CALIFORNIA ISO

California Independent
System Operator

October 15, 2004

BY ELECTRONIC TRANSMISSION

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

Re: California Independent System Operator Corporation
Docket Nos. ER03-746-000, *et al.*
San Diego Gas & Electric Co., *et al*.
Docket Nos. EL00-95-081, *et al*.

Dear Secretary Salas:

Enclosed for electronic filing please find Comments of the California Independent System Operator Corporation Following the October 7, 2004 Technical Conference in the above-referenced docket.

Thank you for your assistance in this matter.

Very truly yours,

/s/ Gene L. Waas

Gene L. Waas

Counsel for the California Independent
System Operator Corporation

Enclosures

cc: All parties of record

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	)	**Docket No. ER03-746-000, *et al.***
San Diego Gas & Electric Company, Complainant,	)	
v.	)	**Docket Nos. EL00-95-000, *et al.***
Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, Respondents.	)	
Investigation of Practices of the California California Power Exchange	)	**Docket Nos. EL00-98-000 *et al.***
		(not consolidated)

COMMENTS OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION FOLLOWING THE OCTOBER 7, 2004 TECHNICAL CONFERENCE

I. INTRODUCTION

Pursuant to the Commission's Order of October 13, 2004 and the previous request of Commission Staff, the California Independent System Operator ("ISO") provides the following comments addressing issues raised at the Technical Conference held in the above captioned dockets on October 7, 2004 ("Conference"). Included as Attachment A to these comments are the revised templates for fuel cost submission as requested by the Commission Staff during the discussion and presentation by the ISO at the Conference.

At the outset the ISO would like to thank the Commission and its Staff for the opportunity to appear and explain its view of the proper methodology for allocating fuel costs as a part of this proceeding and the need for a detailed template for the submission to the ISO of information necessary for this allocation.[1] In the Refund Proceeding, the ISO has been charged with the responsibility of performing the calculations to implement the Commission's orders on the determination of refunds, and thus, it is important that the procedures and formats[2] are appropriate, understood, and accepted, and enable the ISO to carry out the required calculations.

II. COMMENTS

A. The Net vs. Gross Issue

As indicated at the Conference and in previous filings, the ISO believes that calculation of fuel cost allowances and allocation of the costs of those allowances should be done based on net sales and purchases of spot market energy. As demonstrated in the examples presented at the Conference, netting of purchases and sales is more consistent with the principles of cost causation, after taking into consideration each entity's actual contribution to spot market energy supply and/or its actual reliance on spot market purchases. Basing fuel cost allowances and allocation of their costs based on gross purchases would ignore the degree to which each entity either "self-supplied" a portion of its own

[1] The ISO's initial specification of the format and contents of the template in which Market Participants were to submit the information occurred in a posting on the ISO's web site on September 13, 2004.

[2] Capitalized terms otherwise defined herein shall have the meanings set forth in the Master Definitions Supplement, Appendix A to the ISO Tariff.

spot market demand and/or “self-consumed” a portion of its own spot market sales. As illustrated by the examples provided by the ISO at the Conference, the “gross” approach would benefit thermal generators who purchased energy in the ISO Real Time Market, at the expense of all other Market Participants. At the same time, the gross approach would allocate more costs to entities that self-supplied relatively more of their own real-time energy purchases, compared to other participants in the Real-Time Market (some of which self-supplied) their real time energy purchases.

It is absolutely essential that the Commission render a decision on the issue of the gross or net approach in fuel cost determination as soon as possible so that the ISO can continue with its refund activities.

1. The ISO’s Response to the Example Provided by Reliant

At the Conference, Mr. John Stout, a Vice President of Reliant Energy, provided an example purporting to show a potential inequity that could be created if generators were required to net spot market purchases from spot market sales in calculating fuel cost allowances. However, as noted by the ISO at the Conference, the example provided by Mr. Stout was incomplete, in that it does not account for the avoided generation costs (or additional revenues) resulting from the generator’s purchase of decremental energy in this hypothetical example. As shown below, when these avoided generation costs (or additional revenues) are taken into account, the generator in Mr. Stout’s example would recover all fuel costs incurred as a result of its spot market sales and purchases, even if generators are required to net spot market purchases from sales in calculating fuel cost allowances.

