California Independent
System Operator Corporation

May 9, 2016

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: California Independent System Operator Corporation
Docket No. ER16- ___-000

Tariff Amendment to Enhance Gas-Electric Coordination to Address Risks Posed by Limited Operability of Aliso Canyon Natural Gas Storage Facility

Requests for Expedited Treatment and Waiver of Notice Requirements

Dear Secretary Bose:

The California Independent System Operator Corporation (CAISO) submits this tariff amendment to improve its ability to maintain both gas and electric reliability in light of the risks to the CAISO controlled grid posed by the limited operability of the Aliso Canyon natural gas storage facility. Specifically, the enclosed tariff modifications will provide the CAISO with a series of tools it can use in its markets to mitigate operational risks that might lead to electric service interruptions on the CAISO electric grid due to restrictions of gas deliveries to electric generators. The CAISO is also proposing additional procedures to ensure generators have the opportunity to recover their fuel costs during the summer months when they are operating pursuant to a CAISO dispatch.

To address the risks posed by the limited operability of Aliso Canyon in a timely manner, the CAISO needs these tariff revisions to be effective early in the summer, when gas usage in connection with electric generation is generally highest. Therefore, the CAISO respectfully requests that the Commission establish a comment date no later than May 16, 2016, and issue an order by June 1, 2016 that accepts most of the tariff revisions effective June 2, 2016 and accepts the balance of the tariff revisions effective July 6, 2016, as discussed below.

The CAISO anticipates that it may not need some of the tariff revisions this winter or that it may need additional tariff changes, depending on the circumstances and its experience with the proposed set of tariff revisions. For this reason and because the CAISO is requesting a significantly expedited comment and approval process, the CAISO proposes that the Commission accept all of the modifications in this filing only on an interim basis. Specifically, the CAISO is submitting tariff records in this filing that will cause the revised tariff sections to revert automatically on November 30, 2016 to how they read before the changes the CAISO is submitting in this filing take effect.

Considering the particular challenges to reliability this coming summer, the interim nature of the proposal, and the limited amount of time the CAISO had to develop a feasible solution, the CAISO submits that its interim solution to a very challenging and complex set of risks is just and reasonable and should be approved.[1]

I. Executive Summary

In October 2015, a natural gas leak was detected at the Aliso Canyon gas storage facility (Aliso Canyon), the largest gas storage field serving southern California. Although the gas company has now sealed the leak, it cannot resume injecting natural gas into Aliso Canyon, and can only withdraw on a limited basis, if at all, until it obtains necessary regulatory approvals. The limited operability of Aliso Canyon is a concern not only for residential gas customers but also for gas-fired electric generating resources in southern California that normally rely on gas stored in Aliso Canyon. To the extent these gas-fired resources are unable to obtain sufficient gas supplies through pipeline service to meet electric demand, such deficiencies could, under certain circumstances, cause the CAISO to curtail electric service to southern California customers.

At the direction of the Governor of California, the CAISO and other agencies in California organized an Inter-Agency Task Force to assess the risks posed by the limited operability of Aliso Canyon and the actions required to mitigate those risks. The Inter-Agency Task Force identified a number of risks associated with operations during the summer of 2016, including that: (1) daily imbalances between the amount of gas nominated and the amount of actual gas burned that exceed 150 million cubic feet could affect ability maintaining operating pressures, thus undermining pipeline integrity; (2) planned and unplanned outages or curtailments on the gas system could limit pipeline and

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[1] *See ISO New England Inc., et al.,* 144 FERC ¶ 61,204, at PP 21, 42 (2013).

other storage availability; and (3) rapid ramping of electric generation can exceed the dynamic capability of the gas system, thus affecting recovery from contingencies and renewable generation following. The Inter-Agency Task Force also identified a number of actions to mitigate these risks, including changes to the CAISO market to improve gas-electric coordination. A more extensive discussion of this process, and of the implications of the Aliso Canyon leak, is set forth in attachment C to this filing.

The CAISO conducted an expedited stakeholder process to develop tariff revisions to mitigate risks associated with the limited availability of the Aliso Canyon facility.[2] These measures are designed to ensure that the CAISO's dispatches are better coordinated with the constrained gas system and minimize, to the extent possible, the impact of further challenges to gas and electric system reliability this summer. The proposed measures help ensure that the limitations of the constrained gas system are reflected in the CAISO market processes either through bids submitted by affected generators, or through operational tools by which the CAISO reasonably constrains market dispatches and transmission flows to ensure that its markets produce solutions that are reflective of the constraints the gas system imposes on electrical generators. Specifically:

1) To increase access to potentially useful market information prior to the CAISO day-ahead market, the CAISO proposes to provide scheduling coordinators, for informational purposes only, advisory commitment schedules produced in the residual unit commitment process conducted on a two-day-ahead basis and based on available bids and forecasts of system conditions. These advisory schedules are not financially or physically binding but should assist scheduling coordinators with gas procurement decisions and gas nominations processes.

2) Use timelier and more accurate gas commodity prices for commitment costs bid caps, default energy bids, and generated bids in the day-ahead market. This method will reflect prevailing gas prices, in contrast to the CAISO's current day-ahead gas price index, which uses prices published the day before the market run. This will enable the day-ahead market to better capture gas price variability that may occur because of summer constraints, resulting in day-ahead schedules that are better aligned with actual gas system conditions.

3) Increase the gas commodity price used to calculate commitment costs and default energy bids for generators served by the affected gas systems by an amount necessary to ensure that the cost-minimizing market-

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[2] Further details on the CAISO's stakeholder process are contained in attachment C to this filing.

clearing process considers the impact of gas system limitations in dispatching these generators, (*e.g.*, the need to limit the dispatch of these generators for local rather than system-wide needs. This will help mitigate against the real-time market dispatching generators that are affected by the absence of available gas from Aliso Canyon and ensure that the CAISO dispatches do not further aggravate existing gas system constraints.

4) Allow a resource to rebid its resource commitment costs in the CAISO real-time market if the resource was not committed in the day-ahead market and the resource has not already started up and is within its minimum run time range.[3] This can alleviate pressures on the gas and electric system by ensuring that generators' costs in the CAISO real-time market appropriately reflect real-time gas constraints when conditions on the gas system change.

5) Ensure that the CAISO's short-term unit commitment process does not commit resources in real-time that were not committed in the day-ahead and does not automatically resubmit bids into the real-time market. In addition to preventing the commitment of resources that have not bid into the real-time market and that have no obligation to do so, this tariff change will avoid exposing resources to any unplanned real-time gas procurement variability resulting from real-time commitments.

6) Include a new constraint in the CAISO markets that the CAISO operators can use to better ensure that dispatches are consistent with observed gas system limitations and avoid further stressing the gas system, which could in turn adversely impact electric grid reliability. Through this additional operational tool, the CAISO market clearing process will be able to limit the maximum amount of generation dispatched in a given area of the CAISO balancing authority area if burning more gas might risk jeopardizing gas and electric system reliability. Similarly, the CAISO can use the constraint to ensure that a minimum amount of generation is dispatched in a given area if necessary to avoid further stressing the gas system and assure reliability on the electric grid. This constraint will also allow CAISO operators to minimize variations between day-ahead and real-time gas usage if such variations have the potential to undermine gas and electric system reliability.

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[3] The CAISO developed this specific proposal before the issues created by the Aliso Canyon storage facility arose. However, this flexibility is helpful in ensuring that if the generator faces higher costs in the real-time than it did in the day-ahead, it can reflect those higher costs in its bids and allow the CAISO real-time market to consider those costs accordingly.

