and Dispatch control center.
- Building Maintenance: The maintenance of the general office areas and computer facilities with respect to heating/ventilation/air conditioning, indoor air quality, building electrical distribution, structural systems, etc.
- Housekeeping: Janitorial upkeep of the building interiors as well as the appearance of the grounds and other exterior elements.
- Property Leases: Administration of all existing property lease agreements including payments, landlord-tenant issues, and negotiation of changes.
- New Facility Development: Planning, development, and transition into all newly acquired ISO properties, leased or owned.

- Administrative: Tracking, reporting, and benchmarking all ISO Facilities activities and costs.
- Contingency Planning: Working with disaster recovery contractors to insure that the necessary information regarding the buildings, insurance, and business unit requirements are available before any incidents occur.
- Strategic Planning: Continuously looking at the current status of the ISO, possible future changes to the ISO business requirements, the local real estate market and changes in financial opportunities.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Labor Dollar Ratios

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**1361 Office Administration**

**Description:**

The Corporate Services Department has primary responsibility over several distinct corporate functions consisting of Physical Security, Corporate Safety, Administrative and Office Support Services. The main goal of the Corporate Services Department is to ensure a safe and secure work environment and provide the administrative and office support necessary for ISO employees to perform their jobs at the highest levels possible.

Physical Security – Responsible for providing physical protection of ISO personnel and property. This includes workplace violence prevention, investigations of criminal acts, executive protection, risk management/threat assessment, life safety system monitoring, critical systems monitoring and medical first responders.

Safety - Responsible for ensuring compliance with all aspects of corporate safety program including risk assessment, management and mitigation, workers compensation administration, ergonomic compliance and other related safety programs. Responsibilities extend to all visitors, contractors and employees on ISO property or performing services directly controlled by the ISO. Also responsible for ensuring compliance with all applicable local, state, and federal safety laws and regulations.

Administrative and Office Support - Responsible for facilitating corporate support functions including mail services, shipping and receiving, reception desk, office supplies, office automation equipment, conference room set-up and management and related office support services. Also responsible for ensuring consistent policies and procedures are in place for corporate administrative staff.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Labor Dollar Ratios

# 1400 Chief Information Officer

## 1411 Chief Information Officer- General

**Description:**

The Chief Information Officer assumes responsibility for all ISO information services infrastructure, strategies, and key business processes.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Department Direct Costs

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## 1471 IT Planning

**Description:**

The IT Planning Department (formerly Infrastructure Engineering) includes Technology Architecture, Data Architecture, Application Architecture and Information Architecture. These functions define the approaches used to capture and represent both business and software system information, determine and specify high-level modeling approaches and guidelines, identify opportunities for the sharing and reuse of information, lead the construction of information models, define a common terminology based on core business concepts, define and maintain the ISO's architecture and standards; and provide direction and guidance to vendors of infrastructure products and services. The department also coordinates and maintains the IS Division Strategic Plan, facilitates and coordinates the development and maintenance of Division policies and procedures, coordinates engagements with external advisory, assessment, and benchmarking services, and performs advanced technology investigations and evaluations. It furthermore represents IS interests in inter-ISO and RTO activities.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Direct Operating Costs

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## 1420 Asset Management Group

## 1424 Asset Management

**Description:**

The IS Asset Management group (AM) is responsible for enterprise programs and processes related to managing technology assets. Assets include hardware, storage arrays, software licenses, all maintenance, and other IS-related services through their lifecycle. The IS-related services include hardware maintenance and software upgrades and support. AM also assists with the management of the Asset and the Change Management modules of an integrated management tool known as "CHASE". CHASE is the framework that each business unit uses to control the deployment of modifications to their existing system software and maintaining the UNIX and NT custom software release repositories.

The current IT environment includes approximately:

| | |
|---|---|
| · Desktops | 980 |
| · Laptops | 276 |
| · NT Servers | 125 |
| · Unix Servers | 259 |
| · Lease Lines of Credit | 4 |

Yearly trend (from 9/01 to 7/02) shows the IT environment continues to grow in excess of 13% from the primary equipment distribution as follows:

| | |
|---|---|
| · Servers | 316 to 351 |
| · Desktops | 990 to 1128 |

AM manages and coordinates the process for technology related contracts, from bidding the requirements, constructing the contract documents, negotiating the prices and terms, and administering the resulting agreement from beginning to expiration.

AM coordinates IS budget development and administration, hardware warranty and maintenance contract management, software licensing, maintenance contract management, lease administration, asset management, and technology lifecycle process. It tracks expenditures against IS budgets and tracks invoice payments against purchase orders.

AM coordinates activities with procurement, provisioning and technical support groups and prepares lease/purchase requisitions. It verifies invoice accuracy and administers processes for approval and payment.

AM is also responsible for the Change and Configuration Management processes for the IT infrastructure and promotes corporate-wide compliance with Change Management, as well as providing Configuration Management support through CHASE.

In 2003, AM expects to continue to provide the following services:

* Procure or lease equipment and software as determined including refreshes for scheduled servers and workstations throughout ISO.
* Procure hardware maintenance for existing and new equipment.
* Procure maintenance for existing and new software upgrades and renewals.
* Manage relationships with all prime third party vendors including Oracle, Compaq, HP/Compaq Financial Services, Fleet Business Credit Corporation, De Lage Landen Financial Services, LaSalle Leasing, Sun Microsystems, Legato, iPlanet, IBM, Gartner Group, SoftSmiths, Structure Consulting Group, Actuate, EPRI, Iron Mountain Data Security, Veritas and Vitria.
* Coordinate capital and operating budget for the IS (18) cost centers.
* Provide accounting analysis for monthly variance reports and provide year-end forecasts as needed.
* Provide special analyses for finance and accounting to assist corporate level funding allocations to support various requirements.
* Assist with cost analyses for Capital project requests from multiple groups within ISO.
* Track expenditures against budgets; track invoice payments against purchase orders.
* Manage and coordinate the process for technology related contracts, from bidding the requirements, constructing the contract documents, negotiating the prices and terms, and administering the resulting agreement from beginning to expiration.

* Coordinate IS budget development and administration, hardware warranty and maintenance contract management, software licensing, maintenance contract management, lease administration, asset management, and technology lifecycle process.
* Verify invoice accuracy and administer processes for approval and payment.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 67% | 7% | 26% |

---

**1441 Outsourced Contracts**

**Description:**

This department's primary function is to oversee contracts and costs for the outsourced telecommunications services with the IS Asset Management Group. This department is responsible for administrating the MCI contract including asset management, billing and vendor management. In addition, this department provides contract and invoicing review for other telecommunications vendors such as Pacific Bell, Intercall, Arch Communications (paging), AT&T Wireless (cell phones), and Internap (third party internet services).

Outsourced Contracts oversees the contract with MCI for the Energy Communication Network ("ECN") which includes a high-speed, high-availability fiber-optic statewide network connecting the Folsom and Alhambra ISO sites, the Area Control Centers, regional security coordinators, and all Market Participants. The ECN is utilized to control the transmission systems, generators, and Ancillary Service providers. It provides the "marketplace" for the direct Market Participants. In addition, it integrates all power revenue metering points and supports the consolidation of metering data.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Labor Dollar Ratios-Special

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**1430 Computer Operations Center**

**1431 End User Support**

**Description:**

IT User Support Services provides corporate-wide computing infrastructure support including the following:

* Platform Support – Enterprise NT Computing hardware, operating system, and layered product configuration, installation, testing, and maintenance, along with regular system administration duties to

ensure the reliability and effective performance of the computer platforms. This includes both servers and workstations, as well as the integration of third-party products.

* System Management – Regular monitoring of computing infrastructure hardware and software, along with database and application processes to ensure seven-day a week and 24-hour a day availability of platforms and business systems. This function includes the escalation, notification, and documentation of system failures. In addition, system engineers analyze system activity and performance to provide capacity management, including the recommendation for short- and long-term computing infrastructure enhancements. System Management also provides Tivoli (system monitoring software) and NetView design, development, implementation and support of the production and development environments.

* Help Desk and Desk Side Support – Installation, maintenance, and support of the office automation infrastructure, including support to internal users in the use of office automation tools, both hardware and software. In addition, the Help Desk provides central call logging and issue management for office automation, internal communication infrastructure, and facility-related problems and issues.

Responsibilities also include Tape Management for backup and recovery, and paging and cell phone administration.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Direct Operating Costs

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### 1432 Computer Operations - General

**Description:**

This is the general cost center for the Director of Computer Operations Center. End User Support Services (cost center 1431), Production Support Services (cost center 1442), Network Operations (cost Center 1433) and Information Security Services (cost center 1451) report to this Director. This cost center provides for the cost of general support including such items as the administrative assistant, the System Engineering Manager and the general director-level expenses.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Supervised Departments costs

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### 1433 Network Operations

**Description:**

The Network Operations Department was formed during 2002 as a result of the IS reorganization. Network Services is a combination of the Network Engineering unit and the Network Operations unit.

Network Services responsibilities include engineering and support for the ISO's network services, including interfacing with MCI Worldcom on the ISO's Energy Control Network (ECN). The common goal of Network Services is to provide 24x7x365 availability of the ISO's networks. Activities in the Network Services Department support all three ISO service areas.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Labor Dollar Ratios-Special

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## 1442 Production Support

**Description:**

The Production Support Services Department consists of UNIX Administration and Data Base Administration.

Although these groups have different skills sets, the common goal of Production Support Services is to provide 24 x 7 availability, and secure reliable systems and databases, and assist in the implementation and design review of new systems and databases.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Direct Operating Costs

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## 1451 Information Security

**Description:**

The functions of Information Security Services (ISS) are, in part, mandated by Presidential Decision Directive 63 and Executive Orders, which define the protection of Critical Infrastructures to preserve national security and economic stability. In addition, the ISO Tariff establishes that the ISO is responsible for the confidentiality of information used to conduct business in the California Electric Market. ISS is responsible for the development, implementation, and maintenance (including overall security operations and strategic direction) of the ISO Information Security Program and information security staff. The Information Security Program ensures the protection of organizational information and information systems against unauthorized access, use, misuse, modification of information, or denial of use, whether in storage, processing, or transit. Includes measures necessary to detect, document, and counter such threats. Activities that support this continuous process are information security policies, procedures, and standards development for both internal users and market participants. ISS is also responsible for the ISO Information Security Awareness Program that provides education, awareness of and compliance with these policies, procedures and standards. As well, ISS is responsible for the ISO Enterprise Security Architecture that provides security requirements for the design, engineering and implementation of security infrastructure for existing and new network, host, and application solutions.

Other activities ISS provides are the monitoring and auditing of security logs, administration of remote access platforms and digital certificates, enabling applications to use certificates, encryption technologies, responding to and investigating security incidents and leading the Security Incident Response Team (SIRT). ISS also supports business continuity planning and testing for the ISO and external parties.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Direct Operating Costs

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**1460 Corporate & Enterprise Applications**

**1422 Corporate & Enterprise Applications - General**

**Description:**

This group is responsible for the management and administration of the Corporate & Enterprise Applications department. The department is responsible for developing and supporting business applications for our customers. The units reporting to the Corporate & Enterprise Applications group consists of the Corporate Applications, Enterprise Applications, and Analytical & Reporting teams in the cost centers listed below. Please see the descriptions for the cost centers above for detailed information about the customers and systems supported by these teams.

1422 Corporate & Enterprise Applications
1469 Analytical & Reporting (Data Warehouse)
1466 Enterprise Applications
1468 Corporate Applications

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Supervised Departments costs

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**1466 Enterprise Applications**

**Description:**

Enterprise – wide applications and some applications related to operations engineering, settlements, market quality and client relations. Design, implement and support a wide variety of ISO custom and packaged applications and support various business units in their needs related to Information Services. Responsibilities also include application support to Information services as a customer

For new requirements, this team is responsible for performing the initial requirements analysis, evaluating products, and installing, configuring and customizing pre-packaged and custom applications for the stated customers. For implemented systems, responsibilities of this team include application administration, problem management, on-going maintenance, enhancements, and integration of supported software. Supported systems include but are not limited to the following:

-CHASE (Enterprise Services Mgmt.)
-Transmission Registry
-Resource Registry
-Ancillary Services Certification
-TORNADO
-Settlements Validation Tool
-RMR Invoice and Notification Organizer (RINO)
-Reliability Management System (RMS)
-RMR Payment Voucher
-OpsDB
-IMTS
-Online Settlement Dispute System
-RMR Real Time Tool
-Operations Procedure Tracker
-NRI
-RMS
-Rational Suite
-Casewise
-Visual Source Safe

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Direct Operating Costs

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**1468 Corporate Application Support**

**Description:**

The Corporate Applications team supports business application software for Corporate & Strategic Development (Human Resources, Project Office, and Communications), Finance and Accounting, Facilities, Security, and Legal & Regulatory Affairs. This team also supports various enterprise-wide applications including Internet and Intranet.

For new requirements, this team is responsible for performing the initial requirements analysis, evaluating products, and installing, configuring and customizing pre-packaged applications for the stated customers. For implemented systems, responsibilities of this team include application administration, problem management, on-going maintenance, enhancements, and integration of supported software. Supported systems include but are not limited to the following:

* Oracle Financials (Corporate); General Ledger, Accounts Payable, Accounts Receivable, Projects, Purchasing, Fixed Assets, Oracle Financial Analyzer, and Cash Management

* Oracle Financials (Market); General Ledger, Accounts Payable, Accounts Receivable, and Electronic Data Interchange
* Best! Software - AbraHuman Resources Management System; Payroll and Roles (self-service web application)
* Documentum - Enterprise Document Management System
* Internet & Intranet
* Numerous in-house supplemental applications

This team has customer relationship management responsibilities for those departments listed above and primarily supports the "General" departments of the organization. Some of the communication aspects of the Internet site serve CAS and ASREO. The Market Financials system is the only system managed by this department that directly supports ASREO.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Direct Operating Costs

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**1469 Analytical and Reporting**

**Description:**

The Analytical and Reporting group is responsible for and supports the Data Warehouse which focuses on providing the company the ability to analyze, report, query and source non-real-time information from our core operational systems to end-users and second tier applications providing minimal impact to those key operational systems.

These core operational systems includes:

* Automated Dispatch System (ADS)
* Out of Sequence Market Operations Settlement Information System (Osmosis)
* Global Reliability Resource Management Applications (GRMMA)
* Scheduling & Logging for CA ISO (SLIC)
* Meter Data Acquisition System (MDAS)
* Resource Registry (RR)
* Scheduling Infrastructure (SI)
* Settlements

The second tier applications the Data Warehouse sources are:

* Compliance (CAP)
* Settlements / Reliability Must Run (RMR) -RAVE
* Market Monitoring

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Direct Operating Costs

## 1480 Operations Applications

## 1461 Control Systems

**Description:**

Control Systems Services is responsible for providing real-time as well as historical operational data to Real Time Grid Operations and other related functions for the purpose of operating the ISO Controlled Grid. Responsibilities include the maintenance and operation of ISO owned data acquisition and database systems related to the delivery and display of operational data. Control Systems Services cost center ensures operational data meets or exceeds the reliability and availability requirements for the safe, efficient and reliable operation of the ISO Controlled Grid. The delivery and presentation of the operational data is in accordance with all applicable ISO technical standards, practices, procedures and policies. In addition to maintaining and operating the data acquisition and database systems, the Control Systems Services cost center maintains/will maintain the existing and future interfaces to ISO internal and external systems related to the collection archiving and dissemination of real-time operational data.

The Control Systems Services cost center provides the following services as they relate to the collection, delivery and presentation of operational data:

- EMS system support and maintenance
- RIG / DPG and SCADA support maintenance and development
- PI system support and maintenance
- Network Applications support and maintenance
- Grid Operator Training Simulator (GOTS)

Support of User Organizations:

- Grid Operations
- Operations and Engineering
- Outage Scheduling
- Market Compliance
- Market Operations
- Meter Data Acquisition Systems (MDAS)
- Operations Support & Training (OSAT)
- Information Systems
- Data Warehouse

24X7 On Call Support:

- Energy Management System
- SCADA systems (RIG, DPG, ICCP systems)
- Plant Information Systems
- System Interfaces (EMS to Market Systems, SLIC, ETC, TR etc.)

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 100% | 0% | 0% |

## 1462 Field Data Acquisition System (FDAS)

### Description:

The responsibilities of the Field Data Acquisition Systems group are as follows:

* Supporting the Remote Intelligent Gateway ("RIG") interface system in the daily operation of power generation, scheduling, and control of the ISO Controlled Grid. The Automatic Generation Control (AGC) system simultaneously controls Generating Unit output to match resources to load and maintain frequency. Generating Units offering regulation services must be capable of being controlled by the ISO EMS. RIG interface units meet the ISO standards for transporting AGC signals. The ISO has the ability to send either set point or raise/lower signals. Additionally, the RIG has multiple ports to allow control to be switched between the Generator and the ISO.
* Collection, verification and processing of raw meter data into Settlement Quality Meter Data (SQMD), which the ISO uses for generating preliminary and final financial settlement statements for the Market Participants, Market Surveillance and reports.
* Providing Settlement Quality Meter Data (SQMD) for the ISO billing system, including:
  - Auditing the ISO meter inspection process and providing engineering judgment related to proposed and existing metering systems.
  - Operating and maintaining Meter Data Acquisition Systems ("MDAS") that directly acquires metering data from ISO metered entities and receives metering data from SCs.
  - Auditing metering data collection, storage and processing systems of the SCs.
  - Maintaining the metering standards and specifications for approved meters and metering systems.
  - Coordinating and approving proposed metering system-engineering designs.
* Providing support for MDAS systems including
  - System Administration of MDAS NT domain and servers
  - Ad hoc queries and reports for business users
  - Monitoring and maintaining data integrity

### Cost Allocation Methodology and Percentages:

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 30% | 8% | 62% |

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## 1463 Operations Applications - General

### Description:

The Operations Systems Services group supports Control Systems Services (1461), Field Data Acquisition Systems (1462), Settlements Systems Services (1467), and Markets and Scheduling (1481).

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Supervised Departments costs

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**1467 Settlement Systems Services**

**Description:**

Settlement Systems Services (S3) is responsible for the development, maintenance and support of the Settlement System and applications. The Settlements system oversees the financial settlement process (billing and payment) for products and services purchased and sold by the ISO where each settlement will involve a price and a quantity. The Settlements system deals with a variety of services, schemes and contracts all of which are to be considered in finalizing the settlements. The Settlements system finally generates many different charges that will be collected/paid to/from the Business Associates. Also, the Settlement system calculates the Grid Management Charges that will be collected from all the participating Business Associates for providing the services.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 15% | 7% | 78% |

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**1481 Markets and Scheduling**

**Description:**

Markets and Scheduling (M&S) is responsible for the analysis, design, software development, and 24X7 support the of ISO's real-time Market/Scheduling and Compliance applications. This includes, but not limited to, support of the following major applications: SLIC, BITS, ADS, SI/SA, ETC, OASIS, GRRMA, OSMOSIS, ALFS, OATI/ETAG, and CAP. In addition, M&S provides similar services for Integration efforts between the EMS and Market/Scheduling systems.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Direct Operating Costs

# 1500 VP Grid Operations

## 1511 VP Grid Operations - General

**Description:**

The VP Grid Operations oversees all aspects of the ISO Operations division and is responsible for the safe and reliable operation of the power grid; assumes responsibility for ensuring that transmission standards and reliability of electric operations are maintained at high levels; oversees or influences directly the development and implementation of numerous processes, procedures and technologies necessary to enable the deployment of the ISO organization; and assumes responsibility for the development of operations and engineering capabilities necessary to promote the timely implementation of the ISO activities consistent with applicable orders of regulatory bodies including FERC orders, NAESB, NERC and WECC policies.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Department Direct Costs

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## 1530 Operations Scheduling Group

## 1542 Outage Coordination

**Description:**

Outage Coordination performs activities related to the following:

- Approving or denying outage requests to enable necessary maintenance to preserve reliability of generation and transmission facilities while at the same time assuring real-time operating reliability.
- Long-term planning (up to 12 months) for outage coordination for both generation and transmission facilities, interfacing complex generation and transmission facility outages into the existing ISO Outage Coordination Plan.
- Recording, maintaining, and reporting data related to outages.
- Ensuring accurate path ratings and integrated outages to ensure minimum reliability standards are adhered to. The coordinators work closely with Operating Engineers to help accomplish this.
- Finalizing path ratings and allocation percentages, which are then passed on to the inter-tie scheduling group. Additionally, these allocations are passed on to Existing Contracts holders and posted on the Internet as part of the Control Area responsibilities.
- Mitigating congestion when transfer paths are derated. Although this process of mitigating congestion is similar to "scheduling" above, it differs in that by allocating the reduced percentages to the scheduling group, congestion is pre-empted by reducing schedules on a scheduled basis, which allows for better management of congestion.
- Conducting generator inspections to follow-up on forced outages, assuring appropriate attention to repairs, as well as monitoring resource withholding opportunities. These inspections continued in 2002 and are expected to continue through 2003.
- Reporting outage data and managing data. In 2001, new reports included Daily Generator Outage Reports (5), daily Website Postings (4), Forecast vs. Actual Outages, multitudes of special reports

addressing data requests from FERC, EOB, CPUC and others. This reporting requirement continued through 2002 and the number and frequency of such reports increased as expected. It is likely this reporting requirement will continue through 2003.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 100% | 0% | 0% |

## 1544 Real-Time Scheduling

**Description:**

Real-Time Scheduling group consists of a team of NERC and WECC certified operators working shift work in the Control Center in Folsom and Alhambra. Primary Duties/Responsibilities are as follows:

- Implements real time interchange schedules with adjacent control areas.
- Primary contact with Schedule Coordinators for all real time schedule issues
- Monitors and adjust interchange transactions as necessary on real time basis to maintain schedules within path limitations.
- Coordinates with Gen. Dispatch, GRC and CERS to obtain required imbalance energy though existing Market processes and Out of Market sources as needed.
- Performs Allocation and Implementation of real time schedule curtailments based on Unscheduled Flow or Path derates.
- Provides Control Area and Transmission Provider Approval for Electronic Tagging System in Real Time.
- Provides Services as PSE for Electronic Tagging to support CERS sales & exchanges on interties.
- Records and Logs information pertaining to Intertie scheduling.
- Provides Primary ISO responsibility for compliance with NERC Policy 3 and WECC MORC Section 3.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 75% | 15% | 10% |

### 1564 Operations Scheduling - General

**Description:**

Operations Scheduling is the primary interface between the ISO and its 11 adjacent Control Areas as a part of the WECC interconnection. Metered and scheduled interchange is coordinated on a pre-schedule, Real Time, and after-the-fact basis with the neighboring Control Areas. Direct and distinct functions also are performed to enable the ISO markets, congestion, and settlements process. All of these functions require accommodations to assure that Existing Contracts are honored.

All interchange transactions must be coordinated with adjacent and external Control Areas within the limits of the ISO jurisdictional transmission system. This includes implementing and monitoring all interchange schedules into and out of the ISO Control Area regardless of whether they are scheduled on Existing Transmission Contract ("ETC") or New Firm Uses ("NFU") transmission. Interchange scheduled on behalf of all SCs must be reconciled to meet WECC and NERC criteria.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Supervised Departments costs

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### 1565 Pre-Scheduling and Support

**Description:**

The staff of Pre-Scheduling and Support coordinates and schedules energy resources to meet system load requirements and pre-checks all schedules with adjacent utilities to ensure correct intertie totals. Primary internal contacts are with settlements and billing department, legal and regulatory, the Department of Market Analysis and client relations. Due to continuing investigations there have been a need to provide data for the legal and regulatory department. This group serves as a liaison between real-time, pre-schedule and after-the-fact staff. It supports CONG and ASREO as needed with these duties. In addition this group maintains records of ETC's and ATC's for the PTO's while publishing them on a daily basis. The ETC/ATC publication is a cumbersome process that requires minute attention to detail and increasing manual intervention.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 74% | 15% | 11% |

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## 1540 Engineering and Maintenance Group

## 1543 Loads and Resources

**Description:**

The Loads and Resources group is responsible for the following activities:
- Preparing control area and local area load and resource adequacy assessments; writing and publication of ISO Summer and Winter Assessment Reports;
- Preparation of the FERC 714 report;
- Engineering support for environmental issues impacting control area resources;
- Developing and maintaining various ISO operating procedures;
- Participating in WECC committees and workgroups related to interconnected power system operations;
- Providing support for Existing Contract, MSS and System Units, and other Scheduling issues;
- Providing engineering support for ISO contracts issues (e.g., RMR contract, Participating Generator Agreement ("PGA"), etc.)
- Providing engineering support for ISO projects (e.g., Automated Dispatch System ("ADS"), Generator Communication Project ("GCP"), etc.)
- Supporting EMS project development.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 100% | 0% | 0% |

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## 1547 Engineering and Maintenance - General

**Description:**

The Director of Engineering and Maintenance manages the following work groups:
- Transmission Facilities
- Operations Engineering
- Northern Engineering
- Southern Engineering
- Loads and Resources

The responsibilities of this department are:
- Develop ISO Operating Procedures
- Work with Outage Coordination in analyzing clearances
- Prepare summer and winter assessments for the local areas
- Support Real Time Operation and provide on-call services
- Review transmission plans, projects, and new generation for the local areas
- Provide Engineering support for RMR and reliability generation
- Prepare disturbance reports for the local areas
- Participate in WECC working groups and related activities

**Cost Allocation Methodology and Percentages:**

Allocated based on Supervised Departments costs

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### 1558 Transmission Maintenance

**Description:**

Transmission Maintenance manages the creation, implementation, and enforcement of ISO Maintenance Standards; provides for high quality, safe, and reliable service; and manages the creation and implementation of the New Resource Interconnection Processes. Transmission Maintenance works with PTO's to manage the Transmission Register and data and the Transmission Availability reporting processes and databases; works with the PTO's to resolve engineering issues or practices that may impact the availability of the ISO controlled grid; assists with the development of generation maintenance standards as required by SB39xx; provides engineering support to other departments within the ISO on engineering issues effecting the Grid reliability, including protection systems, Transmission facility system design and ratings, etc.; and leads incident investigations on suspected maintenance or work procedure errors.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 98% | 0% | 2% |

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### 1561 Operations Engineering South

**Description:**

Southern Area Operations Engineering is responsible for the technical support of the southern portions of area operation and Bulk system operations. Nearly all Area OE responsibilities directly support the category of CAS.

Core functions of the Area OE include the following: Conduct seasonal operating studies, establish seasonal OTCs and write procedures, support Outage Coordination in the analysis of Transmission and Generation clearances, identify and prepare for grid reliability concerns of the upcoming season (including proposing and managing short-term projects), provide ongoing active participation in and guidance to the Grid Planning process, provide on-call OE support for real-time emergencies, and represent the ISO in technical reliability groups and committees of WECC and regional reliability fora.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 100% | 0% | 0% |

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### 1562 Operations Engineering North

**Description:**

Northern Area Operations Engineering is responsible for the technical support of the northern portions of the ISO Grid. Nearly all Area OE responsibilities directly support the category of "CAS".

Core functions of the Area OEs include the following: Conduct seasonal operating studies and write procedures, support Outage Coordination in the analysis of Transmission and Generation clearances, identify and prepare for grid reliability concerns of the upcoming season (including proposing and managing short-term projects), provide ongoing active participation in and guidance to the Grid Planning process, provide on-call OE support for real-time emergencies, and represent the ISO in technical reliability groups and committees.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 100% | 0% | 0% |

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### 1550 Regional Coordination Group

### 1546 Security Coordination

**Description:**

Security Coordination monitors real-time system conditions to observe and mitigate potential problems as well as react to system emergencies in the Western Interconnection, with the primary focus on the California-Mexico Sub-region of WECC (ISO, LDWP and CFE control areas). Security Coordinators have the final authority to direct operations before, during, and after problems or disturbances with a regional impact.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 100% | 0% | 0% |

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## 1554 Special Projects Engineering

**Description:**

The primary role of Special Project Engineering is to provide Operations personnel with the best technology, tools and advanced applications that solve operating problems, improve grid reliability and facilitate the accurate and timely reporting to various regional reliability organizations and government agencies. Special Projects Engineering provides reports to FERC, NERC and WECC on Control Area Operations. It provides support to all groups within the Operations Division, to other departments within the ISO, and to Market Participants, to ensure and enhance system reliability as well as to facilitate and expand workably competitive markets.

Specific roles and responsibilities include:

- Managing Special Projects that support Operations;
- Developing Wind Generation Forecasting tools
- Creating and Maintaining of Transmission Maps and Geographic data;
- Researching and Developing – Analysis and Installation of tools to improve grid reliability;
- Participating in NERC and WECC committees and task forces relating to Operations and Scheduling;
- Field-testing proposed NERC and WECC Standards;
- Developing concepts for operational control of Distributed Generation resources;
- Developing and direct R&D programs such as the three-year CERTS program; and
- Developing Board Documents for proposed changes in ISO Operations and Markets.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 84% | 0% | 16% |

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## 1566 Regional Coordination - General

**Description:**

Regional Coordination responsibilities include being an active interface with WECC and NERC committees, subcommittees, task forces and work groups; participating in and influencing the transition of NERC to its new organization, NAERO, as well as the formation of the new industry group, the North American Energy Standards Board; tracking the aforementioned groups' work and reporting to executive management; WECC and NERC compliance reporting; the RTO effort including seams issues and coordination with both internal and external organizations in support of CAS, CONG and ASREO.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 83% | 0% | 17% |

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**1560 OSAT Group**

**1548 OSAT Group - General**

**Description:**

The Director of Operations Support and Training (OSAT) is responsible for: overseeing preparation and administration of training across all operations groups, other groups in the ISO, and Market Participants; providing support for ISO efforts to interface with and incorporate markets and deregulation from an operations perspective as they develop inside and outside the ISO; updating, creating and maintaining all ISO Operating Procedures; implementing Emergency Response programs and procedures within the ISO and in coordination with state and federal external agencies; and providing final operations approval of revised and newly developed EMS Displays as required and requested by Control Room personnel.

OSAT provides training and support to all groups within the Grid Operations Division, to other departments within the ISO (particularly ASREO) and to Market Participants to ensure and enhance system reliability as well as to facilitate and expand workably competitive markets. The primary role of OSAT is to provide support to all departments within the Grid Operations Division, including the development of training programs, real-time operations support, development of tools for operations, and coordination of internal and external activities impacting operations.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Supervised Departments costs

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**1549 Operations Training**

**Description:**

The Operations Training group is responsible for identifying, creating, developing and facilitating or administering appropriate training material for grid operations, scheduling, other ISO groups; procuring and implementing necessary hardware and software to accomplish this training; monitoring the activities of various groups (internal and external, *e.g.*, operations support, operations engineering, NERC & WECC personnel) to support the various operations training needs including procedures, reports, EMS needs, tools development and other support activities as needed. Specific roles and responsibilities include:

- Directing the activities of the staff responsible for development and provision of Operations Training to assure appropriate material and processes are created to accomplish training for operation, and other ISO groups;
- Managing support functions to assure training on procedures, tools and other training needs are met for all operations groups, other ISO departments, and external entities;
- Managing vendor relationships and maintaining accountability for work performed;
- Preparing and managing the training budget;
- Representing the ISO in WECC, NERC, CSIC and other fora as required.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 62% | 24% | 14% |

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**1555 Operations Support Group**

**Description:**

The Operations Support Group is responsible for supporting the various market and grid operations needs of the ISO Real Time operations control room floor and the ASREO and Grid Operations business units. Included in these support functions are emergency preparedness and response coordination, emergency event notification, interconnected control area, UDC, PTO and MSS agreement support, Ancillary Services and RMR certification testing, creation, tracking and maintenance of procedures for Grid, Market and Scheduling Operations, various reporting functions including WECC RMS data collection and reporting, development and maintenance of the ISO business continuity plan including business recovery contingency procedures, and other support activities as needed. Specific roles and responsibilities include:

- Managing Operations support functions to assure that procedures, tools, reporting, and other support needs are met for all operations groups, other ISO departments and external entities;
- Preparing and managing the Operations Support Cost Center budget;
- Representing the ISO in WECC, NERC and other fora as required;
- Identifying and managing changes in the Tariff, protocols, and market design that would improve market and grid operations;
- State and federal agency and intra-control area entity communications interdependency support;
- Managing and participating in projects related to the creation or enhancement of ISO operations, functions, processes, procedures or communications;
- Testing and documenting Ancillary Service and RMR certification;
- Coordinating/Collaborating with Planning and Operations Engineering & Maintenance to ensure all prerequisites are met before new generators interconnect with the ISO Grid;
- Managing the Alert, Warning and Emergency notification process ;
- Reporting on WECC Reliability Management System compliance.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 61% | 21% | 18% |

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## 1559 Operations Application Support

**Description:**

OSAT Operations Applications Support's primary role is to provide safe, reliable electric transmission service to all Californians within the ISO control area at the lowest reasonable cost through the development, enhancement and support of specialized custom applications and expert systems designed to improve the efficiency and effectiveness of ISO real-time operations. Specific tasks of the group include:

- Communication with other business units to insure that Operations Systems has the ability to maintain the functionality of existing processes in support of changes to interconnected systems.
- Coordination of Operations Systems and ISO business units to direct the acquisition of new systems and applications in support of end user requirements.
- Actively seek the replacement of existing systems as necessary by providing specifications for RFIs, RFQs, or bid proposals to implement changes to development, test and production environments.
- Coordinate personnel from within the Operations Applications department for the development of specifications and bids for the procurement of new systems or applications, and provide improvements or modifications to existing systems and applications.
- During project implementation, develop levels of expertise for Operations Applications support staff and assure vendor compliance to project design specifications by maintaining consistent staff involvement in all phases of project development.
- Development of standards and procedures for the testing of delivered products to assure they meet all requirements of the original specifications.
- Provision of improvements or modifications to existing systems and applications to support end user requirements through project design, product development, coordination of comprehensive testing of deliverables to assure all requirements of the original specifications have been followed.
- Coordination of project transition from factory development and testing to a production environment by providing training for end-users, developing general system information for all ISO personnel, delivery of all applicable manuals, and provide interface information on vendors for Operations Applications support personnel.
- Ensurance of Operations Applications staff adhere to ISO change management and configuration management policies and procedures in support of Grid Operations systems, applications and databases.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 79% | 10% | 11% |

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**1563 Coordinated Operations**

**Description:**

The Coordinated Operations Group is responsible for identifying issues that impact efficient and reliable Grid Operations (especially as they interface with outside entities such as CERS, and internal groups such as OE, MO, MQ, OSAT, Scheduling, Settlements, Legal & Regulatory, Compliance and Outage Coordination), and then developing enterprise wide solutions for the benefit of the ISO. The group is playing and will continue to play a key role in MD02 development and implementation by providing expert input from the perspective of Grid Operations.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 60% | 10% | 30% |

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**1570 Grid Operations Group**

**1545 Grid Operations - General**

**Description:**

The Grid Operations group is responsible for the following:

- Overseeing and performing all Real Time Operations of the ISO Electrical Grid and Control Area, including managing all aspects of the California Control Area;
- Ensuring reliable and safe operation of the ISO Controlled Grid;
- Ensuring reliable operation includes any authority needed to maintain control of the Grid, including authority over all PTO's and Utility Distribution Companies ("UDC's") in regards to system reliability and system emergencies, the ability to order must run generating units on-line, and manual Load shedding as needed;
- Coordinating Load and system restoration after any contingency or major system disturbance in cooperation with the WECC Security Coordinator;
- Declaring, when appropriate, a Statewide System Emergency as detailed in the Dispatch Protocol, suspending market operations, and setting administrative prices for Ancillary Services needed to resolve the emergency;
- Ensuring compliance with all WECC and NERC criteria, as well as ISO protocols and procedures;
- Working with the WECC Security Coordinator to ensure compliance with all policies and operating procedures applicable to the Western Interconnection;
- Controlling applicable generation to meet inter-tie obligations, contribute to frequency control, and meet any emergency responses and WECC and NERC criteria, in order to support the transmission system and operation of the energy market in the most reliable manner;
- Maintaining documentation for generation operations;

- Procuring additional Ancillary Services as necessary;
- Managing operation of eligible Regulatory Must-Take, Must-Run, and RMR generation;
- Dispatching interruptible loads to maintain required reserve levels during system emergencies; and
- Coordinating generation resources to meet system load requirements and satisfy contractual obligations, and responding to system frequency deviations and voltage issues.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 80% | 10% | 10% |

# 1600 VP General Counsel

## 1611 VP General Counsel - General

**Description:**

The General Counsel cost center (1611) reflects the administrative and office support for the General Counsel. The General Counsel office provides service relating to all the unbundled GMC categories.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Supervised Departments costs

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## 1631 Legal and Regulatory

**Description:**

The Legal & Regulatory Department's responsibilities fall broadly into four functional areas: legal (including contracts and human resource support), litigation (including civil litigation, dispute resolution and investigations), regulatory, and legislative. The majority of the department's costs and resources are associated with the regulatory area, with increasing costs in the litigation area. In the regulatory area, the department directs the preparation of pleadings, Tariff amendments and other regulatory filings; develops factual records and other supporting materials; communicates and advocates the Company's policy objectives to regulatory authorities; reviews and monitors regulatory activities as they may affect the Company's objectives; responds to regulatory inquiries and investigations; and provides advice and counsel concerning Tariff and other regulatory requirements. The department pursues these activities before both state (Electricity Oversight Board, Public Utility Commission, California Energy Commission, California Power Authority) and federal (Federal Energy Regulatory Commission) regulatory authorities.