In addition, at the Conference, FERC staff asked ISO staff about the actual frequency of occurrence of the situation in Mr. Stout's example, which involved an hour in which a generator had both a mitigated sale, and an unmitigated purchase in the ISO's Real Time Market. In response to this request, the ISO is also providing some summary information on the frequency with which such a situation actually occurred.

2. The Generator in Mr. Stout's Example Recovers Full Fuel Costs Even if the Fuel Cost Allowance Is Based on Net Spot Market Sales

The example provided by Mr. Stout is summarized below, using an assumed sales and purchase quantity of 1 MW for clarity, as did Mr. Stout.

- A generator sells 1 MW in the PX Day Ahead market at a price of $500.
- The generator schedules a thermal unit (Unit A) to meet this sale (and subsequently generates 1 MW from this unit).
- The generator buys back 1 MW of decremental energy from the ISO's Real Time Market at a price of $200. (As discussed below, this 1 MW purchase actually represents "backing down" another generating unit (Unit B) below its Hour Ahead Energy schedule by 1

MW, either through an instructed bid for decremental energy or an uninstructed deviation.)

- The Mitigated Market Clearing Price (MMCP) is $200, so that the $500 sale price for energy that the generator sold into the PX Day Ahead market is mitigated to $200, representing a refund obligation of $300.
- The $200 purchase price paid by the generator for decremental energy (or an uninstructed deviation) is not mitigated, so that no refund is due the generator for this purchase.
- Based on gross sales, the generator would be eligible for a $100 fuel cost allowance for PX sales from Unit A, which generated 1 MW.
- However, under the net approach, the generator would not be eligible for a $100 fuel cost allowance for PX sales from Unit A, since this would be offset by the 1 MW of decremental energy purchased in the ISO Real Time Market.

Using this example, Mr. Stout contended that the net approach would unfairly deprive the generator of $100 in fuel cost allowance for the 1 MW produced from Unit 1. However, as noted by the ISO at the Conference, the example is flawed.

The first flaw in Mr. Stout's example is that it is incomplete. The example "ends" at the point where the generator purchases 1 MW of real time energy, and does not account for the impact of this 1 MW of energy on the generator's overall gas costs and revenues.[3] In the ISO Real Time Market, a decremental energy bid is a unit-specific bid, which means the generator's bid to "back down" a unit below its Hour Ahead schedule. In addition, generators may also "purchase" energy in the ISO Real Time Market by generating below their scheduled level, creating a negative uninstructed deviation. Thus, in Mr. Stout's example, the 1 MW of real time energy purchased by the generator actually represents 1 MW of energy the generator was able to sell and schedule in the Day Ahead or Hour Ahead market, say from "Unit B," but did not actually generate in real time. This means the net energy actually supplied to the spot market by the generator's two units in this example (Unit A, which supplied 1 MW into the PX, and Unit B, which was scheduled to supply 1 MW but did not do so, thus creating a demand of 1 MW in real time) is zero.

Furthermore, based on information in Mr. Stout's own example, it can be shown that the benefits to the generator of the real time energy it purchased would have exceeded the $200 purchase price for this energy, and would have fully offset the potential $100 fuel cost allowance at issue in this example. The $100 fuel cost allowance that the generator would receive in this example under the gross approach indicates that the generator's marginal generating cost (i.e., the marginal operating cost of its highest cost unit in operation) is at least $300 ($200 MMCP + $100 fuel cost allowance = $300 total marginal cost). Thus, the decremental energy purchased by the generator by having a "dec bid" from the

[3] In Mr. Stout's example, the generator has 1 MW of sales in the PX, generates 1 MW from Unit 1 to meet this sale, and then purchases another 1 MW through a decremental energy bid. Thus, Mr. Stout's example is incomplete in that the generator's portfolio has an overall surplus of 1 MW. The "sink" or use of this extra 1 MW must be included to complete the example.

second generating unit (Unit B) accepted would have saved the generator $300 or more in overall marginal gas costs.[4] As shown below, when the $300 (minimum) savings in avoided operating costs resulting from the purchase of decremental energy from the ISO are factored into the analysis, netting spot market purchases from sales still allows the generator to recover the total actual fuel costs incurred due to these spot market sales and purchases:

	Before Mitigation	After Mitigation
Revenues from PX Sale	+ $500	+$200 ($300 Refund)
Generating Cost Incurred (Unit 1)	- $300	-$300
Cost of ISO Dec Energy Purchase	- $200	-$200
Generating Cost Avoided (Unit 2)	+ $300	+$300
Net Operating Revenues from Spot Market Purchases/Sales	+$300	$0

Thus, by purchasing the 1 MWh of real time energy, the generator was able to increase profits by $100 ($300 avoided thermal generating cost of Unit B less $200 purchase cost of real time energy). These profits fully compensate the generator for gas costs incurred on Unit A, thus no fuel cost allowance is necessary.