7) Expand the CAISO's authority to reserve internal transfer capability by adjusting transmission constraints on the system and releasing such internal transfer capability as needed. The CAISO can use this operational tool in the market clearing process to help ensure that it dispatches or commits resources from other areas of the grid as necessary to ensure that resources in the southern California region are deployed in a manner that recognizes gas system limitations. In conjunction with authority to reserve internal transfer capability, the CAISO also requests authority to adjust the network model used in the release of monthly congestion revenue rights to ensure that the CAISO does not release rights that will not be sufficiently funded by congestion revenues collected in the day-ahead market.

8) Authorize the CAISO to suspend convergence bidding if the CAISO determines it is adversely affecting market efficiency. This authority is necessary so that virtual bidding does not undermine the measures taken by the CAISO to ensure that schedules and dispatches reflect actual physical conditions. This authority is also necessary to ensure, during the summer months when the system will be constrained and the CAISO is implementing the measures proposed in this filing, that virtual bidding does not result in adverse market outcomes that unfairly transfer revenue from one group of market participants to another.

9) Add tariff provisions allowing scheduling coordinators to seek after-the-fact cost recovery from the Commission in a section 205 filing, to the extent they are otherwise unable to recover their costs through the CAISO's cost-recovery mechanisms.

It is critical that the CAISO implement these tariff revisions early in the summer, when gas usage for electric generation is generally highest, so the CAISO has appropriate procedures and flexibility in place to mitigate the risks presented by the limited operability of Aliso Canyon in a timely manner. The CAISO also plans to make expedited changes to its business practice manuals in order to provide appropriate implementation detail regarding these tariff revisions to coincide with the requested date of the revisions.

II. Background

A. Applicable CAISO Market Provisions and Existing Tariff Authority

1. Overview of CAISO Market Structure and Operation

The CAISO administers both day-ahead and real-time wholesale electricity markets. A primary objective of these interrelated markets is to ensure a sufficient supply of electricity to satisfy demand in the region while maintaining the reliability of the transmission system the CAISO operates (the CAISO controlled grid). These markets simultaneously optimize the procurement of energy and ancillary services and allocate transmission capacity on the CAISO controlled grid based on locational marginal pricing at both internal nodes (*i.e.*, locations within the CAISO balancing authority area) and the interties (*i.e.*, locations for imports to and exports from the CAISO balancing authority area).[4] The tariff sets forth rules for the submission of bids and self-schedules for all the CAISO markets.[5]

The CAISO operates its markets using a market software system that utilizes various information. This information includes transmission constraints that the CAISO enforces consistent with good utility practice to ensure, to the extent possible, that the market model used in each CAISO market reflects all the factors that contribute to actual real-time flows on the CAISO controlled grid and that the CAISO market results are better aligned with actual physical conditions on that grid.[6]

When transmission capacity is scarce, transmission congestion charges arise and are incorporated into locational marginal prices. Market participants can acquire congestion revenue rights (CRRs), which are financial instruments they can use to manage exposure to congestion charges in the day-ahead market.[7] In addition, market participants can engage in convergence bidding (also called virtual bidding) to speculate on price differences, hedge their physical

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[4] Existing tariff section 27, *et seq.* For the sake of clarity, this transmittal letter distinguishes between existing tariff provisions (*i.e.*, provisions in the current CAISO tariff), new tariff provisions (*i.e.*, new provisions that the CAISO proposes to add to the tariff in this filing), revised tariff provisions (*i.e.*, existing tariff provisions that the CAISO proposes to revise in this filing), and deleted tariff provisions (*i.e.*, existing tariff provisions that the CAISO proposes to delete in this filing).

[5] Existing tariff section 30, *et seq.*

[6] Existing tariff section 27.5.6.

[7] Existing tariff section 36, *et seq.*

market positions, and manage their exposure to differences between day-ahead and real-time prices.[8] The CAISO has the authority to suspend or limit virtual bidding activities that can detrimentally affect system reliability or grid operations.[9]

The tariff includes local market power mitigation procedures to enable the CAISO to mitigate the market effects of any conduct that would substantially distort competitive outcomes in the CAISO markets.[10] The local market power mitigation procedures include the calculation of default energy bids and an automated process for determining whether transmission constraints are competitive or non-competitive.[11]

2. Commitment and Compensation of Generating Resources

Pursuant to its tariff, the CAISO optimizes economic commitment and dispatch of generating resources in the markets it operates based on the resources' market bids as well as their commitment costs, default energy bids, and generated bids. The tariff also guarantees recovery of commitment costs and default energy bid costs for CAISO-committed resources through the bid cost recovery mechanism.

a. Commitment Costs

In the day-ahead market, (*i.e*., the integrated forward market and the residual unit commitment process (RUC)), the CAISO commits resources and publishes a financially binding day-ahead schedule. The costs the market considers when making commitment decisions consist of the costs of starting up resources (start-up costs), the costs of running resources at their minimum operating levels (minimum load costs),[12] and transition costs for resources that can operate in different configurations.[13]

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8 Existing tariff section 30.9.

9 Existing tariff section 7.9.

10 Existing tariff section 39, *et seq.*

11 Existing tariff section 39.7, *et seq.* The calculation of default energy bids is further discussed below in section II.A.2.b of this transmittal letter.

12 *See* existing tariff section 31.3; tariff appendix A, existing definitions of "Start-Up Cost" and "Minimum Load Costs."

13 These resources are referred to as "multi-stage generating resources" (MSG resources) in the CAISO tariff.

To the extent these resources do not recover these costs through the market, resources recover through the bid cost recovery process their start-up costs, transition costs, and minimum load costs based on the sum of cost components specified in the tariff that reflect the resources' unit-specific performance parameters.[14] For natural gas-fired resources, one of these cost components is a formulaic value adjusted for fuel-cost variation on a daily basis using a natural gas price calculated as discussed below.[15] These resources can also submit daily bids for their start-up, transition, and minimum load costs that are between zero and a cap of 125 percent of the calculated proxy cost.[16]

The CAISO normally uses a natural gas price index to estimate the formulaic natural gas cost values for a gas-fired resource subject to the proxy cost methodology.[17] The CAISO calculates the gas price index between 7:00 p.m. and 10:00 p.m. Pacific time using up to four (but at least two) natural gas commodity prices published that day from the following sources: Natural Gas Intelligence, SNL Energy/BTU's Daily Gas Wire, Platt's Gas Daily, and the Intercontinental Exchange (ICE).[18] The CAISO uses this gas price index in the day-ahead market run for the following trading day. The same gas price index forms the basis of the commitment costs used in the next day's real-time market.

In market situations involving a spike in gas commodity prices, however, the CAISO uses a more recent gas price. Specifically, if a daily gas price reported by ICE on the morning of the day-ahead market run exceeds 125 percent of the gas price index calculated for the day-ahead market between 7:00 p.m. and 10:00 p.m. on the preceding day, the CAISO will utilize the daily gas price reported by ICE on the morning that the day-ahead market is running in all CAISO cost formulas and market processes for the day-ahead market running that day.[19] The CAISO adopted this procedure based in part on the fact that prior to this spring, ICE usually published gas commodity prices by 10:00 a.m., which is the time when the CAISO's day-ahead market closes. Effective April 1,

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14 Existing tariff section 30.4.1.1.1(a). Under the CAISO tariff, all resources except for those with use limitations recover their commitment costs pursuant to this "proxy cost methodology." Use-limited resources have the option of utilizing the "registered cost methodology" under which they recover their commitment costs pursuant to registered fixed values.

15 *Id.* The tariff also explains how costs of non-natural gas-fired resources are determined. Existing tariff section 30.4.1.1.2.