The litigation area represents the Company in civil litigation and arbitral forums; advises management on disputes and dispute resolution matters; oversees internal and external investigations of the Company and produces ISO records and materials for investigators of third parties; and serves as a contact point for members of the public, regulators and other interested parties in obtaining ISO information and records. The legislative area serves as a contact point for members of the legislature, advises policymakers at the state and federal levels concerning the Company's operations, practices and policies; provides comments and testimony on proposed legislation; responds to inquiries from lawmakers and the state and federal executive offices, and otherwise facilitates communication among Company management and state and federal policymakers. In the legal area, the department negotiates and drafts key vendor contracts and other agreements and counsels management on contract, employment, intellectual property and other general corporate matters. Additionally, the department maintains the corporate records, including the corporate bylaws and Board minutes.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation

Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Direct Operating Costs

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### 1641 Market Analysis

**Description:**

The Department of Market Analysis (DMA) reviews and monitors the efficiency and effectiveness of the ISO markets (Ancillary Service, Congestion Management and Real-Time), generates periodic reports of market performance, investigates observed or reported rule violations and/or market anomalies (e.g. gaming behavior), and develops and/or evaluates sanctions and/or proposed market design changes.

In addition, the department conducts specialized studies and analyses and responds to information requests, serving in essence as the Company's in-house economic consultants. Specific functions of DMA include:

1. Monitoring the market and reporting on market performance, including:
   a. Indices of market performance, including prices, competitive baseline costs, loads, supply availability, outages and bidding patterns
   b. Prices in related markets (such as natural gas, emissions, surrounding areas, etc.)
   c. Level of imports/exports
   d. Ancillary Service Bid Sufficiency
   e. Congestion Management Market and Firm Transmission Rights
   f. Competitiveness of the Market
2. Investigating and reporting on potential gaming and market power abuses.
3. Identifying, reviewing and reporting deliberate or inadvertent violations of market rules or contracts that affect the efficiency of the market.
4. Performing special studies of the impacts of bidding behavior on market efficiency and performance.
5. Performing special studies on market efficiency and performance, both independently and at the request of ISO management, ISO Board of Governors, FERC and various outside agencies.
6. Responding to numerous data requests (including subpoenas).
7. Reviewing ISO rules and protocols from a market performance perspective, and recommending specific changes in market rules and protocols.
8. Working with other areas of the ISO to implement these changes affecting market performance.
9. Supporting the Market Surveillance Committee, by completing special analysis to support reporting and recommendations of the MSC to ISO management.
10. Reporting to Federal Energy Regulatory Commission, California Public Utility Commission, Electricity Oversight Board and many other governmental and regulatory agencies.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 23% | 19% | 58% |

## 1642 Market Surveillance Committee

**Description:**

The role of the ISO Market Surveillance Committee (MSC) is to provide independent external expertise on the ISO market monitoring process as described in the Market Monitoring and Information Protocol (MMIP) and, in particular, to provide independent expert advice and recommendations to the ISO CEO and Governing Board. The MSC is comprised of a body of three or more (currently, four) independent and recognized experts whose combined professional expertise and experience shall encompass the following:

- economics, with emphasis on antitrust, competition, and market power issues in the electricity industry;
- experience in operational aspects of generation and transmission in electricity markets;
- experience in antitrust or competition law in regulated industries; and
- financial expertise relevant to energy or other commodity trading.

The MSC provides recommendations based on evaluation of market data in the form of written reports to the CEO and Governing Board. The MSC may also submit reports to FERC. These reports also may relate to the monitoring program referred to in the MMIP, the analysis of information, the evaluation criteria or any corrective or enforcement actions proposed by the ISO Department of Market Analysis (DMA) or proposed on its own initiative. Upon request of the MSC, the CEO shall publish reports and recommendations of the MSC or incorporate them, if consistent, into the ISO's own reports or recommendations.

At the recommendation of the CEO, the Governing Board may implement MSC recommendations on market rules, Tariff changes and penalties and sanctions.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 9% | 25% | 66% |

## 1651 Board of Governors

**Description:**

This cost center captures Board of Governors expenses for Board meetings, Board member compensation and travel and expense reimbursement for Board members to attend Board meetings and to perform other duties on behalf of the ISO.

Board expenses are considered overhead, and are allocated to the three GMC service categories.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation

Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Labor Dollar Ratios

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**1660 Compliance Group**

**1661 Compliance - General**

**Description:**

The responsibilities of the Compliance Department fall into three categories: Operational Compliance, Compliance Audits and Compliance Systems. Operational Compliance monitors and measures operational performance (*e.g.*, fulfillment of capacity obligations and the delivery of specific quantities of energy within specific timeframes) consistent with contractual commitments and Tariff requirements. Efforts in the past year have continued to focus on encouraging suppliers to follow dispatch instructions and assure compliance with must-offer obligations. Compliance Audits monitors and corrects UFE and meter data timeliness and accuracy problems. These programs include trend analysis for purposes of identifying potential meter errors, site visits for purposes of testing participants' meter units, and training and assistance to Scheduling Coordinators on self-audit requirements. Compliance Systems focuses on developing innovative applications using a rules engine and the ISO's new architecture to assure extendability across the organization, modification as rule changes are required without redesigning software, and replication to automate new Compliance programs efficiently. Additionally the Compliance Department implements and calculates authorized penalties and sanctions for instances of noncompliance, and these programs will be expanded for 2003 through the ISO's Oversight and Investigation Activities Review (O&I Review). Apart from these activities, in recent months the department has assumed a substantial role in supporting state agencies' efforts related to demand programs, and in developing the ISO's Participating Intermittent Resource program. Compliance has also supported investigations by multiple external agencies, providing data, analyses, and extensive interviews.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 82% | 5% | 13% |

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**1662 Compliance - Audits**

**Description:**

See description under 1661.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation

Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 84% | 5% | 12% |

# 1700 VP Market Services

## 1711 VP Market Services - General

**Description:**

The VP of Market Services sets policy, plans, directs, and coordinates through subordinate Directors the activities of the Client Relations, Settlements, Market Operations, Market Quality, and Contracts and Special Project functions of the ISO.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Department Direct Costs

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## 1731 Contracts and Special Projects

**Description:**

The Contracts and Special Projects department is tasked with:
- Developing and negotiating contracts with Market Participants;
- Assisting other Departments and Sections regarding contracts, compliance, FERC matters, and other special projects.

CONTRACTS WORK RESPONSIBILITIES

Development of Agreements with New Clients and Existing Clients:
- Develop new agreements; execute pro forma agreements as needed to expand participation in the ISO, Interconnected Control Area Operating Agreements ("ICAOAs") with other Control Area operators that have not yet executed the ICAOA, and other types of *pro forma* agreements; and
- Assist in enhancing client understanding of ISO agreement terms and conditions.

Contract Activities Based on Regulatory Directives:
- Amend agreements as needed and file with FERC;
- Revise and maintain the standard pro forma agreements; and
- If FERC sets the agreement for hearing, negotiate the settlement of all interventions. If settlement cannot be reached, participate and provide testimony for the litigation proceedings.

Special Agreements:
- Develop and negotiate new agreements and negotiate changes needed to special agreements, such as the TCA and MSS;
- Develop, negotiate and administer any subsequent reliability agreements that may be needed with the changing market design, including ACAP;
- Assist in crafting amendments to the Reliability Must-Run ("RMR") agreement and obtain executed agreements resulting thereof;
- Develop, negotiate and administer replacement of RMR Condition 2 agreements when ACAP is in place;
- Develop Black Start, Voltage Support, and Emergency Assistance Agreements;
- Develop and negotiate Aggregated Distributed Generation Pilot Project agreements;

- Develop and negotiate Demand Response program agreements; and
- Develop and negotiate a QF PGA, if ordered by FERC.

Administration of Contracts:
- Responsible for administration of all contracts executed with Market Participants, including but not limited to contract interpretation, deadlines tracking, and records management;
- Administer RMR, including but not limited to assisting Settlements in the monthly invoicing process, assisting Operations with implementation issues, negotiating amendments to the RMR Agreement, negotiating settlement for all disputes issues, negotiate rates for existing RMR contracts, and develop rates for new agreements; and
- Review operating procedures and operating instructions for consistency with the ISO agreements and ISO Tariff.

Special Projects:
- Administer the ADR requirements of the ISO Tariff;
- Participate in FERC litigation regarding the municipal utilities;
- Act as project leader for the Access Charge proceeding;
- Facilitate relationship with State agencies during the California crisis, including CERS;
- Support or lead teams on Existing Contracts issues;
- Act as project leader for Governmental Entity participation, including as MSS and PTO;
- Maintain a library of all FERC orders impacting agreements and the ISO Tariff;
- Participate in FERC proceedings not initiated by Contracts, including complaints, QF issues and GMC proceedings;
- Assist as needed in the MD02 process;
- Lead the response to the PG&E Plan of Reorganization proceeding, including implementation of the new organizations;
- Participate in the Participating Load Working Group;
- Participate in the New Resource Interconnection work group;
- Participate in CPUC proceedings, as needed;
- Support the ISO's involvement in environmental justice;
- Responsible for ISO Tariff search program;
- Administer and maintain Agreement tracking system; and
- Participate in the Generator Communications Project that establishes telemetry requirements for generators.

OTHER PROJECTS / WORK REQUIREMENTS

Support of other Departments as needed, which may include the Legal and Regulatory Department, other Market Services Departments, Operations, Market Surveillance or IS.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 77% | 2% | 21% |

**1741 Client Relations**

**Description:**

The Client Relations group is the primary business interface between the ISO and its clients (i.e., SCs, transmission owners, Participating Generators, municipalities, and adjacent control areas). To fulfill this responsibility, the Client Relations staff:

- Manages the overall business relationship between the ISO and each of its Clients at all levels;
- Facilitates the business requirements for Participating Generators;
- Resolves operational, market, settlement and Tariff issues on behalf of Clients;
- Certifies and trains Clients (Scheduling Coordinators, Participating Generators and others) for participation in the ISO markets;
- Manages the stakeholder process for market and operational changes; and
- Communicates effectively with market participants on market, operational and regulatory issues.

Because of the broad scope of Client Relations' daily interactions with Clients, staff supports business, strategic and operational activities that affect ISO services in all primary areas: CAS; CONG; and ASREO

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 38% | 9% | 53% |

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**1720 Settlements**

**1721 Billing and Settlements-General**

**Description:**

Settlement and Billing functions are performed for all transactions in the Control Area. Information regarding these transactions is forwarded on a regular basis to the ISO. Scheduling information for Day-Ahead and Hour-Ahead is validated prior to Real Time operations to insure compliance with ISO Tariff and protocols. Subsequent to the Settlement Period, operating and billing data is compiled by the Settlements and Field Data Acquisition departments in order to produce, in accordance with the ISO's payment calendar, both a preliminary and a final settlement statement for each Market Participant.

Examples of major billing and price components necessary for determining final billing are as follows: market clearing prices, bid prices, ex-post prices, and metered information from generators, loads, and inter-tie points. These financial transactions involve billions of dollars each year. Preliminary Statements and Final Settlements are transmitted daily in accordance with the ISO calendar to each Market Participant. The monthly Grid Management Charges are summarized on Preliminary and last Final Statement for the trade month. Monthly Preliminary Invoices, which summarize all charges on the month's Preliminary Statements, and Monthly Final Invoices, which summarize the difference between the summed Preliminary Statements and the summed Final Statements, are sent to each Market Participant in order to collect and pay for use of ISO market and Control Area needs. These functions support all three service areas.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Supervised Departments costs

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## 1722 Application Support

**Description:**

The Business Process Development group assures the best use of technology to facilitate the expedient, timely and accurate delivery of settlement statements and invoices to ISO's Market Participants. The group identifies potential issues with existing business processes/protocols and assists management in formulating solutions. It facilitates the definition and implementation of new settlement protocols/processes. It also serves as the primary department interface with the Information Services (IS) Division to ensure adequate system, operation support and development services are in place to support the mission of the Settlements & Billing Department.

The primary functions include:
- Work with Department staff to identify and prioritize process and technology enhancements to support ISO's Settlements and Billing operation.
- Monitor ISO market design activities, interpret Tariff changes, define detail process requirements, and determine automation and implementation strategies.
- Prepare business requirement documents for system development projects, facilitate and assist in the detail system design, monitor project progress and test new systems/software to assure compliance with business rules.
- Identify potential issues with existing business rules and assist senior management in formulating solutions and new settlement protocols.
- As the primary IS liaison, assure adequate system resources, operation support and development services are in place to support the Department's operation.
- Represent the Department in enterprise wide technology development efforts.
- Collaborate with other Market Services and ISO Departments to improve data flows for effective and efficient business operation.

Functions support all three service categories.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 19% | 7% | 74% |

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## 1723 Tariff and Contract Implementation

**Description:**

The RMR Settlement group, under the Manager of Tariff and Contract Implementation, performs all tasks associated with the validation of RMR invoices provided by the RMR Generator Owners. In this role, the RMR Settlement Group deals with, on almost a daily basis, the ISO dispatchers who handle the RMR units and RMR charges. The RMR Settlement group implements all needed settlement validation modifications brought about by majority decisions of the members of the RMR Contract Schedule O task force.

Additionally, the RMR Settlements group validates invoices of the Summer Reliability Generators. The Manager of Tariff and Contract Implementation supports the efforts of the RMR Settlement group in dealing with both internal and external RMR-related matters, as well as assists the Director of Settlements in the development and implementation of ISO Tariff modifications and other contract implementation issues. Because this group deals with a broad range of issues related to the ISO CAS and ASREO area, it should be considered in both of these categories.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 90% | 0% | 10% |

## 1724 BBS - PSS

**Description:**

The Preliminary Settlements group is responsible for the accuracy and timeliness of Preliminary Settlement Statements, the correct implementation of the necessary manual work-around to the existing Settlements software, and issuing the Preliminary Invoice to Market Participants. The group coordinates with the Operations group to obtain information necessary for production of correct Settlement Statements, and investigates the Settlement impact of proposed operating conditions. The group works with Application Support group and software vendors to design, test, and enhance Settlement software.

The group is responsible for maintaining and operating a billing system for Market Participants, ensuring timely and accurate bills. The group is responsible for Settlements' specific review of the Tariff and making recommendations for changing the Tariff and protocols. The group participates in the redesign projects including MD02. Settlements also handles data requests, discovery requirements, bankruptcy litigation, Market re-runs and FERC mandates, as they relate to Settlements information. The function supports all three GMC service categories.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 17% | 8% | 75% |

**1725 BBS - FSS**

**Description:**

The department is responsible for the accuracy and timeliness of Final Settlement Statements and correct implementation of necessary manual work-arounds to the existing Settlements software and issuing the Final Invoice to Market Participants. The group supports the Client Relations, Market Operations, Metering and Market Quality groups in resolving Market Participant issues and the correct implementation of approved disputed items. The group is also responsible for maintaining and operating the billing system for Market Participants, ensuring timely and accurate bills. The group coordinates with Operations to obtain information necessary for production of correct Settlement Statements and supports the various ISO and stakeholder project teams. Settlements also handles all data requests, discovery requirements, Bankruptcy litigation, Market re-runs and FERC mandates as they relate to Settlements information. Settlements also supports the ISO's Market redesign effort. The function supports all three GMC service categories.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 16% | 7% | 77% |

**1750 Market Operations Group**

**1751 Market Operations - General**

**Description:**

This cost center contains the Director of Market Operations, who oversees the groups listed in the 1750 rollup. The group is responsible for conducting Day-Ahead, Hour-Ahead and Real Time Markets, including:

- Managing inter- and intra-zonal congestion and making changes (via Adjustment Bids);
- Re-dispatching schedules to resolve congestion at the lowest possible cost to customers;
- Managing the Ancillary Service and imbalance energy markets, and calculating the market clearing prices for spinning, non-spinning, replacement and regulation;
- Ensuring that the SCs posting of requirements regarding congestion, losses and Ancillary Services, etc., is reliable;
- Ensuring continuous interface between the ISO and the SCs that will allow SCs to make best use of transmission resources;
- Providing technical expertise on the design of the California market related to the bidding, scheduling, and settlement systems;
- Reviewing market design and prices on a daily basis;
- Providing engineering analysis to support SCs, settlements, and daily operations;

- Providing technical analysis, input, and review of vendor supplied design documents for compliance with ISO-defined requirements;
- Ensuring thorough testing of vendor supplied applications by creating test objectives, conditions, and scripts to be used for module;
- Designing and performing integration testing;
- Documenting and managing vendor-supplied scheduling application software changes in accordance with release management procedures;
- Conducting SC training and SC certification testing;
- Performing software life cycle activities in support of in-house scheduling software requirements necessary for market reliability and accuracy as detailed in the FERC filing and ISO protocols;
- Administering all interface applications between the SI database and all other subsystems;
- Providing system administration support for test and development environments; and
- Providing an advisory role to ISO Market Surveillance group on market power issues.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Supervised Departments costs

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**1752 Manager of Markets**

**Description:**

Markets

Grid Resource Coordinators (GRCs) on this team are responsible for operating all ISO markets for the Day Ahead, Hour Ahead and Real-time operations. GRC's on this team author, review and maintain all documented procedures and protocols in accordance with ISO Tariff and policies. This team is the primary interface with Operations.

Functions:

- Forecast ISO control area load requirements
- Determine in coordination with Operations the hourly Ancillary Service requirements and procurement
- Facilitate Congestion Management markets
- Procure Real-Time Energy (BEEP) for ISO system needs
- Log and procure Out-of-Market energy purchases
- Log and procure Out of Sequence energy purchases
- Define and document Market Operations' procedures
- Coordinate and plan market service requirements with Operations
- Coordinate with Client Services to Communicate with Market Participants
- Provide Training to Market Participants and ISO internal employees
- Perform Automated Mitigation features

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 29% | 30% | 41% |

## 1753 Market Engineering

### Description:

The Market Engineering group is responsible for conducting Day-Ahead, Hour-Ahead and Real Time Markets, including:

- Managing inter- and intra-zonal congestion and making changes (via Adjustment Bids);
- Re-dispatching schedules to resolve congestion at the lowest possible cost to customers;
- Managing the Ancillary Service and imbalance energy markets; and calculating the market clearing prices for spinning, non-spinning, replacement and regulation;
- Ensuring that the SCs posting of requirements regarding congestion, losses and Ancillary Services, etc., is reliable;
- Ensuring continuous interface between the ISO and the SCs that will allow SCs to make best use of transmission resources;
- Providing technical expertise on the design of the California market related to the bidding, scheduling, and settlement systems;
- Reviewing market design and prices on a daily basis;
- Providing engineering analysis to support SCs, settlements, and daily operations;
- Providing technical analysis, input, and review of vendor supplied design documents for compliance with ISO-defined requirements;
- Ensuring thorough testing of vendor supplied applications by creating test objectives, conditions, and scripts to be used for module;
- Designing and performing integration testing;
- Documenting and managing vendor-supplied scheduling application software changes in accordance with release management procedures;
- Conducting SC training and SC certification testing;
- Performing software life cycle activities in support of in-house scheduling software requirements necessary for market reliability and accuracy as detailed in the FERC filing and ISO protocols;
- Administering all interface applications between the SI database and all other subsystems;
- Providing system administration support for test and development environments; and
- Providing an advisory role to ISO Market Surveillance group on market power issues.

### Cost Allocation Methodology and Percentages:

The costs of this department are allocated to the ISO's three unbundled service categories based on:

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 32% | 28% | 40% |

**1755 Business Solutions**

**Description:**

The Market Development and Support group has the overall responsibility of the SI application and all other Market Application (i.e. RMR scheduling, Operator Interface, Existing Transmission Contract application, and Interchange Transaction Scheduling) and Database development, support and security, for support of Day-Ahead, Hour-Ahead and the Real Time Energy Markets. This group also is responsible for overseeing and administering all interface applications between the SI operational databases and all other subsystems (e.g., EMS, SA, BBS, BITS, etc.). Provides system administration support for test and development environments. This position ensures facilitation of Markets through reliable Market applications and databases. All applications and interfaces must be designed and operated to increase the transparency and the efficiency of the Markets. Working with SCs is critical to the success of the ISO in providing needed interfaces to facilitate Markets.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 35% | 10% | 54% |

**1757 Market Integration**

**Description:**

Engineers on the Market Integration team engage in market engineering, information and scheduling design. They are responsible for verifying all business requirements are implemented as per the design of Business Solutions, Market Engineering, and in accordance with ISO Tariff. They provide the technical expertise for ensuring all Market Systems are integrated with legacy applications, processes and procedures. Engineers on this team also analyze the operational and financial impacts of market functionality and provide recommendations on new protocols or procedures based on the analysis.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 25% | 30% | 45% |

**1760 Market Quality Group**

**1756 Market Quality - General**

**Description:**

Market Quality provides a central team in Market Services that ensures the quality of the "bid to book" market transaction data prior to the settlements process. Market Quality achieves this by identifying, monitoring, recommending, implementing and/or executing processes, procedures, system enhancements and controls in the ISO's business process flow to ensure accurate market transaction data flows throughout the ISO business processes. The Market Quality team works together with the ISO's Operations and Market Services business personnel and systems to accomplish this task. Market Quality business processes have been implemented in the following areas:

- Technical dispute analysis and resolution
- Grid and Market Operations transactional review and correction
- Meter data and RMR transactional review and correction
- Master File Data Coordination

Specific tasks performed by the team include the following responsibilities:

- Develop and deploy Market Quality standards, procedures and controls for new and existing business processes including market, settlement, and metering.
- Continually review current market, settlement and operational process to ensure efficiencies. identify potential problems and design quality assurance solutions for preventative and/or corrective actions.
- Identify software inefficiencies on business systems; work with business owners to enhance software efficiency and design solutions for monitoring and quality control.
- Identify policy issues, conduct impact assessment and work with Client Relations, ISO business system owners and policy office to resolve such issues.
- Review new ISO Tariff and contract language to ensure intent of agreements is being met by software, manual process and floor procedures; ensure controls and processes are in place to avoid relevant client disputes.
- Monitor disputes, resolve discrepancies and determine, develop and deploy necessary changes to business processes, procedures and controls to resolve issues.
- Participate in Market and Settlement design teams to develop new market functionality that ensures the quality of market and settlement information and transactions throughout the business process.
- Calculate billable quantities and business transactions when necessary to ensure valid results and quality settlements data.
- Participate in Market and Settlement implementation, testing and Market Simulation of new Market functionality from business quality perspective as well as a customer perspective. Test potential problem scenarios to identify short and long term solutions.
- Ensure that Grid and Market Operations transactional processes and procedures adhere to the Market Quality standards, controls and procedures. Identify areas where additional training is required.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Direct Assignment

| CAS | CONG | ASREO |
|---|---|---|
| 37% | 33% | 30% |

## 1800 VP Corporate and Strategic Development

### 1811 VP Corporate and Strategic Development - General

**Description:**

This cost center contains the costs of the VP for Corporate and Strategic Development. The VP of Corporate and Strategic Development oversees the Human Resources Department, the Communications Department, and the Policy Office (the Policy Office is comprised of Strategic Development, Regulatory Policy and the Project Office), and is the liaison to the Board of Governors.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Supervised Departments costs

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### 1821 Communications

**Description:**

The Communications group is responsible for the Corporate Communications functions of the ISO, including internal and external communications and media relations. The functions of this group include:

- Serving as Public Information Coordinators during all electrical emergencies; holding news conferences and coordinating print, radio and TV news coverage from ISO control room, playing an important role in maintaining reliability of the Grid by promoting conservation.
- Developing and distributing news releases, advisories and media kits, and serving as media spokespersons for the ISO.
- Ensuring consistent internal communications;
- Planning and executing corporate special events;
- Developing and Publishing the Corporate Annual Report
- Maintaining ISO Speakers Bureau and Speech Bank;
- Reviewing and analyzing expenditures, operations, and workflow of the unit to maximize operational efficiency of the organization;
- Coordinating development of business plans, processes, and procedures to manage internal and external communications.

This group is an overhead group.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Direct Operating Costs

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## 1841 Human Resources

**Description:**

The Human Resources Department is responsible for health and welfare benefits design and administration, compensation design and administration, payroll, employee relations, training, recruitment and employee retention, oversight of the staff augmentation function through external contractors, and employee records management. Human Resources is an overhead department; Human Resources activities, tasks, and projects serve employees throughout the organization.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Labor Dollar Ratios

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## 1830 Policy Office

## 1831 Strategic Development

**Description:**

Strategic Development is a collaborative component to the Policy Office, responsible primarily for Market Design initiatives and policies. See Regulatory Policy (Cost Center 1861) for further definition.

This group is an overhead group.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Direct Operating Costs

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## 1851 Project Office

**Description:**

The Project Office is responsible for development, delivery and monitoring of the Project processes at ISO. Additionally, this group facilitates the development and monitoring of corporate goals, and provides corporate reporting for projects and the corporate goals. This group is also responsible for development, maintenance, and implementation of corporate policies not owned by HR, Operations and/or Legal and Regulatory.

The Project Office is an overhead group.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Direct Operating Costs

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## 1861 Regulatory Policy

**Description:**

The Strategic Development, Regulatory Policy and Project Office collectively form the Policy Office (PO). Regulatory Policy is the focal point for articulating the long-term strategy of the ISO and leading the development of ISO policy positions that are consistent with the business and regulatory strategy. Regulatory Policy should provide considered, steady policy guidance for daily operations as well as a foundation for responding to unexpected events and developments. In addition to leading the development of policy positions, the office will be active in ensuring that these positions are consistently communicated internally and externally in all forums (across ISO departments, Board of Governors, regulatory and legislative environs, and engineering venues such as the WECC and stakeholder forums).

The Policy Office will often direct policy development work, but other departments must do much of the work itself. This office is not a self-contained work unit - policy must be developed from a broad array of perspectives from within and outside of the company. "Directing work" means framing the policy questions and identifying the information/analyses necessary to properly answer the questions, managing the work process necessary to develop information, final integration of input, and written articulation of the policy. The Policy Office should facilitate cross-departmental collaboration and initiate interaction with other agencies.

Departmental Mission Statement: To articulate Strategic Objectives and ensure interdepartmental cooperation in the development and implementation of corporate and regulatory policies and plans in a way that guides performance of the ISO's Core Functions.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Direct Operating Costs

## 2100 Other Group

### 2111 Other

**Description:**

This department exists for budgeting purposes only, and contains the funds related to changes in staff costs for the upcoming year.

**Cost Allocation Methodology and Percentages:**

The costs of this department are allocated to the ISO's three unbundled service categories based on the approach noted here. The results of the allocation process are shown in full on the ISO's Cost Allocation Matrix. Results are shown here only for departments which directly assign their costs to the three categories.

Allocated based on Labor Dollar Ratios

## V. OPERATING RESERVE CALCULATION

The 2003 revenue requirement includes a provision related to the Operating & Capital Reserves Account ("Operating Reserve"). This is consistent with the calculation of the ISO revenue requirement in previous years. See Appendix B for the Reserve Calculation for 2003.

From the inception of the ISO's operations, funds collected above and beyond those needed to cover budgeted operating expenses have been used to fund the Operating Reserve. These funds are collected every year at the rate of 25% of budgeted debt service (consisting of principal and interest payments.) The operating reserve is targeted to build to a level equal to 15% of overall budgeted operating expenses (excluding debt service).

The Operating Reserve is calculated separately by unbundled service category. The analysis referred to above shows the operating reserve balances for two years: 2001 and 2002. The 2001 analysis is necessary, as the December 31, 2001 reserve calculation was used in setting the 2002 GMC rates, but this calculation was done prior to the end of 2001, and actual results differed from that forecast. The revised calculation uses actual results to arrive at a beginning reserve balance as of January 1, 2002.

The analysis shows the effects of events in 2002 on the operating reserve, both from a budget and an actual/forecast perspective.

At December 31, 2002, it is anticipated that for each unbundled GMC category, the reserve balance will exceed the reserve requirement, and accordingly, a revenue credit will be available. The amount of the revenue credit available to apply toward 2003 depends on (1) actual costs incurred by each service category during the year (2) revenue under or over-collections for each service category during the year, (3) other revenues such as ISO fines, (4) use of the operating reserve to fund capital expenditures in 2002, and (5) reserve balances for each service at the beginning of the current year.

# VI. CAPITAL BUDGET PROJECT ALLOCATIONS

Capital costs are grouped in the Cost Allocation Matrix according to the six categories shown below:

1. Infrastructure (Direct Assignment): Items include the EMS, Scheduling Infrastructure (SI), Balance of Business Systems (BBS), MDAS (Meter Data Acquisition System), RMR (Reliability Must Run), Market Analysis software, User groups, startup costs, and working capital. A brief description of the systems are as follows:

   Scheduling Infrastructure (SI): SI provides the information management services needed by the scheduling system. It includes the hardware, software and databases that allow the ISO to collect, validate, store, transfer, archive and audit the energy and ancillary services schedules nominated or accepted by the ISO from SC's.

   Scheduling Applications (SA): SA are the applications used by the ISO's scheduling personnel to assess the state of the transmission system, to evaluate the Preferred Schedules submitted by SCs and to establish committed operating schedules. These applications include congestion and transmission management software necessary to assist in congestion management and to determine the transmission price associated with the use of congested inter-zonal transmission paths.

   Balance of Business Systems (BBS): BBS refers to the computer and other systems to support the following business processes: 1) Settlements to calculate payments owed between the ISO and SCs for imbalances, congestion and ancillary services and other charge types; 2) Billing and Credit to support accounting, invoicing, payment and collection of these payments; and 3) General accounting systems and administrative functions associated with daily ISO operations.

   Meter Data Acquisition System (MDAS) – MDAS, also called Field Data Acquisition (FDA), is used to collect metering data from all generators and others connected directly to the transmission lines, tie points and zonal interface points. This refers to the metering standards, data servers, interface equipment, databases and software that allow the ISO to collect that data.

2. Infrastructure (Allocated Items): This category includes items which are generally used by all ISO functions, and are allocated based on the results of the total operating cost allocation, labor dollar ratios, or specific Department results. Examples include Issue management system (Remedy), Security System (CUDA), Corporate Accounting System (Oracle), HR System, Imperitiv, etc.

3. Startup (Allocated Items): These infrastructure items are used by all ISO functions, and are allocated based on either the results of the operating cost allocation or total infrastructure costs.

4. Other Software and Enhancements (Direct Assignment): Items included in this category are allocated based on direct assignment and include EMS/MDAS and the Participating Load program, and SA/SI/BBS.

5. 2000 and 2001 Capital Debt Service: Items in this category include: SA/SI/BBS, EMS/CIM/FDA, EMS, SA/SI/BBS, facilities, furniture, office equipment, land, and building costs. They are allocated based on direct assignment, operating costs and labor dollar ratios.

6. 2003 Cash Funded Capital Expenditures: The cash funded capital expenditures are allocated to the three unbundled service categories based on various approaches, including direct allocation for MD02 and Operating Systems, and

**Descriptions of the 2003 capital projects are included in Appendix A, including cost allocations methods and results. Values of individual capital projects have not been provided to prevent such data from being used in project bidding.**

# CONFIDENTIALITY AGREEMENT FOR THE ~~2003~~ CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION GMC RATE STRUCTURE PROJECT STAKEHOLDER PROCESS ~~RATE AND BUDGET DEVELOPMENT PROCESS~~

This Confidentiality Agreement, dated as of ~~October 7~~_____, 2002, is entered into by and among the California Independent System Operator Corporation ("ISO") and the Stakeholders executing this agreement, listed in Appendix A, in order to facilitate Stakeholder access to Confidential Material ~~that is a~~as part of the ISO's ~~2003 Budget and Rate Development Process~~GMC Rate Structure Project Stakeholder Process.

WHEREAS, the ISO and Stakeholders wish to allow ~~greater~~ the greatest possible Stakeholder access to ~~input into the ISO's~~ ISO Confidential Material in the~~2003 Budget and Rate Development Process~~ GMC Rate Structure Project Stakeholder Process; ~~and~~

~~WHEREAS, the ISO has agreed as part of a settlement agreement in Federal Energy Regulatory Commission Docket Numbers ER02-250-000, ER02-479-000, and ER02-527-000, to make certain documents related to the ISO's 2003 Budget and Rate Development Process available to Stakeholders;~~

NOW, THEREFORE, in consideration of the premises and of the mutual benefits and covenants hereinafter set forth, it is agreed:

1. This Confidentiality Agreement shall govern the use of all Confidential Material produced by, or on behalf of, the ISO during the GMC Rate Structure Project Stakeholder Process ~~2003 Budget and Rate Development Process.~~

2. This Confidentiality Agreement shall remain in effect with respect to Confidential Materials so designated under the terms of this Confidentiality Agreement, until such time as the ISO shall determine and inform the Stakeholders in Appendix A in writing that the Confidential Materials in question are no longer confidential, or the ISO makes the materials available to the public in the form in which it was re-created for release as part of this GMC Rate Structure Project Stakeholder Process.

3. The ISO may designate as Confidential Material any material that is not already available to the public or available in the form in which it is re-created for release as part of this GMC Rate Structure Project Stakeholder Process.

4. Only Reviewing Representatives, as that term is defined in Paragraph 5 may possess, review, or otherwise use Confidential Materials, and they may do so only as provided in this Confidentiality Agreement.

5. Definitions. As used in this Agreement, the singular includes the plural. For purposes of this Confidentiality Agreement:

a. The term "document" should be interpreted to include, but not be limited to, the original and all copies of any written or retrievable matter, including electronic media, or data of any kind, however produced or reproduced.

b. The term "Confidential Material" means (1) documents or oral materials provided by the ISO and designated as such by the ISO; (2) Notes of Confidential Material, whether created by the ISO or by Stakeholders or by any other person or entity; and (3) copies of Confidential Material, by whomsoever made.

c. The term "Notes of Confidential Materials" means memoranda, handwritten notes, or any other form of information (including electronic form) which copies, discloses or derives from materials described in Paragraph 5(b), whether made by the ISO or any other person or entity.

d. "GMC Rate Structure Project Stakeholder Process~~2003 Budget and Rate Development Process~~" means the process indicated by the FERC ALJ in her Initial Decision in Docket No. ER01-313-000, issued 5/10/02, ~~that begins at the ISO in the Summer of 2002 and~~ which will ends with ~~any~~ a filing with the Federal Energy Regulatory Commission ("FERC") by the ISO regarding ~~the~~a revised GMC~~ISO's 2003 budget and/or rates.~~

e. "Executing Party" means any entity that has executed this Confidentiality Agreement.

f. "Reviewing Representative" shall mean a person who has signed a Non-Disclosure Certificate and who is:

i. an attorney, employee or agent of an Executing Party;

ii. an attorney, paralegal or other employee under the supervision or control of the attorney described in 5(f)(i); and

iii. any person retained by an Executing Party for the purpose of advising the Executing Party with regard to the ISO's GMC Rate Structure Project Stakeholder Process~~2003 Budget and Rate Development Process.~~

7. The ISO shall mark all written materials intended to be covered by the terms of this Confidentiality Agreement with the words "Confidential Material" or with words of similar import. The ISO shall instruct Executing Parties that information being conveyed orally and intended by the ISO to be covered by the terms of this Confidentiality Agreement, is Confidential Material. To the extent possible, the ISO shall mark any electronic document intended to be covered by the terms of this Confidentiality Agreement with the words "Confidential Material" or similar words, or, if that is not possible or would be

exceedingly difficult, the ISO shall notify Executing Parties (for example, by covering email transmitting the electronic document) that the electronic document is Confidential Material. The ISO's failure, for whatever reason, to mark any material at the time it is produced to the Executing Parties, or to notify them that oral or electronic material is Confidential Material at the time it is provided, shall not take the material out of the coverage of this Confidentiality Agreement for all time, and the Executing Parties must treat the material as Confidential Material once the ISO has notified them that the material is to be covered by this Confidentiality Agreement.

8. Confidential Material shall be made available under the terms of this Confidentiality Agreement only to Executing Parties and only through their Reviewing Representatives as provided in Paragraph 11.

9. Confidential Material shall be treated as confidential by each Executing Party and by their Reviewing Representative(s) in accordance with this Confidentiality Agreement. Confidential Materials shall not be used except as necessary for Stakeholder involvement in the ISO's GMC Rate Structure Project Stakeholder Process~~2003 Budget and Rate Development Process~~, nor shall Confidential Material be disclosed to any person except Reviewing Representatives who are engaged in the ISO's ~~2003 Budget and Rate Development Process~~ GMC Rate Structure Project Stakeholder Process and who need to know the information in order to represent the Executing Parties in that process. Confidential Material may not be used by any Executing Party other than the ISO in any administrative or judicial proceeding, including any proceeding that results from the GMC Rate Structure Project Stakeholder Process ~~2003 Budget and Rate Development Process,~~ nor may Confidential Material be used by any Executing Party other than the ISO in any arbitration, mediation or other alternative dispute resolution proceeding, including any alternative dispute resolution proceeding that results from the GMC Rate Structure Project Stakeholder Process~~2003 Budget and Rate Development Process~~.

10. Reviewing Representatives may make copies of Confidential Material, and may make Notes of Confidential Material.

11. A Reviewing Representative shall not be permitted to inspect, participate in discussions regarding, or otherwise have access to Confidential Material pursuant to this Confidentiality Agreement unless that Reviewing Representative has first executed a Non-Disclosure Certificate. A copy of the Non-Disclosure Certificate shall be provided to counsel for the ISO before any Confidential Materials may be provided to that Reviewing Representative.

12. All Reviewing Representatives are responsible to comply with the terms of this Confidentiality Agreement.

13. Any Reviewing Representative may disclose Confidential Material to any other Reviewing Representative as long as the disclosing Reviewing

Representative and the receiving Reviewing Representative have both executed a Non-Disclosure Certificate.

14. The contents of Confidential Material or any other form of information that copies or discloses Protected Material shall not be disclosed to anyone other than in accordance with this Confidentiality Agreement and shall be used only in connection with the ISO's GMC Rate Structure Project Stakeholder Process~~2003 Budget and Rate Development Process~~.