4 It can be assumed that the marginal operating cost of the second unit (Unit 2) was equal to or greater than the $300 cost of the unit that kept operating (Unit 1) since the generator would submit dec bids based on the relative marginal operating costs of each unit in descending merit order of cost.

In practice, rather than simply covering its operating costs, the generator in this example may also have earned additional profits from unmitigated sales. For example, if Unit B was pre-scheduled and had a cost of at least $300, then, the output must have been sold in the bilateral market for at least $300. In fact, given the $500 PX price used in this example, it would be more likely the generator earned $500 for this energy in the day ahead bilateral market. By not producing this 1 MW in real time and instead relying on the Real Time Market for this energy, the generator would have been able to earn a profit of up to $300 ($500 sales price for unmitigated bilateral transaction less $200 purchase price for ISO real time energy). While it would be rational for a generator to engage in such transactions, Reliant cannot argue that a fuel cost allowance is necessary to ensure that the generator in this example covers actual gas costs incurred as a result of these non-spot market transactions.

3. The Example Provided by Mr. Stout is Representative of A Minimal Portion of All Mitigated Energy Sales

The alleged inequity in the example provided by Mr. Stout at the Conference stems from the hypothetical situation in which, during any time period, a generator makes a sale of energy in the PX or ISO spot markets that is mitigated, while making a purchase of energy in the ISO spot market that is unmitigated. In this situation, Mr. Stout contends it is inequitable to net an unmitigated purchase from a mitigated sale when calculating the fuel cost allowance based on net sales.

As noted by the ISO at the Conference, after mitigation, the adjusted prices of most sales and purchases during any time interval are in most cases equal, so that the actual value of spot market purchases and sales being netted together are equal. However, in response to FERC staff's questions about the approximate portion of sales which might be netted against lower priced purchases (as in the example presented by Mr. Stout), the ISO has performed the additional analysis described below.

- First, all sales and purchases of energy in the PX and ISO markets that may have been made by thermal generating units within the ISO system by entities that have filed fuel cost allowances were identified based on PX and ISO scheduling and settlement records.
- The portion of these sales/purchases that will be mitigated during the Refund Rerun was then calculated by comparing transaction prices to the Mitigated Market Clearing Price (MMCP).
- The situation described in Mr. Stout's example was identified by indicating hours in which any individual entities made a mitigated sale in the PX or ISO markets that may be attributed to a thermal unit in the ISO system, while also making an unmitigated purchase in the ISO Real Time Market during this same hour. During these hours, the quantity of unmitigated purchases of ISO energy that would be netted against mitigated sales in calculating the fuel cost allowance was calculated.

The result of this analysis indicates that the quantity of mitigated sales in the ISO Market that would be netted against a mitigated purchase in the PX or ISO markets for the purpose of calculating the fuel cost allowance represents about 2.16% of all mitigated sales in the PX or ISO markets. This indicates that the situation in Mr. Stout's example represents an extremely small portion of overall mitigated sales.

4. Netting of Uninstructed Imbalance Energy

The ISO would also like to clarify and re-affirm that during the refund period positive and negative uninstructed energy from different resources in each Scheduling Coordinator's portfolio were "netted" together and settled on a net basis by congestion zone (e.g. NP15, SP15) as part of the ISO's settlement system. At the Conference, Mr. Stout indicated that he did not believe this to be the case, and indicated that uninstructed deviation charges/payments are settled on a unit-by-unit basis, so that a generator may be paid one price for a positive uninstructed deviation on one unit, but get charged a different price for a negative uninstructed deviation on another unit. This potential difference in prices for sales and purchases of uninstructed energy was cited by Mr. Stout as another reason why netting would be inequitable for generators. However, as indicated by the ISO at the Conference and in previous filings[5], uninstructed energy from

[5] See ISO answer to protests on compliance filing on fuel cost allocations, September 14, 2004 at page 8.