16 Existing tariff sections 30.4.1.1.1(b), 30.7.9(c), 30.7.10.

17 *See* existing tariff section 39.7.1.1.1.3(a).

18 All times listed in this transmittal letter are Pacific time.

19 Existing tariff section 39.7.1.1.1.3(b).

however, ICE has changed its publication time to 11:30 a.m, *i.e*., after the CAISO day-ahead market closes.

b. Default Energy Bids under the Variable Cost Option

The CAISO uses default energy bids to mitigate bids of resources subject to local market power mitigation.[20] When a resource's bid is mitigated, the CAISO systems substitute the default energy bid for the resource's bid in the market clearing process and use the default energy bid to determine the resource's bid cost recovery compensation.[21] Default energy bids also factor into the settlement of residual imbalance energy and exceptional dispatches in some circumstances.[22] The default energy bid is intended to allow the resource to recover its marginal cost of producing energy.[23]

Each scheduling coordinator can choose one of the following three options as its preferred option for calculating default energy bids: (1) the variable cost option; (2) the negotiated rate option; or (3) the locational marginal price option.[24] For a gas-fired resource subject to the variable cost option, that option calculates the default energy bid based on incremental fuel costs,[25] which are determined using the same tariff provisions that are used to determine the gas price under the proxy cost methodology as described above.

The CAISO calculates default energy bids for the day-ahead and real-time markets respectively using the same gas commodity price formulas described above for commitment costs.

c. Generated Bids

The CAISO generates cost-based bids when a scheduling coordinator does not submit a bid for a resource that is subject to a must-offer requirement, such as a resource adequacy resource, or pursuant to the generally applicable

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[20] *See* existing tariff section 39.7.1, *et seq.*

[21] See existing tariff section 11.8, *et seq.*

[22] See existing tariff sections 11.5.5-11.5.6.

[23] *See Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at PP 1004-14, 1033-71 (2006).

[24] Existing tariff sections 39.7.1-39.7.1.3. Further, a scheduling coordinator for a frequently mitigated unit has a fourth option for calculating default energy bids, the frequently mitigated unit option. Existing tariff section 39.7.1.4.

[25] Existing tariff sections 39.7.1.1-39.7.1.1.1, 39.7.1.1.1.3-39.7.1.1.1.4.

scheduling and infrastructure bidding rules as set forth in the CAISO tariff and the business practice manual.[26] As with start-up costs, minimum load costs, transition costs, and default energy bids under the variable cost option, the CAISO determines gas costs for generated bids of gas-fired resources using the gas pricing provisions described above.

d. Bid Cost Recovery Process

The CAISO guarantees recovery of start-up costs, minimum load costs, transition costs, and energy bid costs for resources committed by the CAISO through the bid cost recovery mechanism set forth in its tariff.[27] To the extent that a resource's market revenues based on locational marginal prices are insufficient for the resource to recover such costs, the CAISO will pay the resource uplift to ensure that it recovers its costs.

B. Natural Gas Leak at the Aliso Canyon Gas Storage Facility

Please refer to attachment C to this filing for background information regarding the natural gas leak at the Aliso Canyon facility and the implications thereof.

C. Stakeholder Process

Please refer to attachment C for background information regarding the CAISO's stakeholder process leading up to this filing.

III. Proposed Tariff Revisions

Through the stakeholder process, the CAISO developed proposals to mitigate the risks posed by the limited operability of the Aliso Canyon gas storage facility. The tariff revisions proposed in this filing are intended to provide the CAISO with tools to mitigate operational risks that might lead to electric service interruptions on the CAISO electric grid due to restrictions of gas deliveries to electric generators. These tools will help ensure that the CAISO markets consider generator bids and produce prices that reflect gas system limitations, thereby reducing the chance that CAISO dispatches could adversely impact gas system reliability. The totality of these measures will better position the CAISO to operate its system reliably this summer in light of the challenges associated with the limited availability of Aliso Canyon identified by the Inter-Agency Task Force.

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[26] *See* existing tariff sections 30.7.3.4, 40.6.8; tariff appendix A, definition of "Generated Bid."

[27] *See* existing tariff section 11.8, *et seq.*

A. Provide Generators Information Regarding Their Potential Day-Ahead Commitments Prior to the Day-Ahead Market Run

The CAISO proposes to assist scheduling coordinators in making more informed gas procurement decisions by providing them with advisory information regarding their resources' potential commitment in the day-ahead market the CAISO produces through its existing two-day-ahead process. This involves the CAISO running the commitment process based on available bids and estimates of system conditions at that time. CAISO operations personnel currently use these results for internal planning purposes in advance of the day-ahead market. This information will be provided to scheduling coordinators only to advise them of their potential commitments and will not be binding. The CAISO will continue to conduct its actual day-ahead market runs the day prior to the operating day to produce financially and physically binding commitments and dispatches.

The advisory information provided to scheduling coordinators will come in the form of the MWh advisory schedule produced by the residual unit commitment process conducted as part of the typical day-ahead market. The advisory RUC schedule will be communicated to scheduling coordinators through the CAISO's secure communication system and will not include pricing information.[28] Although the precise constraints the operations personnel use may change between market runs until the final set of constraints for the real-time market is determined, the CAISO and stakeholders determined that providing scheduling coordinators with the two-day-ahead residual unit commitment process results would improve their ability to plan for gas procurement.

Without this information, scheduling coordinators would be required to wait until the publication of the day-ahead market results, which is typically at 1:00 p.m. of the day prior to the operating day, for any forecast of their potential commitment. The CAISO understands most gas trading for delivery on the CAISO's trading day occurs earlier in the morning before the day-ahead market publication time. Although market participants can consider demand forecasts and bilateral gas and electric market activity and plan based on their expectations of where economics will place their bids in the CAISO day-ahead market supply curve relative to the demand bid curve, scheduling coordinators are limited in their ability to predict day-ahead market schedules because these schedules are also affected by the numerous constraints modeled by the CAISO market. The advisory schedules will therefore increase their ability to make informed decisions regarding gas procurement.

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[28] New tariff section 6.5.2.2.3. The CAISO notes that the results of the two-day-ahead run will be meaningful only to the extent there are bids available in the CAISO's systems to represent clearing of the two-day-ahead market based on bid-in supply and bid-in demand.

The advisory information would be provided only to the responsible scheduling coordinator for resources bidding into the day-ahead market and not to all market participants. The information reflects confidential schedules, which the CAISO tariff restricts the CAISO from sharing with other market participants. This restriction is reasonable because it is the scheduling coordinators for these resources that must ensure that they have procured and nominate sufficient gas to perform consistent with expected CAISO dispatches.

During the stakeholder process, the CAISO considered moving the day-ahead market timeline to earlier in the day, so that the published day-ahead market results could be taken into account for purposes of procurement and nominations of gas during the first gas scheduling cycle that closes at 11:00 a.m. This would require the CAISO to execute the financially and physically binding runs earlier in the day-ahead, which would be based on less reliable forecast data. The risk of increased forecast error due to moving the day-ahead market timeline would exacerbate the risk that real-time re-dispatch would differ significantly from the day-ahead market schedule, thereby likely undoing any benefits of moving the day-ahead market timeline. Therefore, the CAISO concluded that moving the day-ahead market timeline would be unnecessary and counterproductive.