15. If another person or entity requests or demands, by subpoena or otherwise, any Confidential Material, Counsel for the Executing Party receiving the request or demand will immediately notify counsel for the ISO. All reasonable steps will be taken by the Executing Party receiving the request or demand to permit the assertion of all applicable rights and privileges by the ISO, and the Executing Party receiving such request or demand will cooperate with the ISO in the timely assertion of such rights and privileges, including obtaining a protective order where appropriate. Each Executing Party further agrees that if the ISO is not successful in precluding the requesting person or entity from requiring the disclosure of the Confidential Material, it will furnish only that portion of the Confidential Material which is legally required, and will exercise all reasonable efforts to obtain a ruling or reliable assurances that confidential treatment will be afforded the Confidential Material.

16. Each Executing Party shall be responsible for any breach of this Confidentiality Agreement by employees, agents, financial advisors, attorneys, consultants, directors or affiliates, and agrees, at its sole cost and expense, to take all commercially reasonable measures (including, without limitation, court proceedings) to prohibit its employees, agents, financial advisors, attorneys, consultants, directors or affiliates from disclosing or using the Confidential Material in any manner not authorized by this Confidentiality Agreement.

17. It is understood and agreed that the ISO shall be entitled to seek equitable relief, including injunction and specific performance, as a remedy for any breach or threatened breach of this Confidentiality Agreement by an Executing Party, or any of its employees, agents, financial advisors, attorneys, consultants, directors or affiliates. These remedies will not be deemed to be the exclusive remedies for a violation of the terms of this Confidentiality Agreement, but will be in addition to all other remedies available to the ISO, as the case may be, at law or equity. In the event of litigation relating to this Confidentiality Agreement, if a court of competent jurisdiction determines, in a final, nonappealable order, that an Executing Party or any of its representatives has breached this Agreement, then, in addition to any equitable relief granted, such Participant shall be liable and pay to the ISO the reasonable legal fees and disbursements incurred by the ISO in connection with such litigation, including any appeal therefrom.

18. This Confidentiality Agreement may be signed in counterparts, each of which shall be deemed to be an original, but all of which together shall constitute one and the same instrument.

19. This Confidentiality Agreement shall be governed by and construed in accordance with the laws of the State of California without giving effect to the principles of conflicts of law thereof. Each Executing Party irrevocably and unconditionally consents to submit to the exclusive jurisdiction of the courts of the State of California and the United States of America located in the State of California for any actions, suits or proceedings arising out of or relating to this Agreement and the transactions contemplated hereby, and further agrees that service of any process, summons, notice or document by U.S. registered mail to each Party's address set forth below shall be effective service of process for any action, suit or proceeding brought against a Executing Party in any such court. Each Executing Party irrevocably and unconditionally waives any objection to the laying of venue of any action, suit or proceeding arising out of this Agreement or the transactions contemplated hereby, in the courts of the State of California or the United States of America located in the State of California, and hereby further irrevocably and unconditionally waives and agrees not to plead or claim in any such court that any such action, suit or proceeding brought in any such court has been brought in an inconvenient forum or, provided that service of process has been effected as provided herein or as otherwise provided by law, that said court lacks personal jurisdiction over the Executing Party. Federal entities executing the Confidentiality Agreement are not subject to the laws of the State of California, but are subject to federal law as if transactions covered by this Confidentiality Agreement are fully performed within the State of California.

20. The rights and obligations of each Executing Party under this Confidentiality Agreement may not be assigned to any person or entity without the prior written consent of the ISO, which consent shall not be unreasonably withheld. Subject to the foregoing, this Confidentiality Agreement shall be binding on the respective successors and assigns of the Executing Parties hereto.

21. Each Executing Party hereto willingly and freely consents to every provision of this Confidentiality Agreement, and the individual signing on behalf of such Executing Party represents, by signing, that he or she is fully authorized to bind such Executing Party herein.

AGREED:

| | |
|---|---|
| By:____________________ | By:____________________ |
| Title:____________________ | Title:____________________ |
| Date:____________________ | Date:____________________ |
| On behalf of: The California Independent System Operator Corporation<br>Address:____________________ | On behalf of:____________________<br>Address:____________________<br>____________________ |

______________________________

By:______________________________ By:______________________________

Title:______________________________ Title:______________________________

Date:______________________________ Date:______________________________

On behalf of:______________________ On behalf of:______________________

Address:__________________________ Address:__________________________

______________________________ ______________________________

By:______________________________ By:______________________________

Title:______________________________ Title:______________________________

Date:______________________________ Date:______________________________

On behalf of:______________________ On behalf of:______________________
Address:__________________________ Address:__________________________

______________________________ ______________________________

By:______________________________ By:______________________________

Title:______________________________ Title:______________________________

Date:______________________________ Date:______________________________

On behalf of:______________________ On behalf of:______________________
Address:__________________________ Address:__________________________

______________________________ ______________________________

By:______________________________ By:______________________________

Title:______________________________ Title:______________________________

Date:______________________________ Date:______________________________

On behalf of:______________________ On behalf of:______________________
Address:__________________________ Address:__________________________

______________________________ ______________________________

By:______________________________ By:______________________________

Title:______________________________ Title:______________________________

Date:___________________________

On behalf of:______________________
Address:__________________________

By:_____________________________

Title:___________________________

Date:___________________________

On behalf of:______________________
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By:_____________________________

Title:___________________________

Date:___________________________

On behalf of:______________________
Address:__________________________

By:_____________________________

Title:___________________________

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On behalf of:______________________
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| Title:____________________ | Title:____________________ |
| Date:____________________ | Date:____________________ |
| On behalf of:______________ | On behalf of:______________ |
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| By:______________________ | By:______________________ |
| Title:____________________ | Title:____________________ |
| Date:____________________ | Date:____________________ |
| On behalf of:______________ | On behalf of:______________ |
| Address:__________________ | Address:__________________ |

**NON-DISCLOSURE CERTIFICATE**

I hereby certify my understanding that access to Confidential Material is provided to me pursuant to the terms and restrictions of the Confidentiality Agreement for the ~~2003~~ California Independent System Operator Corporation GMC Rate Structure Project Stakeholder Process ~~Budget and Rate Development Process~~ ("Confidentiality Agreement"), dated ~~October 7~~December 19, 2002, by and between the California Independent System Operator Corporation ("ISO") and the Executing Parties as defined therein, and that I have read and understand the terms of that Confidentiality Agreement. I agree to be bound by the terms of that Confidentiality Agreement. I will not disclose to anyone the contents of Confidential Material, any notes or memoranda, or any other form of information that copies or discloses or is derived from Confidential Material other than in accordance with the Confidentiality Agreement. I acknowledge that a violation of my undertakings in this certificate constitutes a breach of the Confidentiality Agreement.

By (Print):________________________

Title:____________________________

Representing:______________________

Signature:_________________________

Date:_____________________________

| Grouping | Activities within proposed Grouping | Indicative Cost Centers (there will be some overlap among cost centers) | MID Functions |
|---|---|---|---|
| 1. Real-Time Grid Operations | Ancillary Services management:<br>• Dispatch of energy associated with Ancillary Services, including:<br>o Regulation<br>o Spin<br>o Non-spin<br>o Replacement reserve<br>o Black start<br>Monitoring of system conditions and dispatching to maintain reliability:<br>• Load and resource balancing<br>• Transmission line/path congestion management<br>• Voltage control<br>• Frequency control<br>• System emergency management<br>• Power flow studies and security analyses<br>Determination of resource adequacy<br>Coordinating Western Interconnection reliability with all WECC Reliability Coordinators<br>Integration and communication with other Control Areas:<br>• Interconnected switching operations for planned and unplanned outages<br>• Generation and transmission equipment outage coordination<br>Interchange scheduling<br>ETC scheduling and administration<br>EMS and Telemetry management | 1544 – Real Time Scheduling<br>1564 – Operations Scheduling<br>1546 – Security Coordination<br>1545 – Grid Operations<br>1566 – Regional Coordination<br>1461 – Control Systems | Resolving energy imbalances<br>Managing transmission flows |

Originator: Ben Arikawa
Last updated: 12/19/2002
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| | | | |
|---|---|---|---|
| 2. Interchange Pre-Scheduling | Day-ahead/Hour-ahead scheduling<br>• ETAG (NERC-required electronic schedule tagging)<br>• Existing Transmission Contracts Calculator (ETCC) and scheduling<br>• New Firm Uses (NFU) scheduling<br>Reconciliation of schedules and interchange after-the-fact<br>NERC/WECC/CAISO Tariff required reporting<br>Weekly:<br>• Inadvertent Interchange report<br>• NERC reports (Inadvertent Interchange, ETAG)<br>• WECC "donut" report<br>Monthly:<br>• WECC Unscheduled Flow curtailment report<br>Quarterly:<br>• Quarterly California Energy Commission 1305 report<br>Annually:<br>• SDG&E DOE report<br>• FERC 714 report<br>• Report of Economic Operation | 1565 – Pre-scheduling and Support | Scheduling generators, loads and transmission facilities |
| 3. Outage Coordination (other than real time) | Pre-planning of and preparation for generation and transmission outages<br>Generation and transmission equipment outage tracking and data/record keeping<br>On-site generation outage monitoring (SB-39 compliance)<br>Outage reporting (web site updates and regulatory agency reporting)<br>Supply of Generation and Transmission data for OASIS postings | 1542 – Outage Coordination | Resolving energy imbalances Managing transmission flows |

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Last updated: 12/19/2002
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|---|---|---|---|
| 4. Operations Engineering, Maintenance, and Support: | Transmission Maintenance:<br>• Develop, monitor and enforce of transmission maintenance standards<br>• Manage and oversee new generation interconnections, major capacity additions or upgrades and supporting Transmission Planning in project tracking.<br>• Manage, analyze, prepare reports on system availability, reliability, and outage records.<br>• Manage, audit, investigate, approving Transmission Maintenance Practices.<br>• Manage, oversee, and approve the equipment ratings.<br>Operations Engineering:<br>• Perform seasonal, annual, and, as necessary special analysis of transmission system performance and ratings.<br>• Review, approve and provide specification on daily system configurations, emergency conditions, clearances and operational conditions.<br>• Develop, prepare and update operating procedures.<br>• Perform operational studies and system security analyses<br>Operations Support:<br>• Manage the development, preparation and revision of all ISO Operating Procedures:<br>  • Transmission grid<br>  • Market Operations<br>  • Generation<br>  • Emergency<br>• Perform generating unit ancillary service certification and P-MAX testing<br>• Manage UDC and Inter-Control Area Operating agreements | 1558 – Transmission Maintenance<br>1561 – Operations Engineering, South<br>1562 – Operations Engineering, North<br>1554 – Special Projects Engineering<br>1549 – Operations Training Group<br>1555 – Operations Support Group<br>1559 – Operations Application Support<br>1563 – Coordinated Operations | Resolving energy imbalances<br>Managing transmission flows |

| | | | |
|---|---|---|---|
| 5. Grid Planning | Transmission Planning:<br>• Perform system transmission planning to ensure overall reliability<br>• Perform reserve requirement studies<br>• Perform Long-term (monthly, annual and longer) load forecasting<br>• Determine long term *transmission* resource adequacy<br>Regional Coordination:<br>• Coordinate participation in NERC, WECC, NAESB, ESC, and OSC<br>• Monitor and participate in resolving seams issues in the Western Interconnection<br>• Provide Control Area and interconnection mapping services to real time operations.<br>Determine long-term *generation* resource adequacy:<br>• Manage, develop, prepare, publish and participate in seasonal system load and generation assessments.<br>• Participate, guide, influence, and maintain records on environmentally constrained generation units.<br>• Determine dual fuel generator requirements<br>Determine Reliability Must-Run ("RMR") contract requirements<br>Review Participating Transmission Owners ("PTOs") Bulk Power Program and new generator or load interconnection studies | 1521 – Grid Planning<br>1543 – Loads and Resources<br>1566 – Regional Coordination | Managing transmission flows |

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| | | | |
|---|---|---|---|
| 6. Market Operations (A/S, RT & DA Energy, Transmission/Congestion) | Manage congestion (inter-zonal intra-zonal, LMP when implemented)<br>Manage transmission and generation schedules:<br>• Day and Hour-Ahead schedules (including Participating Intermittent Resources)<br>• Day-Ahead market (under MD02)<br>• Determine schedule feasibility<br>Perform weekly, daily and hourly load forecasting<br>Operate A/S and Real-Time markets<br>Determine market clearing prices (A/S and Energy)<br>Mitigate bids (real time and forward)<br>Maintenance of market information postings (transmission/market OASIS)<br>Operate unit commitment service under SMD<br>Mitigate market power in Day-Ahead, Hour-Ahead and Real Time markets<br>Develop and manage demand response participation<br>Administer FTRs:<br>• Perform FTR auctions (Primary)<br>• Coordinate FTR bilateral trading (Secondary)<br>• Calculate and determine feasibility of FTR capacity | 1752 – Manager of Markets<br>1753 – Market Application and Testing<br>1757 – Market Integration<br>1756 – Market Quality | Administering markets |

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| | | | |
|---|---|---|---|
| 7. Marketing monitoring and compliance | Collect and analyze information on market behavior<br>Develop new market rules or changes to market rules in response to market behavior<br>Prepare and provide reports to regulatory authorities<br>Perform oversight and investigations | 1641 – Market Analysis<br>1642 – Market Surveillance Committee<br>1661 - Compliance<br>1662 – Data Quality Group | Administering markets |

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Last updated: 12/19/2002
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| | | | |
|---|---|---|---|
| 8. Settlements, Billing, Credit Administration and Metering | Determine charges associated with:<br>• Transmission services<br>• Day-Ahead schedules and markets (A/S and Energy)<br>• Hour-Ahead schedules and markets (A/S and Energy)<br>• Real time balancing energy market<br>• Congestion management<br>• Administrative charges, including the Grid Management Charge<br>Manage settlement data<br>Manage ETC manual settlements<br>Administration of RMR settlements<br>Prepare market and GMC invoices<br>Prepare special invoices for FERC fees, interest, etc.<br>Perform settlement statement reruns<br>Market/settlements design and settlements training<br>Dispute resolution, GFN, arbitration and monitoring<br>Credit and collateral management<br>• Manage collections and payments<br>• SC financial security analysis<br>Determination of losses and allocation<br>Metering and data management<br>• Collect and validate data from ISO polled meters<br>• Repository of data polled from ISO polled meters and data submitted by SCs<br>• Responsible for site inspection of metering sites<br>• Responsible for setting up RIG data bases and submitting data into EMS<br>• Push data to Settlement databases<br>Manage Participating Intermittent Resources settlements | 1722 – Application Support<br>1723 – Tariff and contract implementation<br>1724 – BBS-PSS<br>1725 – BBS-FSS<br>1462 – Field Data Acquisition<br>1321 - Accounting<br>1331 – Treasury and Financial Planning | Allocated |

| | | | |
|---|---|---|---|
| 9. Account Management Services and Training | Provide ISO Tariff, Systems, Market and Settlements guidance to market participants<br>Communicate scheduled events to market participants<br>Communicate Market information<br>Develop training curriculum<br>Provide training to Market Participants (Settlements, System Infrastructure, Market Design)<br>Facilitate stakeholder process<br>Facilitate resolution of Market Participant issues | 1741 – Client Relations | Allocated |
| 10. ISO contract administration | Administer ISO contracts (non-vendor, e.g., RMR, PTO, MSS)<br>Negotiate, manage, litigate contracts | 1731 – Contracts and Special Projects | Allocated (Managing transmission flows) |
| 11. Administrative and General (not directly assigned elsewhere) | CEO<br>Finance and Accounting<br>Legal<br>HR<br>Regulatory policy and affairs<br>Information services<br>Strategic development<br>Communications | 1111 – CEO<br>1651 – Board of Governors<br>1241 – MD02 (currently)<br>1300 – Finance indirects<br>1400 – Information Services indirects<br>1600 – Legal and Regulatory indirects<br>1700 – Market Services indirects<br>1800 – Corporate and Strategic Development indirects | Allocated |
| 12. Startup costs | Recover costs associated with Startup | | Allocated |

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**Preliminary ~~List of Functions (Services)~~Grouping of Activities for ISO Rate Structure**
**Version 12/~~06~~16/2002**

| ~~Service (Function)~~Grouping | Activities within proposed ~~service (function)~~Grouping |
|---|---|
| 1. Real-Time Grid Operations | Ancillary Services management:<br>• Dispatch of energy associated with Ancillary Services, including:<br>o Regulation<br>o Spin<br>o Non-spin<br>o Replacement reserve<br>o Black start<br>Monitoring of system conditions and dispatching to maintain reliability:<br>• Load and resource balancing<br>• Transmission line/path congestion management<br>• Voltage ~~C~~control<br>• Frequency control<br>• System emergency management<br>• Power flow studies and security analyses<br>Determination of resource adequacy<br>Coordinating Western Interconnection reliability with all WECC Reliability Coordinators<br>Integration and communication with other Control Areas:<br>• Interconnected switching operations for planned and unplanned outages<br>• Generation and transmission equipment outage coordination ~~(in real time)~~<br>Interchange scheduling ~~(in real time)~~<br>ETC scheduling and administration<br>EMS and Telemetry management ~~(in real time)~~ |

Originator: Ben Arikawa
Last updated: 12/~~06~~19/2002
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| | |
|---|---|
| 2. Interchange Pre-Scheduling | Day-ahead/Hour-ahead scheduling<br>• ETAG (NERC-required electronic schedule tagging)<br>• Existing Transmission Contracts Calculator (ETCC) and scheduling<br>• New Firm Uses (NFU) scheduling<br>Reconciliation of schedules and interchange after-the-fact<br>NERC/WECC/CAISO Tariff required reporting<br>Weekly:<br>• Inadvertent Interchange report<br>• NERC reports (Inadvertent Interchange, ETAG)<br>• WECC "donut" report<br>Monthly:<br>• WECC Unscheduled Flow curtailment report<br>Quarterly:<br>• Quarterly California Energy Commission 1305 report<br>Annually:<br>• SDG&E DOE report<br>• FERC 714 report<br>• Report of Economic Operation |
| 3. Outage Coordination (other than real time) | Pre-planning of and preparation for generation and transmission outages<br>Generation and transmission equipment outage tracking and data/record keeping<br>On-site generation outage monitoring (SB-39 compliance)<br>Outage reporting (web site updates and regulatory agency reporting)<br>Supply of Generation and Transmission data for OASIS postings |

| | |
|---|---|
| 4. Operations Engineering, Maintenance, and Support: | Transmission Maintenance:<br>• Develop, monitor and enforce of transmission maintenance standards<br>• Manage and oversee new generation interconnections, major capacity additions or upgrades and supporting Transmission Planning in project tracking.<br>• Manage, analyze, prepare reports on system availability, reliability, and outage records.<br>• Manage, audit, investigate, approving Transmission Maintenance Practices.<br>• Manage, oversee, and approve the equipment ratings.<br>Operations Engineering:<br>• Perform seasonal, annual, and, as necessary special analysis of transmission system performance and ratings.<br>• Review, approve and provide specification on daily system configurations, emergency conditions, clearances and operational conditions.<br>• Develop, prepare and update operating procedures.<br>• Perform operational studies and system security analyses<br>Operations Support:<br>• Manage the development, preparation and revision of all ISO Operating Procedures:<br>    • Transmission grid<br>    • Market Operations<br>    • Generation<br>    • Emergency<br>• Perform generating unit ancillary service certification and P-MAX testing<br>• Manage UDC and Inter-Control Area Operating agreements<br>• Manage dynamic energy scheduling agreements and interfaces<br>• Manage required WECC Reliability Management System (RMS) and NERC<br>• Maintain Compliance Program data collection, tracking, storage and reporting processes |
| | |

| | |
|---|---|
| 5. Grid Planning | Transmission Planning:<br>• Perform system transmission planning to ensure overall reliability<br>• Perform reserve requirement studies<br>• Perform Long-term (monthly, annual and longer) load forecasting<br>• Determine long term *transmission* resource adequacy<br>Regional Coordination:<br>• Coordinate participation in NERC, WECC, NAESB, ESC, and OSC<br>• Monitor and participate in resolving seams issues in the Western Interconnection<br>• Provide Control Area and interconnection mapping services to real time operations.<br>Determine long-term *generation* resource adequacy:<br>• Manage, develop, prepare, publish and participate in seasonal system load and generation assessments.<br>• Participate, guide, influence, and maintain records on environmentally constrained generation units.<br>• Determine dual fuel generator requirements<br>Determine Reliability Must-Run ("RMR") contract requirements<br>Review Participating Transmission Owners ("PTOs") Bulk Power Program and new generator or load interconnection studies |

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Last updated: 12/~~06~~19/2002
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| | |
|---|---|
| 6. Market Operations (A/S, RT & DA Energy, Transmission/Congestion) | Manage congestion (inter-zonal intra-zonal, LMP when implemented)<br>Manage transmission and generation schedules:<br>• Day and Hour-~~-~~Ahead schedules (including Participating Intermittent Resources)<br>• Day-Ahead market (under MD02)<br>• Determine schedule feasibility<br>Perform weekly, daily and hourly load forecasting<br>Operate A/S and Real-Time markets<br>Determine market clearing prices (A/S and Energy)<br>Mitigate b~~B~~ids ~~mitigation~~ (real time and forward)<br>Maintenance of market information postings (transmission/market OASIS)<br>Operate u~~U~~nit commitment service under SMD<br>Mitigate market power in Day-Ahead, ~~and~~ Hour-~~-~~Ahead and Real Time markets<br>Develop~~ment~~ and manage~~ment~~ ~~of~~ demand response participation<br>Administer FTRs:<br>• Perform FTR auctions (Primary)<br>• Coordinate FTR bilateral trading (Secondary)<br>• Calculate and determine feasibility of FTR capacity |
| 7. Marketing monitoring and compliance | Collect and analyze information on market behavior<br>Develop new market rules or changes to market rules in response to market behavior<br>Prepare and provide reports to regulatory authorities<br>Perform oversight and investigations |

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<table>
<tr><td>8. Settlements, Billing, Credit Administration and Metering</td><td>Determine charges associated with:<ul><li>Transmission services</li><li>Day-Ahead schedules and markets (A/S and Energy)</li><li>Hour-~~-~~Ahead schedules and markets (A/S and Energy)</li><li>Real time balancing energy market</li><li>Congestion management</li><li>Administrative ~~Grid Management C~~charges, including the Grid Management Charge</li></ul>Manage settlement data<br>Manage ETC manual settlements ~~administration~~<br>Administration of RMR settlements<br>Prepare market and GMC invoices<br>Prepare special invoices for FERC fees, interest, etc.<br>Perform settlement statement reruns<br>~~Assist with M~~Mmarket/settlements design and settlements training<br>Dispute resolution, GFN, arbitration and monitoring<br>Credit and collateral management<ul><li>Manage collections and payments</li><li>SC financial security analysis</li></ul>Determination of losses and allocation<br>Metering and data management<ul><li>Collect and validate data from ISO polled meters</li><li>Repository of data polled from ISO polled meters and data submitted by SCs</li><li>Responsible for site inspection of metering sites</li><li>Responsible for setting up RIG data bases and submitting data into EMS</li><li>Push data to Settlement databases</li></ul>Manage Participating Intermittent Resources settlements</td></tr>
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| | |
|---|---|
| 9. Account Management Services and Training | Provide ISO Tariff, Systems, Market and Settlements guidance to ~~customers~~market participants<br>Communicate scheduled events to ~~customers~~market participants<br>Communicate Market information ~~to customers~~<br>Develop training curriculum<br>Provide training to Market Participants (Settlements, System Infrastructure, Market Design)<br>Facilitate stakeholder process<br>Facilitate resolution of Market Participant issues |
| 10. ISO contract administration | Administer ISO contracts (non-vendor, e.g., RMR, PTO, MSS)<br>Negotiate, manage, litigate contracts |
| 11. Administrative and General (not directly assigned elsewhere) | CEO<br>Finance and Accounting<br>Legal<br>HR<br>Regulatory policy and affairs<br>Information services<br>Strategic development<br>Communications |
| 12. Startup costs | Recover costs associated with Startup |

**Preliminary Grouping of Activities for ISO Rate Structure**
**Version 12/19/2002**

| Grouping | Activities within proposed Grouping | Indicative Cost Centers (there will be some overlap among cost centers) |
|---|---|---|
| 1. Real-Time Grid Operations | Ancillary Services management:<br>• Dispatch of energy associated with Ancillary Services, including:<br>  o Regulation<br>  o Spin<br>  o Non-spin<br>  o Replacement reserve<br>  o Black start<br>Monitoring of system conditions and dispatching to maintain reliability:<br>• Load and resource balancing<br>• Transmission line/path congestion management<br>• Voltage control<br>• Frequency control<br>• System emergency management<br>• Power flow studies and security analyses<br>Determination of resource adequacy<br>Coordinating Western Interconnection reliability with all WECC Reliability Coordinators<br>Integration and communication with other Control Areas:<br>• Interconnected switching operations for planned and unplanned outages<br>• Generation and transmission equipment outage coordination<br>Interchange scheduling<br>ETC scheduling and administration<br>EMS and Telemetry management | 1544 – Real Time Scheduling<br>1564 – Operations Scheduling<br>1546 – Security Coordination<br>1545 – Grid Operations<br>1566 – Regional Coordination<br>1461 – Control Systems |

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| 2. Interchange Pre-Scheduling | Day-ahead/Hour-ahead scheduling<br>• ETAG (NERC-required electronic schedule tagging)<br>• Existing Transmission Contracts Calculator (ETCC) and scheduling<br>• New Firm Uses (NFU) scheduling<br>Reconciliation of schedules and interchange after-the-fact<br>NERC/WECC/CAISO Tariff required reporting<br>Weekly:<br>• Inadvertent Interchange report<br>• NERC reports (Inadvertent Interchange, ETAG)<br>• WECC "donut" report<br>Monthly:<br>• WECC Unscheduled Flow curtailment report<br>Quarterly:<br>• Quarterly California Energy Commission 1305 report<br>Annually:<br>• SDG&E DOE report<br>• FERC 714 report<br>• Report of Economic Operation | 1565 – Pre-scheduling and Support |
| 3. Outage Coordination (other than real time) | Pre-planning of and preparation for generation and transmission outages<br>Generation and transmission equipment outage tracking and data/record keeping<br>On-site generation outage monitoring (SB-39 compliance)<br>Outage reporting (web site updates and regulatory agency reporting)<br>Supply of Generation and Transmission data for OASIS postings | 1542 – Outage Coordination |

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| 7. Marketing monitoring and compliance | Collect and analyze information on market behavior<br>Develop new market rules or changes to market rules in response to market behavior<br>Prepare and provide reports to regulatory authorities<br>Perform oversight and investigations | 1641 – Market Analysis<br>1642 – Market Surveillance Committee<br>1661 - Compliance<br>1662 – Data Quality Group |

Originator: Ben Arikawa
Last updated: 12/19/2002
"Note: Parties should clearly note that this grouping of activities and the assignment of cost centers may be altered as a result of the ongoing deliberations and developments in this process."

| | | |
|---|---|---|
| 8. Settlements, Billing, Credit Administration and Metering | Determine charges associated with:<br>• Transmission services<br>• Day-Ahead schedules and markets (A/S and Energy)<br>• Hour-Ahead schedules and markets (A/S and Energy)<br>• Real time balancing energy market<br>• Congestion management<br>• Administrative charges, including the Grid Management Charge<br>Manage settlement data<br>Manage ETC manual settlements<br>Administration of RMR settlements<br>Prepare market and GMC invoices<br>Prepare special invoices for FERC fees, interest, etc.<br>Perform settlement statement reruns<br>Market/settlements design and settlements training<br>Dispute resolution, GFN, arbitration and monitoring<br>Credit and collateral management<br>• Manage collections and payments<br>• SC financial security analysis<br>Determination of losses and allocation<br>Metering and data management<br>• Collect and validate data from ISO polled meters<br>• Repository of data polled from ISO polled meters and data submitted by SCs<br>• Responsible for site inspection of metering sites<br>• Responsible for setting up RIG data bases and submitting data into EMS<br>• Push data to Settlement databases<br>Manage Participating Intermittent Resources settlements | 1722 – Application Support<br>1723 – Tariff and contract implementation<br>1724 – BBS-PSS<br>1725 – BBS-FSS<br>1462 – Field Data Acquisition<br>1321 - Accounting<br>1331 – Treasury and Financial Planning |
| | | |

Originator: Ben Arikawa
Last updated: 12/19/2002
"Note: Parties should clearly note that this grouping of activities and the assignment of cost centers may be altered as a result of the ongoing deliberations and developments in this process."

| | | |
|---|---|---|
| 9. Account Management Services and Training | Provide ISO Tariff, Systems, Market and Settlements guidance to market participants<br>Communicate scheduled events to market participants<br>Communicate Market information<br>Develop training curriculum<br>Provide training to Market Participants (Settlements, System Infrastructure, Market Design)<br>Facilitate stakeholder process<br>Facilitate resolution of Market Participant issues | 1741 – Client Relations |
| 10. ISO contract administration | Administer ISO contracts (non-vendor, e.g., RMR, PTO, MSS)<br>Negotiate, manage, litigate contracts | 1731 – Contracts and Special Projects |
| 11. Administrative and General (not directly assigned elsewhere) | CEO<br>Finance and Accounting<br>Legal<br>HR<br>Regulatory policy and affairs<br>Information services<br>Strategic development<br>Communications | 1111 – CEO<br>1651 – Board of Governors<br>1241 – MD02 (currently)<br>1300 – Finance indirects<br>1400 – Information Services indirects<br>1600 – Legal and Regulatory indirects<br>1700 – Market Services indirects<br>1800 – Corporate and Strategic Development indirects |
| 12. Startup costs | Recover costs associated with Startup | |

Originator: Ben Arikawa
Last updated: 12/19/2002
"Note: Parties should clearly note that this grouping of activities and the assignment of cost centers may be altered as a result of the ongoing deliberations and developments in this process."

Cost of Service Information 01-06-03.txt

MessageFrom: Ross Hemphill [rchemphill@lrca.com]
Sent: Monday, January 06, 2003 8:53 AM
To: Arikawa, Benurence□50□Laurence□50□Cc: Jan Pritchard; Laurence Kirsch

Subject: Cost of Service Information

Ben,

Please see the attached memo regarding information needs for MID.

Ross

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Ross C. Hemphill, Ph.D.
Christensen Associates
Tel: 608-231-2266 (Ext. 168)
Fax: 608-231-1365

Website: www.LRCA.com

**From:** CRCommunications
**Sent:** Wednesday, January 08, 2003 5:05 PM
**To:** ISO Market Participants
**Subject:** CAISO Notice: Stakeholder Meeting - 2004 GMC Rate Structure Project

**MARKET NOTICE**

***January 8, 2003***

**In** **Re:**

**FERC Decision in ER01- 313- 000, Settlement in ER02- 250- 000**

**Stakeholder Meeting - 2004 GMC Rate Structure Project**

**ISO Market Participants:**

On January 13, 2003 the California ISO ("ISO") will hold a stakeholder meeting to discuss the 2004 Grid Management Charge ("GMC") Rate Structure Project. The meeting will be from 9:30 a.m. to 3:00 p.m. at the ISO's headquarters in Folsom.

**Background**

Following Judicial direction from the Federal Regulatory Energy Commission, the ISO, initiated the "2004 GMC Rate Structure Project" in mid-summer 2002 to review comprehensively the existing GMC structure and to develop a new GMC rate structure to be in place by January 2004. This review is open to all Stakeholders and has involved the active participation of a number of entities thus far. In past meetings, participants and the ISO have reviewed the structure of Stakeholder participation, rate structures of other ISOs, FERC Staff views on ISO rates as a formula rate, various rate methodologies and ISO activities and data requirements for development of rate proposals. The next Project meeting will be on January 13, 2003 as noted above. Additional information regarding past Project activities is accessible in the ISO web site at <http://www.caiso.com/docs/2002/08/02/2002080216283419989.html>.

**Process Moving Forward**

The ISO requests that participants in the Project provide input on various rate design elements in order to assist the ISO in developing a revised GMC structure and methodology. The ISO may also ask participants to present their own rate structure proposals.

As the Project moves towards creating draft new methodologies, the ISO emphasizes that the Project is open and encourages participation from entities that have not yet contributed.

If you would like to attend the January 13th meeting, please RSVP to Michelle Gamble (mgamble@caiso.com <mailto:mgamble@caiso.com> or (916) 351-2118) by 12 noon on Friday, January 9th.

The agenda and presentation materials will be emailed to the participants later this week.

If you would like to be placed on the distribution list for announcements and documents for the 2004 GMC Rate Structure Project, please email Michelle at the address above. Please ask to be added to the GMC WG distribution list.