different resources in each Scheduling Coordinator's portfolio are "netted" together and settled on a net basis by region in the ISO's settlement system. [6]

5. Netting of PX Market Sales and Purchases

The ISO would also like to note that the example provided by Mr. Stout involves netting of purchases from one segment of the spot market (the ISO Real Time Market) from sales in another segment of the spot market (the PX market). The ISO believes that such netting is appropriate due to the close inter-relationship between these segments of the overall spot market, and the fact that the commission has found that the entire spot market was dysfunctional during the Refund Period. However, the ISO notes that even if the Commission should not require netting of PX and ISO sales and purchases due to concern about differences in sales and purchase prices, the Commission should clarify that such netting is required within the PX market, in cases when an entity was both a buyer and seller. An example of such netting within the PX market, and how this should be reflected in the template for fuel cost submissions is provided below. For clarity, the entity is the example is also assumed to have made sales in the PX Block Forward Market (BFM), in order to highlight how these forward market sales must be netted of PX Day Ahead market sales.

- The entity has sold 500 MW in the PX Block Forward market.

[6] Mr. Stout may have been referring to instructed energy payments which, as noted at the Conference, are made by location and are not netted together as part of the ISO settlement process.

- The submits 1,000 MW of supply bids in the PX Day Ahead market and has these accepted.
- The entity also submits 200 MW of demand bids in the PX market and has these accepted.

In this example, the entity has net spot sale in the PX Day Ahead market of 300 MW (1.000 MW sales – 500 MW BFM sale obligation – 200 MW purchase = 300 MW sales in PX Day Ahead market). Assuming these sales were mitigated (i.e. the PX MCP was greater than the MMCP), the entity's fuel cost allowance submission should identify up to 300 MW of capacity from thermal generating units that were scheduled to operate in the Day Ahead market in Table 1 of the fuel cost allowance template, and base the fuel cost allowance on the incremental fuel costs associated with the Day Ahead schedules of these of specific generating units.

With this approach, netting of sales and purchases within the PX market is directly incorporated into the amount of sales reported in Table of the fuel cost allowance. Then, as a separate step, in cases where the generator was a net purchaser of real time energy from the ISO (as reported in Tables 2 through 4 of the template), these purchases would be netted off from net PX sales reported in Table 1.

In sum, the ISO provides this example to highlight the distinction between netting within market segments (such as within the PX Day Market) and the type of netting between PX and ISO transactions described in Mr. Stout's example. As shown in the example above, netting within market segments (such as within the PX Day Market) is easily incorporated into the templates provided by the ISO. The ISO encourages the Commission to clarify that type of netting should be performed, even if the Commission does not require netting between PX and ISO sales and purchases.

B. Fuel Cost Allowance Templates For Submission of Data

As indicated at the Conference and in previous filings, the ISO welcomes clarification of the two specific issues raised by generators in response to the template for fuel cost allowance submissions developed by the ISO, in accordance with the Commission's order of September 2, 2004, titled *Order on Auditor Selection and Request for Waiver and Clarifying Audit Issues*, 108 FERC ¶ 61,219 (2004). These two issues are (1) the operating point used to calculate the heat rates, and (2) whether in calculating the fuel cost allowance the generator's fuel cost should be compared to the MMCP or to the fuel price index used to calculate the MMCP.

The ISO believes that there was general agreement at the Conference that two changes should be made in the templates for fuel cost allowance submissions. First, the incremental heat rate of units should be based on the metered operating level of each unit, rather than the Acknowledged Operating Target (AOT), as was done in the calculation of the MMCPs used in calculating refunds. Second, that the fuel cost allowance should be based on the difference in the generator's daily average fuel cost as compared to the fuel price index used to calculate the MMCP.

As discussed at the Conference, the ISO has revised its templates to incorporate these changes, and is including these as Attachment A to this filing.[7] In addition, in response to comments and requests at the conference, the ISO has provided suggested tables for documenting and supporting fuel cost allowance submissions for imports into the ISO system, and is including these as Attachment B to this filing.

III. CONCLUSION

Wherefore, for the reasons stated above the ISO respectfully asks the Commission to accept these comments on the Technical Conference on Fuel Cost Allocation and Submission of Templates to be used in Refund Calculations held on October 7, 2004.