B. Implement an Improved Day-Ahead Gas Price Index

The CAISO proposes to improve the accuracy of the gas commodity price indices that it uses to calculate commitment cost proxy costs, generated bids, and default energy bids used by the day-ahead market so that they reflect the most recent gas commodity price information. Using information that more accurately reflects prevailing gas commodity costs will enhance the day-ahead market's ability to dispatch resources efficiently. It also means that resources cleared in the day-ahead market will be compensated based on fuel prices that better reflect their actual costs of procurement.[29] The CAISO expects that these improvements will be particularly helpful in reflecting constrained gas conditions resulting from the limited operability of Aliso Canyon. However, these changes will apply to all resources in the CAISO balancing authority area so that the day-ahead market uses consistent and more accurate gas prices system-wide.

Specifically, the CAISO proposes to revise the tariff to state that, for the day-ahead market, the CAISO will use as the gas price index a volume-weighted

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[29] As explained above, permitting adequate recovery of such costs accords with Commission precedent. *See Cal. Indep. Sys. Operator Corp.*, 145 FERC ¶ 61,082, at PP 21-24; *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at PP 1004-14, 1033-71.

average price that ICE calculates based on trades transacted on ICE during its next-day trading window, *i.e.*, on the morning of the CAISO's day-ahead market.[30] If, for any reason, the volume-weighted average price is not available from ICE during this period, the CAISO will use the most recently calculated price indices.[31] For example, if the CAISO cannot obtain price data on a particular day, it will use the prior evening's price index.

This new procedure will replace the CAISO's existing day-ahead procedure, which requires the CAISO to calculate its day-ahead gas price index using at least two or more of the following publications: Natural Gas Intelligence, SNL Energy/BTU's Daily Gas Wire, Platt's Gas Daily, and the Intercontinental Exchange. This revised day-ahead procedure does not affect the calculation of the real-time gas price index, which will continue to be based on two or more of these publications. The CAISO proposes that this new procedure become effective as of July 6, 2016, which is the earliest date by which the CAISO can implement it.

This new procedure provides the benefit of using more up-to-date price data produced by ICE compared to the current procedure that requires the CAISO to use price data from the evening before the day-ahead market run. Using this more up-to-date price information has the advantage of accounting for fuel cost increases that may be developing on a given day, thereby better reflecting resources' fuel cost exposure when they purchase gas for the operating day. This, in turn, enables the day-ahead market to conduct a more efficient and informed dispatch because the bids will incorporate more timely information regarding the resource's potential gas price exposure. The use of the gas price index reported by ICE on the morning of the day-ahead market will reflect gas trading for the next operating day. As the CAISO Department of Market Monitoring (DMM) notes in its comments on the CAISO's proposal, the bulk of gas trading for delivery the next day occurs by 8 a.m.[32]

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30 New tariff section 39.7.1.1.1.3(b). To make the organization of the provisions in section 39.7.1.1.1.3 clear, the CAISO has broken the section out into new subsections (a) through (d). The CAISO notes that while the use of lettered subsections in section 39.7.1.1.1.3 is new, some of the language in subsections (a)-(c) is unchanged from existing tariff section 39.7.1.1.1.3 and the rest of that language is revised. New subsection (d) is discussed below in section III.C of this transmittal letter.

31 New tariff section 39.7.1.1.1.3(a). In addition, the CAISO proposes to clarify the existing tariff provisions regarding public market information to state that the CAISO will publish the natural gas price used for the real-time market and daily greenhouse gas price indices when available. Revised tariff sections 6.5.2.3.4, 6.5.4.2.3.

32 DMM comments on Revised Draft Final Proposal at 8 (May 6, 2016) (DMM Comments). The DMM Comments are provided in attachment F to this filing.

The new procedure also obviates the need for the CAISO to retain its existing manual gas price spike procedure, which authorizes the CAISO, when a gas price spike occurs, to calculate gas price indices for gas-fired resources manually using a daily gas price reported by ICE on the morning of the day-ahead market run.[33] The CAISO adopted this procedure based, in part, on the fact that ICE's morning publication time (almost always 10:00 a.m.) coincided with the timing of the CAISO's day-ahead market, which normally closes at 10:00 a.m. and issues its results by 1:00 p.m.[34] As of April 1, 2016, however, ICE now publishes its gas commodity prices at 11:30 a.m., *i.e.*, after the day-ahead market closes. Waiting for 11:30 a.m. to calculate the day-ahead gas price indices would require the CAISO to re-open bidding in the day-ahead market after 11:30 a.m., close the day-ahead market until about 12:45 p.m., and publish the day-ahead market results potentially by about 3:45 p.m. Changing the day-ahead market timeline in this manner is not ideal, as it will delay the ability of gas-fired resources to prudently procure and nominate gas to meet CAISO dispatch instructions. For this reason, as well as the fact that the CAISO now plans to calculate day-ahead gas price indices routinely based on price information released on the morning of the day-ahead market run, the CAISO proposes to delete the gas commodity price-spike provisions from the tariff.[35]

C. Increase the Gas Price Applicable to Commitment Cost Caps and Default Energy Bids for Resources on the SoCalGas and SDG&E Systems for the Real-Time Market

The CAISO proposes to increase the gas price used to calculate the commitment costs for gas-fired resources subject to the proxy cost methodology[36], generated bids for resource adequacy resources, and default energy bids under the variable cost option used for mitigation, by an amount necessary to ensure the real-time market appropriately recognizes the increased constraints of resources in the southern California region. This is intended to: (1) improve the dispatch of these resources so that they are more likely to be dispatched to address local needs rather than system needs; (2) better account for systematic differences between day-ahead and same day natural gas prices;

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[33] *See* existing tariff section 39.7.1.1.1.3(b).

[34] See sections II.A.2.a-II.A.2.b of this transmittal letter.

[35] Deleted tariff section 39.7.1.1.1.3(b). To reflect the deletion of these provisions, the CAISO also proposes to delete the cross-references to the provisions that appear elsewhere in the tariff. New tariff section 39.7.1.1.1.3(a); deleted tariff sections 30.4.1.2(b), 31.6.1(v).

[36] Resources subject to the proxy cost methodology are permitted to submit bids for their commitment costs, so long as those bids are greater than zero and less than or equal to 125 percent of the proxy commitment costs calculated by the CAISO. *See* existing tariff sections 30.4.1.1.5, 30.7.9, and 30.7.10.

and (3) improve the ability to manage the generators' gas usage within applicable gas balancing rules

For the real-time market, the CAISO uses a gas price index based on at least two gas commodity prices from at two or more gas price publications plus the gas base transportation rate, plus other inputs. Commitment cost bids are capped at 125 percent of the cost calculated by the CAISO. Generated bids and default energy bids under the variable cost option include an adder of 10 percent to the CAISO's calculation of costs based on the gas price indices.[37] The CAISO proposes to increase the gas price component of these formulas for use in the real-time market to reflect the constraints on the southern California gas system arising from the unavailability of Aliso Canyon.

Under these conditions, intra-day (*i.e.*, real-time) gas availability will likely decrease and there will be tightened gas balancing requirements and these current commitment costs, generated bids, and default energy bids will likely not fully accommodate these conditions. This is because the CAISO's current calculation of the gas price does not include information from the intra-day gas commodity markets regarding gas prices or risk of noncompliance with gas balancing rules, as the CAISO's current calculation of the gas commodity price is based on trading for next-day delivery. Therefore, under the current rules, the resulting commitment costs, generated bids, and default energy bids may not allow resources the ability to manage gas-balancing requirements within tightened tolerance bands and the calculated gas price may not fully capture real-time gas commodity prices on all days.