**Client Relations Communications.0715**

CRCommunications@caiso.com <mailto:CRCommunications@caiso.com>

*Proposed Agenda*
2004 GMC Stakeholder Process
January 13, 2003
9:30 a.m. to 3:00 p.m.
California ISO
Room 101A – 1a
101 Blue Ravine Road
Folsom, CA

Conference Call-in #888-788-6681
Passcode: 921065

| | | |
|---|---|---|
| I. | Introductions / Announcements | 9:30 – 9:45 |
| II. | Distribute Final Project Charter | 9:45 – 10:00 |
| III. | Discussion of distribution of documents and communications and postings to GMC web page | 10:00 – 10:15 |
| IV. | Statements on desirable rate design elements by parties: MID, CPUC/EOB, CAC, CAISO, etc | 10:15 – 10:45 |
| V. | Break | 10:45 – 11:00 |
| VI. | Confidentiality issues/NDA | 11:00 – 11:20 |
| VII. | Discussion of data | 11:20 – 12:00 |
| VIII. | Lunch | 12:00 – 12:45 |
| IX. | Discussion of ISO list of activities | 12:45 – 1:30 |
| X. | Discussion of ETC workload | 1:30 – 2:30 |
| XI. | Summary of ISO-NE rate structure | 2:30 – 2:45 |
| XII. | Discussion of next steps | 2:45 – 3:00 |

**California ISO**

**2004 GMC Rate Structure Project**

**Contact List for January 13, 2003 Meeting at PG&E Headquarters**

| Last Name | First | Company | Telephone | E-mail Address | Present |
|---|---|---|---|---|---|
| Alessandri | Patrick | EOB | (916) 322-8672 | palessandri@eob.ca.gov | x |
| Aoki | Rod | CAC | (415) 421-4143 | rsa@a-klaw.com | x |
| Arikawa | Ben | ISO | (916) 608-5958 | barikawa@caiso.com | x |
| Bracht | Kirk | CPUC | (415) 703-2868 | kwb@caiso.com | x |
| Cohen | David | Navigant Consulting | (503) 708-7852 | dcohen@navigantconsulting.com | x |
| Hansen | Bert | SCE | (626) 302-3649 | berton.hansen@sce.com | x |
| Hawkins | David | ISO | | dhawkins@caiso.com | x |
| Hoffman | Kyle | ISO | (916) 608-7057 | khoffman@caiso.com | x |
| Kaplan | Katie | IEP | (916) 448-9499 | kaplan@iepa.com | x |
| Lam | Tony | EOB | (916) 322-8632 | tlam@eob.ca.gov | x |
| Leiber | Phil | ISO | (916) 351-2168 | pleiber@caiso.com | x |
| Lengenfelder | David | FERC | (916) 294-0175 | david.lengenfelder@ferc.gov | x |
| LeVine | Debi | ISO | (916) 351-2144 | dlevine@caiso.com | x |
| McGuffin | Mike | ISO | (916) 608-5753 | mmcguffin@caiso.com | x |
| Mi | JingChao | CDWR | (916) 653-1095 | jmi@water.ca.gov | x |
| Morrison | Stephen | ISO | (916) 608-7143 | smorrison@caiso.com | x |
| Peterson | Mike | ISO | (916) 608-5896 | mpeterson@caiso.com | x |
| Ryan | Mike | WAPA | (916) 353-4434 | mryan@wapa.gov | x |
| Shea | Karen | CPUC | (415) 703-5404 | kms@cpuc.ca.gov | x |
| Takehara | James | NCPA | (916) 781-4293 | james.takehara@ncpa.com | x |
| Walz | Edna | CDWR | (916) 324-1720 | ewalz@doj.ca.gov | x |
| Withrow | David | ISO | (916) 608-7134 | dwithrow@caiso.com | x |
| Wolfe | Lisa | EOB | (916) 322-8613 | lwolfe@eob.ca.gov | x |
| Yakin | Dale | PG&E | (415) 973-1752 | dgy4@pge.com | x |
| Hemphill | Ross | Christensen Associates | (608) 321-2266 | rchemphill@lrca.com | phone |
| Kehrein | Carolyn | EMS | (707) 678-9506 | cmkehrein@ems-ca.com | phone |
| Kirsch | Laurence | Christensen Associates | (415) 663-8608 | lkirsch@lrca.com | phone |
| Neal | Sean | MID | | | phone |
| Paradise | Theodore | ISO | | | phone |
| Pritchard | Jan | MID | (209) 526-7490 | janp@mid.org | phone |

**Exhibit 6 (GCP-5)**

# ISO NEW ENGLAND INC.

**FERC DOCKET NO. ER03-__________**

**Rate Design**

**Test Year 2003**

**Exhibit 6 (GCP-5)**
**Schedule 1.0**
**Page 1 of 2**

## ISO New England Inc.

**FERC DOCKET NO. ER03-__________**

**Billing Determinants for Calendar Year 2002 and Test Year 2003**

**Before Implementation of SMD**

| Line No. | Month | Source | Schedule 1 Network Load (kW) | Schedule 2 Transaction Units (TUs) | Schedule 2 Volumes (GWH) | Schedule 3 Peak Volumes Elect. Load (kW) | Schedule 3 Peak Volumes Injections (kW) |
|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) |
| | | | | CY 2002 | | | |
| 1 | Jan-02 | Actual | 19,158,728 | 2,728,506 | 22,742,173 | 22,244,566 | 25,241,267 |
| 2 | Feb-02 | Actual | 19,135,642 | 2,554,168 | 20,119,933 | 21,828,483 | 26,994,289 |
| 3 | Mar-02 | Actual | 18,167,098 | 2,596,543 | 21,319,938 | 21,001,201 | 25,637,250 |
| 4 | Apr-02 | Actual | 18,474,392 | 2,521,559 | 20,073,570 | 21,949,646 | 25,019,096 |
| 5 | May-02 | Actual | 18,353,776 | 2,723,018 | 20,661,432 | 21,159,587 | 24,782,062 |
| 6 | Jun-02 | Actual | 22,841,634 | 2,671,791 | 21,583,264 | 25,663,966 | 28,021,120 |
| 7 | Jul-02 | Actual | 24,735,678 | 2,922,489 | 25,513,501 | 27,671,578 | 28,568,490 |
| 8 | Aug-02 | Actual | 25,063,918 | 2,847,078 | 25,703,278 | 28,167,405 | 30,417,323 |
| 9 | Sep-02 | Est. | 20,443,396 | 2,470,630 | 20,803,532 | 22,266,958 | 25,282,845 |
| 10 | Oct-02 | Est. | 17,440,072 | 2,611,401 | 20,636,743 | 19,439,630 | 23,802,796 |
| 11 | Nov-02 | Est. | 18,041,447 | 2,548,352 | 20,123,284 | 20,342,156 | 23,613,269 |
| 12 | Dec-02 | Est. | 19,689,125 | 2,600,192 | 22,027,025 | 21,706,857 | 25,243,504 |
| 13 | Totals | | 241,544,906 | 31,795,727 | 261,307,673 | 273,442,033 | 312,623,311 |
| 14 | | | | | | | |
| 15 | | | | TY 2003 | | | |
| 16 | Jan-03 | Est. | 19,580,220 | 2,728,506 | 23,051,466 | 22,733,946 | 25,796,575 |
| 17 | Feb-03 | Est. | 19,556,626 | 2,554,168 | 20,393,564 | 22,308,710 | 27,588,163 |
| 18 | Mar-03 | Est. | 18,566,774 | 2,596,543 | 21,609,889 | 21,463,227 | 26,201,270 |
| 19 | Apr-03 | Est. | 18,880,829 | 2,521,559 | 20,346,570 | 22,432,538 | 25,569,516 |
| 20 | May-03 | Est. | 18,757,559 | 2,723,018 | 20,942,428 | 21,625,098 | 25,327,267 |
| 21 | Jun-03 | Est. | 23,344,150 | 2,671,791 | 21,876,796 | 26,228,573 | 28,637,585 |
| 22 | Jul-03 | Est. | 25,279,863 | 2,922,489 | 25,860,485 | 28,280,353 | 29,196,997 |
| 23 | Aug-03 | Est. | 25,615,324 | 2,847,078 | 26,052,843 | 28,787,088 | 31,086,504 |
| 24 | Sep-03 | Est. | 20,893,151 | 2,470,630 | 21,086,460 | 22,756,831 | 25,839,068 |
| 25 | Oct-03 | Est. | 17,823,754 | 2,611,401 | 20,917,403 | 19,867,302 | 24,326,458 |
| 26 | Nov-03 | Est. | 18,438,359 | 2,548,352 | 20,396,961 | 20,789,683 | 24,132,761 |
| 27 | Dec-03 | Est. | 20,122,286 | 2,600,192 | 22,326,592 | 22,184,408 | 25,798,861 |
| 28 | Total | | 246,858,894 | 31,795,727 | 264,861,457 | 279,457,758 | 319,501,024 |

(1) 2002 amounts escalated as follows:

| | | | | | |
|---|---|---|---|---|---|
| Escalation Factors | 1.0220 | 1.0000 | 1.0136 | 1.0220 | 1.0220 |

## ISO New England Inc.
**FERC DOCKET NO. ER03-__________**
**Billing Determinants for Calendar Year 2002 and Test Year 2003**
**After Implementation of SMD**

| Line No. | Month | Source | Schedule 1 Network Load (kW) | Schedule 2 Transaction Units (TUs) | Schedule 2 Volumes (GWH) | Schedule 3 Peak Volumes Elect. Load (kW) | Schedule 3 Peak Volumes Injections (kW) |
|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) |
| | | | | CY 2002 | | | |
| 1 | Jan-02 | Actual | 19,158,728 | 2,728,506 | 22,742,172 | 22,244,566 | 24,947,824 |
| 2 | Feb-02 | Actual | 19,135,642 | 2,554,168 | 20,118,950 | 21,828,483 | 26,920,925 |
| 3 | Mar-02 | Actual | 18,167,098 | 2,596,543 | 21,317,858 | 21,001,201 | 25,480,428 |
| 4 | Apr-02 | Actual | 18,474,392 | 2,521,559 | 20,073,170 | 21,949,646 | 24,654,641 |
| 5 | May-02 | Actual | 18,353,776 | 2,723,018 | 20,661,433 | 21,159,587 | 24,682,059 |
| 6 | Jun-02 | Actual | 22,841,634 | 2,671,791 | 21,582,028 | 25,663,966 | 27,615,136 |
| 7 | Jul-02 | Actual | 24,735,678 | 2,922,489 | 25,513,474 | 27,671,578 | 28,488,384 |
| 8 | Aug-02 | Actual | 25,063,918 | 2,847,078 | 25,702,150 | 28,167,405 | 30,351,719 |
| 9 | Sep-02 | Est. | 20,443,396 | 2,470,630 | 20,803,531 | 22,266,958 | 25,261,151 |
| 10 | Oct-02 | Est. | 17,440,072 | 2,611,401 | 20,626,381 | 19,439,630 | 23,798,875 |
| 11 | Nov-02 | Est. | 18,041,447 | 2,548,352 | 20,123,284 | 20,342,156 | 23,613,505 |
| 12 | Dec-02 | Est. | 19,689,125 | 2,600,192 | 22,023,484 | 21,706,857 | 25,160,824 |
| 13 | Totals | | 241,544,906 | 31,795,727 | 261,287,916 | 273,442,033 | 310,975,471 |
| 14 | | | | | | | |
| 15 | | | | TY 2003 | | | |
| 16 | Jan-03 | Est. | 19,580,220 | 2,728,506 | 23,051,466 | 22,733,946 | 25,496,677 |
| 17 | Feb-03 | Est. | 19,556,626 | 2,554,168 | 20,392,568 | 22,308,710 | 27,513,185 |
| 18 | Mar-03 | Est. | 18,566,774 | 2,596,543 | 21,607,781 | 21,463,227 | 26,040,997 |
| 19 | Apr-03 | Est. | 18,880,829 | 2,521,559 | 20,346,165 | 22,432,538 | 25,197,043 |
| 20 | May-03 | Est. | 18,757,559 | 2,723,018 | 20,942,428 | 21,625,098 | 25,225,064 |
| 21 | Jun-03 | Est. | 23,344,150 | 2,671,791 | 21,875,543 | 26,228,573 | 28,222,669 |
| 22 | Jul-03 | Est. | 25,279,863 | 2,922,489 | 25,860,458 | 28,280,353 | 29,115,129 |
| 23 | Aug-03 | Est. | 25,615,324 | 2,847,078 | 26,051,699 | 28,787,088 | 31,019,457 |
| 24 | Sep-03 | Est. | 20,893,151 | 2,470,630 | 21,086,459 | 22,756,831 | 25,816,896 |
| 25 | Oct-03 | Est. | 17,823,754 | 2,611,401 | 20,906,900 | 19,867,302 | 24,322,450 |
| 26 | Nov-03 | Est. | 18,438,359 | 2,548,352 | 20,396,960 | 20,789,683 | 24,133,002 |
| 27 | Dec-03 | Est. | 20,122,286 | 2,600,192 | 22,323,003 | 22,184,408 | 25,714,362 |
| 28 | Total | | 246,858,894 | 31,795,727 | 264,841,432 | 279,457,758 | 317,816,931 |

(1) 2002 amounts escalated as follows:

| | (c) | (d) | (e) | (f) | (g) |
|---|---|---|---|---|---|
| Escalation Factors | 1.0220 | 1.0000 | 1.0136 | 1.0220 | 1.0220 |

**ISO NEW ENGLAND INC.**
**FERC DOCKET NO. ER03-_________**
**Annual Revenue Comparison at Present and Proposed Rates - Without SMD Amortization**
**Test Year 2003**

| | | | | | Annual Revenue Analysis | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | At 2002 Approved Rates | | | At 2003 Proposed Rates | | | | |
| Line | Tariff | 2003 Billing Units | | | Approved | | Calculated | Average | | Total | Change | |
| No. | Schedule | | Blocks | Total | Rates | | Revenue | Rates | | Revenue | $ | % |
| | (a) | | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) |
| | | | | | | | (c) x (d) | | | (c) x (g) | (i) - (f) | (j) / (f) |
| 1 | **Schedule 1** | | | | | | | | | | | |
| 2 | Network | Total | | 246,858,894 | $ 0.05019 | /kW-mo. | $ 12,389,848 | $ 0.05993 | /kW-mo. | $ 14,794,241 | $ 2,404,393 | 19.41% |
| 3 | Point-To-Point | | | | | | | | | | | |
| 4 | Firm | | | | | | | | | | | |
| 5 | Monthly | | | | $ 0.05019 | /kW-mo. | | $ 0.05993 | /kW-mo. | | | |
| 6 | Weekly | | | | $ 0.01158 | /kW-week | | $ 0.01383 | /kW-week | | | |
| 7 | Daily | | | | $ 0.00232 | /kW-day | | $ 0.00277 | /kW-day | | | |
| 8 | Non-Firm | | | | | | | | | | | |
| 9 | Monthly | | | | $ 0.05019 | /kW-mo. | | $ 0.05993 | /kW-mo. | | | |
| 10 | Weekly | | | | $ 0.01158 | /kW-week | | $ 0.01383 | /kW-week | | | |
| 11 | Daily | | | | $ 0.00165 | /kW-day | | $ 0.00198 | /kW-day | | | |
| 12 | Hourly | | | | $ 0.00007 | /kW-hour | | $ 0.00008 | /kW-hour | | | |
| 13 | | | | | | | | | | | | |
| 14 | | | | | | | | | | | | |
| 15 | **Schedule 2** | | | | | | | | | | | |
| 16 | TUs | | | | | | | | | | | |
| 17 | Block 1 | First | 12,500 | 10,540,897 | $ 0.18791 | /TU-hour | $ 1,980,740 | $ 0.25330 | /TU-hour | $ 2,670,007 | | |
| 18 | Block 2 | Next | 27,000 | 8,625,214 | $ 0.17082 | /TU-hour | $ 1,473,359 | $ 0.23027 | /TU-hour | $ 1,986,150 | | |
| 19 | Block 3 | Over | 39,500 | 12,629,616 | $ 0.15374 | /TU-hour | $ 1,941,677 | $ 0.20725 | /TU-hour | $ 2,617,428 | | |
| 20 | | Total | | 31,795,727 | | | $ 5,395,776 | | | $ 7,273,585 | | |
| 21 | | | | | | | | | | | | |
| 22 | Volumes | | | | | | | | | | | |
| 23 | Block 1 | First | 250,000 | 87,595,480 | $ 0.11126 | /mWh | $ 9,745,873 | $ 0.16862 | /mWh | $ 14,770,633 | | |
| 24 | Block 2 | Next | 1,250,000 | 129,812,256 | $ 0.10115 | /mWh | $ 13,130,510 | $ 0.15329 | /mWh | $ 19,899,420 | | |
| 25 | Block 3 | Over | 1,500,000 | 47,453,721 | $ 0.09103 | /mWh | $ 4,319,712 | $ 0.13796 | /mWh | $ 6,546,927 | | |
| 26 | | Total | | 264,861,457 | | | $ 27,196,095 | | | $ 41,216,980 | | |
| 27 | | | | | | | | | | | | |
| 28 | | Total | | | | | $ 32,591,871 | | | $ 48,490,565 | $ 15,898,694 | 48.78% |
| 29 | | | | | **80/20** | | | **100/0** | | | | |
| 30 | **Schedule 3** | | | | | | | | | | | |
| 31 | NCP Electrical Load | | | 279,457,758 | $ 0.04624 | /kW-mo. | $ 12,922,127 | $ 0.08367 | /kW-mo. | $ 23,381,513 | | |
| 32 | NCP Injections | | | 319,501,024 | $ 0.00991 | /kW-mo. | $ 3,166,255 | $ - | /kW-mo. | $ - | | |
| 33 | | Total | | 598,958,782 | | | $ 16,088,382 | | | $ 23,381,513 | $ 7,293,131 | 45.33% |
| 34 | | | | | | | | | | | | |
| 35 | Totals | | | | | | $ 61,070,101 | | | $ 86,666,319 | $ 25,596,218 | 41.91% |

**ISO NEW ENGLAND INC.**
**FERC DOCKET NO. ER03-_________**
**Rate Design Summary - Without SMD Amortiztion**
**Test Year 2003**

| Line No. | Tariff Schedule (a) | 2003 Target Revenue W/O SMD Amort. (b) | | 2003 Billing Units Before SMD Blocks (c) | | 2003 Billing Units Before SMD Total (d) | Proposed Rates W/O SMD Amortization (e) | (f) | Calculated Revenue (g) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | **Schedule 1** | **$ 14,794,241** | | Total | | 246,858,894 | $ 0.05993 | /kW-mo. | **$ 14,794,241** |
| 2 | Network | | | | | | | | |
| 3 | Point-To-Point | | | | | | | | |
| 4 | Firm | | | | | | $ 0.05993 | /kW-mo. | |
| 5 | Monthly | | | | | | $ 0.01383 | /kW-week | |
| 6 | Weekly | | | | | | $ 0.00277 | /kW-day | |
| 7 | Daily | | | | | | | | |
| 8 | Non-Firm | | | | | | $ 0.05993 | /kW-mo. | |
| 9 | Monthly | | | | | | $ 0.01383 | /kW-week | |
| 10 | Weekly | | | | | | $ 0.00198 | /kW-day | |
| 11 | Daily | | | | | | $ 0.00008 | /kW-hour | |
| 12 | Hourly | | | | | | | | |
| 13 | | | | | | | | | |
| 14 | | | | | | | | | |
| 15 | **Schedule 2** | **$ 48,490,565** | | | | | | | |
| 16 | TUs | $ 7,273,585 | 15.0% | | | | | | |
| 17 | Block 1 | | | First | 12,500 | 10,540,897 | $ 0.25330 | /TU-hour | $ 2,670,007 |
| 18 | Block 2 | | | Next | 27,000 | 8,625,214 | $ 0.23027 | /TU-hour | $ 1,986,150 |
| 19 | Block 3 | | | Over | 39,500 | 12,629,616 | $ 0.20725 | /TU-hour | $ 2,617,428 |
| 20 | | | | Total | | 31,795,727 | | | $ 7,273,585 |
| 21 | | | | | | | | | |
| 22 | Volumes | $ 41,216,980 | 85.0% | | | | | | |
| 23 | Block 1 | | | First | 250,000 | 87,595,480 | $ 0.16862 | /mWh | $ 14,770,633 |
| 24 | Block 2 | | | Next | 1,250,000 | 129,812,256 | $ 0.15329 | /mWh | $ 19,899,420 |
| 25 | Block 3 | | | Over | 1,500,000 | 47,453,721 | $ 0.13796 | /mWh | $ 6,546,927 |
| 26 | | | | Total | | 264,861,457 | | | $ 41,216,980 |
| 27 | | | | | | | | | **$ 48,490,565** |
| 28 | | | | Total | | | | | |
| 29 | | | | | | **100/0 NCP EL/NCP Injection Split** | | | |
| 30 | **Schedule 3** | **$ 23,381,513** | | | | | | | |
| 31 | NCP Electrical Load | $ 23,381,513 | 100.0% | | | 279,457,758 | $ 0.08367 | /kW-mo. | $ 23,381,513 |
| 32 | NCP Injections | $ - | 0.0% | | | 319,501,024 | $ - | /kW-mo. | $ - |
| 33 | | | | Total | | 598,958,782 | | | **$ 23,381,513** |
| 34 | | | | | | | | | **$ 86,666,319** |
| 35 | Totals | **$ 86,666,319** | | | | | | | |

**ISO NEW ENGLAND INC.**
**FERC DOCKET NO. ER03-________**
**January - June Cost Recovery - Without SMD Amortization**
**Test Year 2003**

| Line No. | Tariff Schedule (a) | 2003 Target Revenue W/O SMD Amort. (b) | | 2003 Billing Units (1) Blocks (c) | | 2003 Billing Units (1) Total (d) | Proposed Rates W/O SMD Amortization (e) | (f) | Calculated Revenue (g) (d) x (e) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | **Schedule 1** | **$ 14,794,241** | | Total | | 118,686,158 | $ 0.05993 | /kW-mo. | **$ 7,112,855** |
| 2 | Network | | | | | | | | |
| 3 | Point-To-Point | | | | | | | | |
| 4 | Firm | | | | | | | | |
| 5 | Monthly | | | | | | $ 0.05993 | /kW-mo. | |
| 6 | Weekly | | | | | | $ 0.01383 | /kW-week | |
| 7 | Daily | | | | | | $ 0.00277 | /kW-day | |
| 8 | Non-Firm | | | | | | | | |
| 9 | Monthly | | | | | | $ 0.05993 | /kW-mo. | |
| 10 | Weekly | | | | | | $ 0.01383 | /kW-week | |
| 11 | Daily | | | | | | $ 0.00198 | /kW-day | |
| 12 | Hourly | | | | | | $ 0.00008 | /kW-hour | |
| 13 | | | | | | | | | |
| 14 | | | | | | | | | |
| 15 | **Schedule 2** | **$ 48,490,565** | | | | | | | |
| 16 | TUs | $ 7,273,585 | 15.0% | First | 12,500 | 5,217,766 | $ 0.25330 | /TU-hour | $ 1,321,659 |
| 17 | Block 1 | | | Next | 27,000 | 4,274,451 | $ 0.23027 | /TU-hour | $ 984,289 |
| 18 | Block 2 | | | Over | 39,500 | 6,303,368 | $ 0.20725 | /TU-hour | $ 1,306,343 |
| 19 | Block 3 | | | Total | | 15,795,585 | | | $ 3,612,291 |
| 20 | | | | | | | | | |
| 21 | | | | | | | | | |
| 22 | Volumes | $ 41,216,980 | 85.0% | First | 250,000 | 42,055,790 | $ 0.16862 | /mWh | $ 7,091,583 |
| 23 | Block 1 | | | Next | 1,250,000 | 62,015,865 | $ 0.15329 | /mWh | $ 9,506,651 |
| 24 | Block 2 | | | Over | 1,500,000 | 24,149,059 | $ 0.13796 | /mWh | $ 3,331,712 |
| 25 | Block 3 | | | Total | | 128,220,714 | | | $ 19,929,946 |
| 26 | | | | | | | | | |
| 27 | | | | | | | | | **$ 23,542,236** |
| 28 | | | | Total | | | | | |
| 29 | | | | | | **100/0 NCP EL/NCP Injection Split** | | | |
| 30 | **Schedule 3** | **$ 23,381,513** | | | | | | | |
| 31 | NCP Electrical Load | $ 23,381,513 | 100.0% | | | 136,792,093 | $ 0.08367 | /kW-mo. | $ 11,445,043 |
| 32 | NCP Injections | $ - | 0.0% | | | 159,120,376 | $ - | /kW-mo. | $ - |
| 33 | | | | Total | | 295,912,469 | | | **$ 11,445,043** |
| 34 | | | | | | | | | **$ 42,100,135** |
| 35 | Totals | **$ 86,666,319** | | | | | | | |

(1) Test year Billing Units for January through June 2003 before implementation of SMD.

Exhibit 6 (GCP-5)
Schedule 2.0
Page 4 of 4

**ISO NEW ENGLAND INC.**
**FERC DOCKET NO. ER03-________**
**Rate Design Summary - Without SMD Amortization (July Through December 2003)**
**Test Year 2003**

| Line No. | Tariff Schedule (a) | 2003 Revenue Requirement For Mar - Dec 2003 (b) | | Billing Units (2) Blocks (c) | | Billing Units (2) Total (d) | Proposed Rates Without SMD Amortization (e) | (f) | Calculated Revenue (g) (d) x (e) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | **Schedule 1 (1)** | $ 7,681,386 | | Total | | 128,172,736 | $ 0.05993 | /kW-mo. | $ 7,681,386 |
| 2 | Network | | | | | | | | |
| 3 | Point-To-Point | | | | | | | | |
| 4 | Firm | | | | | | $ 0.05993 | /kW-mo. | |
| 5 | Monthly | | | | | | $ 0.01383 | /kW-week | |
| 6 | Weekly | | | | | | $ 0.00277 | /kW-day | |
| 7 | Daily | | | | | | | | |
| 8 | Non-Firm | | | | | | $ 0.05993 | /kW-mo. | |
| 9 | Monthly | | | | | | $ 0.01383 | /kW-week | |
| 10 | Weekly | | | | | | $ 0.00198 | /kW-day | |
| 11 | Daily | | | | | | $ 0.00008 | /kW-hour | |
| 12 | Hourly | | | | | | | | |
| 13 | | | | | | | | | |
| 14 | | | | | | | | | |
| 15 | **Schedule 2 (1)** | $ 39,041,430 | | | | | | | |
| 16 | TUs | $ 5,775,259 | 15.0% | | | | | | |
| 17 | Block 1 | | | First | 12,500 | 5,323,131 | $ 0.39955 | /TU-hour | $ 2,126,860 |
| 18 | Block 2 | | | Next | 27,000 | 4,350,763 | $ 0.36323 | /TU-hour | $ 1,580,318 |
| 19 | Block 3 | | | Over | 39,500 | 6,326,248 | $ 0.32690 | /TU-hour | $ 2,068,082 |
| 20 | | | | Total | | 16,000,142 | | | $ 5,775,259 |
| 21 | | | | | | | | | |
| 22 | Volumes | $ 33,266,171 | 85.0% | | | | | | |
| 23 | Block 1 | | | First | 250,000 | 45,539,690 | $ 0.26351 | /mWh | $ 12,000,383 |
| 24 | Block 2 | | | Next | 1,250,000 | 67,796,391 | $ 0.23956 | /mWh | $ 16,241,231 |
| 25 | Block 3 | | | Over | 1,500,000 | 23,304,662 | $ 0.21560 | /mWh | $ 5,024,556 |
| 26 | | | | Total | | 136,640,743 | | | $ 33,266,171 |
| 27 | | | | | | | | | $ 39,041,430 |
| 28 | | | | Total | | | | | |
| 29 | | | | | | **100/0 NCP EL/NCP Injection Split** | | | |
| 30 | **Schedule 3 (1)** | $ 13,502,369 | | | | | | | |
| 31 | NCP Electrical Load | $ 13,502,369 | 100.0% | | | 142,665,665 | $ 0.09464 | /kW-mo. | $ 13,502,369 |
| 32 | NCP Injections | $ - | 0.0% | | | 160,380,648 | $ - | /kW-mo. | $ - |
| 33 | | | | Total | | 303,046,313 | | | $ 13,502,369 |
| 34 | | | | | | | | | $ 60,225,185 |
| 35 | Totals | $ 60,225,185 | | | | | | | |

(1) Revenue Requirement for Jan. through June and July through December 2003 prior to SMD.

| | Total Rev Req. With SMD (Exh 6 (GCP-3)) | Amount Recovered Jan. - Jun. (Pg 2, Col. (g)) | Amount Recovered Jul. - Dec. (Col. (b) above) |
|---|---|---|---|
| Schedule 1 | $ 14,794,241 | $ 7,112,855 | $ 7,681,386 |
| Schedule 2 | | | |
| TUs @ 15% | $ 9,387,550 | $ 3,612,291 | $ 5,775,259 |
| VMs @ 85% | $ 53,196,117 | $ 19,929,946 | $ 33,266,171 |
| Total Sch 2 | $ 62,583,667 | $ 23,542,236 | $ 39,041,430 |
| Schedule 3 | $ 24,947,413 | $ 11,445,043 | $ 13,502,369 |
| Total | $ 102,325,320 | $ 42,100,135 | $ 60,225,185 |

(2) Test year Billing Units for July through December 2003 prior to implementation of SMD.

## ISO NEW ENGLAND INC.

**FERC DOCKET NO. ER03-__________**

**Annual Revenue Comparison at Present and Proposed Rates - With SMD Amortization Beginning March 1, 2003**

**Test Year 2003**

| Line No. | Tariff Schedule | 2003 Billing Units | | | Annual Revenue Analysis: 2002 Approved Rates | | | Annual Revenue Analysis: 2003 Proposed Rates | Change | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Blocks | Total | Approved Rates | | Calculated Revenue | Total Revenue (1) | $ | % |
| | (a) | | (b) | (c) | (d) | (e) | (f) (c) x (d) | (g) From Pages 2 and 3 | (h) (g) - (f) | (i) (h) / (f) |
| 1 | **Schedule 1** | | | | | | $ 12,389,848 | $ 14,794,241 | $ 2,404,393 | 19.41% |
| 2 | Network | Total | | 246,858,894 | $ 0.05019 | /kW-mo. | | | | |
| 3 | Point-To-Point | | | | | | | | | |
| 4 | Firm | | | | | | | | | |
| 5 | Monthly | | | | $ 0.05019 | /kW-mo. | | | | |
| 6 | Weekly | | | | $ 0.01158 | /kW-week | | | | |
| 7 | Daily | | | | $ 0.00232 | /kW-day | | | | |
| 8 | Non-Firm | | | | | | | | | |
| 9 | Monthly | | | | $ 0.05019 | /kW-mo. | | | | |
| 10 | Weekly | | | | $ 0.01158 | /kW-week | | | | |
| 11 | Daily | | | | $ 0.00165 | /kW-day | | | | |
| 12 | Hourly | | | | $ 0.00007 | /kW-hour | | | | |
| 13 | | | | | | | | | | |
| 14 | | | | | | | | | | |
| 15 | **Schedule 2** | | | | | | | | | |
| 16 | TUs | | | | | | | | | |
| 17 | Block 1 | First | 12,500 | 10,540,897 | $ 0.18791 | /TU-hour | $ 1,980,740 | $ 3,962,549 | | |
| 18 | Block 2 | Next | 27,000 | 8,625,214 | $ 0.17082 | /TU-hour | $ 1,473,359 | $ 2,939,857 | | |
| 19 | Block 3 | Over | 39,500 | 12,629,616 | $ 0.15374 | /TU-hour | $ 1,941,677 | $ 3,894,454 | | |
| 20 | | Total | | 31,795,727 | | | $ 5,395,776 | $ 10,796,860 | | |
| 21 | | | | | | | | | | |
| 22 | Volumes | | | | | | | | | |
| 23 | Block 1 | First | 250,000 | 87,595,480 | $ 0.11126 | /mWh | $ 9,745,873 | $ 21,895,124 | | |
| 24 | Block 2 | Next | 1,250,000 | 129,812,256 | $ 0.10115 | /mWh | $ 13,130,510 | $ 29,488,595 | | |
| 25 | Block 3 | Over | 1,500,000 | 47,453,721 | $ 0.09103 | /mWh | $ 4,319,712 | $ 9,798,486 | | |
| 26 | | Total | | 264,861,457 | | | $ 27,196,095 | $ 61,182,206 | | |
| 27 | | | | | | | $ 32,591,871 | $ 71,979,066 | $ 39,387,194 | 120.85% |
| 28 | | Total | | | | | | | | |
| 29 | | | | | 80/20 | | | | | |
| 30 | **Schedule 3** | | | | | | | | | |
| 31 | NCP Electrical Load | | | 279,457,758 | $ 0.04624 | /kW-mo. | $ 12,922,127 | $ 25,991,347 | | |
| 32 | NCP Injections | | | 319,501,024 | $ 0.00991 | /kW-mo. | $ 3,166,255 | $ - | | |
| 33 | | Total | | 598,958,782 | | | $ 16,088,382 | $ 25,991,347 | $ 9,902,965 | 61.55% |
| 34 | | | | | | | $ 61,070,101 | $ 112,764,653 | $ 51,694,552 | 84.65% |
| 35 | Totals | | | | | | | | | |

(1) From Exhibit (GCP-5), Schedule 3.0, Pages 2 and 3, the sum of Calculated Revenue in Column (g).

## ISO NEW ENGLAND INC.
**FERC DOCKET NO. ER03-________**
**January - February Cost Recovery - Without SMD Amortization**
**Test Year 2003**

| Line No. | Tariff Schedule (a) | 2003 Target Revenue W/O SMD Amort. (b) | | | 2003 Billing Units (1) Blocks (c) | 2003 Billing Units (1) Total (d) | Proposed Rates W/O SMD Amortization (e) | Proposed Rates W/O SMD Amortization (f) | Calculated Revenue (g) (d) x (e) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | **Schedule 1** | **$ 14,794,241** | | | | | | | |
| 2 | Network | | | Total | | 39,136,846 | $ 0.05993 | /kW-mo. | **$ 2,345,469** |
| 3 | Point-To-Point | | | | | | | | |
| 4 | Firm | | | | | | | | |
| 5 | Monthly | | | | | | $ 0.05993 | /kW-mo. | |
| 6 | Weekly | | | | | | $ 0.01383 | /kW-week | |
| 7 | Daily | | | | | | $ 0.00277 | /kW-day | |
| 8 | Non-Firm | | | | | | | | |
| 9 | Monthly | | | | | | $ 0.05993 | /kW-mo. | |
| 10 | Weekly | | | | | | $ 0.01383 | /kW-week | |
| 11 | Daily | | | | | | $ 0.00198 | /kW-day | |
| 12 | Hourly | | | | | | $ 0.00008 | /kW-hour | |
| 13 | | | | | | | | | |
| 14 | | | | | | | | | |
| 15 | **Schedule 2** | **$ 48,490,565** | | | | | | | |
| 16 | TUs | $ 7,273,585 | 15.0% | | | | | | |
| 17 | Block 1 | | | First | 12,500 | 1,759,385 | $ 0.25330 | /TU-hour | $ 445,652 |
| 18 | Block 2 | | | Next | 27,000 | 1,497,793 | $ 0.23027 | /TU-hour | $ 344,901 |
| 19 | Block 3 | | | Over | 39,500 | 2,025,496 | $ 0.20725 | /TU-hour | $ 419,774 |
| 20 | | | | Total | | 5,282,674 | | | $ 1,210,327 |
| 21 | | | | | | | | | |
| 22 | Volumes | $ 41,216,980 | 85.0% | | | | | | |
| 23 | Block 1 | | | First | 250,000 | 14,650,789 | $ 0.16862 | /mWh | $ 2,470,463 |
| 24 | Block 2 | | | Next | 1,250,000 | 21,802,445 | $ 0.15329 | /mWh | $ 3,342,181 |
| 25 | Block 3 | | | Over | 1,500,000 | 6,991,796 | $ 0.13796 | /mWh | $ 964,619 |
| 26 | | | | Total | | 43,445,031 | | | $ 6,777,264 |
| 27 | | | | | | | | | **$ 7,987,590** |
| 28 | | | | Total | | | | | |
| 29 | | | | | | | | | |
| 30 | **Schedule 3** | **$ 23,381,513** | | | | **100/0 NCP EL/NCP Injection Split** | | | |
| 31 | NCP Electrical Load | $ 23,381,513 | 100.0% | | | 45,042,656 | $ 0.08367 | /kW-mo. | $ 3,768,603 |
| 32 | NCP Injections | $ - | 0.0% | | | 53,384,738 | $ - | /kW-mo. | $ - |
| 33 | | | | Total | | 98,427,394 | | | **$ 3,768,603** |
| 34 | | | | | | | | | **$ 14,101,663** |
| 35 | Totals | **$ 86,666,319** | | | | | | | |

(1) Test year Billing Units for January and February 2003 before implementation of SMD.

## ISO NEW ENGLAND INC.
**FERC DOCKET NO. ER03-________**
**Rate Design Summary - With SMD Amortization (March Through December 2003)**
**Test Year 2003**

| Line No. | Tariff Schedule (a) | 2003 Revenue Requirement For Mar - Dec 2003 (b) | | Billing Units (2) Blocks (c) | Billing Units (2) Total (d) | Proposed Rates With SMD Amortization (e) | (f) | Calculated Revenue (g) (d) x (e) |
|---|---|---|---|---|---|---|---|---|
| 1 | **Schedule 1 (1)** | **$ 12,448,772** | Total | | 207,722,048 | $ 0.05993 | /kW-mo. | **$ 12,448,772** |
| 2 | Network | | | | | | | |
| 3 | Point-To-Point | | | | | | | |
| 4 | Firm | | | | | | | |
| 5 | Monthly | | | | | $ 0.05993 | /kW-mo. | |
| 6 | Weekly | | | | | $ 0.01383 | /kW-week | |
| 7 | Daily | | | | | $ 0.00277 | /kW-day | |
| 8 | Non-Firm | | | | | | | |
| 9 | Monthly | | | | | $ 0.05993 | /kW-mo. | |
| 10 | Weekly | | | | | $ 0.01383 | /kW-week | |
| 11 | Daily | | | | | $ 0.00198 | /kW-day | |
| 12 | Hourly | | | | | $ 0.00008 | /kW-hour | |
| 13 | | | | | | | | |
| 14 | | | | | | | | |
| 15 | **Schedule 2 (1)** | **$ 63,991,475** | | | | | | |
| 16 | TUs | $ 9,586,533 | 15.0% | | | | | |
| 17 | Block 1 | | First | 12,500 | 8,781,512 | $ 0.40049 | /TU-hour | $ 3,516,897 |
| 18 | Block 2 | | Next | 27,000 | 7,127,421 | $ 0.36408 | /TU-hour | $ 2,594,956 |
| 19 | Block 3 | | Over | 39,500 | 10,604,120 | $ 0.32767 | /TU-hour | $ 3,474,680 |
| 20 | | | Total | | 26,513,053 | | | $ 9,586,533 |
| 21 | | | | | | | | |
| 22 | Volumes | $ 54,404,942 | 85.0% | | | | | |
| 23 | Block 1 | | First | 250,000 | 72,912,427 | $ 0.26641 | /mWh | $ 19,424,660 |
| 24 | Block 2 | | Next | 1,250,000 | 107,957,533 | $ 0.24219 | /mWh | $ 26,146,415 |
| 25 | Block 3 | | Over | 1,500,000 | 40,527,438 | $ 0.21797 | /mWh | $ 8,833,867 |
| 26 | | | Total | | 221,397,398 | | | $ 54,404,942 |
| 27 | | | | | | | | |
| 28 | | | Total | | | | | **$ 63,991,475** |
| 29 | | | | | **100/0 NCP EL/NCP Injection Split** | | | |
| 30 | **Schedule 3 (1)** | **$ 22,222,743** | | | | | | |
| 31 | NCP Electrical Load | $ 22,222,743 | 100.0% | | 234,415,102 | $ 0.09480 | /kW-mo. | $ 22,222,743 |
| 32 | NCP Injections | $ - | 0.0% | | 264,807,070 | $ - | /kW-mo. | $ - |
| 33 | | | Total | | 499,222,171 | | | **$ 22,222,743** |
| 34 | | | | | | | | |
| 35 | Totals | **$ 98,662,990** | | | | | | **$ 98,662,990** |

(1) Revenue Requirement for March through December 2003 After SMD
Total Annual Revenue Requirement With SMD (see Exhibit (GCP-3)).
Amount Recovered in January and February 2003 (see Pg 2, Column (g)).

| | Total Rev Req. With SMD (Exh 6 (GCP-3)) | Amount Recovered Jan. - Feb. (Pg 2, Col. (g)) | Amount Recovered Mar. - Dec. (Col. (b) above) |
|---|---|---|---|
| Schedule 1 | $ 14,794,241 | $ 2,345,469 | $ 12,448,772 |
| Schedule 2 | | | |
| TUs @ 15% | $ 10,796,860 | $ 1,210,327 | $ 9,586,533 |
| VMs @ 85% | $ 61,182,206 | $ 6,777,264 | $ 54,404,942 |
| Total Sch 2 | $ 71,979,066 | $ 7,987,590 | $ 63,991,475 |
| Schedule 3 | $ 25,991,347 | $ 3,768,603 | $ 22,222,743 |
| Total | $ 112,764,653 | $ 14,101,663 | $ 98,662,990 |

(2) Test year Billing Units for March through December 2003 after implementation of SMD.