Respectfully Submitted,

/s/ Gene L. Waas

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Date: October 15, 2004

[7] In addition, another error in the fuel cost allowance formula in Table 1, identified by FERC staff, has been corrected.

CERTIFICATE OF SERVICE

I hereby certify that I have on this 15th day of October 2004, served copies of the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

/s/ Gene L. Waas
Gene L. Waas

Attachment A

Revised Format for Fuel Cost Allowance Submissions
For Generating Units Within ISO system

Table 1. Format for Fuel Cost Allowance Submissions for Mitigated PX Energy Sales

Col. Ref	Variable	Description
A	Opr_dt	Operation Date
B	Opr_hr	Operating Hour (hour ending)
C	PX_ID	Participant ID used in PX settlement records (Short_Name)
D	Unit_ID	ISO unit identification code
E	DA_MW	Final Day Ahead Energy schedule for unit for hour
F	QTY	Quantity (MWh) of generator's PX sales during hour attributed to unit
G	PRICE	Price ($/MWh) for PX sales attributed to unit in hour
H	REV	Revenues from transaction prior to price mitigation (F x G)
I	MMCP	Mitigated Market Price (Hourly)
J	QTY_M	Quantity of participant's PX sales during hour attributed to unit in hour subject to price mitigation (F if I < G; otherwise 0)
K	REV_M	Revenues from transaction after price mitigation (F x Min(G, I))
L	M_QTY	Metered output of unit during hour (MWh)
M	IHR	Incremental heat rate for unit during hour for mitigated sales at unit's average operating point during hour (Column L) in MMBTU/MWh
N	FUEL	Calculated incremental fuel input (consumption) for mitigated sales of unit during hour (L x M)
O	FUEL_PRC	Avg. daily cost ($/MMBTU) for fuel input (consumption) for mitigated spot market sales by generator during operating day.
P	GAS_PRC	Gas price used in calculating MMCP
Q	FCA	Fuel Cost Allowance (0 if O <= P ; otherwise Min [N x (O – P), H – K])

Notes:

[1.F] Should not exceed unit's Day Ahead energy schedule or metered generation level for hour. The sum of Table 1, Column F for all units identified as providing a portion of PX Day Ahead energy sales from a generator's portfolio should add up to total sales of PX energy from a generator's portfolio during hours that is attributable to total amount of energy scheduled in Day Ahead market by a generator's thermal units (taking into account PX sales met by other supply sources, such as inter-SC trades from other suppliers, imports and purchases from PX during same hour).

[1.M] Marginal heat rates used by ISO = Non-monotonic incremental heat rate of unit at AOT, as defined in calculations of MMCP. Hourly non-monotonic heat rates may be calculated based on average of non-monotonic heat rates for each 10-minute interval used by ISO in calculating MMCP, or non-monotonic heat rate at average AOT for hour.

[1.P] As confirmed by the independent auditor based on generator's fuel purchase data, and total fuel consumption associated with spot market sales in PX and ISO that were mitigated (i.e. had a transaction price < MMCP) during operating day. Sum of the FUEL columns in Tables 1, 2 and 4 represent gas consumption for mitigate sales prior to any netting of sales/purchases between sales in different markets (e.g. netting of ISO market purchases from PX sales, etc.)

Table 2. Format for Fuel Cost Allowance Submissions
for Mitigated ISO Instructed Energy (IE) Sales