The limited availability of Aliso Canyon means a lack of nearby storage to respond to electric ramping needs as well as a limited ability, when there is a deterioration of gas pipeline pressures, for Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) to support large increases of gas receipts onto their systems relative to their scheduled capacity or deliver the increased amounts of gas in real-time to generators. Because of these constraints, it will be better for the CAISO real-time market to dispatch generators on these gas systems only for local electrical needs while avoiding dispatching these generators to meet general CAISO system needs that could be met by resources that are not subject to these strict gas limitations. The commitment cost bid caps, generated bids, and default energy bids resulting from the gas price index based on the next-day gas commodity price currently used by the real-time market may be too low to allow the resource to bid commitment costs or to reflect generated or mitigated energy offers in the real-time market that reflect gas system limitations, and may thereby prevent a generator on the affected gas system from being economically dispatched by the

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[37] See sections II.A.2.a-II.A.2.b of this transmittal letter.

CAISO for system needs. When generators on the affected gas system are under tightened gas balancing requirements, and they will presumably reflect these tightened balancing requirements in their bids, which will achieve the desired result of making the real-time market more likely to dispatch these resources only for local electrical needs.

The commitment cost costs, generated bids, and default energy bids resulting from the gas price index based on the next-day gas commodity price currently used by the real-time market may be insufficient to allow generators on the affected gas systems to manage gas balancing requirements under the tightened balancing tolerance bands. This can be the case even when the CAISO enforces the proposed gas constraint limiting the incremental dispatch of generators in a particular area to a maximum or minimum gas usage. Even when the CAISO would be enforcing the proposed gas constraint, it is preferable for the CAISO to have the ability to differentiate between generators that are at risk of violating balancing rules and those that have gas available to respond to dispatch.

For example, under a low-operational flow order (OFO) scenario, the pipeline pressure is dropping because nominated gas is lower than the actual gas demand driving down that pressure. To balance the pressure at a more sustainable level, customers need to either increase their nominated flows or reduce their demand. If a customer had an imbalance outside the tolerance band and was unable to procure and nominate flow to reduce this imbalance, the customer would need to either reduce its gas burn or incur a noncompliance penalty. Under the proposed rule changes, the electric generator customer will be able to hold or reduce its gas burn by bidding into the CAISO market at higher costs so the real-time market is less likely to commit the resource or dispatch it up.

To address these problems as well as the ability to reflect expectations regarding real-time commodity prices, the CAISO proposes to revise the tariff to increase the gas commodity price for resources connected to the SoCalGas or SDG&E systems for purposes of determining the CAISO's real-time gas price indices.[38] Specifically, for the real-time market, the CAISO will increase the calculated gas price for resources receiving gas service from SoCalGas and SDG&E by an amount that it determines is necessary to: (1) improve the dispatch of these resources so that they are more likely to be dispatched to address local needs rather than system needs; (2) better account for systematic differences between day-ahead and same-day natural gas prices; and (3)

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[38] New tariff section 39.7.1.1.1.3(d). Aside from the introduction of the increased gas price discussed in this section of the transmittal letter, the CAISO proposes no other changes to how it calculates gas prices for the real-time market pursuant to section 39.7.1.1.1.3.

improve the ability to manage the generators' gas usage within applicable gas balancing rules. These tariff revisions will enable the real-time market clearing process to avoid dispatching these resources for system needs so that is likely to only dispatch these resources to address local needs rather than system needs. The increased amount should also be sufficient to allow resources to account more effectively for systematic differences between day-ahead and same-day gas commodity prices in their bids. Further, the increased amount will provide additional headroom to reflect costs of generators operating within the applicable gas balancing rules under the expected constrained gas conditions this summer.

In order to achieve these goals, for resources connected to the SoCalGas or SDG&E systems for the real-time market, the CAISO will, beginning on July 6,[39] initially increase the gas commodity price used for determining commitment costs by 75 percent, *i.e.*, the gas commodity price will be 75 percent higher than it would have been absent the increase. The CAISO will also have the ability to subsequently increase or decrease the gas commodity price based on the CAISO's evaluation of whether the current increase is successfully accomplishing the three criteria described above, whether a higher increase is necessary to do so, or whether a lesser increase could achieve these criteria. However, any increase in the commitment cost gas price will be capped at $2.50 plus two times the next-day gas index price. This same procedure will be used for determining default energy bids under the variable cost option, except that the initial increase will be 25 percent, and any increase in the generated or default energy bid gas commodity price will be capped at 100 percent.

The initial 75-percent increase of the gas commodity price for use in determining the commitment cost proxy cost is just and reasonable. As DMM explained in its comments, it performed an analysis of how effective amounts added to the gas commodity price for resources in the SoCalGas and SDG&E gas areas would be in affecting the likely system-wide dispatch order. The analysis showed that, if the objective is to make such resources more expensive than most resources outside the SoCalGas and SDG&E gas areas and thus slightly higher in the economic merit order than other resources that could be committed to meet system needs, then 75 percent is a reasonable starting point because it results in about four-fifths of all resources in the SoCalGas and SDG&E gas areas being more expensive than resources elsewhere.[40] DMM also "strongly recommend[ed] that the [CA]ISO should have the flexibility necessary to adjust the gas price level used in calculating commitment cost bid

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39 July 6 represents the earliest date by which the CAISO could implement this increased gas price procedure.

40 DMM Comments at 1-3, 17-25.

caps based on observed market conditions and outcomes."[41] The CAISO agrees that this flexibility is necessary because if it finds during the summer that a 75-percent increase no longer accomplishes the goal of representing the affected resources as sufficiently more costly relative to other resources for purposes of system-wide dispatch, the CAISO should be able to recalibrate the price increase to an amount that accomplishes this goal.

The cap on the amount by which the gas commodity price would be increased for use in determining commitment cost proxy cost ($2.50 plus two times the next-day gas index price) is also just and reasonable because this cap level is equivalent to the price that a generator would pay for gas if it violated an OFO based on the current SoCalGas and SDG&E gas tariffs.[42] Therefore, this is likely the highest real-time gas price that resources in southern California can be exposed to in managing their applicable gas balancing rules. Thus, the adjustment to the gas commodity price will ensure that commitment costs remain within the zone of reasonableness.[43] Also, the commitment cost bid cap of 125 percent of the CAISO calculation of all costs, including gas costs, will remain unchanged so resources will remain free to submit commitment cost bids so long as they do not exceed the 125-percent cost cap.

The same increase that applies to commitment costs will apply to the CAISO's calculation of the generated bids for resource adequacy resources that are under a must-offer requirement but fail to submit a bid in the real-time

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[41] *Id.* at 3.

[42] The next-day gas index price approximates the price a generator would have to pay to replace the gas it used to avoid weekly or monthly imbalance charges. A generator would additionally pay the OFO charge which for SoCalGas is the next-day gas index price plus $2.50. Thus, the total cost a generator would pay for violating an OFO is the $2.50 plus the two times the next-day gas index price**.** DMM states on page 4 of its comments that it does not support basing the commitment cost caps on gas penalties, stating that this could provide an incentive for generators to violate gas balancing requirements. The CAISO disagrees. The CAISO believes the price a generator would pay to violate an OFO represents the maximum price the real-time market would have to consider to respect gas system constraints and avoid violating gas balancing requirements.

[43] The Commission has explained that "the courts and this Commission have recognized that there is not a single just and reasonable rate. Instead, we evaluate [proposals submitted under section 205 of the Federal Power Act] to determine whether they fall into a zone of reasonableness. So long as the end result is just and reasonable, the [proposal] will satisfy the statutory standard." *Calpine Corp. v. Cal. Indep. Sys. Operator Corp.*, 128 FERC ¶ 61,271, at P 41 (2009) (citations omitted). *See also New England Power Co.*, 52 FERC ¶ 61,090, at 61,336 (1990), *aff'd sub nom. Town of Norwood v. FERC*, 962 F.2d 20 (D.C. Cir. 1992), citing *City of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984) (rate design proposed need not be perfect, it merely needs to be just and reasonable).

market. The CAISO's current market systems utilize the same fuel index for the generated bid calculation as they use for the commitment costs calculation.