Exhibit 6 (GCP-5)
Schedule 4.0
Page 1 of 2

## ISO New England Inc.
### FERC DOCKET NO. ER03-_________
### Comparison of Schedule 2 Revenue From Transactional Units (TU) For 2002

Comparison Of Monthly TU Data For CY 2002

| Line No. | Month | Source For TY 2001 | TY 2002 TUs Per 2002 ISO Tariff: Total TUs | First 12,500 | Next 27,000 | Over 39,500 | Source For CY 2001 | CY 2002 TUs Per 2002 ISO Tariff Filing: Total TUs | First 12,500 | Next 27,000 | Over 39,500 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) |
| | | | | | | Billing Determinants - TUs (1) | | | | | |
| 1 | Jan-02 | Jan-01 | 2,271,525 | 818,109 | 593,145 | 860,271 | Actual | 2,728,506 | 896,965 | 770,273 | 1,061,268 |
| 2 | Feb-02 | Feb-01 | 2,201,032 | 795,634 | 572,108 | 833,290 | Actual | 2,554,168 | 862,420 | 727,520 | 964,228 |
| 3 | Mar-02 | Mar-01 | 2,455,718 | 837,922 | 638,180 | 979,616 | Actual | 2,596,543 | 855,855 | 697,240 | 1,043,448 |
| 4 | Apr-02 | Apr-01 | 2,319,266 | 837,479 | 611,000 | 870,787 | Actual | 2,521,559 | 841,735 | 663,675 | 1,016,149 |
| 5 | May-02 | May-01 | 2,426,917 | 854,319 | 636,067 | 936,531 | Actual | 2,723,018 | 880,445 | 719,772 | 1,122,801 |
| 6 | Jun-02 | Jun-01 | 2,528,413 | 865,634 | 635,145 | 1,027,634 | Actual | 2,671,791 | 880,346 | 695,971 | 1,095,474 |
| 7 | Jul-02 | Jul-01 | 2,694,111 | 896,537 | 646,807 | 1,150,767 | Actual | 2,922,489 | 920,959 | 803,835 | 1,197,695 |
| 8 | Aug-02 | Aug-01 | 2,835,871 | 902,411 | 706,081 | 1,227,379 | Actual | 2,847,078 | 924,346 | 769,751 | 1,152,981 |
| 9 | Sep-02 | Sep-00 | 2,234,142 | 806,888 | 582,509 | 844,745 | Sep-01 | 2,470,630 | 862,729 | 655,898 | 952,003 |
| 10 | Oct-02 | Oct-00 | 2,360,183 | 820,644 | 587,382 | 952,157 | Oct-01 | 2,611,401 | 861,471 | 716,521 | 1,033,409 |
| 11 | Nov-02 | Nov-00 | 2,241,457 | 812,348 | 582,180 | 846,929 | Nov-01 | 2,548,352 | 861,136 | 696,935 | 990,281 |
| 12 | Dec-02 | Dec-00 | 2,320,540 | 834,386 | 594,159 | 891,995 | Dec-01 | 2,600,192 | 892,490 | 707,823 | 999,879 |
| 13 | Totals | | 28,889,175 | 10,082,311 | 7,384,763 | 11,422,101 | | 31,795,727 | 10,540,897 | 8,625,214 | 12,629,616 |
| 14 | | | | | | | | | | | |
| 15 | **Totals** | **Jan - Dec** | **28,889,175** | | | | | **31,795,727** | | | |
| 16 | | | | | | | | | | | |
| 17 | 2002 Approved Rates for Schedule 2 | | | $ 0.18791 | $ 0.17082 | $ 0.15374 | | | $ 0.18791 | $ 0.17082 | $ 0.15374 |
| 18 | | | | | | | | | | | |
| 19 | | | | | | Initial Estimate of Revenue From TUs (1) | | | | | |
| 20 | Jan-02 | TY Est | $ 387,310 | $ 153,731 | $ 101,321 | $ 132,258 | Actual | $ 463,286 | $ 168,549 | $ 131,578 | $ 163,159 |
| 21 | Feb-02 | TY Est | 375,345 | 149,508 | 97,727 | 128,110 | Actual | 434,573 | 162,057 | 124,275 | 148,240 |
| 22 | Mar-02 | TY Est | 417,074 | 157,454 | 109,014 | 150,606 | Actual | 440,346 | 160,824 | 119,103 | 160,420 |
| 23 | Apr-02 | TY Est | 395,616 | 157,371 | 104,371 | 133,875 | Actual | 427,762 | 158,170 | 113,369 | 156,223 |
| 24 | May-02 | TY Est | 413,170 | 160,535 | 108,653 | 143,982 | Actual | 461,015 | 165,444 | 122,951 | 172,619 |
| 25 | Jun-02 | TY Est | 429,145 | 162,661 | 108,495 | 157,988 | Actual | 452,730 | 165,426 | 118,886 | 168,418 |
| 26 | Jul-02 | TY Est | 455,875 | 168,468 | 110,488 | 176,919 | Actual | 494,502 | 173,057 | 137,311 | 184,134 |
| 27 | Aug-02 | TY Est | 478,882 | 169,572 | 120,613 | 188,697 | Actual | 482,442 | 173,694 | 131,489 | 177,259 |
| 28 | Sep-02 | TY Est | 380,998 | 151,622 | 99,504 | 129,871 | Estimate | 420,517 | 162,115 | 112,040 | 146,361 |
| 29 | Oct-02 | TY Est | 400,928 | 154,207 | 100,337 | 146,385 | Estimate | 443,151 | 161,879 | 122,396 | 158,876 |
| 30 | Nov-02 | TY Est | 382,303 | 152,648 | 99,448 | 130,207 | Estimate | 433,112 | 161,816 | 119,050 | 152,246 |
| 31 | Dec-02 | TY Est | 395,419 | 156,789 | 101,494 | 137,135 | Estimate | 442,340 | 167,708 | 120,910 | 153,721 |
| 32 | Totals | | $ 4,912,066 | $ 1,894,567 | $ 1,261,465 | $ 1,756,034 | | $ 5,395,776 | $ 1,980,740 | $ 1,473,359 | $ 1,941,677 |
| 33 | | | | | | | | | | | |
| 34 | **Totals** | **Jan - Dec** | **$ 4,912,066** | | | | | **$ 5,395,776** | | | |
| 35 | | | | | | | | | | | |
| 36 | **Initial True-Up Estimate - Over (Under) Recovery For Jan - Dec** | | | | | | | **$ 483,710** | | | |

**Exhibit 6 (GCP-5)**
**Schedule 4.0**
**Page 2 of 2**

## ISO New England Inc.
### FERC DOCKET NO. ER03-________
### Comparison of Schedule 2 Revenue From Transactional Units (TU) For 2001

Comparison Of Monthly TU Data For CY 2001

| Line No. | Month | Source For TY 2001 | TY 2001 TUs Per 2001 ISO Tariff: Total TUs | First 12,500 | Next 27,000 | Over 39,500 | Source For CY 2001 | CY 2001 TUs Per 2002 ISO Tariff Filing: Total TUs | First 12,500 | Next 27,000 | Over 39,500 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) |
| | | | | | | Billing Determinants - TUs (1) | | | | | |
| 1 | Jan-01 | May-99 | 1,685,649 | 617,490 | 386,205 | 681,953 | Actual | 2,252,917 | 805,601 | 587,045 | 860,271 |
| 2 | Feb-01 | Jun-99 | 1,745,693 | 645,431 | 413,963 | 686,299 | Actual | 2,184,198 | 783,100 | 567,808 | 833,290 |
| 3 | Mar-01 | Jul-99 | 1,829,336 | 668,233 | 423,203 | 737,899 | Actual | 2,437,076 | 825,380 | 632,080 | 979,616 |
| 4 | Apr-01 | Aug-99 | 1,905,916 | 713,891 | 437,183 | 754,842 | Actual | 2,301,275 | 824,963 | 605,525 | 870,787 |
| 5 | May-01 | Sep-99 | 1,859,527 | 724,427 | 416,031 | 719,069 | Actual | 2,408,317 | 841,819 | 629,967 | 936,531 |
| 6 | Jun-01 | Oct-99 | 1,984,429 | 766,770 | 441,769 | 775,890 | Actual | 2,510,337 | 853,058 | 629,645 | 1,027,634 |
| 7 | Jul-01 | Nov-99 | 1,865,469 | 760,742 | 414,249 | 690,479 | Actual | 2,674,767 | 883,293 | 640,707 | 1,150,767 |
| 8 | Aug-01 | Dec-99 | 2,049,018 | 806,979 | 477,335 | 764,704 | Actual | 2,816,527 | 889,167 | 699,981 | 1,227,379 |
| 9 | Sep-01 | Jan-00 | 2,216,357 | 833,510 | 564,815 | 818,032 | Actual | 2,470,630 | 862,729 | 655,898 | 952,003 |
| 10 | Oct-01 | Feb-00 | 2,250,877 | 846,621 | 591,468 | 812,788 | Actual | 2,611,401 | 861,471 | 716,521 | 1,033,409 |
| 11 | Nov-01 | Mar-00 | 2,392,895 | 911,826 | 597,678 | 883,392 | Actual | 2,548,352 | 861,136 | 696,935 | 990,281 |
| 12 | Dec-01 | Apr-00 | 2,168,655 | 861,132 | 534,871 | 772,652 | Actual | 2,600,192 | 892,490 | 707,823 | 999,879 |
| 13 | Totals | | 23,953,821 | 9,157,050 | 5,698,770 | 9,098,001 | | 29,815,989 | 10,184,207 | 7,769,935 | 11,861,847 |
| 14 | | | | | | | | | | | |
| 15 | **Totals** | **Jul - Dec** | **12,943,272** | | | | | **15,721,869** | | | |
| 16 | | | | | | | | | | | |
| 17 | 2001 Settlement Rates for Schedule 2 | | | $ 0.22472 | $ 0.20429 | $ 0.18386 | | | $ 0.22472 | $ 0.20429 | $ 0.18386 |
| 18 | | | | | | | | | | | |
| 19 | | | | | | Initial Estimate of Revenue From TUs (1) | | | | | |
| 20 | Jan-01 | | $ 343,046 | $ 138,762 | $ 78,898 | $ 125,385 | | $ 459,134 | $ 181,035 | $ 119,928 | $ 158,171 |
| 21 | Feb-01 | | 355,794 | 145,041 | 84,569 | 126,184 | | 445,186 | 175,978 | 115,998 | 153,210 |
| 22 | Mar-01 | | 372,293 | 150,165 | 86,457 | 135,672 | | 494,722 | 185,479 | 129,128 | 180,114 |
| 23 | Apr-01 | | 388,525 | 160,425 | 89,313 | 138,787 | | 469,193 | 185,386 | 123,703 | 160,104 |
| 24 | May-01 | | 379,994 | 162,793 | 84,991 | 132,209 | | 490,062 | 189,174 | 128,697 | 172,192 |
| 25 | Jun-01 | | 405,214 | 172,308 | 90,249 | 142,657 | | 509,273 | 191,699 | 128,631 | 188,943 |
| 26 | Jul-01 | TY Est | 382,534 | 170,954 | 84,627 | 126,953 | Actual | 540,966 | 198,494 | 130,891 | 211,582 |
| 27 | Aug-01 | TY Est | 419,459 | 181,344 | 97,515 | 140,600 | Actual | 568,481 | 199,814 | 143,000 | 225,668 |
| 28 | Sep-01 | TY Est | 453,098 | 187,306 | 115,387 | 150,405 | Actual | 502,903 | 193,872 | 133,994 | 175,037 |
| 29 | Oct-01 | TY Est | 460,525 | 190,253 | 120,832 | 149,441 | Actual | 529,973 | 193,590 | 146,379 | 190,004 |
| 30 | Nov-01 | TY Est | 489,428 | 204,905 | 122,100 | 162,422 | Actual | 517,967 | 193,514 | 142,377 | 182,075 |
| 31 | Dec-01 | TY Est | 444,844 | 193,514 | 109,269 | 142,061 | Actual | 529,002 | 200,560 | 144,602 | 183,840 |
| 32 | Totals | | $ 4,894,754 | $ 2,057,772 | $ 1,164,207 | $ 1,672,775 | | $ 6,056,863 | $ 2,288,595 | $ 1,587,327 | $ 2,180,941 |
| 33 | | | | | | | | | | | |
| 34 | **Totals** | **Jul - Dec** | **$ 2,649,888** | | | | | **$ 3,189,293** | | | |
| 35 | | | | | | | | | | | |
| 36 | **Initial True-Up Estimate - Over (Under) Recovery For Jul - Dec** | | | | | | | **$ 539,405** | | | |

(1) 2001 Settlement Rates became effective on July 1, 2001.

# BILLING DETERMINANTS UNDER SMD FOR THE ISO TARIFF

**Prepared for:**

**ISO NEW ENGLAND INC.**

**September 13, 2002**

## A. Introduction

ISO New England recovers its operating and maintenance costs through a self-funding tariff by which its costs of providing services are allocated to three separate Schedules. Each Schedule is billed separately using various volumetric and/or transaction units. The rate design for the ISO Tariff reflected in the Settlement Agreement approved in 2001 is in effect through December 31, 2003.

Implementation of the Standard Market Design (SMD) in New England is scheduled to occur in the first quarter of 2003. Under SMD, some of the cost recovery billing determinants for the ISO Tariff cease to exist in their current form. In order to preserve the settlement rate design, ISO New England has mapped equivalent billing determinants to be used in the ISO Tariff once SMD is implemented in the cases where the current billing determinants for Schedules 2 and 3 will no longer exist in their current form. Real-Time billing determinants are used under SMD in order to maintain consistency with the current billing determinants, which are also Real-Time values. With its tariff revisions filed on November 1, 2002 for the 2003 calendar year, the ISO proposes to include, in addition to "pre-SMD" rates effective on January 1, 2003, rates reflecting these mapped billing determinants effective on the SMD Effective Date.

The subsequent sections and Attachment 1 describe for each Schedule of the ISO Tariff the current billing determinant, the mapping of the equivalent billing determinant under SMD, why such mapping is appropriate and the impact, if any, of such mapping.

For the ISO Tariff, even though some billing determinants no longer exist in their current form under SMD, the current billing determinants can be mapped to billing determinants available under the SMD with minimal impact on the Customers. With the proposed billing determinant mapping, recognizing the assumptions detailed below, the estimated total net cost shift between sectors (based on 2002 test year revenue requirements, rates and transaction/load patterns) is $14,300, compared with the 2002 ISO Tariff revenue requirement of $61.2 million. Therefore, the SMD implementation should have minimal impact on the Customers in regard to the ISO Tariff charges.

## B. Schedule 1 – Scheduling, System Control and Dispatch Service

Schedule 1 applies to each Customer that is obligated to pay the Regional Network Service rate and to each Customer that is a Transmission Customer receiving Point-to-Point Transmission Service. Under the current market, for Customers obligated to pay the Regional Network Service rate, the billing determinant is Network Load for the month; and for Customers receiving Point-to-Point Transmission Service, the billing determinant is Reserved Capacity for each transaction scheduled to occur during the month as Point-to-Point Transmission Service. Under SMD, the billing determinants for Schedule 1 will not change.

## C. Schedule 2 – Energy Administration Service (EAS)

Schedule 2 applies to each Participant that has an account for Energy. Each such Participant is an EAS Customer and pays an amount based on Energy Transaction Units (TUs) and an amount based on Volumetric Measures.

1. Energy Transaction Units

Energy TUs are the sum for the month for an EAS Customer of Bilateral Contract Block-Hours, Generator Block-Hours and Energy Non-Zero Spot Market Settlements, provided, however, that Bilateral Contract Block-Hours do not include Life of Unit Contracts, Vermont Yankee Multiple Owner Contracts or Pool Planned Units (the "Energy TU Exclusion").

a. Bilateral Contract Block-Hours

Bilateral Contract Block-Hours are assigned to the EAS Customers that submit Bilateral Contracts for Energy. The Bilateral Contract Block-Hours are associated with Bilateral Contracts for Energy where Bilateral Contracts are defined as:

i) Load Asset Contracts,
ii) Unit Contracts,
iii) Obligation System Contracts,
iv) Other System Contracts and
v) External Contracts.

Under SMD, Bilateral Contract Block-Hours will still be assigned to EAS Customers that submit Bilateral Contracts for Energy. However, the current market contract types are replaced by:

i) Internal Bilateral for Load,
ii) Internal Bilateral for Market associated with Energy and
iii) External Transactions.

Under SMD, the Bilateral Contract Block-Hours in Real-Time associated with these new contract types will be used as the billing determinant in order to maintain consistency with the current billing determinants which are also Real-Time. There is no way to forecast the change in volume of Bilateral Contracts under SMD and its impact on Energy TUs. However, the same EAS Customers will still be responsible for this charge.

b. Energy TU Exclusion

The Energy TU Exclusion is associated with Unit Contracts. Under SMD, Unit Contracts have been eliminated; however, the effect of a Unit Contract which establishes entitlement in a unit may be accomplished through the asset registration process by designating the percent ownership(s) of a unit. Under SMD, this attribute may be changed on the first of the month and remains in effect for the calendar month. Since

Unit Contracts no longer exist under SMD, the Energy TU Exclusion is no longer required. That is, an EAS Customer should not receive a "credit" for an Energy TU that such EAS Customer is no longer being charged for.

c. Generator Block-Hours

Generator Block-Hours are assigned to the Lead Participants for each Generator or Dispatchable Load and are associated with quantities of Energy with related prices contained in the Bids. Under SMD, Generator Block-Hours will still be assigned to the Lead Participants. However, under the current market, the Lead Participant submits a Bid with bid blocks for each hour of the day. Under SMD, the Lead Participant submits daily bid blocks. Therefore, the number of daily bid blocks in the price based Real-Time schedule will be multiplied by 24 hours per day in order to maintain consistency with the current billing determinants.

d. Energy Non-Zero Spot Market Settlements

Under the current market, Participants with Energy Non-Zero Spot Market Settlements are assigned Energy TUs for those hours for which the Participant has a positive or negative Adjusted Net Interchange in the Energy Market. Under SMD, Adjusted Net Interchange no longer exists. However, its equivalent will be calculated by summing the Real-Time Locational Adjusted Net Interchange over all Locations to determine if the Participant has a positive or negative Real-Time "System" Adjusted Net Interchange in the Energy Market. Under SMD the billing determinants for this portion of Schedule 2 will not change.

2. <u>Volumetric Measures</u>

The Volumetric Measures component for an EAS Customer is equal to the sum of its Electrical Load for the month and its Injections for the month; provided, however, that Injections associated with Energy imported into the NEPOOL Control Area by Bangor Hydro-Electric Company across the New Brunswick tie is excluded up to 300 MW for rate calculation and billing purposes (the "BHEC Exclusion").

a. Electrical Load

Electrical Load for the month is one of the two current billing determinants for the Volumetric Measure component of Schedule 2. Electrical Load no longer exists under SMD. Real-Time Load Obligation for the month summed over all Locations is the approximate equivalent of Electrical Load. However, Electrical Load includes PTF losses, including losses associated with NEPOOL Through or Out Transmission Service, and non-PTF tie losses. Real-Time Load Obligation does not include these losses.

The definition of Real-Time Load Obligation from Market Rule 1 is:

- Each Participant shall have for each hour a Real-Time Load Obligation for energy at each Location equal to the MWhs of load, where such MWhs of load shall include External Transaction sales and shall have a negative value, at that Location, adjusted for any applicable internal bilateral transactions which transfer Real-Time load obligations.

In Electrical Load, PTF losses, with the exception of losses associated with Through or Out service, are allocated to Participants pro-rata based on load. Therefore, for the PTF losses, there is no cost shift between Participants in using Electrical Load as a billing determinant versus using Real-Time Load Obligation. However, in Electrical Load, non-PTF tie losses and PTF losses associated with Through or Out service are allocated to the Participants that are a party to the transactions using the non-PTF ties and Through or Out service on a transactional basis. Real-Time Load Obligation does not reflect this transaction specific allocation, thereby shifting these costs pro-rata over all Participants with Real-Time Load Obligation.

b. Injections

Injections for the month is the other current billing determinant for the Volumetric Measure component of Schedule 2. Under SMD, the billing determinant will be Real-Time Generation Obligation. Real-Time Generation Obligation equals the summation over all Nodes of the Participant's Ownership Share at each Node multiplied by the revenue metered generation in Real-Time at each Node plus the summation over all External Nodes of Participant's Supply Offers delivered at such Nodes over all hours of the month. This mapping is equivalent; except that under SMD, entitlement which is modeled by Ownership Share is restricted to calendar month increments. Whereas, under the current market, entitlement which is modeled by a Unit Contract may be of lesser duration than a month.

c. BHEC Exclusion

Under the current market, Injections associated with energy imported into the NEPOOL Control Area by Bangor Hydro-Electric Company across the New Brunswick Ties are excluded (up to 300 MW) for billing and rate calculation purposes from the Volumetric Measure component of Schedule 2. Under SMD, such Supply Offers submitted by Bangor Hydro-Electric Company and delivered at the New Brunswick External Node(s) over all hours of the month, up to 300 MW for any given hour of the month, will continue to be excluded. Under SMD, the BHEC Exclusion from the Volumetric Measure component of Schedule 2 will not change.

## D. <u>Schedule 2 – Estimated Cost Shift</u>

The following assumptions were used to estimate the cost shift for Schedule 2:

- loss data was based on non-PTF tie and Through or Out service transactions for test year 2002;
- all of the non-PTF tie and Through or Out losses were modeled in the first Volumetric Measure block; and

- entitlements at the first of each month were maintained throughout the calendar month to model Ownership Share.

The worst case estimate of the cost shift attributed to non-PTF tie and Through or Out service losses is to assume that all of these losses fall in the first Volumetric Measure block which has the highest rate associated with it.

The assumption of modeling Ownership Share as the entitlements set at the beginning of each month and maintained for the calendar month is also substantiated by the minimal number of Unit Contracts of less than one month duration and the megawatthours associated with such contracts. During the period from September 2000 through August 2001, there were 69 contracts of less than one month duration accounting for 0.26% of the total Schedule 2 megawatthour Injections.

Using the above assumptions to estimate the revenue collected from each sector for Schedule 2, the net cost shift between sectors for 2002 using the proposed billing determinants under SMD would be approximately $11,500. There will be negative and positive cost shifts between Participants within sectors. The revenue requirement for Schedule 2 for the 2002 test year is $32.7 million. Recognizing that this future impact is being estimated based on the above assumptions, the SMD implementation of using Real-Time Load Obligation and Real-Time Generation Obligation as the billing determinants should have minimal impact on the Participants in regard to Schedule 2.

## E. Schedule 3 – Reliability Administration Service

Schedule 3 applies to each Customer that is a Participant based on the Participant's Non-Coincident Peak (NCP) Electrical Load and NCP Injections. Schedule 3 also applies to each Transmission Customer taking Point-to-Point Transmission Service that is not a Participant.

### 1. Non-Coincident Peak (NCP) Electrical Load

NCP Electrical Load for the month is one of the two current billing determinants for Schedule 3. NCP Electrical Load no longer exists under SMD. Real-Time NCP Load Obligation for the month summed over all Locations is the approximate equivalent of NCP Electrical Load. However, NCP Electrical Load includes PTF losses, including losses associated with Through or Out service, and non-PTF tie losses. Real-Time NCP Load Obligation does not include these losses.

In NCP Electrical Load, PTF losses, with the exception of losses associated with Through or Out service, are allocated to Participants pro-rata based on load. Therefore, for the PTF losses, there is no cost shift between Participants in using NCP Electrical Load as a billing determinant versus using Real-Time NCP Load Obligation. However, in NCP Electrical Load, non-PTF tie losses and PTF losses associated with Through or Out service are allocated to the Participants that are a party to the transactions using the non-PTF ties and Through or Out service on a transactional basis. Real-Time NCP Load

Obligation does not reflect this transaction specific allocation, thereby shifting these costs pro-rata over all Participants with Real-Time NCP Load Obligation.

2. Non-Coincident Peak (NCP) Injections

   Injections for the month is the other current billing determinant for the Volumetric Measure component of Schedule 3. The Injection component of the Schedule 3 charge is only effective through the end of December 31, 2002. In 2003, 100% of the Schedule 3 revenue requirement will be collected based only on load, not injections. Accordingly, no mapping of this billing determinant is required.

3. Non-Participant Transmission Customers taking Point-to-Point Transmission Service

   This component of Schedule 3 applies to each Customer that is a non-Participant Transmission Customer receiving Point-to-Point Transmission Service. Under the current market, for Customers receiving Point-to-Point Transmission Service the billing determinant is the duration of the each transmission reservation during the month reserved as Point-to-Point Transmission Service. Under SMD the billing determinants for this component of Schedule 3 will not change.

## F. Schedule 3 – Estimated Cost Shift

Following are the assumptions used to estimate the cost shift for Schedule 3:

- loss data was based on non-PTF tie and Through or Out service transactions for test year 2002; and
- all of the non-PTF tie and Through or Out losses were modeled in the first Volumetric Measure block.

The worst case estimate of the cost shift attributed to non-PTF tie and Through or Out service losses is to assume that all of these losses fall in the first Volumetric Measure block of the 2002 ISO Tariff, which has the highest rate associated with it.

For purposes of this estimated cost shift, since the Schedule 3 revenue requirement will be collected 100% from load in 2003, the estimated cost shift below only includes the impact due to the load component of Schedule 3.

Using the above assumptions to estimate the revenue collected from each sector for Schedule 3, the net cost shift between sectors for 2002 using the proposed billing determinants under SMD would be approximately $12,700. There will be negative and positive cost shifts between Participants within sectors. The revenue requirement for Schedule 3 for the 2002 test year is $16.0 million. Recognizing that this future impact is being estimated based on the above assumptions, the SMD implementation of Real-Time NCP Load Obligation as the billing determinant should have minimal impact on the Participants in regard to Schedule 3.

## G. Conclusion

For the ISO Tariff, even though some billing determinants no longer exist under SMD, the current billing determinants can be mapped to billing determinants available under the SMD with minimal impact on the Customers. Recognizing the assumptions used to estimate the future impact of the proposed billing determinant mapping, the net cost shift between sectors would be approximately:

- $11,500 for Schedule 2; and
- $12,700 for Schedule 3

The estimated total net cost shift between sectors for 2002 is $14,300. The total revenue requirement under the ISO Tariff for the 2002 test year is $61.2 million. The estimated cost shifts between sectors are tabulated below and the details are highlighted in Attachment 2. Negative values are a benefit; and positive values are a liability.

| | Estimated Total Change In Revenue $ | | | |
|---|---|---|---|---|
| | Schedule 1 | Schedule 2 | Schedule 3 | Total |
| Sector | $ | $ | $ | $ |
| Generation | $ - | $ 7,184 | $ 4,270 | $ 11,454 |
| Transmission | $ - | $ 3,113 | $ (12,659) | $ (9,545) |
| Supplier | $ - | $ (11,481) | $ 6,713 | $ (4,768) |
| Publicly Owned | $ - | $ 1,184 | $ 1,676 | $ 2,859 |
| End User | $ - | $ - | $ - | $ - |
| Totals | $ - | $ (0) | $ 0 | $ (0) |

| ISO Tariff Schedule | Current Billing Determinant | Billing Determinant under SMD | Conclusion |
|---|---|---|---|
| Schedule 1 – Network Customer | Network Customer's Monthly Network Load | Network Customer's Monthly Network Load | Same billing determinant. |
| Schedule 1 – Transmission Customer receiving Point-to-Point Transmission Service | Reserved Capacity | Reserved Capacity | Same billing determinant. |
| Schedule 2 – Energy Transaction Units | Bilateral Contract Block-Hours associated with Bilateral Contracts for Energy where Bilateral Contracts are defined as:<br>1. Load Asset Contracts<br>2. Unit Contracts<br>3. Obligation System Contracts<br>4. Other System Contracts<br>5. External Contracts | Bilateral Contract Block-Hours associated with Bilateral Contracts for Energy where Bilateral Contracts are defined as:<br>1. Internal Bilateral for Load Block-Hours in Real-Time<br>2. Internal Bilateral for Market Block-Hours associated with Energy in Real-Time<br>3. External Transactions in Real-Time | New contract types. Same billing determinant. |
| Schedule 2 – Energy Transaction Units | Exclusion of Bilateral Contract Block-Hours associated with Life of Unit Contracts, Vermont Yankee Multiple Owner Contracts and Pool Planned Unit Contracts | None, Unit Contracts do not exist under SMD. | Null set results in effectively no exclusion. |
| Schedule 2 – Energy Transaction Units | Generator Block-Hours associated with quantities of Energy with related prices contained in the hourly Bids | Generator Block-Hours = number of blocks in the price based Real-Time daily schedule * 24 hours/day | Equivalent billing determinant. |
| Schedule 2 – Energy Transaction Units | Energy Non-Zero Spot Market Settlements: Hours | For each Participant for each hour, sum the Real-Time | Equivalent billing determinant. |

| ISO Tariff Schedule | Current Billing Determinant | Billing Determinant under SMD | Conclusion |
|---|---|---|---|
| | for which the Participant has a positive or negative Adjusted Net Interchange in the Energy Market | Locational Adjusted Net Interchange over all Locations to determine if the Participant has a positive or negative Real-Time "System" Adjusted Net Interchange in the Energy Market | |
| Schedule 2 – Volumetric Measure | Electrical Load for the month | Real-Time Load Obligation for the month summed over all Locations | Approximate equivalent billing determinant. |
| Schedule 2 – Volumetric Measure | Injections for the month | Real-Time Generation Obligation for the month =<br>In Real-Time, the Σ over all Nodes of (Participant's % ownership at each Node * revenue metered generation in Real-Time at each Node) + Σ over all External Nodes of Participant's Supply Offers delivered at such Nodes over all hours of the month | Approximate equivalent billing determinant. |
| Schedule 2 – Volumetric Measure | Exclusion of Injections associated with energy imported into the NEPOOL Control Area by Bangor Hydro-Electric Company across the New Brunswick Ties (up to 300 MW) | Exclude Supply Offers delivered at the New Brunswick External Node(s) over all hours of the month, up to 300 MW for any given hour of the month. | Same exclusion. |
| Schedule 3 – NCP Electrical Load | Non-Coincident Peak Electrical Load | Real-Time NCP Load Obligation for the month summed over all Locations | Approximate equivalent billing determinant. |

| **ISO Tariff Schedule** | **Current Billing Determinant** | **Billing Determinant under SMD** | **Conclusion** |
|---|---|---|---|
| Schedule 3 – NCP Injections | NCP Injections | Real-Time NCP Generation Obligation =<br>In Real-Time, the Σ over all Nodes of (Participant's % ownership at each Node * revenue metered generation in Real-Time at each Node) + Σ over all External Nodes of Participant's Supply Offers delivered at such Nodes for the NCP hour | The Injection component of the Schedule 3 charge is only effective through the end of December 31, 2002. In 2003, 100% of the Schedule 3 revenue requirement will be collected based only on load, not injections. Accordingly, no mapping of this billing determinant is required. |
| Schedule 3 – Non-Participant Transmission Customer receiving Point-to-Point Transmission Service | Duration of transmission reservations | Duration of transmission reservations | Same billing determinant. |

# ISO NEW-ENGLAND

# SUMMARY OF METHODS IN THE 2003

# ADMINISTRATIVE COST RECOVERY

Note: This Summary and Attachments were prepared solely for the purpose of information and encouraging discussion. None of the contents may be regarded by the reader as any form of offer, undertaking, policy, proposal or commitment by the sender.

**ISO NEW-ENGLAND**
**ADMINISTRATIVE COST RECOVERY**

Background - ISO-NE began operations on July 1, 1997 with the transfer of staff from, and using the equipment of the NEPOOL control center.

ISO-NE is responsible for operating:

1. New England's bulk power system, including administration of the New England Power Pool ("NEPOOL").
2. Open Access Transmission Tariff (the "NEPOOL Tariff"), and
3. The region's restructured wholesale electricity marketplace.

ISO-NE RATE DESIGN 2001 SETTLEMENT AGREEMENT in ER01-316-000.
[Settlement Agreement effective through 12/31/03]

Capital Expenses associated with SMD 1.0 are accounted for in a <u>Separate</u> CAPITAL FUNDING TARIFF filing.

ISO-NE furnish 3 Administrative Services :

1. SCHEDULE 1- Scheduling Services
2. SCHEDULE 2 - Energy Administration Service (EAS)
3. SCHEDULE 3 - Reliability Administration Service (RAS)

In essence, the three Services represent the three functions to which the ISO's costs are functionalized.

Attachment 1 describes the functions and services for each Schedule.

BILLING DETERMINANTS

Attachment 2 is a September 13, 2002 white paper describing the Billing Determinants Under SMD for the ISO-NE Tariff.

## SCHEDULE 1- Scheduling Services

### Schedule 1 Billing Determinants

Billing determinants are the monthly Network Load, and the Reserved Capacity of Point-to-Point Transmission Service (including Unauthorized Use) Under the Settlement Agreement, the billing determinants for Schedule 1 are not subject to declining block rates.

Schedule 1 revenues collected from Point-to-Point Transmission Service customers are credited to each Network Customer that month in proportion to each Network Customer's monthly Network Load in that month.

2003 annual billing determinants = 246,858,694 kW-months

## SCHEDULE 2 - Energy Administration Service (EAS)

### Schedule 2 Billing Determinants

Under the Settlement Agreement, the billing determinants for Schedule 2 are based on "Transaction Units" ("TUs") and "Volumetric Measures" ("VMs").

The TUs measure the frequency and duration of activity and are indifferent to the size (e.g., capacity) of any particular transaction.

The VMs seek to capture a customer's "physical" reliance on the system administered by the ISO and thus the benefit received.

Per Settlement Agreement Allocation of Schedule 2 Revenue Requirement–

1. 15% to Tus.
2. 85% to VMs.
3. Schedule 2 billing determinants, TUs and VMs, are subject to declining block rates, spread over three blocks for each billing determinant.

The Settlement Agreement includes amendments to the initially proposed definitions of TUs in Schedule 2 to address certain contracts involving jointly owned resources and joint-action agencies in order to avoid the creation of multiple TUs for what are essentially single transactions.

For Example:

TUs will be adjusted to reduce or eliminate:

1. Certain Preexisting Multi- year Contracts ("PMC"),
2. Life of Unit Contracts,
3. Vermont Yankee Multiple Owner Contracts, and
4. Pool Planned Unit Contracts to eliminate an overstatement of transactions actually taking place.

Injections associated with energy imported into the NEPOOL Control Area by Bangor Hydro-Electric Company up to 300 MW across the New Brunswick Ties are to be excluded from the definitions of injections and EAS VMs.

See Attachment 3, is the ISO-NE Billing Determinants and Rate Revenue calculations shown in Exhibit 6 Schedules 1.0 through 4.0 at the end of this document.

## SCHEDULE 3 - Reliability Administration Service (RAS)

### Schedule 3 Billing Determinants

Under the Settlement Agreement, the rate design for Schedule 3 allocates, in calendar year 2003, 100 percent of revenues based on customers' Non-Coincident Peak Electrical Load.

2003 Total underlying Non-coincident peak electrical load is 279,457,758 kW-months.

## ISO-NE ADMINISTRATIVE SERVICES REVENUE REQUIREMENT COMPARISON 2003 TO 2002

| | 2003 | 2002 | Increase |
|---|---|---|---|
| ISO-NE | $112.8 million | $61.1 million | $51.7 million or by 84.6% |

$10.5 million O&M and Implementation costs of SMD 1.0;
$38.2 million Debt Service Payments on SMD
$ 3.0 million 2001 & 2002 True-up Adj Revenue Requirement
$51.7 million

ISO-NE 2003 REVENUE REQUIREMENT (INCLUDING TRUE-UPS BY SCHEDULE IS:

Schedule 1 for 2003 is $14,794,241 (13.12%).

Schedule 2 for 2003 is a maximum of $71,979,066 (63.83%).

Under the A Rates, effective January 1, 2003, the Schedule 2 revenue requirement is $48,490,565. Under the B Rates, the Schedule 2 revenue requirement is $62,583,667. Under the C Rates, the Schedule 2 revenue requirement is $71,979,066.

Schedule 3 for 2003 is up to $25,991,347 (23.05%).

Under the A Rates, the Schedule 3 revenue requirement is $23,381,513. Under the B Rates, the Schedule 3 revenue requirement is $24,947,413. Under the C Rates, the Schedule 3 revenue requirement is $25,991,347.

2003 Revenue Requirement has four elements:

1. 2003 Core Operating Budget;
2. 2001 True-Up Adjustment;
3. 2002 True-up Adjustment;
4. Incremental amount of prior year depreciation.

ISO-NE Tariff True-up provision specified in Section 2.3(1) provides for adjustments if revenue shortfalls are attributable to the TUs in Schedule 2.

In the event of a revenue short fall attributable to TUs, the shortfall allocation has two components.

1. The Initial True-Up Adjustment – would allocate 50/50 between TUs and Volumes instead of the usual 15/85 allocation to TUs and Volumes.

2. The Final True-Up Adjustment – would increase the percentage allocation of the shortfall to Volumes by an additional percentage equal to the percentage decreases, which occurred between the number of TUs used in the true-up and the number of TUs that ISO had used in the original projection of the rates for that year.

ISO-NE Added Sources of Revenues:

1. Demand Response Initiative –Demand Response Providers (DRP) who are not NEPOOL Participants may also participate in programs directly through the ISO. DRP will be subject to the applicable financial assurance criteria and will be charged an annual service fee of $5,000. This fee will be applied to ISO expenses and may be superceded by a future provision in the ISO Tariff[1].

2. Non-Participants that want to participate in the FTR Auction or to become an FTR Holder via the secondary market and

[1] ISO-NE assumes that Demand response ("DR") is a key element of well functioning electricity markets, because by enabling price and load responsive behavior, the wholesale electricity market will function more efficiently.

have satisfied the applicable financial assurance criteria will be charged a one time FTR Registration Fee of $5,000[2].

ISO-NE Direct-charge Activities [Under Sections 8.1 through 8.4 or the Tariff]

ISO-NE charges and collects the costs of:

a. performing studies,
b. fulfilling information requests **,
c. implementing non-standard contract provisions
d. providing weekly billing services

** In fulfilling information and re-billing requests of a significant and non-routine nature, ISO-NE charges its associated direct and indirect costs to the requestor. Revenues from these charges will be credited to the revenue requirement of the Services to which the information is requested in the True-up calculation.

[2] For 2003, as discussed with NEPOOL Participants, these fees will be credited to Schedule 1 revenues and accounted for in the true- ups specified in Section 2.3(2) of the ISO Tariff. This fee may be superseded by a future provision in the ISO Tariff.

# ATTACHMENT 1

# DESCRIPTION OR ISO-NE FUNCTIONS AND SERVICES UNDER EACH SCHEDULE

## SCHEDULE 1 – SCHEDULING SERVICES

Schedule 1 of the ISO Tariff provides the terms, conditions and rates for the ISO's provision of Scheduling Service, which includes provision of the transmission-related Ancillary Service identified in Schedule 1 of the NEPOOL Tariff as Scheduling, System Control and Dispatch Service.