Col. Ref.	Variable	Description
A	Opr_dt	Operation Date (TRADING DATE in ISO Settlement records)
B	Opr_hr	Operating Hour (TRADING HOUR in ISO Settlement records)
C	Rt_Int	10-minute interval, 1-6 (TRADING INT in ISO Settlement records)
D	SC_ID	Participant ID for transaction from ISO settlement records (Short Name for SC corresponding to numerical Business Associate ID).
E	Unit_ID	ISO unit identification code (LOCATION ID in ISO Settlement records)
F	E_TYPE	Energy type (SP=Spin, NS=Non-spin, SE=Supplemental energy, OOM=out-of-market)
G	CHRG_TYPE	401 = instructed energy priced at or below the (soft) price cap, 481 = instructed energy priced above the (soft) price cap
H	QTY	Quantity (MWh) of Instructed Energy sold through transaction during interval from unit (from BILLABLE QUANTITY in ISO Settlement records)
I	PRICE	Price ($/MWh) for Instructed Energy (IE) sold through transaction during interval from unit (from PRICE in ISO Settlement records)
J	REV	Revenues from transaction prior to price mitigation (H x I).
K	MMCP	Mitigated Market Price (for 10-minute interval)
L	QTY_M	Quantity of participant's UE sales from transaction during 10-minute interval subject to price mitigation (H if K < I; otherwise 0)
M	REV_M	Revenues from transaction after price mitigation (H x Min (I, K))
N	M_QTY	Avg. operating level of unit during interval (Metered MWh x 6)
O	IHR	Incremental heat rate for unit during 10-minute interval for mitigated sales at unit's average operating point during interval (Col N) in MMBTU/MW.
P	FUEL	Calculated incremental fuel input (consumption) for mitigated sales of unit during interval (L x O)
Q	FUEL_PRC	Avg. daily cost ($/MMBTU) for fuel input (consumption) for mitigated spot market sales by generator during operating day.
R	GAS_PRC	Gas price used in calculating MMCP
S	FCA	Fuel Cost Allowance (0 if Q <= R ; otherwise Min [P x (Q – R), J – M])

Notes:

[1.G] During the "soft cap " period starting Dec. 8, 2000, the final settlement quantity and price for sales of Instructed Energy over the $250/$150 soft caps must be calculated by combining final Billable Quantities and Billable Prices for both 401 and 481 chares types. In testimony during refund proceedings, generators have indicated they are able to perform this calculation based on ISO settlement records. However, the ISO stands ready to provide these data to the Commission and generators upon request in order to facilitate completion and verification of fuel cost allowance submissions.

Table 3. Format for Fuel Cost Allowance Submissions for Mitigated ISO Uninstructed Energy (UE) Sales (SC Portfolio Level)

Col. Ref	Variable	Description
A	Opr_dt	Operation Date (TRADING DATE in ISO Settlement records)
B	Opr_hr	Operating Hour (TRADING HOUR in ISO Settlement records)
C	Rt_Int	10-minute interval 1-6 (TRADING INT in ISO Settlement records)
D	SC_ID	Participant ID for transaction from ISO settlement records (Short Name for SC corresponding to numerical Business Associate ID).
E	Region_ID	Region ID from ISO uninstructed energy settlement records used to indicate whether uninstructed energy for each was settled by netting each SCs portfolio on a system-wide or zonal basis (in hours of real time congestion). If real time congestion, 1= NP15 and 2=SP15. If no congestion, 1= uniform system prices/charges.
F	E_TYPE	UE = Uninstructed energy
G	CHRG_TYPE	407 = Uninstructed energy
H	QTY	Quantity (MWh) of Uninstructed Energy sold through transaction during interval by SC in ISO system or in zone (if real time energy market split zonally). From BILL_QTY for SC during interval in SS_SETTLEMENT_DETAILS table.
I	PRICE	Price ($/MWh) for Uninstructed Energy (UE) sold through transaction during interval by SC (from PRICE in ISO Settlement records)
J	REV	Revenues from transaction prior to price mitigation (H x I).
K	MMCP	Mitigated Market Price (for 10-minute interval)
L	QTY_M	Quantity of participant's UE sales from transaction during interval subject to price mitigation (H if K < I; otherwise 0)
M	REV_M	Revenues from transaction after price mitigation (H x Min(I, K))
N	FUEL	Calculated incremental fuel input (consumption) for mitigated sales of UE from SC's portfolio during interval. Sum of Column I in Table 4 for all units identified as providing a portion of SC's total net UE sales during interval.
O	FUEL_PRC	Avg. daily cost ($/MMBTU) for fuel input (consumption) for mitigated spot market sales by generator during operating day.
P	GAS_PRC	Gas price used in calculating MMCP
Q	FCA	Fuel Cost Allowance (0 if O <= P ; otherwise Min [N x (O – P), J – M])

Notes:

[3.G] Sum of Table 4, Column G for all units identified as providing a portion of total sales of uninstructed energy from generators portfolio should add up to total sales of uninstructed energy from a generator's portfolio during interval as reported in Table 3, Column H.

[4.I] Sum of Table 4, Column J for all units identified as providing a portion of total net sales of uninstructed energy from a generator's portfolio should add up to total fuel input/consumption associated with total uninstructed energy from a generator's portfolio during interval as reported in Table 3, Column N.