Increasing the gas commodity price used in determining the default energy bid by 25 percent is also just and reasonable. As DMM explained in its comments, it is appropriate that the initial increase in the gas commodity price for use in determining the default energy bid be set at a lower level than the initial increase in the gas commodity price for use in determining the commitment cost proxy costs. Although generators can submit commitment cost bids up to 125 percent of their proxy costs, generators can submit energy bids up to a bid cap of $1,000/MWh.[44] These energy bids are only subject to mitigation in the event that congestion occurs and the supply that can relieve the congestion is deemed uncompetitive pursuant to the CAISO's local market power mitigation procedures. If subject to mitigation, energy bids are capped by the higher of a competitive market clearing price or the default energy bid. Thus, unlike commitment costs, energy bids are only subject to mitigation, and the bidding resources can only be dispatched based on their mitigated bids, when the energy produced by the resources is necessary to meet a local need within an uncompetitive area. In addition, energy bids set the market price for the entire market, while commitment costs do not. For these reasons, DMM believes that "the gas index used in calculating Default Energy Bids in the SoCal gas area would need to be inflated by a much lower amount than the gas index used in calculating commitment costs."[45]

Thus, it is just and reasonable to use a lower initial increase in the gas commodity price for determining the default energy bids as compared to commitment costs, even though it provides less ability for generators to manage gas imbalances, because it balances the impact a resource's default energy bid price has on its ability to manage imbalances with the impact it has on system-wide locational marginal prices. Default energy bids only come into play when a resource's bid is mitigated as part of local market power mitigation. Thus, the default energy bid price has smaller impact on a resource's ability to manage its gas imbalances than do commitment costs. Because the price established pursuant to this mechanism in order to account for potential gas commodity price volatility may be greater than actual gas commodity prices on any specific day, this higher default energy bid price could set system-wide marginal energy costs at a level that is not just and reasonable. DMM recommended a 25-percent initial increase of the gas commodity price used in determining the default energy bid as an alternative to the initial 75-percent increase of the gas commodity price used for determining commitment costs, based on DMM's conclusion that a 25

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44 Existing tariff section 39.6.1.1.

45 DMM Comments at 4-5.

percent increase will be sufficient to provide additional headroom for generators to manage their usage in real-time when being limited by local market power mitigation procedures.[46] Further, for the same reasons outlined above with respect to balancing the impact that a resource's default energy bid price has on its ability to manage imbalances with the impact it has on system-wide locational marginal prices, capping at 100 percent any subsequent increases to gas prices used for determining default energy bids is just and reasonable.

DMM stated that it is prepared to work with the CAISO to determine whether gas prices warrant increasing the gas price used in determining commitment costs and default energy bids.[47] Upon determining that a further increase in the gas commodity price is necessary for either commitment costs, generated bids, or default energy bids, the CAISO will issue a market notice specifying the amount of the increase. The CAISO will apply these provisions regardless of the amount of the increase exclusively to generators connected to the SoCalGas and SDG&E gas systems until the CAISO issues a market notice stating a different increase.

Finally, because of the need to implement this mechanism as soon as possible (by early July), the CAISO will not be able to perform a market simulation prior to instituting it. The CAISO will, however, perform internal testing consistent with its standard software development process. Further, the CAISO will have the flexibility to implement a higher or lower gas price increase, subject to caps, based on its ongoing evaluation of the effectiveness of particular increases in achieving the goals stated above.

D. Allow Resources to Rebid Commitment Costs in the Real-Time Market

Under the current tariff rules, when scheduling coordinators bid commitment costs into the day-ahead market on behalf of resources, the resources are locked into those day-ahead commitment cost bids in the real-time market.[48] Thus, scheduling coordinators have no flexibility to reflect any intervening gas imbalance limitations and their associated economic impacts on real-time gas prices in their real-time market commitment cost bids. The current tariff rules may also result in inefficient resource commitment, because the real-time market will incorrectly value commitment costs based on these bids instead of bids reflecting current conditions at the time of the real-time market. These

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46 *Id.* at 5-6.

47 *Id.* at 7.

48 Existing tariff section 30.5, which sets forth bidding rules for the CAISO markets, does not currently permit resources to change their day-ahead commitment cost bids in real-time.

limitations will be particularly likely to occur this summer due to the limited availability of the Aliso Canyon facility. If the real-time market is unable to reflect changing gas system conditions, it will be incapable of dispatching resources optimally, which could threaten electric system reliability and further constrain the gas system.

To address these issues, the CAISO proposes to revise the tariff to provide that a scheduling coordinator may submit new daily bids in the real-time market for commitment costs for resources or MSG configurations for which the scheduling coordinator previously submitted such bids in the day-ahead market, subject to the two exceptions discussed below.[49] The scheduling coordinator will be able to submit the new daily bids any time starting after the close of the day-ahead market, and the new bids will apply to all remaining eligible hours of the day unless subsequently modified by the scheduling coordinator. The increased bidding flexibility provided by these tariff revisions will enable scheduling coordinators to submit commitment cost bids that better reflect gas imbalance limitations and the associated financial impacts as well as changes in gas commodity prices. This, in turn, will allow the real-time market to better determine the set of resource commitments needed to efficiently serve load, taking into account any gas system limitations, so that locational marginal prices send more accurate price signals to both generation and load throughout the CAISO system.

There are two exceptions to this additional flexibility specified in the tariff revisions.[50] These exceptions are necessary to preserve the integrity of day-ahead market results and to alleviate the potential ability for resources to inflate their bid cost recovery.[51]

First, in order to preserve day-ahead commitments, scheduling coordinators will be prohibited from rebidding their commitment costs in the real-time market for trading hours in which the resource or MSG configuration has received a day-ahead schedule or a start-up instruction in RUC, *i.e.*, when the

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[49] Revised tariff section 30.5.1(b).

[50] In addition, DMM explained that it will be "closely scrutinizing changes to commitment costs in real time that coincide with bid cost recovery payments." DMM Comments at 9.

[51] *Id.* If the CAISO is unable to implement the two exceptions through an automated process, the CAISO will monitor the markets for rebidding of commitment costs that violates the two exceptions and will refer any tariff violations it detects to the Commission. Furthermore, the fact that only these two prohibitions are explicitly mentioned does not provide market participants a safe harbor for any other adverse market behavior that results in market inefficiencies. The same general prohibitions against market behavior that adversely impacts market outcomes specified in existing tariff section 39 will continue to apply to this and all parts of the CAISO markets. The CAISO and its DMM will take all necessary and appropriate actions to address these situations.

resource has a binding RUC commitment. This first exception is necessary because the integrated forward market and the RUC process can consider and dispatch resources with longer start times than the resources that the real-time market can consider and dispatch. As a result, permitting resources with binding day-ahead commitments to increase their commitment costs in real-time could lead to inefficient dispatches and distortions in the day-ahead market. This is the case because if the day-ahead market had considered the increased commitment costs rebid by a resource in real-time, it might have dispatched a less expensive resource with a longer start time that, because of its longer start time, would not be available to be dispatched in the real-time market. In other words, the rebidding resource in this scenario would never have been dispatched by the day-ahead market in the first place. Furthermore, the CAISO calculates and pays bid cost recovery separately for the day-ahead and real-time markets so resources are fully compensated for procuring gas for day-ahead schedules.