Scheduling Service includes the transmission-related service required to schedule at the pool level the movement of power through, out of, within, or into the NEPOOL Control Area. It does not cover expenses of dispatching Energy, which are collected as part of the charges in Schedule 2. Scheduling Service is an Ancillary Service for Transmission Service under the NEPOOL Tariff that can be provided only by the ISO (and cooperating Participants, as described below) and all Transmission Customers must purchase this Service from the ISO.

Functions performed by the ISO in connection with this Service include:

- Processing and implementation of requests for Transmission Service, including support of the NEPOOL OASIS node;
- Coordination of transmission system operation (including administration of reactive power requirements under Schedule 2 of the NEPOOL Tariff) and implementation of necessary control actions by the ISO and support for these functions;
- Billing associated with transmission services provided under the NEPOOL Tariff;
- Transmission system planning which supports this Service; and
- Administrative support for the aforementioned functions.

The Schedule 1 revenue requirement does not change with the implementation of SMD 1.0, because the SMD 1.0 capital expenses do not relate to the ISO's Schedule 1 activities.

## SCHEDULE 2 – EAS

Energy Administration Service is the service provided by the ISO to administer the Energy Market and facilitate Interchange Transactions, bilateral transactions and generation bids in accordance with the RNA.

**Bidding:** Bids are communicated to and implemented by the ISO. The actual outputs of such resources are monitored against schedules and accounted for in the settlement process.

**Bilateral transactions:** The characteristics of all bilateral transactions are submitted to the ISO. Bilateral transactions crossing the NEPOOL Control Area boundary are coordinated with the adjacent control area and jointly implemented. Dispatchability parameters related to each purchase and sale transaction are administered by the ISO. While bilateral transactions internal to the NEPOOL Control Area do not require similar action by the ISO, the seller and buyer in each such transaction must be tracked to allow proper accounting in the Energy settlement process.

**Energy Market transactions:** The ISO dispatches energy resources that are bid into the spot Energy Market by the Participants. The optimum output schedule for the actual use of resources to meet NEPOOL's total energy needs is determined and implemented by the ISO. The amount of each Participant's purchases and/or sales in the Energy Market (*i.*e., Interchange Transactions) are determined by the ISO through comparing the Participant's needs for energy with the actual output of its resources. The Energy Clearing Price is the product of the bidding process. On and after the SMD Effective Date, the locational marginal prices are the product of the bidding process. The Energy and dollar settlements are administered by the ISO.

In summary, ISO functions which comprise EAS (in addition to the core operation of the Energy Market) include:

- Generation dispatch related to the Energy Market;
- Energy accounting;
- Loss determination and allocation;
- Billing preparation;
- Administration of the Energy Imbalance Service under Schedule 4 of the NEPOOL Tariff;
- Market power monitoring and mitigation for the Energy Market;

- Sanctions activities;
- Energy Market assessments and reports; and
- Formulation of additional Market Rules and proposals to modify existing rules.
- Administration of FTRs and ARRs.

## SCHEDULE 3 – RAS

RAS is the service provided by the ISO to administer the Reliability Markets (and facilitate reliability-related transactions and arrangements) in accordance with the RNA and to provide other reliability and informational services. These latter services are of a type not directly related to the transmission and Energy services provided under Schedules 1 and 2, and are expenses of operating the NEPOOL Control Area generally, rather than expenses attributable to serving a particular Customer.

The several Reliability Markets have distinct purposes:

· **Operating Reserve Markets.** These Markets provide a Participant with a means of satisfying its share of the region's requirements for TMSR, TMNSR, and TMOR. As noted above, these Markets will cease upon SMD 1.0 implementation, and the ISO will instead administer the reserve compensation.

· **Automatic Generation Control ("AGC") or Regulation Market.** This market (referred to as the "Regulation Market" after the SMD Effective Date) provides a Participant with a means of satisfying its share of the region's AGC requirements.

· **The ICAP Settlement.** With the replacement of the ICAP auction with a deficiency charge, the ISO is administering the calculation of ICAP requirements and unit capabilities and imposing a deficiency charge upon Participants who fail to contract or self-supply a sufficient quantity of ICAP to meet their ICAP requirements. As noted above, the ICAP mechanism will change with SMD 1.0 implementation.

The AGC and Operating Reserve Markets are also a means by which Transmission Customers will acquire Ancillary Services under Schedules 3, 5, 6 and 7, respectively, of the NEPOOL Tariff.

Examples of the functions performed (in addition to the core operation of the Reliability Markets) include:

- Generation dispatch associated with Reliability Markets;
- Reliability Markets accounting;
- Billing preparation;
- NEPOOL generation emissions analysis;
- Risk profile updates;
- Triennial review of resource adequacy;
- Preparation of regional reports and load forecasts and profiles (CELT, EIA, NERC);
- Support of power supply, environmental and market reliability planning activities;
- Market power monitoring, mitigation and assessment of the Reliability Markets; and
- Formulation of additional Reliability Market rules and proposals to modify existing rules.

# ATTACHMENT 2

## White Paper describing ISO-NE Billing Determinants Under SMD

# ATTACHMENT 3

## ISO-NE 2002 AND 2003 BILLING DETERMINANTS

CHRISTENSEN ASSOCIATES

Laurits R. Christensen Associates, Inc.
4610 University Avenue, Suite 700
Madison, Wisconsin 53705-2164

Voice 608.231.2266 Fax 608.231.2108

TO: Ben Arikawa

FROM: Ross Hemphill

DATE: 1/6/03

SUBJECT: Functionalization of California ISO Costs

The conference call on December 23, 2002 helped me understand the process being used by the ISO to assign/allocate costs and develop rates. Nonetheless, I do not see how your method can facilitate the cost apportionment and rate structure recommended by MID nor how it can facilitate any evaluations that other stakeholders might wish to undertake. This memorandum serves to state what is needed from the ISO to properly evaluate the MID proposal and how the GMC rate structure might better serve all stakeholders.

As reflected in Dr. Laurence Kirsch's "Cookbook" for revision of the ISO's GMC, the first step in a traditional utility ratemaking process is to identify the utility's functions. In such a process, functions are defined by the products and services *provided by the utility and consumed by the customer*. The ISO's "Preliminary Grouping of Activities for ISO Rate Structure" (Version 12/19/2002) does not identify such functions. Instead, the groupings are, as named, merely groupings of activities. They may be helpful to the ISO in understanding the activities that it performs, but they are not helpful for defining or costing the services that the ISO provides to its customers.

Also, it became clear during the conference call of December 23rd that the ISO intends to use these groupings as "building blocks" for quantifying and evaluating alternative proposals. Although it might be a worthy goal, the groupings identified cannot serve as building blocks for quantifying and evaluating the MID proposal because some of the groupings include multiple functions. For example, the first grouping, "Real-Time Grid Operations," clearly includes some activities that resolve energy imbalances and others that manage transmission flows. Consequently, it will not be possible to derive functional costs directly from these groupings of activities.

What is required to properly evaluate the MID proposal is a cost of service process that is consistent with the industry standard for utility ratemaking. There are many advantages to developing and following such a standard process. It will lead to the efficient and equitable ISO rates described in the Kirsch testimony. Also, developing and following a standard cost of service and ratemaking process will help the ISO and its customers deal with the very real uncertainty regarding the future functions performed by the ISO.

To be consistent with this traditional ratemaking process, we would like the ISO to provide us with the total costs (for the 2001-2002 timeframe) of each of the following four functions:

1. Resolving Energy Imbalances
2. Managing Transmission Flows
3. Scheduling Generators, Loads, and Transmission Facilities
4. Administering Markets

The costs for these four functions should sum to the ISO's total revenue requirement. We would like the ISO to provide us with a step-by-step description of how the costs were assigned and allocated to result in the total costs for each function. This description should provide a mapping of the cost assignment from the cost activity level on up or, if appropriate, from the account level on up. This mapping should be in sufficient detail to allow us to replicate the results and evaluate the methods used. Where cost center numbers are apportioned across functions, the ISO should provide the rationale and data used to derive the proportions applied. When allocations are performed, the ISO should provide the data used to derive the respective allocation factors.

This cost of service information should then be used along with the billing determinant data requested earlier (and discussed in previous communications and meetings) to calculate the ISO rates in accordance with the MID proposal specified in Dr. Kirsch's testimony and embellished in the cookbook.

I hope this memo clarifies what is needed to evaluate the MID proposal. If you have any questions or would desire any clarification about our information needs, don't hesitate to call me.

CHRISTENSEN ASSOCIATES

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Madison, Wisconsin 53705-2164

Voice 608.231.2266 Fax 608.231.2108

# MEMORANDUM

TO: Ben Arikawa

FROM: Ross C. Hemphill

DATE: December 19, 2002

SUBJECT: Organization of Cost of Service Information

I have been asked by MID to review the cost allocation and ratemaking process employed by the ISO as it evaluates the revision of the GMC as proposed by Dr. Laurence Kirsch. I have been dealing with cost allocation and ratemaking issues for the past 25 years, and was the Director of Electric Pricing (responsible for all cost of service and ratemaking activities) for Niagara Mohawk during the mid 1990s.

As a starting point for my review of the ISOs costing and ratemaking process, I looked at the GMC informational rate filing ("Informational Filing") submitted to FERC by the ISO on November 8, 2002; and I also looked at a number of informal communications that have taken place among the stakeholders on the issues of service definitions and costs. In looking over these documents, I find two fundamental problems:

1. The parties use inconsistent nomenclature when discussing cost issues. We find the terms "function," "activity," and "service" used interchangeably in ISO documents and in communications among the stakeholders. An important goal of the stakeholder process will be to simply get everyone speaking the same language.

2. The documents indicate no discernable cost assignment and allocation logic that can serve as the basis for deriving cost-based rates for each of the services provided by the ISO. Such logic should be developed and documented so that any party can trace rates to their individual cost components.

It is my understanding that the ISO has engaged Barkovich and Yap, Inc. as rate consultants for this stakeholder process. I suggest that the ISO ask Barkovich and Yap to propose an "industry standard" structure for cost accounting and subsequent ratemaking that will be employed by the ISO and regularly reviewed by stakeholders in the ratemaking process. I offer a few basic suggestions in developing this standard:

There should be a clear delineation between the terms "categories of service," "functions," and "activities." The ISO currently assigns costs to one of three "categories of service" listed below:

- Control Area Services (CAS)
- Congestion Management (CONG)
- Ancillary Services and Real-Time Energy Operations (ASREO)

Based upon the Kirsch testimony and subsequent consideration of his proposal, however, we believe there are four functions performed by the ISO that should be separately treated in a cost-of-service and ratemaking framework:[1]

- Resolving Energy Imbalances
- Managing Transmission Flows
- Scheduling Generator Loads and Transmission Facilities
- Administering Markets

These functions partly overlap and partly differ from the "categories of service" that the ISO now uses.

The cost-of-service method needs to include a stronger allocation and assignment logic for apportioning costs among functions. For example, the Kirsch testimony, in specifying a method for apportioning the costs of CAS among the first three functions listed above, provides logic as to why this cost apportionment will lead to the development of efficient rates.

We should view "activities" as accounting identifiers that can be used to trace expenditures of time and money to the service categories or maybe directly to the functions.

I hope these ideas will promote discussion and progress in developing the cost-of-service and ratemaking procedures that are employed by the ISO in 2004 and beyond.

---

[1] This deviates from the Kirsch testimony by dropping "managing emergencies" as a separate function and adding "administering markets." The management of emergencies can reasonably be considered an extreme form of resolving imbalances and managing flows. The "administering markets" function (which was not the subject of the Kirsch testimony because it was outside of the scope of the Control Area Services category) identifies the costs associated with the arrangement, administration, and monitoring of trades among market participants. This function may be similar to the ISO's proposed ASREO category; however, additional investigation is needed to verify this.

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System Operator

# 2004 GMC Rate Structure
# Stakeholders Meeting

## Existing Transmission Contracts (ETC's)
## Workload Overview

**January 13, 2003**

# Presentation Agenda

- ETC Definitions
- Existing Transmission Rights
- ISO ETC Facts / Figures
- ETC Scheduling & Systems
- ETC Capacity Reservation Mechanism
- ISO "Incremental" ETC Workload

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# ETC Definitions

- **Existing Contracts:** The contracts which grant transmission service rights, in existence on the ISO Operations date.
- **Reservation:** Transmission Capacity
  (provided to the ISO by the RPTO's.)
- **Usage:** Energy or A/S schedule using the transmission reservation capacity
  (provided by the responsible SC)

# Existing Transmission Rights

- Prepaid Transmission service rights, therefore, no wheeling or access charges,
- Exempt from Congestion Management and Usage charges,
- Often, ETC rights allow for changes in Power Flow schedules, right up to Real Time
- Duration of contracts varies – some expired in 2002, others extend out 22 more years

# ISO ETC Facts / Figures

- ETC rights are represented by over **120** active Contract Reference Numbers (CRNs)
- ETCs represent approximately **40** % of total MW capacity of the Inter & Intra-ties
- ETC rights are scheduled by **16** SCs
- MW value of ETC rights is approximately **26,500** MW (total of bi-lateral rights)
- ETC power flows comprise roughly **20**% of system load

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# Existing Transmission Rights - Scheduling

- PTO and ISO must honor all ETC / Existing Contract Rights
- ISO receives ETC / IA operating instructions from RPTO
- ISO reserves back ETC capacity, accordingly
- Responsible SCs schedule ETC rights, using CRNs and Contract Usage Templates in SI/SA

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# ETC Scheduling - ISO Systems

- **Master File** – PF Model, Pseudo Generators, CRNs association
- **Pre-Scheduling** - ETC Calculator (ETCC)
- **SI/SA** – CONG Management, ETCC
- **Metering** - Logical Meter Calculation & Validation
- **Settlements** – Automated and Manual Work Around Tools

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# ETC Capacity Reservation Mechanism

- Total Transfer Capability (**TTC**), modified to reflect system operation and protection constraints
  = Operational Transfer Capability (**OTC**)

- **OTC – ETC = ATC** (Available Transfer Capability) for **NFU**, or **"the Market"**

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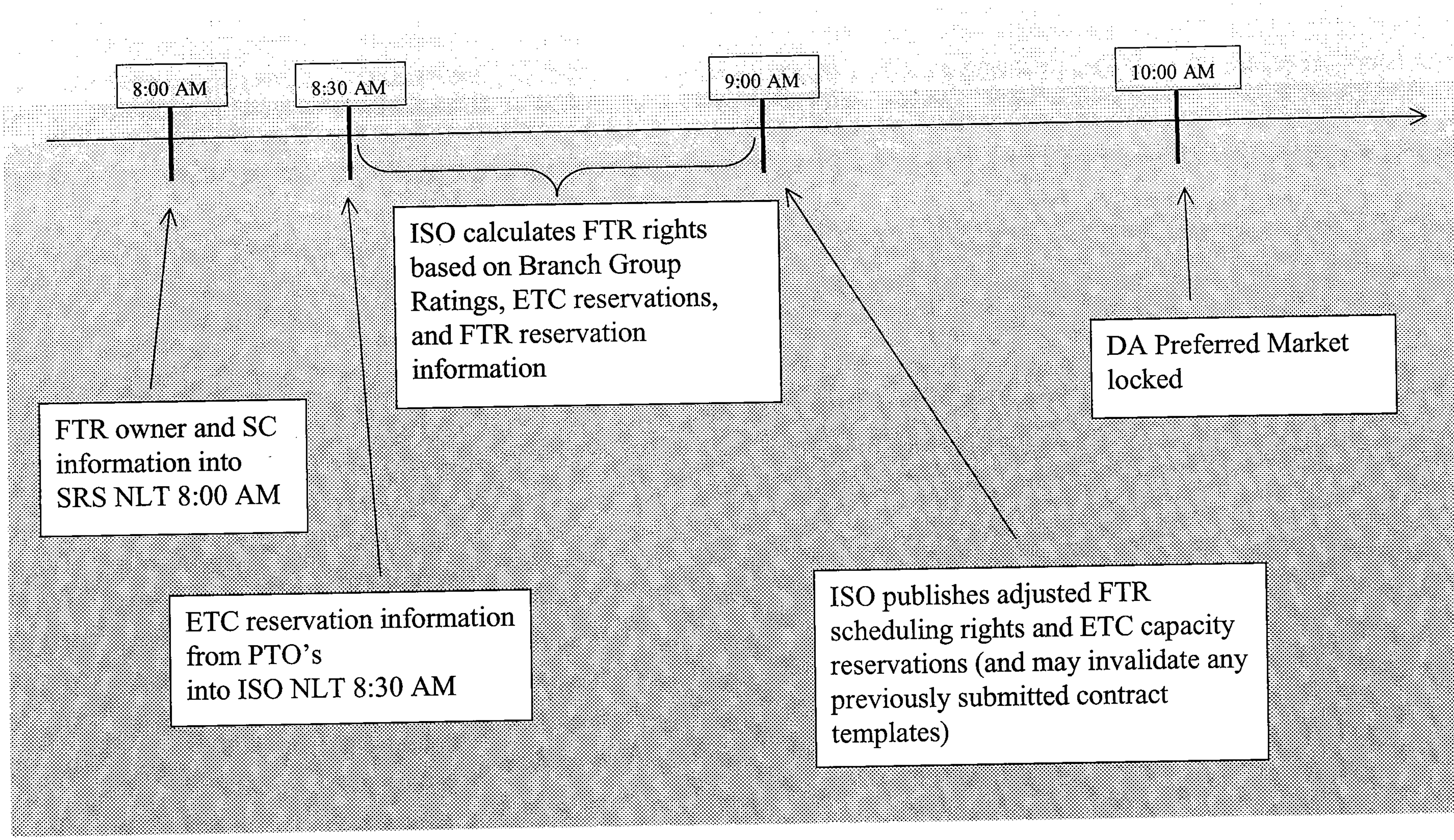
## ETC and FTR Timeline in the Day Ahead Market



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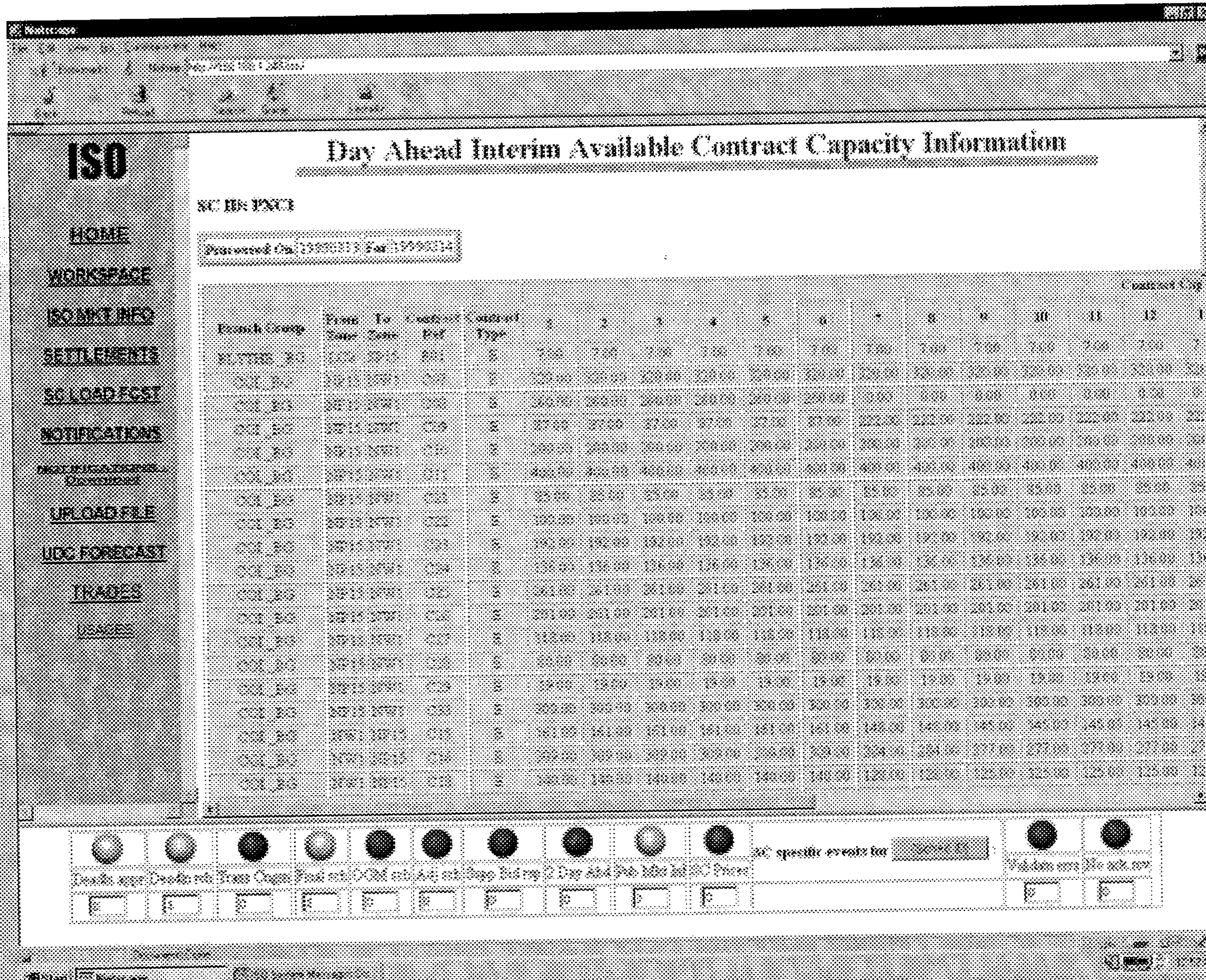

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# ISO ETC Incremental Workload

- **Pre-Scheduling** –PTO Operating Instructions and Reservation Quantities administration
- **RT Scheduling** – RT adjustments, ETC Communication & Coordination between ISO, PTO, ETC rights holders
- **Grid Ops & Market Ops** - SA/SI: CONG, ETC Calculator (ETCC), SC & PTO Coordination
- **Metering** - Logical Meter Calculation & Validation
- **Settlements** – Manual ETC settlements, dispute resolution
- **OE, Market Quality, Contracts, Legal & Client Relations** - ETC related projects, account management, dispute resolution, contracts & litigation

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# ISO "Incremental" ETC Workload Estimate

## ISO FTEs dedicated to ETC processing, over and above routine workload –

## Approximately 13 FTEs

* Estimate of ETC associated workload, in excess of routine NFU Transmission schedule processing. ETC processing semi-automated due to prior ISO system modifications (ETC Calculator, use of SI/CRNs and CUTs and Settlements Work-Around Tools)

* Estimate reflects incremental labor workload only, and does not capture prior capital and labor for ISO expenditures on system and software modifications, required to honor ETCs

**CONFIDENTIALITY AGREEMENT FOR THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION GMC RATE STRUCTURE PROJECT STAKEHOLDER PROCESS**

This Confidentiality Agreement, dated as of January 10, 2003, is entered into by and among the California Independent System Operator Corporation ("ISO") and the Stakeholders executing this agreement in order to facilitate Stakeholder access to Confidential Material as part of the ISO's GMC Rate Structure Project Stakeholder Process.

WHEREAS, the ISO and Stakeholders wish to allow the greatest possible Stakeholder access to ISO Confidential Material in the GMC Rate Structure Project Stakeholder Process;

NOW, THEREFORE, in consideration of the premises and of the mutual benefits and covenants hereinafter set forth, it is agreed:

1. This Confidentiality Agreement shall govern the use of all Confidential Material produced by, or on behalf of, the ISO during the GMC Rate Structure Project Stakeholder Process.

2. This Confidentiality Agreement shall remain in effect with respect to Confidential Materials so designated under the terms of this Confidentiality Agreement, until such time as the ISO shall determine and inform the Stakeholders in Appendix A in writing that the Confidential Materials in question are no longer confidential, or the ISO makes the materials available to the public in the form in which it was re-created for release as part of this GMC Rate Structure Project Stakeholder Process.

3. The ISO may designate as Confidential Material any material that is not already available to the public or available in the form in which it is re-created for release as part of this GMC Rate Structure Project Stakeholder Process.

4. Only Reviewing Representatives, as that term is defined in Paragraph 5 may possess, review, or otherwise use Confidential Materials, and they may do so only as provided in this Confidentiality Agreement.

5. Definitions. As used in this Agreement, the singular includes the plural. For purposes of this Confidentiality Agreement:

a. The term "document" should be interpreted to include, but not be limited to, the original and all copies of any written or retrievable matter, including electronic media, or data of any kind, however produced or reproduced.

b. The term "Confidential Material" means (1) documents or oral materials provided by the ISO and designated as such by the ISO; (2) Notes of Confidential Material, whether created by the ISO or by Stakeholders or by any other person or entity; and (3) copies of Confidential Material, by whomsoever made.

c. The term "Notes of Confidential Materials" means memoranda, handwritten notes, or any other form of information (including electronic form) which copies, discloses or derives from materials described in Paragraph 5(b), whether made by the ISO or any other person or entity.

d. "GMC Rate Structure Project Stakeholder Process" means the process indicated by the FERC ALJ in her Initial Decision in Docket No. ER01-313-000, issued 5/10/02, which will end with a filing with the Federal Energy Regulatory Commission ("FERC") by the ISO regarding a revised GMC

e. "Executing Party" means any entity that has executed this Confidentiality Agreement.

f. "Reviewing Representative" shall mean a person who has signed a Non-Disclosure Certificate and who is:

i. an attorney, employee or agent of an Executing Party;

ii. an attorney, paralegal or other employee under the supervision or control of the attorney described in 5(f)(i); and

iii. any person retained by an Executing Party for the purpose of advising the Executing Party with regard to the ISO's GMC Rate Structure Project Stakeholder Process

6. The ISO shall mark all written materials intended to be covered by the terms of this Confidentiality Agreement with the words "Confidential Material" or with words of similar import. The ISO shall instruct Executing Parties that information being conveyed orally and intended by the ISO to be covered by the terms of this Confidentiality Agreement, is Confidential Material. To the extent possible, the ISO shall mark any electronic document intended to be covered by the terms of this Confidentiality Agreement with the words "Confidential Material" or similar words, or, if that is not possible or would be exceedingly difficult, the ISO shall notify Executing Parties (for example, by covering email transmitting the electronic document) that the electronic document is Confidential Material. The ISO's failure, for whatever reason, to mark any material at the time it is produced to the Executing Parties, or to notify them that oral or electronic material is Confidential Material at the time it is provided, shall not take the material out of the coverage of this Confidentiality Agreement for all time, and the Executing Parties must treat the material as Confidential Material once the ISO has notified them that the material is to be covered by this Confidentiality Agreement.

7. Confidential Material shall be made available under the terms of this Confidentiality Agreement only to Executing Parties and only through their Reviewing Representatives as provided in Paragraph 11.

8. Confidential Material shall be treated as confidential by each Executing Party and by their Reviewing Representative(s) in accordance with this Confidentiality Agreement. Confidential Materials shall not be used except as necessary for Stakeholder involvement in the ISO's GMC Rate Structure Project Stakeholder Process, nor shall Confidential Material be disclosed to any person except Reviewing Representatives who are engaged in the ISO's GMC Rate Structure Project Stakeholder Process and who need to know the information in order to represent the Executing Parties in that process. Confidential Material may not be used by any Executing Party other than the ISO in any administrative or judicial proceeding, except that an Executing Party may use Confidential Material in such a proceeding that results from the GMC Rate Structure Project Stakeholder Process if such Confidential Material continues to be treated and maintained as confidential in accordance with a Protective Order issued as part of such administrative or judicial proceeding. Confidential Material also may not be used by any Executing Party other than the ISO in any arbitration, mediation or other alternative dispute resolution proceeding, nor may Confidential Material be used by any Executing Party other than the ISO in any arbitration, mediation or other alternative dispute resolution proceeding, including any alternative dispute resolution proceeding that results from the GMC Rate Structure Project Stakeholder Process.

9. Reviewing Representatives may make copies of Confidential Material, and may make Notes of Confidential Material.

10. A Reviewing Representative shall not be permitted to inspect, participate in discussions regarding, or otherwise have access to Confidential Material pursuant to this Confidentiality Agreement unless that Reviewing Representative has first executed a Non-Disclosure Certificate. A copy of the Non-Disclosure Certificate shall be provided to counsel for the ISO before any Confidential Materials may be provided to that Reviewing Representative.

11. All Reviewing Representatives are responsible to comply with the terms of this Confidentiality Agreement.

12. Any Reviewing Representative may disclose Confidential Material to any other Reviewing Representative as long as the disclosing Reviewing Representative and the receiving Reviewing Representative have both executed a Non-Disclosure Certificate.

13. The contents of Confidential Material or any other form of information that copies or discloses Protected Material shall not be disclosed to anyone other than in accordance with this Confidentiality Agreement and shall be used only in connection with the ISO's GMC Rate Structure Project Stakeholder Process.

14. If another person or entity requests or demands, by subpoena or otherwise, any Confidential Material, Counsel for the Executing Party receiving the request or demand will immediately notify counsel for the ISO. All reasonable steps will be taken by the Executing Party receiving the request or demand to permit the assertion of all applicable rights and privileges by the ISO, and the Executing Party receiving such request or demand will cooperate with the ISO in the timely assertion of such rights and privileges, including obtaining a protective order where appropriate. Each Executing Party further agrees that if the ISO is not successful in precluding the requesting person or entity from requiring the disclosure of the Confidential Material, it will furnish only that portion of the Confidential Material which is legally required, and will exercise all reasonable efforts to obtain a ruling or reliable assurances that confidential treatment will be afforded the Confidential Material.

15. Each Executing Party shall be responsible for any breach of this Confidentiality Agreement by employees, agents, financial advisors, attorneys, consultants, directors or affiliates, and agrees, at its sole cost and expense, to take all commercially reasonable measures (including, without limitation, court proceedings) to prohibit its employees, agents, financial advisors, attorneys, consultants, directors or affiliates from disclosing or using the Confidential Material in any manner not authorized by this Confidentiality Agreement.

16. It is understood and agreed that the ISO shall be entitled to seek equitable relief, including injunction and specific performance, as a remedy for any breach or threatened breach of this Confidentiality Agreement by an Executing Party, or any of its employees, agents, financial advisors, attorneys, consultants, directors or affiliates. These remedies will not be deemed to be the exclusive remedies for a violation of the terms of this Confidentiality Agreement, but will be in addition to all other remedies available to the ISO, as the case may be, at law or equity. In the event of litigation relating to this Confidentiality Agreement, if a court of competent jurisdiction determines, in a final, non-appealable order, that an Executing Party or any of its representatives has breached this Agreement, then, in addition to any equitable relief granted, such Participant shall be liable and pay to the ISO the reasonable legal fees and disbursements incurred by the ISO in connection with such litigation, including any appeal therefrom.

17. This Confidentiality Agreement may be signed in counterparts, each of which shall be deemed to be an original, but all of which together shall constitute one and the same instrument.

18. This Confidentiality Agreement shall be governed by and construed in accordance with the laws of the State of California without giving effect to the principles of conflicts of law thereof. Each Executing Party irrevocably and unconditionally consents to submit to the exclusive jurisdiction of the courts of the State of California and the United States of America located in the State of California for any actions, suits or proceedings arising out of or relating to this Agreement and the transactions contemplated hereby, and further agrees that service of any process, summons, notice or document by U.S. registered mail to

each Party's address set forth below shall be effective service of process for any action, suit or proceeding brought against a Executing Party in any such court. Each Executing Party irrevocably and unconditionally waives any objection to the laying of venue of any action, suit or proceeding arising out of this Agreement or the transactions contemplated hereby, in the courts of the State of California or the United States of America located in the State of California, and hereby further irrevocably and unconditionally waives and agrees not to plead or claim in any such court that any such action, suit or proceeding brought in any such court has been brought in an inconvenient forum or, provided that service of process has been effected as provided herein or as otherwise provided by law, that said court lacks personal jurisdiction over the Executing Party. Federal entities executing the Confidentiality Agreement are not subject to the laws of the State of California, but are subject to federal law as if transactions covered by this Confidentiality Agreement are fully performed within the State of California.

19. The rights and obligations of each Executing Party under this Confidentiality Agreement may not be assigned to any person or entity without the prior written consent of the ISO, which consent shall not be unreasonably withheld. Subject to the foregoing, this Confidentiality Agreement shall be binding on the respective successors and assigns of the Executing Parties hereto.

20. Each Executing Party hereto willingly and freely consents to every provision of this Confidentiality Agreement, and the individual signing on behalf of such Executing Party represents, by signing, that he or she is fully authorized to bind such Executing Party herein.

AGREED:

By:________________________

Title:______________________

Date:_______________________

On behalf of: The California Independent
System Operator Corporation
151 Blue Ravine Road
Folsom,
California 95630

By:______________________________

Title:___________________________

Date:___________________________

On behalf of:______________________
Address:__________________________
_________________________________

## NON-DISCLOSURE CERTIFICATE

I hereby certify my understanding that access to Confidential Material is provided to me pursuant to the terms and restrictions of the Confidentiality Agreement for the California Independent System Operator Corporation GMC Rate Structure Project Stakeholder Process ("Confidentiality Agreement"), dated January 10, 2003, by and between the California Independent System Operator Corporation ("ISO") and the Executing Parties as defined therein, and that I have read and understand the terms of that Confidentiality Agreement. I agree to be bound by the terms of that Confidentiality Agreement. I will not disclose to anyone the contents of Confidential Material, any notes or memoranda, or any other form of information that copies or discloses or is derived from Confidential Material other than in accordance with the Confidentiality Agreement. I acknowledge that a violation of my undertakings in this certificate constitutes a breach of the Confidentiality Agreement.

By (Print):__________________________

Title:______________________________

Representing:________________________

Signature:___________________________

Date:______________________________

CALIFORNIA ISO

California Independent
System Operator

# Discussion of Functionalization into ISO Services

**January 13, 2003**

**2004 GMC Rate Structure Project**

Ben T. Arikawa
Senior Financial Analyst

(916) 608-5958

# FERC Accounts

- Production
- Distribution
- Transmission
- Customer Accounts
- Customer Service
- Administrative and General

# Dilemma

- ISO has no Production or Distribution Function
- What services does the ISO provide?

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# MID's ISO Functions

- Resolving Energy Imbalances
- Managing Transmission Flows
- Scheduling Generation, Loads and Transmission Facilities
- Administering Markets

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# Other Functions

- Customer Service
- Others (?)

**Preliminary Listing of Billing Determinant Data, Use and Source (12/17/2002 version)**

| | Data | Frequency | Period | Comments | Completed |
|---|---|---|---|---|---|
| 1. | Gross control area load (energy) plus exports | Monthly | Calendar months, September 2001 – August 2002 | Current billing determinant for Control Area Services. | Yes |
| 2. | Net control area load (energy) plus exports | Monthly | see above | Not including behind the meter load of QFs and municipals | Yes |
| 3. | Scheduled load plus exports | Monthly | see above | Use for scheduling charge if created | |
| 4. | Maximum coincident demand~~, both~~ ~~gross and~~ net | Monthly | see above | This is the sum of the maximum demand for each SC during the month coinciding with the ISO peak. For d~~D~~evelopment of a demand charge | Yes |
| 5. | Maximum non-coincident demand, ~~both~~ ~~gross and~~ net | Monthly | see above | This is the sum of the maximum demand for each SC during the month not coinciding with the ISO peak.~~plus (for gross) the sum of the connected loads for all behind-the-meter self-generation loads.~~ For ~~D~~development of a demand charge | Yes |

By: Ben Arikawa
Last updated: 12/17/2002

| | | | | | |
|---|---|---|---|---|---|
| 6. | Maximum non-coincident absolute net uninstructed deviation (demand) | Monthly | see above | For each SC, this is the SC's maximum absolute net uninstructed deviation during any 10-minute interval ~~of the current month and the preceding 11 months.~~ The net uninstructed deviation is the absolute value of load deviations from schedules less generation deviations from schedules. Or alternatively, the difference between actual load and actual generation for an SC under the current system of balanced scheduling. For MID proposal | Yes |
| 7. | Sum of absolute net uninstructed deviations (energy) | Hourly (or interval?) | see above | For each SC, this is the sum of the SC's absolute net uninstructed deviations during each of the 10-minute intervals in that month. For MID proposal | Yes |
| 8. | Power withdrawals from the ISO-controlled grid (energy) | Monthly | see above | For each SC, this is the actual power that the SC withdraws from the ISO-controlled grid. This is actual metered load, not estimated gross load. Equivalent to net control area load plus exports. | Same as #2 |

By: Ben Arikawa
Last updated: 12/17/2002

| | | | | | |
|---|---|---|---|---|---|
| 9. | Sum of each SC's maximum purchases and sales of Ancillary Services, Supplemental Energy, and Imbalance Energy (both instructed and uninstructed). Not to include self provided AS | Monthly | see above | For development of demand charge for market operations. May be the same as 6 above. | Yes |
| 10. | Total purchases and sales of Ancillary Services, Supplemental Energy, and Imbalance Energy (both instructed and uninstructed). Not to include self provided AS | Monthly | see above | For development of energy charge for market real time activity (same as current billing determinant). Original GMC ASREO Bucket ~~May be the same as 7 above.~~ | Yes |
| 11. | Number of SCs | Monthly | see above | For development of customer charge. | |
| 12. | FTR MW | Annual | see above | For development of FTR administration charge | |

By: Ben Arikawa
Last updated: 12/17/2002

| | | | | | |
|---|---|---|---|---|---|
| 13. | Number of transactions by SC, which would include scheduled loads, purchases/sales of ancillary services, supplemental energy, and imbalance energy, inquiries, etc. Note: this information would only be made available to stakeholders aggregated across all SCs. (No party made a specific request for this data.) | Monthly | see above | For use in developing a graduated customer charge if one is desired -- SCs can be grouped in to several groups depending upon their size (maximum demand and/or number of transactions). The information that would be given out would be aggregated up to categories—Category A includes xx SCs, Category B includes yyy SCs, etc. where we would define the parameters of the various categories. Need definition of transaction. No current request for this information. | |
| 14. | Interzonal scheduled flows (HA) | Monthly | See above | Hour-Ahead scheduled flows across zones. Current billing determinant of interzonal congestion management (CONG) rate component. | <u>Yes</u> |
| 15. | Real time transactions | | | PG&E may request this later. | |

By: Ben Arikawa
Last updated: 12/17/2002

Outstanding items from January 13th 2004 GMC Rate Structure Project meeting

1. Muni vs. QF behind the meter load for SCE, Bert Hansen
2. Cohen's paper on ISO-NE
3. Conference call with MID re: Ross Hemphill's memo
4. Data not yet compiled (scheduled load, FTR MW[however, defined], number of SCs)
5. Location of MD 02 compliance filing
6. Send out data
7. Send out data response to CPUC
8. Jim Price's testimony from 2001 GMC proceeding
9. NDA
10. Sign in sheet
11. Stephen Morrison to check RPTO TCA

# Status Report:
# Grid Management Charge

**January 13, 2003**
Market Issues Forum

Ben T. Arikawa
Senior Financial Analyst
barikawa@caiso.com
(916) 608-5958

# Topics

- Settlement Agreement in ER02-250-000, *et.al.* (2002 GMC rate filing, November 2001)
- GMC Information Filing, ER 03-181-000, filed November 2002
- 2004 GMC Rate Structure Project

# ER 02-250-000 Settlement Agreement

- Filed October 2002
- Settles all issues except for issue related to Southwest Power Link
- Accepted by FERC on December 26, 2002
  http://www2.caiso.com/docs/2002/12/27/2002122713380312422.pdf
- Refunds with interest due to market on charges for self-provided Ancillary Services in 2002

# ER 02-250-000 Settlement Agreement (cont.)

- ISO filed request for clarification from FERC
  http://www2.caiso.com/docs/2003/01/07/2003010715543726055.pdf
  - Timeline in FERC Letter does not match Settlements timeline
  - ISO requested ability to provide refunds by February 5, 2003

# GMC Information Filing ER03-181-000

- Settlement Agreement allowed an informational filing for 2003 GMC and revenue requirement
- Filed at FERC November 8, 2002
- FERC Letter accepting 2003 GMC filing (December 31, 2002)
  http://www2.caiso.com/docs/2002/12/31/2002123111284820607.pdf

# 2004 GMC Rate Structure Project

- Impetus for Project
  - Need for overhaul of GMC structure
  - Initial Decision in ER01-313-000
  - Settlement in ER02-250-000
- Goal – Develop new rate structure for 2004
- Rate structure to be used in Budget process for 2004 starting in June/July 2003

# 2004 GMC Rate Structure Project (cont.)

- Partial list of topics covered
  - Rate design 101
  - FERC Staff on Formula Rates
  - ISO Activities
  - Data requirements for different proposals
  - Other ISO rate structures
  - Rate design criteria
  - Past ISO GMC proceedings

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# 2004 GMC Rate Structure Project (cont.)