Table 4. Format for Fuel Cost Allowance Submissions for Mitigated ISO Uninstructed Energy (UE) Sales (Unit Level)

Col. Ref.	Variable	Description
A	Opr_dt	Operation Date (TRADING DATE in ISO Settlement records)
B	Opr_hr	Operating Hour (TRADING HOUR in ISO Settlement records)
C	Rt_Int	10-minute interval (TRADING INT in ISO Settlement records)
D	SC_ID	Participant ID for transaction from ISO settlement records (Short Name for SC corresponding to numerical Business Associate ID).
E	Unit_ID	ISO unit identification code (LOCATION ID in ISO Settlement records)
F	ZONE_ID	ISO Congestion zone in which resource is located (NP15,SP15,ZP26).
G	UE	Uninstructed energy (MWh) from unit for interval from ISO settlement data (SS_UNINSTR_ENERGY_DETAILS table provided with ISO settlement data).
H	M_QTY	Avg. operating level of unit during hour or interval (Metered MWh x 6)
I	IHR	Incremental heat rate for unit during interval for mitigated sales at unit's average operating point during interval (Col. M) in MMBTU/MW
J	FUEL	Calculation of incremental fuel input (consumption) for portion of SC's mitigated uninstructed energy sales attributed to unit during interval (G x I)

Notes:

[4.G] Sum of Table 4, Column G for all units identified as providing a portion of total net sales of uninstructed energy from a generator's portfolio should add up to total net sales of uninstructed energy from generators portfolio during interval as reported in Table 3, Column H.

[4.I] Sum of Table 4, Column J for all units identified as providing a portion of total net sales of uninstructed energy from a generator's portfolio should add up to total fuel input/consumption associated with total uninstructed energy from a generator's portfolio during interval as reported in Table 3, Column N.

Attachment B

Revised Format for Fuel Cost Allowance Submissions
For Generating Units Outside of ISO system

Table I-1. Format for Fuel Cost Allowance Submissions for Mitigated PX Energy Sales for Resources Outside of ISO system

Col. Ref	Variable	Description
A	Opr_dt	Operation Date
B	Opr_hr	Operating Hour (hour ending)
C	PX_ID	Participant ID used in PX settlement records (Short_Name)
D	SC_ID	Schedule Coordinator ID under which import schedule was submitted to ISO
E	TIE_POINT	Tie point (from ISO Schedule and Settlement records)
F	INTERCHG_ID	Interchange ID (from ISO Schedule and Settlement records)
G	DA_MW	Final Day Ahead Energy schedule for resource
H	QTY	Quantity (MWh) of generator's PX sales during hour attributed to resource
I	PRICE	Price ($/MWh) for PX sales attributed to resource in hour
J	REV	Revenues from transaction prior to price mitigation (H x I)
K	MMCP	Mitigated Market Price
L	QTY_M	Quantity of participant's PX sales during hour attributed to resource in hour subject to price mitigation (H if K < I; otherwise 0)
M	REV_M	Revenues from transaction after price mitigation (L x Min(K, I))
N	FUEL	Calculated incremental fuel input (consumption) for mitigated sale (supported by unit level data in Table I-2, Column K)
O	FUEL_PRC	Avg. daily cost ($/MMBTU) for fuel input (consumption) for mitigated spot market sales by generator during operating day.
P	GAS_PRC	Gas price used in calculating MMCP
Q	FCA	Fuel Cost Allowance (0 if O <= P ; otherwise Min [N x (O – P), J – M])

Notes:

[1.N] Total incremental fuel consumption associated with sales should be supported by unit-level data in Table I-2. Unit level data in Table I-2 should be linked to transaction level data in Table I-1 by the following fields: Opr_dt, Opr_hr, PX_ID, SC_ID, Tie_point, and Interchg_id (which, in combination, create a unique electronic identifier for any scheduled submitted to the ISO)

Table I-2. Format for Fuel Cost Allowance Submissions for Mitigated PX Energy Sales from Resources Outside of ISO System