Second, scheduling coordinators will be prohibited from rebidding their commitment costs in the real-time market for trading hours that span the minimum run time of the resource or MSG configuration after the CAISO has committed the resource or the scheduling coordinator has self-committed the resource in the real-time market.[52] This second exception is necessary because the CAISO market cannot reconsider commitment costs and de-commit a resource or MSG configuration for the duration of a minimum run time. Consequently, any increase to commitment costs during this period would inappropriately inflate bid cost recovery payments and would provide no benefit to the efficiency of the market dispatch.

The rebidding flexibility and the prohibitions will apply to all resources on the CAISO system. In March 2016, the CAISO Board of Governors approved the CAISO's proposal to provide this additional flexibility to all scheduling coordinators that participate in the CAISO's real-time market. Therefore, unlike some of the changes the CAISO proposes in this amendment, this change will apply to all scheduling coordinators and not just resources in the southern California system. Although the CAISO does not anticipate that resources not connected to the affected gas system will have the same degree of limitations with respect to gas imbalances, implementing this flexibility for all scheduling coordinators in the real-time market for summer 2016 is beneficial for two reasons. First, areas geographically proximate to SoCalGas and SDG&E experiencing similar gas system limitations may, to some degree, experience

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52 This proposal was originally developed in the Bidding Rules Enhancements stakeholder initiative before the CAISO moved it to the Aliso Canyon Gas Electric Coordination stakeholder initiative and modified it. Minimum run time means the minimum amount of time that a generating unit must stay on-line after being started up prior to being shut down, due to physical operating constraints. Tariff appendix A, existing definition of "Minimum Run Time."

spillover effects. Therefore, providing this flexibility for the coming summer period will allow all resources to better reflect their increased or decreased commitment costs in the real-time, enabling the real-time market to reach a more optimal solution for the system overall. Second, even resources not directly affected by gas limitations may need to be started in real-time more frequently due to the overall effects of the Aliso Canyon limitations on the CAISO system. Consequently, these resources may also have a greater need for flexibility in managing real-time gas commodity price changes and gas imbalances.

E. Revise the CAISO's Short-Term Unit Commitment Process to Facilitate Resources' Gas Procurement Evaluations

The CAISO proposes to revise the tariff provisions regarding its short-term unit commitment process for the real-time market so that the short-term unit commitment process does not commit resources that were not bid into the real-time market if they were not scheduled or committed in the day-ahead. The short-term unit commitment process looks ahead over multiple intervals to anticipate commitment needs, and as currently configured, may commit a resource in the real-time even if the resource does not have a bid in the real-time or a real-time must-offer requirement. This can occur because under the current market rules the short-term unit commitment process may consider any bid submitted to any of the CAISO markets, including the day-ahead. Therefore, if a resource does not submit a bid in the real-time market and does not have a real-time must-offer requirement, if it submitted a bid in the day-ahead market, even if was not committed in the day-ahead market, it may be committed in the real-time market. The CAISO Board of Governors approved a change to this rule in March 2016, so that the short-term unit commitment process will no longer result in such commitments. Although the CAISO had already planned to file this modification as a permanent change to its tariff, the CAISO proposes to apply this new rule on an interim, expedited basis to all resources this summer to reduce uncertainty with respect to real-time gas procurement requirements and decisions.

Specifically, the CAISO tariff will state that the short-term unit commitment process will utilize (1) bids that were previously submitted in the real-time market by the scheduling coordinator for the trading hour, or (2) the clean bid from the day-ahead market if the resource has a day-ahead schedule or received a start-up instruction in RUC for the trading hour, or if the resource has a real-time must-offer obligation for that trading hour.[53] These tariff revisions will align the short-term unit commitment process with the ability of resources to rebid their commitment costs. This alignment is particularly necessary during the summer months when electric reliability is particularly vulnerable when gas system conditions worsen. Because these resources will not be dispatched by the real-

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[53] Revised tariff section 34.6.

time market if they do not submit bids in the real-time market, have a real-time must-offer obligation, or are not committed in the day-ahead, they will not be expected to have procured gas for real-time dispatch. This will provide resources with greater certainty with respect to their gas procurement decisions, thereby helping to reduce differences between nominated gas and real-time burn, which is one of the main risks associated with the limited availability of Aliso Canyon.

The CAISO proposes to make an additional change in light of the changes to the short-term unit commitment process. Pursuant to the existing tariff, the short-term unit commitment process commits short-start units and medium-start units, but not long-start units or extremely long-start resources, in the real-time.[54] Therefore, in the tariff provisions describing the types of resource adequacy resources that must be available to participate in the real-time market, the CAISO proposes to clarify that these availability requirements apply to fast-start, short-start and medium-start units but do not apply to long-start units or extremely long-start resources.[55] This does not impose an additional obligation on medium-start units that are resource adequacy resources because the CAISO currently generates bids in the short-term unit commitment process for these resources if they bid into the day-ahead market, which they are required to do.

F. Include New Constraint to Allow the CAISO to Better Ensure that Dispatches Are Consistent with Gas System Limitations

The CAISO proposes to implement a constraint in the CAISO markets that constrains the maximum or minimum amount of natural gas that can be burned by natural gas-fired resources, based on limitations, in applicable gas regions anticipated by the CAISO during specific hours.[56] While the bidding rules and measures specified above are expected to result in better visibility of the impacts of the constrained gas system on the electric system through the bids and commitment costs submitted by market participants, it is necessary to adopt additional tools to further ensure that CAISO operators can maintain the system reliably. The proposed natural gas constraint will permit CAISO operators to enforce in the day-ahead or real-time markets a constraint or constraints to limit the dispatch of generators in the affected areas to a maximum gas usage if there is a limitation on the maximum amount of gas used.[57] The constraint or

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[54] *See* existing tariff section 34.6. As their names imply, these different types of units differ from one another based on how long they take to start up. See tariff appendix A, existing definitions of “Short Start Unit,” “Medium Start Unit,” “Long Start Unit,” and “Extremely Long Start Resource.”

[55] Revised tariff section 40.6.3.

[56] New tariff section 27.11.

[57] The CAISO will inform the affected generators that they are subject to the constraint or constraints.

constraints will also limit CAISO market dispatch of the affected generators in the real-time market to a maximum or minimum gas usage if there is a limitation that relates to differences between gas scheduled with the gas company and gas consumed during the operating day due to gas system imbalance limitations. These measures are necessary because electric reliability could be compromised if the CAISO's market inputs do not adequately reflect gas system constraints.

The CAISO proposes to enforce the natural gas constraint in the day-ahead market, the real-time market, or both, depending on electric or gas system conditions. The CAISO will enforce the constraint based on its assessment of gas and electric conditions but will coordinate with the gas companies to the greatest extent possible to ensure the limitations imposed by the constraint in the market are consistent with the limitations observed on the gas system. For example, a gas company may notify the CAISO it will have an outage on its pipelines that reduces the availability of fuel in a defined gas region to an expected maximum amount prior to the close of the day-ahead market. In such cases, the CAISO may enforce the constraint in both the day-ahead and the real-time markets to ensure the CAISO market does not dispatch or commit resources that exceed the maximum burn in the specified region. If an unplanned gas outage occurs after the day-ahead market or a gas curtailment is issued during the real-time market, the CAISO may also enforce the constraint in the real-time market run for similar reasons. Similarly, if the CAISO anticipates that large imbalances between gas schedules and gas consumed could compromise gas reliability and consequently electric system reliability, it may enforce either or both maximum and minimum constraints.