- Participants
  - Regulatory agencies – CPUC, EOB
  - Governmental entities – MID, NCPA, other munis represented through Navigant, CDWR
  - IOUs – Sempra, PG&E, SCE
  - Others – IEP, CAC

# 2004 GMC Rate Structure Project (cont.)

- Meetings
  - October 2002 through January 2003
  - Next meeting scheduled for February 19, 2003 possibly in San Francisco
- Meetings planned through May/June 2003
  - Everyone is welcome to attend
  - Debi Le Vine/Phil Leiber co-leads
- Documents available –
  http://www.caiso.com/docs/2002/08/02/2002080216283419989.html

**From:** Arikawa, Ben
**Sent:** Wednesday, January 15, 2003 1:29 PM
**To:** GMC WG
**Subject:** Conference call with MID re: functionalization, cost allocation (note corrected date)

**My apologies, it is Thursday, January 16th at 9:00 AM.**

The conference call with MID is scheduled for:

**Thursday, January 16, 2003**
**9:00 - 11:00 AM (PST)**
**call in #: 888-788-6681**
**passcode: 921065**

MID will have Laurence Kirsch, Ross Hemphill, and Jan Pritchard. The ISO will have Phil Leiber, Cathy Yap and me on the call. We will be discussing how the ISO and MID can proceed on the analysis of the MID rate structure proposal.

Ben Arikawa
Senior Financial Analyst
California Independent System Operator
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Folsom, CA 95630

Voice: (916) 608-5958
fax: (916) 351-2259

email: barikawa@caiso.com

CALIFORNIA ISO

California Independent
System Operator

Notes of January 16, 2003 conference with MID to discuss MID concerns in 2004 GMC Rate Structure Project

On the conference call, or portions of the call, were:

| | |
|---|---|
| Laurence Kirsch (MID) | Karen Shea (CPUC) |
| Ross Hemphill (MID) | Lisa Wolfe (EOB) |
| Jan Pritchard (MID) | Dale Yakin (PG&E) |
| Sean Neal (MID) | Mike Peterson (ISO) |
| Mike McGuffin (ISO) | John Springer (ISO) |
| Phil Leiber (ISO) | Ben Arikawa (ISO) |
| Catherine Yap (Barkovich and Yap) | |

Our discussion began on the topic of the availability of billing determinant data and its release. The ISO did commit to release aggregate billing determinants within the next day. MID specifically requested interval deviation data by SC (masked and a minimum of six months stale), which the ISO committed to supplying within one week subject to the potential need to issue a market notice prior to its release. The initial release would be for 10 months (Sept. 2001 - June 2002).

The next topic was how best to approach the allocation of costs to MID's four functions. MID argued that only the ISO had the knowledge and insight necessary to perform the allocation.

The ISO laid out three options. These were (1) for the ISO to provide all information to MID for MID to do the allocation themselves; (2) for the ISO to provide MID with information and the ISO to assist MID in developing the allocations with a possible all day meeting at the ISO; and, (3) ISO to perform allocation with assistance and clarification from MID. MID preferred option 3. The ISO preferred option 1.

After some discussion, in order to make progress, we decided to exchange and review information and have an additional conference call on Thursday, January 23rd, 9:00 - 11:00 AM to discuss our reviews and plan next steps. MID still believes that option 3 is preferable.

In summary, we agreed to the following:

1. Distribution of 10 months (Sept 2001 - June 2002) of interval level deviation data by SC within the next week subject to the need to have a market notice prior to release.

2. ISO will provide MID (and the rest of the GMC WG)
    a. 2000 Operational Audit
    b. ISO Board version of 2003 Budget document (NDA signature necessary)
    c. CAM template modified to include MID's four functions (NDA signature necessary)
    d. job descriptions for personnel in each department

3. MID will provide a Statement BA equivalent document part of the FERC documentation in the ISO GMC informational filing) for ISO to clarify what activities fall under each of MID's functions.

4. Conference call on Thursday, January 23rd, 9-11 AM to discuss where we are.

Results of conference call with MID re MID proposal 01-16-03.txt
From: JAN PRITCHARD [JanP@MID.ORG]
Sent: Thursday, January 16, 2003 1:33 PM
To: BArikawa@caiso.com; PLeiber@caiso.com; lkirsch@lrca.com; ross@lrca.com
Subject: Results of conference call with MID re: MID proposal

Ben,

I agree with the substance of your report. However, I have to point out that the three options were "laid out" unilaterally by the ISO. MID
entered the GMC 2004 activity with the clear understanding that the stakeholder process would be conducted under the scenario currently styled by the ISO as "Option 3". I wouldn't want the GMC WG to conclude
from this report that MID's agreement to extend today's discussion constitutes any validation or acceptance of the "Option" concept. I believe it would be best to record the fact that the ISO and MID are not
of one mind with respect to this issue.

Jan

2BBYvx.370000000.9914

>>> "Arikawa, Ben" <BArikawa@caiso.com> 01/16/03 11:56AM >>>
Let me know if this agrees with what you recall before I send it out t o
the
entire GMC WG.

On the conference call, or portions of the call, were:

| | |
|---|---|
| Laurence Kirsch (MID) | Karen Shea (CPUC) |
| Ross Hemphill (MID) | Lisa Wolfe (EOB) |
| Jan Pritchard (MID) | Dale Yakin (PG&E) |
| Sean Neal (MID) | Mike Peterson (ISO) |
| Mike McGuffin (ISO) | John Springer (ISO) |
| Phil Leiber (ISO) | Ben Arikawa (ISO) |
| Catherine Yap (Barkovich and Yap) | |

Our discussion began on the topic of the availability of billing determinant
data and its release. The ISO did commit to release aggregate billing determinants within the next day. MID specifically requested interval deviation data by SC (masked and a minimum of six months stale), which the
ISO committed to supplying within one week subject to the potential

need to
issue a market notice prior to its release. The initial release would
be
for 10 months (Sept. 2001 - June 2002).

The next topic was how best to approach the allocation of costs to
MID's
four functions. The options laid out were (1) for the ISO to provide
all
information to MID for MID to do the allocation themselves; (2) for th
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ISO
to provide MID with information and the ISO to assist MID in developin
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the
allocations with a possible all day meeting at the ISO; and, (3) ISO
to
perform allocation with assistance and clarification from MID. After
some
discussion, we decided to exchange and review information and have an
additional conference call on Thursday, January 23rd, 9:00 - 11:00 AM
to
discuss our review and plan next steps.

In summary, we agreed to the following:

1. distribution of 10 months (Sept 2001 - June 2002) of interval level
deviation data by SC within the next week subject to the potential nee
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to
have a market notice prior to release.

2. ISO will provide MID (and the rest of the GMC WG)
   a. 2000 Operational Audit
   b. ISO Board version of 2003 Budget document (NDA signature
necessary)
   c. CAM template modified to include MID's four functions (NDA
signature necessary)
   d. job descriptions for personnel in each department

3. MID will provide a Statement BA equivalent document for ISO to
clarify
what activities fall under each of MID's functions.

4. Conference call on Thursday 9-11 AM to discuss where we are.

Ben Arikawa

Senior Financial Analyst
California Independent System Operator
151 Blue Ravine Road
Folsom, CA 95630

Voice: (916) 608-5958
fax: (916) 351-2259

email: barikawa@caiso.com

RE Results of conference call with MID re MID proposal 01-16-03.txt
From: Leiber, Phil
Sent: Thursday, January 16, 2003 4:50 PM
To: Pritchard, Jan; Kirsch, Laurence; Hemphill, Ross; Neal, Sean
Cc: Arikawa, Ben
Subject: RE: Results of conference call with MID re: MID proposal

Jan, Lawrence, Ross, Sean:

Attached please find the modified CAM document referred to in our conference call today.

I have also provided a list of steps and suggestions (as the first tab

in that worksheet) as to how this exercise can proceed. We recognize you have concerns about how the cost allocation should be performed, and we will attempt to work together to resolve them so that you are able to achieve your objectives.

The ISO has sent via FedEx the ISO Board Version of 2003 Budget document, and will also provide the job descriptions in the next day.

This material is being provided subject to the NDA.

Also attached below are references to the ISO's Operational and SAS70 audit reports. While I do not believe reference to these reports is necessary to conduct this allocation exercise (as the ISO Board versio
n
of 2003 Budget document is quite comprehensive), you may find this material useful. These documents are available to the public, and are

posted on the ISO website.

Operations Audit (for 2001....2002 not yet complete)

http://www.caiso.com/docs/09003a6080/13/e2/09003a608013e20f.pdf
http://www.caiso.com/docs/09003a6080/14/0f/09003a6080140f9d.pdf

SAS 70 Report
http://www.caiso.com/docs/09003a6080/18/c5/09003a608018c5a3.pdf

Philip Leiber, Treasurer & Director of Financial Planning
California ISO
(916) 351-2168

(916) 351-2259 (fax)

-----Original Message-----
From: Arikawa, Ben
Sent: Thursday, January 16, 2003 3:35 PM
To: GMC WG
Subject: Results of conference call with MID re: MID proposal

On the conference call, or portions of the call, were:

| | |
|---|---|
| Laurence Kirsch (MID) | Karen Shea (CPUC) |
| Ross Hemphill (MID) | Lisa Wolfe (EOB) |
| Jan Pritchard (MID) | Dale Yakin (PG&E) |
| Sean Neal (MID) | Mike Peterson (ISO) |
| Mike McGuffin (ISO) | John Springer (ISO) |
| Phil Leiber (ISO) | Ben Arikawa (ISO) |
| Catherine Yap (Barkovich and Yap) | |

Our discussion began on the topic of the availability of billing determinant data and its release. The ISO did commit to release aggregate billing determinants within the next day. MID specifically requested interval deviation data by SC (masked and a minimum of six months stale), which the ISO committed to supplying within one week subject to the potential need to issue a market notice prior to its release. The initial release would be for 10 months (Sept. 2001 - Jun
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The next topic was how best to approach the allocation of costs to MID's four functions. MID argued that only the ISO had the knowledge and insight necessary to perform the allocation.

The ISO laid out three options. These were (1) for the ISO to provide

all information to MID for MID to do the allocation themselves; (2) fo
r
the ISO to provide MID with information and the ISO to assist MID in developing the allocations with a possible all day meeting at the ISO;

and, (3) ISO to perform allocation with assistance and clarification

RE Results of conference call with MID re MID proposal 01-16-03.txt from MID. MID preferred option 3. The ISO preferred option 1.

After some discussion, in order to make progress, we decided to exchange and review information and have an additional conference call

on Thursday, January 23rd, 9:00 - 11:00 AM to discuss our reviews and plan next steps. MID still believes that option 3 is preferable.

In summary, we agreed to the following:

1. distribution of 10 months (Sept 2001 - June 2002) of interval level

deviation data by SC within the next week subject to the need to have a
market notice prior to release.

2. ISO will provide MID (and the rest of the GMC WG)
   a. 2000 Operational Audit
   b. ISO Board version of 2003 Budget document (NDA signature necessary)
   c. CAM template modified to include MID's four functions (NDA signature necessary)
   d. job descriptions for personnel in each department

3. MID will provide a Statement BA equivalent document part of the FER C
documentation in the ISO GMC informational filing) for ISO to clarify what activities fall under each of MID's functions.

4. Conference call on Thursday, January 23rd, 9-11 AM to discuss where

we are.

Ben Arikawa
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fax: (916) 351-2259

email: barikawa@caiso.com

Need for market notice for data release 01-16-03.txt

From: Arikawa, Ben
Sent: Thursday, January 16, 2003 3:38 PM
To: Pritchard, Jan; Kirsch, Laurence; Hemphill, Ross
Cc: Leiber, Phil; Morrison, Stephen
Subject: Need for market notice for data release

Jan,

A market notice will be required prior to the release of the SC specific data (masked and "stale"). We will be working on getting tha
t
out tomorrow, asking for protests within 5 business days which puts us

on track to release the data late Thursday or Friday of next week.

Ben Arikawa
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California Independent System Operator
151 Blue Ravine Road
Folsom, CA 95630

Voice: (916) 608-5958
fax: (916) 351-2259

email: barikawa@caiso.com

**From:** CRCommunications
**Sent:** Thursday, January 16, 2003 5:12 PM
**To:** ISO Market Participants
**Cc:** Morrison, Stephen; Leiber, Phil; Arikawa, Ben; McGuffin, Mike
**Subject:** CAISO Notice - SC Data Release - ISO 2004 GMC Rate Structure Project

# MARKET NOTICE

**January 16, 2003**

**Market Participants and Scheduling Coordinators:**

## ISO 2004 GMC Rate Structure Project
## SC Data Release

**The California ISO was directed by FERC** (Initial Decision of Hon. Bobbie J. McCartney ALJ in Docket ER01-313-000 etc.) **to undertake a comprehensive review of its GMC rate structure** during the course of 2003. **That project must permit effective stakeholder participation, including stakeholder testing of alternative methods of rate design. To facilitate that the ISO has been asked to release certain SC related data to specified stakeholders. The data in question is deviation data by SC, by 10 minute interval starting September 2001.**

To the extent that this request seeks information that is confidential under ISO Tariff Section 20.3.2., the ISO has required confidential treatment for such information. **Any stakeholder acquiring access to such data must first have executed the ISO's Confidentiality Agreement for this Project.** In addition the ISO has removed all means of identifying specific SCs. **Finally, the ISO does not currently intend to release any data for this Project until six months after the passage of the Trade Dates in question.**

π

Therefore, given the foregoing safeguards, the ISO plans to produce appropriate materials at the close of business January 23, 2003, unless the ISO receives a court or other appropriate order that prohibits disclosure. If you have any questions, please contact ISO Corporate Counsel, Stephen Morrison, at smorrison@caiso.com

Client Relations Communications.1002
CRCommunications@caiso.com <mailto:CRCommunications@caiso.com>

Agenda 01-21-03.txt

From: JAN PRITCHARD [JanP@MID.ORG]
Sent: Tuesday, January 21, 2003 3:58 PM
To: BArikawa@caiso.com
Cc: SMN@dwgp.com
Subject: Agenda

Ben,

We will go with the ISO's agenda for Tursday.

Jan

2BBYvx.370000000.9914

Agenda for tomorrow's MIDCAISO call 01-22-03.txt

From: Arikawa, Ben
Sent: Wednesday, January 22, 2003 11:52 AM
To: Pritchard, Jan; Hemphill, Ross; Kirsch, Laurence
Cc: Leiber, Phil
Subject: Agenda for tomorrow's MID/CAISO call

Jan,

I'm sorry, I forgot to send this out to you this morning. Ross and I discussed it this morning and I made some modifications. I will send this out after lunch, possibly about 1:30 along with your statement BA
.

Ben Arikawa
Senior Financial Analyst
California Independent System Operator
151 Blue Ravine Road
Folsom, CA 95630

Voice: (916) 608-5958
fax: (916) 351-2259

email: barikawa@caiso.com

Agenda
MID/CAISO conference call
2004 GMC Rate Structure Project
Thursday, January 23, 2003
9:00 – 11:00 AM
Call in number: 888-788-6681
Pass code: 921065

1. Status of Uninstructed Deviation data
2. MID Statement BA
3. ISO documents provided
    a. 2001 Operational Audit
    b. 2002 SAS 70
    c. Board Budget Book
4. How to proceed with cost allocation
    a. MID
    b. ISO
5. Next steps

CHRISTENSEN ASSOCIATES

Laurits R. Christensen Associates, Inc.
4610 University Avenue, Suite 700
Madison, Wisconsin 53705-2164

Voice 608.231.2266 Fax 608.231.2108

TO: Ben Arikawa

FROM: Ross Hemphill & Laurence Kirsch

DATE: 1/21/03

SUBJECT: Wholesale Customer Rate Functions

As agreed during last week's conference call, we have prepared our own version of Statement BA. This is attached hereto. While we expect that our description of the functions is at least 95% accurate, we are aware that further information from the ISO about its operations and accounting may induce us to refine some details; so we have labeled this Statement BA as a "draft."

We look forward to speaking with you again this Thursday.

**Wholesale Customer Rate Functions**

### Resolving Energy Imbalances

This category includes the costs of all of those activities that the ISO performs, in advance and near real time, that are oriented toward assuring that the power system manages, at every instant in time, to have resources almost exactly equal to loads (including losses). Advance activities include: performing operation studies; conducting system security analyses; conducting system planning studies; and determining and enforcing regulation and reserve requirements. Near real-time activities include: integrating ISO operations with those of other control areas; coordinating facility outages; scheduling and dispatching generation, imports, exports, and wheeling; and settlement, billing, and metering costs.[1] This category does *not* include the market-making activities that the ISO performs to allow market participants to resolve their own imbalances before real-time.

Relative to the ISO's Statement BA, this category includes that portion of the Control Area Services costs that are related to resolving energy imbalances, plus that portion of Market Operations / ASREO costs that are related to arranging trades in real time.

### Managing Transmission Flows

This category includes the costs of all of those activities that the ISO performs, in advance and near real time, that are oriented toward assuring that transmission flows do not exceed transmission capabilities. Advance activities include: performing operation studies; conducting system security analyses; fostering transmission maintenance standards; conducting system planning studies; and planning transmission. Near real-time activities include: integrating ISO operations with those of other control areas; coordinating facility outages; and scheduling and dispatching generation, imports, exports, and wheeling. Costs that are not related to the other three functions shall be deemed to fall within the Managing Transmission Flows function.

Relative to the ISO's Statement BA, this category includes all Congestion Management costs, plus that portion of the Control Area Services costs that are related to managing transmission flows.

### Scheduling Generators, Loads, and Transmission Facilities

This category includes the incremental costs that the ISO incurs whenever SCs change their schedules. These incremental costs include the capital, labor, and operations costs of having facilities and staff available to provide this service.

[1] Settlement, billing, and metering costs can split between the Resolving Energy Imbalances function and the Administering Markets function in proportion to their relative transactions volumes.

Relative to the ISO's Statement BA, this category includes all that portion of the Control Area Services costs that are related to scheduling.

**Administering Markets**

This category includes all costs of market-making activities. These activities are those that allow market participants to enter voluntary energy or ancillary services trades with one another in advance of real time. In principle, equivalent trading services could be provided by independent brokers; except that the ISO, like a stock exchange, needs to also provide the market monitoring services required to assure the market's integrity. Consequently, the costs of administering markets are those of having the hardware, software, communications, and personnel systems required to support trades in advance of real time, including settlement, billing, and metering costs.

Relative to the ISO's Statement BA, this category includes those Market Operations / ASREO costs that are related to making markets in energy and ancillary service in advance of real time. They do not include the costs of implementing or administering real-time trades.

**Mapping of ISO Rate Groups to MID Functions**

The following matrix shows how the ISO rate groups are related to the functions described in this Statement:

| **FROM** | **TO** | | | |
|---|---|---|---|---|
| | Resolving Energy Imbalances | Managing Transmission Flows | Scheduling | Administering Markets |
| Control Area Services | ✓ | ✓ | ✓ | |
| Congestion Management | | ✓ | | |
| Market Operations / ASREO | ✓ | | | ✓ |

**Notes from 9:00 – 11:00 AM January 23, 2003 GMC conference call with MID and other parties.**

On the conference call, or portions of the call, were:

Laurence Kirsch (MID)
Ross Hemphill (MID)
Jan Pritchard (MID)
Sean Neal (MID)
Mike McGuffin (ISO)
Phil Leiber (ISO)
Catherine Yap (Barkovich and Yap)
Patrick Alessandri (EOB)
Judy Nickel (ISO)
Karen Shea (CPUC)
Lisa Wolfe (EOB)
Dale Yakin (PG&E)
Mike Peterson (ISO)
John Springer (ISO)
Ben Arikawa (ISO)
Stephen Morrison (ISO)
David Timson (ISO)

The first item discussed was the status of the deviation data that MID requested. The data has been compiled into a Microsoft Access database. The ISO will create CDs with this database and distribute the CDs on Friday subject to the lack of objections from any market participant. As of this morning, no party had notified the ISO of any objections. This data will be sent only to parties that have executed the Confidentiality Agreement, signed and faxed in the Non-Disclosure Agreement and have requested the data. On the call, PG&E and the EOB requested copies of the data.

PG&E asked some clarifying questions about the four functions proposed by MID. A significant portion of the discussion concerned defining the "Scheduling Generation, Load and Transmission Facilities" function. MID initially proposed that this function should only be for incremental schedule changes, not for the bulk of scheduling. After some discussion, it was agreed that defining this function and developing billing determinant data for this function should take a lower priority relative to the other functions.

The discussion turned to the descriptions of functions provided by MID. There was agreement that the descriptions assisted all in understanding MID's proposal, but that there would be some areas in which judgment would be needed in order to make assignments of cost centers. MID agreed to make the "first cut" assignment of cost centers to their functions using the modified Cost Allocation Matrix that the ISO had sent out. The ISO agreed to provide MID with access to two staff members with knowledge of Grid Operations to assist MID in making the "first cut" assignments.

MID pointed out that there might be some errors in the formulas contained in the modified Cost Allocation Matrix. They pointed out that a quick test indicated that less than 100% of the costs were allocated (accounted for) once all assignments were made. The ISO agreed that errors were possible and that they would be fixed.

MID asked if all available data had been given to them. The ISO replied that it had, except for current information on job descriptions, which are considered highly confidential and could not be released at this time.

A follow-up conference call was scheduled for Thursday, January 30, 2003 at 9:30.

ISO Resources for Cost Allocation Exercise 01-23-03.txt

From: Leiber, Phil
Sent: Thursday, January 23, 2003 4:32 PM
To: Pritchard, Jan; Hemphill, Ross; Kirsch, Laurence; Neal, Sean
Cc: Arikawa, Ben; Hawkins, David (CAISO); Lyon, Deane
Subject: ISO Resources for Cost Allocation Exercise

As discussed in today's call, we have identified resources who will be

available to help in the assessment of how ISO costs can be assigned t
o
the MID proposed service categories.

Those resources are:

David Hawkins   Manager, Special Projects Engineering (Operations)
Tel. (916) 351-4465
Deane Lyon   Director, Operations Support & Training

Tel. (916) 351-2428

Their schedules over the next several days:

David Hawkins
------------------
Monday, Jan. 27 Out of the Office
Tuesday, Jan. 28 Out of the Office
Wednesday, Jan 29. In the Office but unavailable from 10am to 1 PM
Thursday, Jan 30. In the Office but unavailable from 10am to Noon
Friday, Jan 31. Out of the Office
Monday- Thursday Feb. 3-6th - In the Office and Available
Friday Feb. 7th Out of the office

Deane Lyon
------------------
Monday, Jan. 27 Busy 10-11, possibly available at other times during the day
Tuesday, Jan. 28 Likely available after 11am
Wednesday, Jan. 29 Busy 8-9, 3-5
Thursday, Jan. 30 Busy 8-5
Friday, Jan. 31 Available
Monday, Feb. 3 Available

Deane and David are knowledgable about the ISO's overall operations, the current GMC rate structure, and have been provided with the MID proposed service category descriptions. We have discussed this effort with Deane and David, and mentioned that the materials we provided to MID should be permit MID to make significant progress in the cost allocations, but that they, as ISO resources will need to help where additional clarity is required.

You are also welcome to contact either Ben or myself at any time. If you have trouble getting through to either of David or Deane (as of course they have ongoing responsilities and other "emergencies" may arise), we will involve other ISO operations staff as necessary.

Philip Leiber, Treasurer & Director of Financial Planning
California ISO
(916) 351-2168
(916) 351-2259 (fax)

FW MID conference call notes 01-24-03 .txt

From: Arikawa, Ben
Sent: Friday, January 24, 2003 10:56 AM
To: Pritchard, Jan; Hemphill, Ross; Kirsch, Laurence
Subject: FW: MID conference call notes

Please review the notes I have written. If you see anything inaccurat
e
or if I have left anything out, let me know before noon Monday.

Note: the attached documents are circulated by the sender solely for the express purpose of informing discussion. Therefore, none of the contents may be regarded by the reader as any form of offer, undertaking, policy, proposal or commitment by the sender, author or the California ISO.

Ben Arikawa
Senior Financial Analyst
California Independent System Operator
151 Blue Ravine Road
Folsom, CA 95630

Voice: (916) 608-5958
fax: (916) 351-2259

email: barikawa@caiso.com

Edits to 123 Meeting Notes 01-27-03.txt

From: lkirsch@svn.net
Sent: Monday, January 27, 2003 11:02 AM
To: BArikawa@caiso.com
Cc: janp@mid.org; smn@dwgp.com; rchemphill@lrca.com
Subject: Edits to 1/23 Meeting Notes

Ben:

Attached please find our tracked markup of your meeting notes. We have just a few edits.

Laurence
*******************************************************
Laurence D. Kirsch
Laurits R. Christensen Associates, Inc.
e-mail: LKIRSCH@LRCA.COM
voice: (415) 663-8608
fax: (415) 663-8818

Please visit our website at WWW.LRCA.COM
*******************************************************

RE Preliminary Functional Assignments 01-29-03.txt

From: lkirsch@svn.net
Sent: Wednesday, January 29, 2003 9:31 AM
To: Arikawa, Ben; Pritchard, Jan; rchemphill@lrca.com
Subject: RE: Preliminary Functional Assignments

Ben:

You are welcome to do so.

Laurence

On 29 Jan 2003, at 8:29, Arikawa, Ben wrote:

Do you mind if I share this with the rest of the participants?

-----Original Message-----
From: lkirsch@svn.net [mailto:lkirsch@svn.net]
Sent: Tuesday, January 28, 2003 8:34 PM
To: BArikawa@caiso.com
Cc: janp@mid.org; rchemphill@lrca.com
Subject: Preliminary Functional Assignments

Ben:

Attached please find a memorandum to you plus an accompanying spreadsheet.

Laurence

*******************************************************
Laurence D. Kirsch
Laurits R. Christensen Associates, Inc.
e-mail: LKIRSCH@LRCA.COM
voice: (415) 663-8608
fax: (415) 663-8818

Please visit our website at WWW.LRCA.COM
*******************************************************

*******************************************************
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fax: (415) 663-8818

Please visit our website at WWW.LRCA.COM

******************************************************

# 2004 GMC Rate Structure Project, a Stakeholder Process

**Business Opportunity/Problem: [State the problem(s) the project will address in business terms. State the problem's impact to the business including the effects and costs (tangible, where possible]**

The California ISO ("ISO") needs to recover its start-up, capital, and operation and maintenance costs (collectively referred to as ISO costs or revenue requirement) through the Grid Management Charge ("GMC"). The ISO believes that a complete reassessment of the GMC Rate Structure[1] is warranted at this time given past experiences with GMC ratemaking, and anticipated future changes. The Initial Decision by the Federal Energy Regulatory Commission ("FERC") Administrative Law Judge in the 2001 GMC proceeding directed the ISO "to undertake a comprehensive stakeholder review for the purpose of re-evaluation of the GMC structure in 2003" and "the ISO is directed to make a Section 205 filing upon completion of that re-evaluation process in 2003."[2]

An added challenge is the fact that the ISO is making significant changes to the current market design over the period of the MD02 effort [3](potentially extending from 2002-2006). The existing GMC rate structure needs to be re-evaluated to address stakeholder concerns in preparation of the 2004 GMC Rate setting process in the fall of 2003. Significant challenges in evaluating appropriate changes will be the lack of clarity regarding timing and composition of the MD02[4] and FERC Standard Market Design elements[5], and lack of data related to the effect of these changes on potential billing determinant volumes and costs.. Parties recognize that future changes to the GMC may be appropriate outside the scope of this effort.

## Goals/Objectives:

**Primary Goals/Objectives: [List in business terms the project's primary purpose and the high level results expected from its completion]**

The primary goal of the 2004 GMC Rate Structure Project is through a stakeholder process develop and implement a GMC rate methodology that best supports the new and still

---

[1] Rate Structure includes: determination of services provided (current and future), accumulation of overall costs, cost allocation, rate design (including billing determinants). While not the primary focus of this group, the overall level of ISO costs (also referred to as the ISO revenue requirement) is of concern to ISO stakeholders, and consideration of a mechanism to adequately address this issue prospectively may be necessary.

[2] The intention of the direction is to work during 2003 for implementation of a new GMC structure in 2004.

[3] MD02 is being funded through the currently existing rate structure/budgets.

[4] Since the inception of this 2004 GMC Rate Structure Project, the timeline for MD02 has been delayed, with Phase II and III originally targeted for 2003, now scheduled for mid-2004. Given the uncertainty as to the ultimate composition and timing of specific elements of MD02, some participants in this process believe it may be prudent to limit major changes to the current GMC structure and to reconsider such changes in the future. However, as no consensus exists on this point, the Project will proceed without a limitation on the scope of potential changes due to this issue, recognizing that this can be revisited at any time.

[5] The FERC SMD NOPR was issued in July 2002. A summary of key dates related to SMD is located at: http://www.ferc.gov/Electric/rto/Mrkt-Strct-comments/nopr/smd-key-dates.pdf The California ISO plans to submit "Reply Comments" by a February 17, 2003 deadline. A FERC whitepaper on SMD is scheduled for release in April 2003, and a Final Rule is to be published in Summer 2003, As of January 2003, there is some speculation that this will be delayed due to opposition from various quarters.

changing market design in a way that achieves equity between Market Participants and provides for the collection of the ISO's costs.

**The objectives of this effort are to:**

- Develop a rate structure that meets the FERC "just and reasonable" standard, and appropriately allocates ISO costs among the ISO's users.
- Develop a rate structure based on the principle of cost causation which charges customers for the cost of services that they use/cause;
- Design a rate structure that is easy to administer (including reasonably cost effective, and benefits of change should outweigh the costs) and understandable;
- Develop a rate structure that does not result in unmanageable adverse operational impacts;
- Develop a rate structure that is arrived at through an open and balanced stakeholder process;
- Recover approved ISO costs in a stable, low risk manner without excess volatility;
- Have the new rate structure filed with FERC by November 1, 2003, so that it can be effective January 1, 2004, and
- Meet the terms of the 2002 GMC Settlement Agreement, which set forth issues to be covered in this 2004 GMC Stakeholder Process.

**Benefits: [List the key advantages of accomplishing the project. State in terms of tangible savings, wherever possible]**

Advantages of accomplishing this project include:

- Responding to the FERC Administrative Law Judge's 2001 GMC Initial Decision.
- A periodic review of the appropriateness of the ISO GMC structure.

From the ISO's perspective, additional advantages of accomplishing this project include:

- Development of better working relationships with Market Participants.
- Potential for reduced litigation at FERC related to future GMC filings.
- Possible better alignment of operational incentives with financial incentives affecting both the ISO and market participants.

**Scope: [Describe the boundaries of the project in terms of what it includes and what it does not include]**

Develop GMC rate structure to be effective January 1, 2004 that considers and evaluates various rate methodologies/structures, including but not limited to, the one currently in use, and the applicability of each proposal to the needs of impacted parties, including Market Participants and the ISO.

This effort will actively seek stakeholder participation in the development of the recommended solution. Feedback regarding disposition of all participation, including proposal status and comment review will be provided to all participants.

This effort will produce recommendation(s) that are given to the ISO. The ISO will set forth such recommendation(s) in the memorandum to the Board of Governors. The ISO Board of Governors will determine the 2004 GMC rate methodology to be filed by the ISO with FERC.

Excluded from the scope of this effort are issues related to the level or composition of the ISO budgets. However, ISO spending on various elements of the ISO's changing responsibilities related to MD02 and/or SMD may be considered as appropriate in the consideration of rate structure. Stakeholders recognize that integration of the ISO budget process and the rate structure is necessary to arrive at a November 1, 2003 filing that incorporates these elements.

**Product Deliverables: [The major elements of work that will be completed on the project. The set of specific, measurable, tangible, verifiable results expected from the completion of the project]**

- A project charter agreed to by all participants.
- Proposals from the Market Participants and the ISO regarding rate design options.
- A tool showing potential rates to aid in analysis of overall rate design proposals, and to permit consideration of GMC charges for various scheduling coordinators.
- A preliminary Cost Allocation Matrix to set forth costs for various potential ISO service categories.
- A rate design proposal for ISO Governing Board approval.

**Constraints: [List the factors that limit the project team's options (schedule, cost or scope/quality). Indicate which is the driving factor for the project; i.e. a predefined budget constrains scope and staffing]**

- Project due date is constrained by the FERC rate filing schedule (outside project control).
- Lack of clarity regarding ultimate MD02/SMD timeline and elements.
- Lack of data on the future effect of MD02/SMD market rules.
- Historical data on potential billing determinants and the level of granularity of cost/accounting records
- Finite team resources limit exploration and analysis of alternatives.

**Risks: [State the major exposures to possible delay, or failure in meeting the stated goals/objectives of the project]**

1. Time constraints of all parties due to the changes in market structure both by the ISO's MD02 and FERC's Standard Market Design Notice Of Proposed Rulemaking.
2. Inability to reach consensus on a rate design could result in extended litigation at FERC.
3. Lack of data regarding the effect of MD02 market changes and timing issues of MD02 could result in the adoption of a rate design that has significantly different impacts than anticipated.
4. Market instability due to regulatory risk and the potential for creditworthiness issues could divert team attention from this effort.

| | | |
|---|---|---|
| **ISO Project Leads:** | Debi Le Vine, Contracts; | Phil Leiber, Finance |
| **ISO Team Members:** | | |
| Jan Addy, Project Office; | Ben Arikawa, Finance; | Mike Epstein, Finance; |
| Don Fuller, Settlements; | Deane Lyon, OSAT; | Kevin Graves, Ops, Eng & Maintenance; |
| Mike McGuffin, Settlements; | Mike Peterson, OSAT; | Stephen Morrison, Legal & Regulatory; |
| David Withrow, Policy Office; | | Kyle Hoffman, Client Relations |
| **ISO Project Executive Sponsor:** | Bill Regan, CFO; | |

**Project Milestones: [If possible, list the key accomplishment points, required approvals, set dates.]**

1. Process Kickoff with Stakeholders — August 29, 2002
2. Develop and approve Project Charter
3. Develop and approve evaluation criteria for proposals
4. Proposals due from Market Participants and ISO
5. Proposal evaluation
6. Develop recommended solution
7. ISO provide update to MIF during process
8. ISO present to ISO Governing Board — May, 2003

**See following page for more detailed list of requirements**

# Project Completion Steps

January

- Finalize list of ISO groupings of activities
- Distribute aggregate billing determinant data for use in proposal development

February

- Meeting on February 19:
    - Stakeholders present initial conceptual proposals
    - ISO presents its initial conceptual proposal

March

- ISO completes indicative/preliminary allocation of 2003 costs to groupings of activities list
- Proposal evaluation
- ISO/Stakeholders present refined proposals with cost/billing determinant data
- Communicate status through MIF

April

- Proposal evaluation
- Customer impact analysis
- Development of consensus proposal?
- Communicate status through MIF

May

- Present design to ISO governing board for approval

June

- Implementation of rate structure for use in 2004 budget development

July

- ISO Budgeting Commences

October

- Board approval of ISO 2004 budget

November

- File rate structure and budget/rate proposal at FERC

rmation supporting cost allocations of bond funded capital expenditures 01-28-03

From: Arikawa, Ben
Sent: Tuesday, January 28, 2003 4:51 PM
To: Kirsch, Laurence; Hemphill, Ross; Pritchard, Jan
Cc: Leiber, Phil; Cogdill, Jan; Morrison, Stephen
Subject: Information supporting cost allocations of bond funded capita
l
expenditures

Ross and Laurence:

Attached are some supporting documents for the allocation of bond funded capital expenditures. There is a Word document with the descriptions of the various systems. The "Capital2 without capital detail" spreadsheet has additional descriptions of systems. The "2003Capi without 2003 detail" spreadsheet contains more detail about capital expenditures for the year 2000 bonds.