Col. Ref	Variable	Description
A	Opr_dt	Operation Date
B	Opr_hr	Operating Hour (hour ending)
C	PX_ID	Participant ID used in PX settlement records (Short_Name)
D	SC_ID	Schedule Coordinator ID under which import schedule was submitted to ISO
E	TIE_POINT	Tie point (from ISO Schedule and Settlement records)
F	INTERCHG_ID	Interchange ID (from ISO Schedule and Settlement records)
G	Unit_name	Name of generating unit
H	QTY	Quantity (MWh) of generator's PX sales during hour attributed to unit
I	M_QTY	Metered output of unit during hour (MWh)
J	IHR	Incremental heat rate for unit during hour for mitigated sales at unit's average operating point during hour (M_QTY) in MMBTU/MWh
K	FUEL	Calculated incremental fuel input (consumption) for mitigated sales of unit during hour (H x J)
L	Notes	Optional text field for any notes necessary to document calculations or data sources

Table I-3. Format for Fuel Cost Allowance Submissions for Mitigated ISO Instructed Energy (IE) Sales for Resources Outside of ISO system

Col. Ref.	Variable	Description
A	Opr_dt	Operation Date (TRADING DATE in ISO Settlement records)
B	Opr_hr	Operating Hour (TRADING HOUR in ISO Settlement records)
C	Rt_Int	10-minute interval, 1-6 (TRADING INT in ISO Settlement records)
D	SC_ID	Participant ID for transaction from ISO settlement records (Short Name for SC corresponding to numerical Business Associate ID).
E	TIE_POINT	Tie point (from ISO Schedule and Settlement records)
F	INTERCHG_ID	Interchange ID (from ISO Schedule and Settlement records)
G	E_TYPE	Energy type (SP=Spin, NS=Non-spin, SE=Supplemental energy, OOM=out-of-market)
H	CHRG_TYPE	401 = instructed energy priced at or below the (soft) price cap, 481 = instructed energy priced above the (soft) price cap
I	QTY	Quantity (MWh) of Instructed Energy sold through transaction during interval from unit (from BILLABLE QUANTITY in ISO Settlement records)
J	PRICE	Price ($/MWh) for Instructed Energy (IE) sold through transaction during interval from unit (from PRICE in ISO Settlement records)
K	REV	Revenues from transaction prior to price mitigation (I x J).
L	MMCP	Mitigated Market Price
M	QTY_M	Quantity of participant's UE sales from transaction during 10-minute interval subject to price mitigation (I if L < J; otherwise 0)
N	REV_M	Revenues from transaction after price mitigation (I x Min (J, L))
O	FUEL	Calculated incremental fuel input (consumption) for resources used to make mitigated sale (supported by unit level data in Table I-4)
P	FUEL_PRC	Avg. daily cost ($/MMBTU) for fuel input (consumption) for mitigated spot market sales by generator during operating day.
Q	GAS_PRC	Gas price used in calculating MMCP
R	FCA	Fuel Cost Allowance (zero if P <= Q ; otherwise Min [M x (P – Q), K-N])

Notes:

[1.H] During the "soft cap " period starting Dec. 8, 2000, the final settlement quantity and price for sales of Instructed Energy over the $250/$150 soft caps must be calculated by combining final Billable Quantities and Billable Prices for both 401 and 481 charges types. In testimony during refund proceedings, generators have indicated they are able to perform this calculation based on ISO settlement records. However, the ISO stands ready to provide these data to the Commission and generators upon request in order to facilitate completion and verification of fuel cost allowance submissions.

Table I-4. Format for Fuel Cost Allowance Submissions for Mitigated ISO Instructed Energy (IE) Sales for Resources Outside of ISO System

Unit Level Calculation of Fuel Quantities

Col. Ref	Variable	Description
A	Opr_dt	Operation Date
B	Opr_hr	Operating Hour (hour ending)
C	SC_ID	Schedule Coordinator ID under which import schedule was submitted to ISO
D	TIE_POINT	Tie point (from ISO Schedule and Settlement records)
E	INTERCHG_ID	Interchange ID (from ISO Schedule and Settlement records)
F	Unit_name	Name of generating unit
G	QTY	Quantity (MWh) of generator's mitigated UE sales in Table I-3 attributed to unit
H	M_QTY	Metered output of unit during hour (MWh)
I	IHR	Incremental heat rate for unit during hour for mitigated sales at unit's average operating point during hour/interval (M_QTY) in MMBTU/MWh
J	FUEL	Calculated incremental fuel input (consumption) for mitigated sales of unit during interval (G x I)
K	Notes	Optional text field for any notes necessary to document calculations or data sources