If you have additional questions, please contact either Jan Cogdill (916.351.2302) or Phil Leiber (916.351.2168).

Note: the attached documents are circulated by the sender solely for the express purpose of informing discussion. Therefore, none of the contents may be regarded by the reader as any form of offer, undertaking, policy, proposal or commitment by the sender, author or the California ISO.

Ben Arikawa
Senior Financial Analyst
California Independent System Operator
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Folsom, CA 95630

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fax: (916) 351-2259

email: barikawa@caiso.com

# Memorandum

**To:** Participants in 2004 GMC Rate Structure Project

**From:** Ben T. Arikawa, Senior Financial Analyst

**Date:** January 29, 2003

**Re:** **Conference call information and other 2004 GMC Rate Structure Project related items**

---

This memorandum contains information about the next conference call, the next 2004 GMC Rate Structure Project meeting, the charter for the 2004 GMC Rate Structure Project and data availability.

**Thursday, January 30, Conference Call information**

Conference call information for tomorrow's conference call is:

Thursday, January 30, 2003
9:30-11:00 AM
Call in # 1-888-788-6681
Pass code 921065

The tentative agenda is:

- MID (Kirsch & Hemphill) describe the assignment process and input thus far.
- ISO questions regarding assignment process.
- Discuss questions raised in MID (Kirsch & Hemphill) memo accompanying spreadsheet.
- Discuss additional information needs and action plan for meeting these needs.
- Next Steps

Attached to the e-mail distributing this memorandum are the documents prepared by Ross Hemphill and Laurence Kirsch of Christensen Associates.

Also, in response to MID's request for more information concerning the assignment of bond costs to functions, the ISO sent three documents to MID. These are a Word document with the descriptions of the various ISO systems, a spreadsheet, "***Capital2 without capital detail***," that has additional descriptions of some ISO systems and a spreadsheet, "***2003Capi without 2003 detail***," that contains more detail about capital expenditures for the year 2000 bonds. The first two items are attached to the e-mail message. The third item will be send on request to those parties that have signed the Confidentiality Agreement and Non-Disclosure Certificate.

**Wednesday, February 19, 2003 GMC meeting information** Exh. No. ISO- 158, Page 2 of 2

PG&E has graciously offered to host the next meeting on February 19, 2003 in San Francisco. A notice concerning the reservation of parking in PG&E's parking facility was sent out on January 23, 2003. A copy of that notice is attached to the e-mail message, which is being used to distribute this memorandum. Parking spaces are still available. Please contact Michelle Gamble (mgamble@caiso.com) to request a space reservation.

Prior to the meeting, we will send out more detailed meeting information, including the call in number and a proposed agenda, to the GMC WG distribution list as well as market participants.

**2004 GMC Rate Structure Project Charter**

An updated charter is attached to the e-mail message. If you have comments or questions, please contact Phil Leiber, (916) 351-2168.

**Distribution of aggregated billing determinant data**

A complete set of the aggregated data should be available by Friday, January 31 and will be sent to all those participants on the GMC WG distribution list. This data will include the estimated QF and municipal behind the meter load used in the calculation of gross control area load (energy).

**Deviation data prepared for MID**

The MID deviation data is available for those that have signed the Confidentiality Agreement and the Non-Disclosure Certificate. As of today, the EOB, CAC, and PG&E have requested the CD. If you wish to have a copy of the data, please e-mail me with your street address and telephone number so that we can send this information to you by Federal Express.

**Preliminary assignment of SCs to customer classes**

For the purpose of determining customer impacts, we have begun to assign SC IDs to the following customer categories:

- IOU
- Governmental entity
- Generator
- Marketer/Broker or Other.

This assignment is not yet complete, but will be distributed to the GMC WG distribution list, possibly within the next week.

If you have any questions about any of the information contained in this memorandum or about the process, please do not hesitate to contact me by phone, (916) 608-5958, or e-mail at barikawa@caiso.com.

RE Preliminary Functional Assignments 01-29-03.txt

From: lkirsch@svn.net
Sent: Wednesday, January 29, 2003 9:31 AM
To: Arikawa, Ben; Pritchard, Jan; rchemphill@lrca.com
Subject: RE: Preliminary Functional Assignments

Ben:

You are welcome to do so.

Laurence

On 29 Jan 2003, at 8:29, Arikawa, Ben wrote:

Do you mind if I share this with the rest of the participants?

-----Original Message-----
From: lkirsch@svn.net [mailto:lkirsch@svn.net]
Sent: Tuesday, January 28, 2003 8:34 PM
To: BArikawa@caiso.com
Cc: janp@mid.org; rchemphill@lrca.com
Subject: Preliminary Functional Assignments

Ben:

Attached please find a memorandum to you plus an accompanying spreadsheet.

Laurence

******************************************************
Laurence D. Kirsch
Laurits R. Christensen Associates, Inc.
e-mail: LKIRSCH@LRCA.COM
voice: (415) 663-8608
fax: (415) 663-8818

Please visit our website at WWW.LRCA.COM
******************************************************

******************************************************
Laurence D. Kirsch
Laurits R. Christensen Associates, Inc.
e-mail: LKIRSCH@LRCA.COM
voice: (415) 663-8608
fax: (415) 663-8818

Agenda for 130 Conference Call 01-29-03.txt

MessageFrom: Ross Hemphill [rchemphill@lrc re□□i
Sent: Wednesday, January 29, 2003 12:14 PM
To: Arikawa, Ben
Cc: Jan Pritchard; Laurence Kirsch
Subject: Agenda for 1/30 Conference Call

Ben,

If I could amend Laurence's earlier e-mail, I suggest the following agenda:

1.. MID (Kirsch & Hemphill) describe the assignment process and input thus far.
2.. ISO questions regarding assignment process.
3.. Discuss questions raised in MID (Kirsch & Hemphill) memo accompanying spreadsheet.
4.. Discuss additional information needs and action plan for meeting these needs.
5.. Next Steps

Thanks,

Ross

---

Ross C. Hemphill, Ph.D.
Vice President
Christensen Associates
Tel: 608-231-2266 (Ext. 168)
Cell: 608-712-7513
Website: http://www.LRCA.com

Available Hours for Kirsch Hemphill 01-30-03.txt
MessageFrom: Ross Hemphill [rchemphill@lrca.com]
Sent: Thursday, January 30, 2003 11:47 AM
To: Arikawa, Ben
Cc: Jan Pritchard; Laurence Kirsch
ubject: Available Hours for Kirsch & Hemphill

Ben,

Attached is a table with available times for Laurence Kirsch and me.
As you can see, we are pretty flexible during the next week and a half
.

Ross

---

Ross C. Hemphill, Ph.D.
Vice President
Christensen Associates
Tel: 608-231-2266 (Ext. 168)
Cell: 608-712-7513
Website: http://www.LRCA.com

2004 GMC Project conference call re MID rate proposal.txt

From: Arikawa, Ben
Sent: Friday, January 24, 2003 9:35 AM
To: GMC WG
Subject: 2004 GMC Rate Structure Project conference call re: MID rate proposal

2004 GMC Rate Structure Project
Conference Call
Subject: Follow up discussion with MID on MID proposal
Thursday, January 30, 2003
9:30-11:00 AM
Call in # 1-888-788-6681
Pass code 921065

The purpose of the conference call is to discuss MID progress on development of its proposal and whether additional ISO assistance is required. Other topics may also be discussed.

Ben Arikawa
Senior Financial Analyst
California Independent System Operator
151 Blue Ravine Road
Folsom, CA 95630

Voice: (916) 608-5958
fax: (916) 351-2259

email: barikawa@caiso.com

CHRISTENSEN ASSOCIATES

Laurits R. Christensen Associates, Inc.
4610 University Avenue, Suite 700
Madison, Wisconsin 53705-2164

Voice 608.231.2266 Fax 608.231.2108

TO: Ben Arikawa

FROM: Ross Hemphill & Laurence Kirsch

DATE: 1/28/03

SUBJECT: Preliminary Functional Assignments

We have performed a first-cut functional assignment of the cost categories that were shaded red or yellow in the file "2003 Cost Allocation Matrix- Appendix C-MID.xls" that Phil Leiber sent to us last week. Our assignment appears in the attached spreadsheet "Assignments 030128.xls."

We emphasize that our functional cost assignment is not a proposal or recommendation, by either us or MID, but is instead a starting point for discussion. Because we have made this assignment on the basis of a couple of paragraphs of ISO text explaining each of the cost categories, we understand that our information is incomplete, to say the least. We hope that our assignment will serve as a catalyst for the ISO providing additional information – through conversation, for example – that will allow greater accuracy.

## Some Principles

In the "Comments" column of our spreadsheet, we have expressed, in rather few words, some principles by which further iterations may become more accurate. Specifically, where it appears to us that the cost assignments of several items might have a similar basis, we have preceded the comment with a bracketed number that is shared by the similar items. These bracketed numbers have the following approximate meanings:

[1] This item assures power balance and manages flows. We have used this split when descriptions clearly indicate a balancing component. For this exercise, we have used a 2:3 cost ratio.

[2] This item mainly manages flows but also assures power balance. We have used this split when we presume there is a balancing component although it is not explicit in the descriptions. For this exercise, we have used a 1:4 cost ratio.

[3] This item involves settlements. The assignment should be apportioned based on the volumes traded in the real-time imbalance market relative to the advance markets. Because we do not yet have real-time imbalance market data, for this exercise we have presumed a 2:3 ratio of real-time imbalance market volumes to advance market volumes.[1]

[4] This item should be apportioned based on the relative volumes of business for each of the functions. Though in principle it would be best to measure volumes in terms of dollar values, the practical approach is to use MWh volumes. Data already available to us indicate that transmission flow volumes are roughly five times market transactions volumes (excluding the real-time imbalance market). For this exercise, we have used a cost ratio that depends on this 5:1 ratio and the 2:3 ratio mentioned in the preceding paragraph.

Some Administering Markets cells are highlighted yellow where some portion of an item appears to be assignable to this function, though the main split is between the other two functions. For example, split [2] is usually 20% to Resolving Imbalances and 80% to Managing Transmission Flows. For item #1542 (Outage Coordination), 10% is assigned to Administering Markets because of the mention of market monitoring as part of this item; so the remaining 90% of the cost is assigned on a 20%/80% basis (implying 18% and 72%) in accordance with split [2].

We have not made assignments for items without department numbers because we have no written information about what these items are.

**What We Want to Know**

There are two big categories of things that we would like to know.

First, for the four splits listed above, what are the most accurate splits we can achieve within our time and other constraints? The good news is that the most important split is [4] because it accounts for about half of the costs we have examined; and it also happens to be the split for which an objective basis is most readily available. Split [3] can be performed on a similarly objective basis. Getting splits [1] and [2] right will be harder, which brings us to the second category.

The second category concerns how the ISO managers responsible for each cost center see the appropriate assignments. For the larger dollar items, it is important to get managers to estimate the portions of their budgets that are spent Resolving Imbalances and Administering Markets. (The remainder can be assigned to Managing Transmission Flows.)

Thanks again for your help. We look forward to speaking with you on Thursday.

---

[1] We understand that such data have been sent to us, so we should be able to refine the ratios by next week.

| ISO Dept # | Operating Costs | Percent Allocation Res Imb | Man Flow | Sched GL&T | Admin Mkts | Comments |
|---|---|---|---|---|---|---|
| 1500 | Operations - Direct Costs | | | | | |
| 1521 | Grid Planning | | 100 | | | transmission planning only |
| 1542 | Outage Coordination | 18 | 72 | | 10 | [2] gen outage coord'n assures power balance, inspections are for market monitoring |
| 1543 | Loads and Resources | 20 | 80 | | | [2] partly concerned with generation adequacy |
| 1544 | Real-Time Scheduling | 40 | 60 | | | [1] partly to assure balance, partly to manage flows |
| 1545 | Grid Operations - General | 40 | 60 | | | [1] partly to assure balance, partly to manage flows |
| 1546 | Security Coordination | 20 | 80 | | | [2] presumably this has a balancing element |
| 1554 | Special Projects Engineering | 19 | 76 | | 5 | [2] includes generation planning, minor assistance in market development |
| 1555 | Operations Support Group | 36 | 54 | | 10 | [1] partly to assure balance and to manage flows, minor assistance in market developmt |
| 1558 | Transmission Maintenance | | 100 | | | transmission planning only |
| 1561 | Operations Engineering South | 20 | 80 | | | [2] presumably this has a balancing element |
| 1562 | Operations Engineering North | 20 | 80 | | | [2] presumably this has a balancing element |
| 1563 | Coordinated Operations | 20 | 80 | | | [2] presumably this has a balancing element |
| 1565 | Pre-Scheduling and Support | 36 | 54 | | 10 | [1] partly to help market monitoring |
| 1566 | Regional Coordination - General | 20 | 80 | | | [2] this seems to have a minor balancing element |
| 1549 | Operations Training | 36 | 54 | | 10 | [1] partly to assure balance, partly to manage flows; presume a small market component |
| 1559 | Operations Application Support | | 100 | | | transmission planning only |
| 1511 | VP Grid Operations - General | 19 | 76 | | 5 | [2] partly to assure balance, presume a small market component |
| 1547 | Engineering and Maintenance - General | 20 | 80 | | | [2] presumably this has a balancing element |
| 1548 | OSAT | 32 | 48 | | 20 | [1] partly to assure balance, partly to manage flows; a small market component |
| 1564 | Operations Scheduling - General | 40 | 60 | | | [1] partly to assure balance, partly to manage flows |
| 1700 | VP Market Services | | | | | |
| 1722 | Application Support | 40 | | | 60 | [3] settlements: should be related to market volumes |
| 1723 | Tariff and Contract Implementation | | 100 | | | the purpose of RMR is to manage congestion |
| 1724 | BBS - PSS | 40 | | | 60 | [3] settlements: should be related to market volumes |
| 1725 | BBS - FSS | 40 | | | 60 | [3] settlements: should be related to market volumes |
| 1731 | Contracts and Special Projects | | 100 | | | no indication of balancing or market functions |
| 1741 | Client Relations | 10 | 75 | | 15 | [4] should be allocated in proportion to relative volumes of the overall business |
| 1752 | Manager of Markets | 40 | | | 60 | [3] should be related to market volumes |
| 1753 | Market Engineering | 40 | | | 60 | [3] should be related to market volumes |
| 1755 | Business Solutions | 40 | | | 60 | [3] should be related to market volumes |
| 1756 | Market Quality - General | 40 | | | 60 | [3] settlements: should be related to market volumes |
| 1757 | Market Integration | 40 | | | 60 | [3] should be related to market volumes |
| 1400 | Information Services - Direct Costs | | | | | |
| 1424 | Asset Management | 10 | 75 | | 15 | [4] should be allocated in proportion to relative volumes of the overall business |
| 1441 | Outsourced Contracts | 10 | 75 | | 15 | [4] should be allocated in proportion to relative volumes of the overall business |
| 1461 | Control Systems | 40 | 60 | | | [1] partly to assure balance, partly to manage flows |
| 1462 | Field Data Acquisition System (FDAS) | 45 | 10 | | 45 | partly AGC for balancing, partly settlements |
| 1467 | Settlement Systems Services | 40 | | | 60 | [3] settlements: should be related to market volumes |
| 1600 | Legal - Direct Costs | | | | | |
| 1641 | Market Analysis | | | | 100 | assures market integrity |
| 1642 | Market Surveillance Committee | | | | 100 | assures market integrity |
| 1661 | Compliance - General | 100 | | | | examines uninstructed deviations |
| 1662 | Compliance - Audits | 100 | | | | examines uninstructed deviations |
| 1241 | MD02 | | | | | |
| 1241 | MD02 | 10 | 75 | | 15 | [4] should be allocated in proportion to relative volumes of the overall business |
| | Other Revenues | | | | | |
| | WSCC Security Coordination | | | | | |
| | 1998 Bonds | | | | | |
| | Infrastructure - Direct Assigned Items | | | | | |
| | EMS | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | SI | | | | | |
| | SA | | | | | |
| | BBS (Billing & Settlements) | | | | | |
| | MDAS (Metering) | | | | | |
| | RMR-Software | | | | | |
| | Market Anaysis Software | | | | | |
| | Vehicles MDAS/Metering | | | | | |
| | FERC Study Software | | | | | |
| | GCP/RIG (Generator Communication with ISO) | | | | | |
| | SRS Software (FTR related) | | | | | |
| | ETC Software | | | | | |
| | FTR Auction software | | | | | |
| | ACC Upgrades (Communication btw ISO and IOUs) | | | | | |
| | Other Software and Enhancements | | | | | |
| | 2000 Spending: EMS/MDAS/Participating Load Prog | | | | | |
| | 2000 Spending: SA/SI/BBS | | | | | |
| | 2000 Spending: Other Systems/Vehicles | | | | | |
| | Total 2000 Bonds | | | | | |
| | 2000 Spending:SA/SI/BBS | | | | | |
| | 2000 Spending: EMS/CIM/FDA | | | | | |
| | 2001 Spending: EMS | | | | | |
| | 2001 Spending: SA/SI/BBS | | | | | |
| | Cash Funded Cap Ex 2003 Capital Budget | | | | | |
| | 2003 Budget: Operating Systems | | | | | |
| | 2003 Budget: MD02 | | | | | |
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**Draft Notes from 9:30 – 11:00 AM January 30, 2003 GMC conference call with MID and other parties.**

On the conference call, or portions of the call, were:

| | |
|---|---|
| Laurence Kirsch (MID) | David Hawkins (ISO) |
| Ross Hemphill (MID) | Rod Aoki (CAC) |
| Jan Pritchard (MID) | Dale Yakin (PG&E) |
| Mike Peterson (ISO) | Tony Lam (EOB) |
| John Springer (ISO) | Jing Chao Mi (CDWR-SWP) |
| Phil Leiber (ISO) | Ben Arikawa (ISO) |
| Catherine Yap (Barkovich and Yap) | David Cohen (Navigant Consulting) |

Agenda

- MID (Kirsch & Hemphill) describe the assignment process and input thus far.
- ISO questions regarding assignment process.
- Discuss questions raised in MID (Kirsch & Hemphill) memo accompanying spreadsheet.
- Discuss additional information needs and action plan for meeting these needs.
- Next Steps

This call was scheduled so that MID could review its preliminary assignment of ISO cost center costs to their functions with the ISO and other participants and could discuss with the ISO questions that MID had with respect to its preliminary assignments.

The call began with Laurence Kirsch and Ross Hemphill providing a description of how they proceeded to assign cost center costs to each of their functions, "Resolving Energy Imbalances," "Managing Transmission Flows," and "Administering Markets." Some time was spent reviewing the various documents that MID had received from the ISO in response to their request for additional information.

There was some confusion over a fourth function, "Scheduling Generation, Load and Transmission Facilities." On the January 23, 2003, conference call, this function was discussed. It was decided that the development of costs assignments for this function would be lower in priority than that for the other three functions.

There was a discussion of the various proportions that MID had used to "preliminarily" assign costs. MID gave an explanation of the four proportions used in its cost assignments. There was a discussion with Cathy Yap and David Cohen regarding the rationale and use of the proportions.

The ISO agreed with MID that more detail concerning the method of allocating bond-funded capital expenditures was needed. The ISO did commit to providing the relevant staff to discuss this with MID within the next two weeks.

There was a discussion of the various cost centers that might be considered "overhead," and how those might be assigned. Specifically, cost center 1441 (outsourced contracts) was discussed.

During subsequent discussion, cost center 1544 (Real-Time Scheduling) was discussed. The ISO offered a description of the activities under this cost center. Based on this discussion, MID might consider changing its preliminary assignment of costs to functions. It is likely that this will be discussed in more detail in a subsequent conference call.

After more discussion about specific cost centers, it was decided that the ISO would make available in a series of conference calls staff knowledgeable about the costs and activities within the various cost centers. It was agreed that the first call would be at 9:30 AM, Monday, February 3, 2003 with David Hawkins, and possibly other staff from Grid Operations, to discuss Grid Operations cost centers and activities. The ISO agreed to arrange additional conference calls for the other areas, Market Services, Information Services, Market Analysis and Compliance, MD02 and bond financed capital. To the extent possible, these were to be arranged during the week of February 3 – 7.

MID agreed to provide the availability of its consultants over the next two weeks to assist the ISO in scheduling these conference calls.

Draft meeting notes from 1302003 conference call 01-31-03.txt

From: Arikawa, Ben
Sent: Friday, January 31, 2003 11:02 AM
To: Hemphill, Ross; Kirsch, Laurence; Pritchard, Jan
Cc: Leiber, Phil; Morrison, Stephen; Neal, Sean
Subject: Draft meeting notes from 1/30/2003 conference call

Ross, Laurence, Jan,

Please review the attached draft meeting notes and send me your comments/edits. I will send out an e-mail before 2:00 (PST) with conference call information. We have not yet identified who will be available in addition to David Hawkins Monday at 9:30 AM.

Ben Arikawa
Senior Financial Analyst
California Independent System Operator
151 Blue Ravine Road
Folsom, CA 95630

Voice: (916) 608-5958
fax: (916) 351-2259

email: barikawa@caiso.com

Modifications to Memo 01-31-03.txt

MessageFrom: Ross Hemphill [rchemphill@lrca.com]
Sent: Friday, January 31, 2003 12:28 PM
To: Arikawa, Ben
Cc: Laurence Kirsch; Jan Pritchard
Subject: Modifications to Memo

Ben, attached is a markup of your meeting notes. Only typo type changes are made and tracked. Ross

---

Ross C. Hemphill, Ph.D.
Vice President
Christensen Associates
Tel: 608-231-2266 (Ext. 168)
Cell: 608-712-7513
Website: http://www.LRCA.com

CALIFORNIA ISO

California Independent
System Operator

# Memorandum

**To:** Keith Casey, Market Analysis
Jan Cogdill, Accounting and Finance
Bruce Drummond, Asset Management
Kyle Hoffman, Client Account Management
Eric Leuze, Compliance
Ali Miremadi, Client Business Services
David Hawkins, Special Projects Engineering
Deane Lyon, Operations Support & Training

**From:** Ben Arikawa, Senior Financial Analyst

**Date:** January 31 2003

**Re:** **Providing information concerning divisional cost center activities to MID consultants**

---

Phil Leiber identified you as knowledgeable persons with respect to the activities and cost centers within your respective divisions. As part of the 2004 GMC Rate Structure Project, we are under instructions from the ALJ in ER01-313-000, et.al., to assist the Modesto Irrigation District (MID) in the development of their proposal. The MID consultants, Laurence Kirsch and Ross Hemphill, require our assistance on the development of cost assignments from our cost centers to their functionalization of ISO services. These functions are "Resolving Energy Imbalances," "Managing Transmission Flows," and "Administering Markets."

MID needs assistance from the ISO so that they may more intelligently assign cost centers to these functions as a step in developing their own ISO rate design. To that end, we have been holding a series of conference calls with MID and their consultants to assist them in the process. These conference calls have been in addition to the regularly scheduled monthly stakeholder meetings of the 2004 GMC Rate Structure Project.

We have given MID documentation on our Budget, including the 2003 GMC information filing, the "Board Budget Book," which was provided to the ISO Board, and a modified version of the Cost Allocation Matrix. Using this information, they were able to develop a preliminary assignment of cost center costs to their functions. (See attached e-mail from Laurence Kirsch, along with the attached Word document and Excel file.) This preliminary assignment was discussed at a conference call held on January 30, 2003. During the call, it was agreed that the ISO would make available by conference call staff knowledgeable in Grid Operations, Market Services, Information Services, Legal and Regulatory, MD02 and bond/capital accounts.

Attached to the e-mail transmitting this memo are several documents that recount the history of our interactions with MID and their consultants. These are:

1. Notes of three conference calls with MID
    a. January 16, 2003
    b. January 23, 2003
    c. January 30, 2003
2. MID consultant memoranda dated
    a. December 19, 2002
    b. January 6, 2003
    c. January 21, 2003
    d. January 28, 2003
3. MID consultant prepared spreadsheet, dated January 28, 2003

We are attempting to schedule the conference call(s) within the next week in order to give MID the opportunity to present its proposal before the full stakeholder meeting scheduled for February 19, 2003. The length of the calls will vary greatly. The call concerning Grid Operations will take several hours, while the discussion of Market Analysis and Compliance may take less than one hour.

David Hawkins is currently scheduled to talk to the MID consultants on Monday, February 3, 2003 beginning at 9:30 AM. It may be instructive for you to listen in briefly to get an understanding of the types of questions that the MID consultants will ask.

If you are unavailable next week, please designate a replacement, so that we can act expeditiously.

If you have any questions or would like a copy of any of the other documents referred to in this memo, please let me know. If you think that a pre-conference call meeting is necessary, please let either Phil Leiber or me know and we will arrange it.

Thank you for your consideration of this request.

Updated Spreadsheet 02-03-03.txt

From: lkirsch@svn.net
Sent: Monday, February 03, 2003 1:47 PM
To: BArikawa@caiso.com; DHawkins@caiso.com
Cc: janp@mid.org; rchemphill@lrca.com
Subject: Updated Spreadsheet

Ben and David:

Attached please find our update of the spreadsheet. This differs from the earlier version in that: a) a new column ("Dollars") has been added to facilitate calculation of the derived assignments (e.g., Dept #1511); b) figures in the Percent Assignment columns have been updated to accept all of David's suggestions; c) a new column ("Check") has been added to indicate the "Dept #" rows that we have discussed with ISO staff and that reflect the ISO staff's recommendations; d) text in the Comments column has been updated; and e) initial assignments have been made for most of the 1998 bond accounts.

Please let me know if we have made any inadvertent errors in our update. And thanks for a very productive conversation this morning.

Laurence

*****************************************************

Laurence D. Kirsch
Laurits R. Christensen Associates, Inc.
e-mail: LKIRSCH@LRCA.COM
voice: (415) 663-8608
fax: (415) 663-8818

Please visit our website at WWW.LRCA.COM

*****************************************************

RE Updated Spreadsheet 02-03-03a.txt

From: lkirsch@svn.net
Sent: Monday, February 03, 2003 8:48 PM
To: Arikawa, Ben; Pritchard, Jan; rchemphill@lrca.com
Cc: janp@mid.org; rchemphill@lrca.com
Subject: RE: Updated Spreadsheet

Ben:

You're right. Attached please find a corrected spreadsheet that puts that 100% figure in the right column.

Laurence

On 3 Feb 2003, at 16:42, Arikawa, Ben wrote:

Laurence,

The assignments in the 1500's are consistent with our discussions this
morning. I think that there is a mistake on line 59, RMR software. You have it assigned 100% to the scheduling function. I think that you probably meant 100% to the managing transmission flows function.

Note: the e-mail is circulated by the sender solely for the express purpose of informing discussion. Therefore, none of the contents may
be regarded by the reader as any form of offer, undertaking, policy, proposal or commitment by the sender, author or the California ISO.

Ben Arikawa
Senior Financial Analyst
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151 Blue Ravine Road
Folsom, CA 95630

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fax: (916) 351-2259

email: barikawa@caiso.com

-----Original Message-----
From: lkirsch@svn.net [mailto:lkirsch@svn.net]
Sent: Monday, February 03, 2003 1:47 PM

RE Updated Spreadsheet 02-03-03a.txt

To: BArikawa@caiso.com; DHawkins@caiso.com
Cc: janp@mid.org; rchemphill@lrca.com
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Please visit our website at WWW.LRCA.COM
******************************************************

RE Updated Spreadsheet 02-03-03.txt

From: Arikawa, Ben
Sent: Monday, February 03, 2003 4:42 PM
To: 'lkirsch@svn.net'; Arikawa, Ben; Hawkins, David (CAISO)
Cc: Pritchard, Jan; rchemphill@lrca.com
Subject: RE: Updated Spreadsheet

Laurence,

The assignments in the 1500's are consistent with our discussions this

morning. I think that there is a mistake on line 59, RMR software. You have it assigned 100% to the scheduling function. I think that yo
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Note: the e-mail is circulated by the sender solely for the express purpose of informing discussion. Therefore, none of the contents may be regarded by the reader as any form of offer, undertaking, policy, proposal or commitment by the sender, author or the California ISO.

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email: barikawa@caiso.com

-----Original Message-----
From: lkirsch@svn.net [mailto:lkirsch@svn.net]
Sent: Monday, February 03, 2003 1:47 PM
To: BArikawa@caiso.com; DHawkins@caiso.com
Cc: janp@mid.org; rchemphill@lrca.com
Subject: Updated Spreadsheet

Ben and David:

Attached plea, Janecember 04, 2002 11:18 AMonversation this mornin
from the earlier version in that: a) a new column ("Dollars") has been added to facilitate calculation of the derived assignments (e.g., Dept #1511); b) figures in the Percent Assignment columns

have been updated to accept all of David's suggestions; c) a new column ("Check") has been added to indicate the "Dept #" rows that we have discussed with ISO staff and that reflect the ISO staff's recommendations; d) text in the Comments column has been updated; and e) initial assignments have been made for most of the 1998 bond accounts.

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Laurence

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*****************************************************

**From:** Leiber, Phil
**Sent:** Monday, February 03, 2003 7:05 PM
**To:** Hemphill, Ross; Kirsch, Laurence; Pritchard, Jan
**Cc:** Neal, Sean; GMC WG
**Subject:** CAISO Notice - PricewaterhouseCoopers Operational Audit -- Use in Development of MID Rate Structure Proposal

In my email to MID of January 16 (attached below), I referred MID representatives to several sources of information which might be of value to them in their cost allocation and assignment process. Included in this list was the ISO's 2002 Operational Audit. That document was not yet available as of January 16. It is available now, as discussed in the market notice below.

Philip Leiber, Treasurer & Director of Financial Planning
California ISO
(916) 351-2168
(916) 351-2259 (fax)

-----Original Message-----
From: Leiber, Phil
Sent: Thursday, January 16, 2003 4:50 PM
To: Pritchard, Jan; Kirsch, Laurence; Hemphill, Ross; Neal, Sean
Cc: Arikawa, Ben
Subject: RE: Results of conference call with MID re: MID proposal

-----Original Message-----
**From:** CRCommunications
**Sent:** Friday, January 31, 2003 5:34 PM
**To:** ISO Market Participants
**Subject:** CAISO Notice - PricewaterhouseCoopers Operational Audit

# MARKET NOTICE
## *January 31, 2003*

## PricewaterhouseCoopers Operational Audit

### ISO Market Participants:

PricewaterhouseCoopers (PwC) has released its CAISO Operational Audit dated January 7, 2003. You can access this document on the CAISO web site at <http://www.caiso.com/docs/2003/01/31/2003013117171821306.pdf>.

The ISO will present this report to the Audit Committee of the ISO Board of Governors at its next meeting, scheduled for February 20, 2003.

If you have any questions, please contact Gregory Van Pelt at gvanpelt@caiso.com <mailto:gvanpelt@caiso.com> or (916) 351-2190. If you would like a PDF file of the report, please contact Michelle Gamble at mgamble@caiso.com <mailto:mgamble@caiso.com> or (916) 351-

2314.

**Client Relations Communications.0715**
**CRCommunications@caiso.com <mailto:CRCommunications@caiso.com>**

---

Jan, Lawrence, Ross, Sean:

Attached please find the modified CAM document referred to in our conference call today.

I have also provided a list of steps and suggestions (as the first tab in that worksheet) as to how this exercise can proceed. We recognize you have concerns about how the cost allocation should be performed, and we will attempt to work together to resolve them so that you are able to achieve your objectives.

The ISO has sent via FedEx the ISO Board Version of 2003 Budget document, and will also provide the job descriptions in the next day.

This material is being provided subject to the NDA.

Also attached below are references to the ISO's Operational and SAS70 audit reports. While I do not believe reference to these reports is necessary to conduct this allocation exercise (as the ISO Board version of 2003 Budget document is quite comprehensive), you may find this material useful. These documents are available to the public, and are posted on the ISO website.

Operations Audit (for 2001....2002 not yet complete)

http://www.caiso.com/docs/09003a6080/13/e2/09003a608013e20f.pdf
http://www.caiso.com/docs/09003a6080/14/0f/09003a6080140f9d.pdf

SAS 70 Report
http://www.caiso.com/docs/09003a6080/18/c5/09003a608018c5a3.pdf

Philip Leiber, Treasurer & Director of Financial Planning

California ISO
(916) 351-2168
(916) 351-2259 (fax)

itional Capital Cost Information related to Development of MID Proposal 02-04-03.

From: Leiber, Phil
Sent: Tuesday, February 04, 2003 5:48 PM
To: Kirsch, Laurence; Hemphill, Ross; Pritchard, Jan; Neal, Sean
Cc: Morrison, Stephen; Arikawa, Ben
Subject: Additional Capital Cost Information related to Development of MID Proposal

Gentlemen:

As discussed in today's conference call, here is additional informatio
n
that will be useful in developing allocation factors for the last several items on your matrix. You will note that the task isn't quit
e
as easy as we thought it might be. While we have provided detail on the individual line items that make up some of the aggregated amounts,

even at this level, some spending affects more than one system. In such cases, you can assume an equal spending for each system. For example:

$100 for Item X related to SA/SI/BBS. Assume 1/3 splits for each of SA/SI/BBS.

This information is ISO Confidential and is provided subject to the ND
A
agreement.

Philip Leiber, Treasurer & Director of Financial Planning
California ISO
(916) 351-2168
(916) 351-2259 (fax)

of this afternoon's conference call with MID and next conference call info 02-04

From: Leiber, Phil
Sent: Tuesday, February 04, 2003 4:03 PM
To: GMC WG
Subject: Results of this afternoon's conference call with MID and next conference call info

Here is a brief recap of this afternoon's call.

Overview
---------
The call was conducted from 1pm-2:30pm. Significant progress was made

in discussing the allocation of ISO capital costs to MID categories. Some items were left often for further discussion related to O&M costs
,
and for additional information to be provided by ISO on cost splits between capital items.

Objective:
-------------
Discuss ISO capital (bond financed and direct funded) costs, and how such costs can be allocated to the MID proposed service categories.

Participants:
------------
Phil Leiber, CAISO
Jan Cogdill, CAISO
Ross Hemphill, Representing MID
Laurence Kirsch, Representing MID
Tony Lam, EOB
Patrick Alessandri, EOB
Karen Shea, CPUC
David Cohen, Representing municipal interests

Content
------------
Discussed documents to be used in the call. Distributed documents to parties that did not yet have the documents.

Stepped through the listing of ISO capital costs prepared by MID (an extract from the ISO's modified cost allocation matrix provided to MID

and other participants)

In addition to topics directly associated with the call objective, the group also discussed other issues including MD02 timing and spending, ETCs, background of initial capital expenditures, potential considerations to enhance cost control, and other topics.

The call resulted in numerous changes to the initial allocations made by MID as placeholders. Several capital cost allocations will be based on the users of the systems (so the allocation will be dependent on related O&M costs). The last several items in the analysis will be allocated by MID after the ISO provides additional information as to the cost splits between various ISO systems.

MID will distribute (aiming for 2/5/2003) a revised spreadsheet reflecting the changes discussed in today's call.

----------------------------------------

The next call is tomorrow, Wednesday, February 5th, 9am-10, covering the allocation of ISO Market Services and Compliance costs to the MID proposed service categories.

Like the other calls related to the MID proposal, other parties are welcome to listen in and participate on the call. The purpose of the call is to assist MID in the development of their proposal, as the ISO was directed to do in the FERC ALJ's Initial Decision on the 2001 GMC rate case.

Call in # 888-788-6681
pass code 921065

Note: the attached documents are circulated by the sender solely for the express purpose of informing discussion. Therefore, none of the contents may be regarded by the reader as any form of offer, undertaking, policy, proposal or commitment by the sender, author or the California ISO.

Philip Leiber, Treasurer & Director of Financial Planning
California ISO
(916) 351-2168
(916) 351-2259 (fax)

Assignments Spreadsheet Update 030205.txt

From: lkirsch@svn.net
Sent: Wednesday, February 05, 2003 1:44 PM
To: BArikawa@caiso.com
Cc: DHawkins@caiso.com; kcasey@caiso.com; PLeiber@caiso.com; janp@mid.org; rchemphill@lrca.com
Subject: Assignments Spreadsheet Update 030205

Ben:

Attached is today's update. Italicized figures are the ones that we expect to change further, either because we have not yet had the initial ISO review of those figures or because they are dependent upon other figures that might change.

Please feel free to let me know if you have any comments, and to distribute the spreadsheet as you think appropriate.

Laurence
*****************************************************
Laurence D. Kirsch
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Written document for posting on ISO website 02-05-03.txt

From: Arikawa, Ben
Sent: Wednesday, February 05, 2003 11:43 AM
To: Pritchard, Jan; Hemphill, Ross; Kirsch, Laurence
Subject: Written document for posting on ISO website

Jan,

Do you want to rewrite the Statement BA for posting on the GMC webpage
?
We will post (subject to the usual clearances) whatever you want in preparation for the next meeting.

Note: the attached documents are circulated by the sender solely for the express purpose of informing discussion. Therefore, none of the contents may be regarded by the reader as any form of offer, undertaking, policy, proposal or commitment by the sender, author or the California ISO.

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