This provision will allow the CAISO to proactively respond to conditions on the gas system as they develop and better ensure that its market dispatches reflect actual gas system conditions. Given the expectation of tight constraints caused by the limited operability of Aliso Canyon, and the potential for such constraints to arise quickly, it is critical for purposes of both gas and electric system reliability that the CAISO have the authority to take action ahead of such occurrences to ensure that its dispatch reflects as much as possible the conditions on the natural gas system. Under-dispatching or over-dispatching resources in gas-constrained regions could each negatively impact pipeline conditions, thereby exacerbating existing gas system limitations. This, in turn, has the potential to lead to significant outages or curtailments of gas-fired generating resources, thereby threatening the reliability of the electric system.

For example, if the gas system is experiencing limitations affecting specific regions of the CAISO electric grid, but the CAISO market system lacks the ability to capture those limitations through market constraints, the market could clear generation based on submitted bids and system conditions on the electric grid that do not account for gas system limitations. This could potentially occur in the

CAISO real-time market even if generators on the affected systems are reflecting tightened gas balancing requirements in their bids. Such dispatches could aggravate the already constrained gas system conditions compromising gas reliability, resulting in gas curtailments that result in the inability of gas generators to access gas needed to serve the electric grid reliably. If this occurs and electric generators cannot access gas to serve load and power cannot be delivered into the local area, this will likely result in electric curtailments. Per the Risk Assessment Report issued by the Inter-Agency Task Force, without authority to reflect gas system limitations in the CAISO market there is a risk that the unavailability of Aliso Canyon could result in electric curtailments on several days across the summer period.

The proposed constraint, when binding, would ensure that generation in the day-ahead or real-time market is dispatched taking into consideration the gas system limitations. Because the CAISO cannot predict at this time exactly how and when the gas system will be constrained over the summer period, it is seeking authority to reflect any such limitations through market constraints based on its observations of gas system limitations and how those limitations could impact electric reliability if not appropriately reflected in the CAISO markets.[58]

The constraint will be implemented using generation nomograms that will include the generators within the affected areas.[59] The nomogram will affect the congestion component of the relevant generators' locational marginal prices and will have a relaxation parameter value (*i.e.*, a "penalty price") associated with relaxing the constraint. The CAISO will establish this parameter to function appropriately relative to the parameters for other constraints enforced in the market and will specify the specific parameter in the business practice manual for market operations.[60] The CAISO may limit the enforcement of the constraint to

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[58] A detailed mathematical description of the constraint is provided on pages 18-23 of the Revised Draft Final Proposal, which is contained in attachment D to this filing. The CAISO will include relevant implementation details in the business practice manual, which the CAISO plans to post for review prior to the requested effective date of this provision.

[59] A nomogram is a set of operating or scheduling rules that are used to ensure that simultaneous operating limits are respected. Tariff appendix A, existing definitions of "Nomogram" and "Contingency". Detailed mathematical information regarding nomograms is provided on pages 35-44 of the Revised Draft Final Proposal.

[60] The constraint parameter establishing the penalty price for the gas constraint is a "penalty factor" that governs the conditions under which constraints may be relaxed and if relaxed will impact the prices at applicable locations. The parameters that impact prices are specified in existing tariff section 27.4.3 with further detail provided in the business practice manual for market operations, which the CAISO will update to provide detail regarding the new constraint parameter. A detailed description of how the CAISO will establish the penalty price relative to other penalty prices used in the market is provided on pages 23-25 of the Revised Draft Final Proposal.

specific affected area(s) and hours, and maximum or minimum gas burn for each hour based on information it obtains through coordination with the gas company. In the event that the CAISO determines that additional generation from the affected gas-fired resources is needed above the level of the constraint for electric reliability purposes, the CAISO will dispatch such additional generation through exceptional dispatches after coordinating with the applicable gas system operator.

Pursuant to the new tariff provisions, when the constraint is binding, the shadow price of the constraint will be reflected in the marginal cost of congestion component of the resource-specific locational marginal prices of only the affected gas-fired resources. The shadow price of the constraint will not be reflected in the marginal cost of congestion component of point-of-receipt locational marginal prices, inclusive of trading hub and other aggregated locations, and will not be reflected in locational marginal prices used for settling other supply besides the affected generators, load, virtual bids, or congestion revenue rights.[61] The CAISO will implement this approach by applying the constraint only to the resource-specific price at the connectivity node (CNode) used to dispatch affected generators but not to the bus location reflecting the point of delivery or receipt on the CAISO controlled grid.[62] It is just and reasonable to apply the shadow price of the constraint only to the resource-specific locational marginal price for generators connected to the affected gas systems because they are the only market entities subject to the gas limitations. When the constraint is binding, the market will ensure the generation subject to the constraint will not be dispatched higher or lower than the constraint's limits. When a maximum gas burn limit is binding, the CNode locational marginal price (*i.e.*, the affected generator's locational marginal price) will decrease, which will tend to reduce the amount of energy the CAISO market dispatches from an affected generator. When the minimum gas burn limit is binding, the CNode locational marginal price will increase, which will tend to increase the amount of energy the CAISO market dispatches from an affected generator

In the figure below, the grey circle represents a generator's (G1)'s physical topological connection to a network node, the CNode. In this example, there is only one piece of equipment connected to a CNode. Therefore, the CNode and

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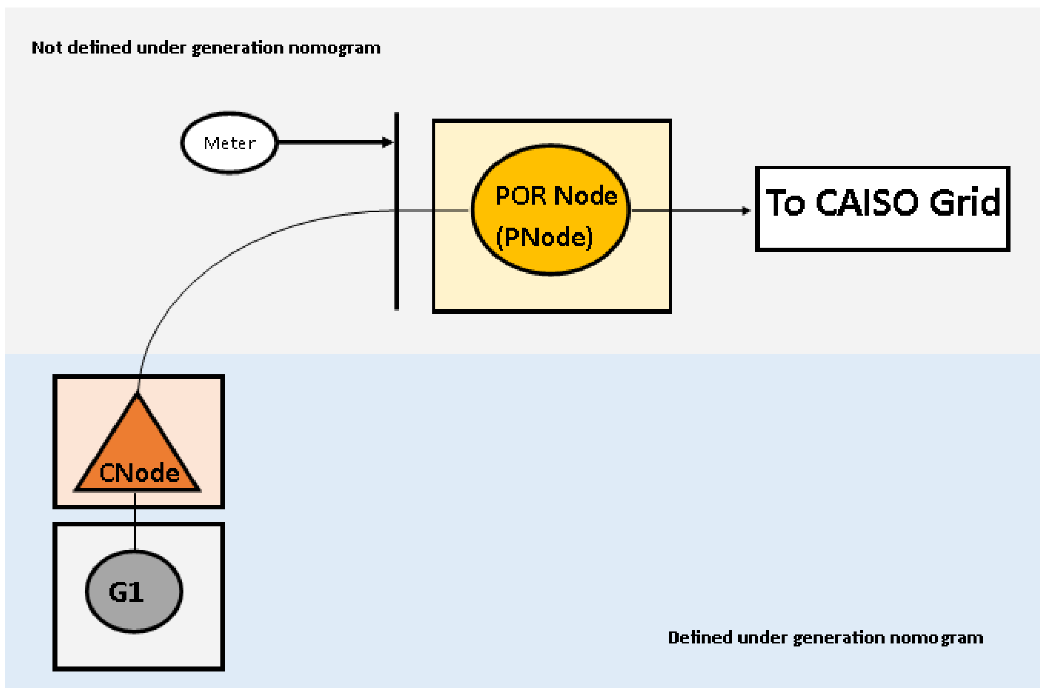
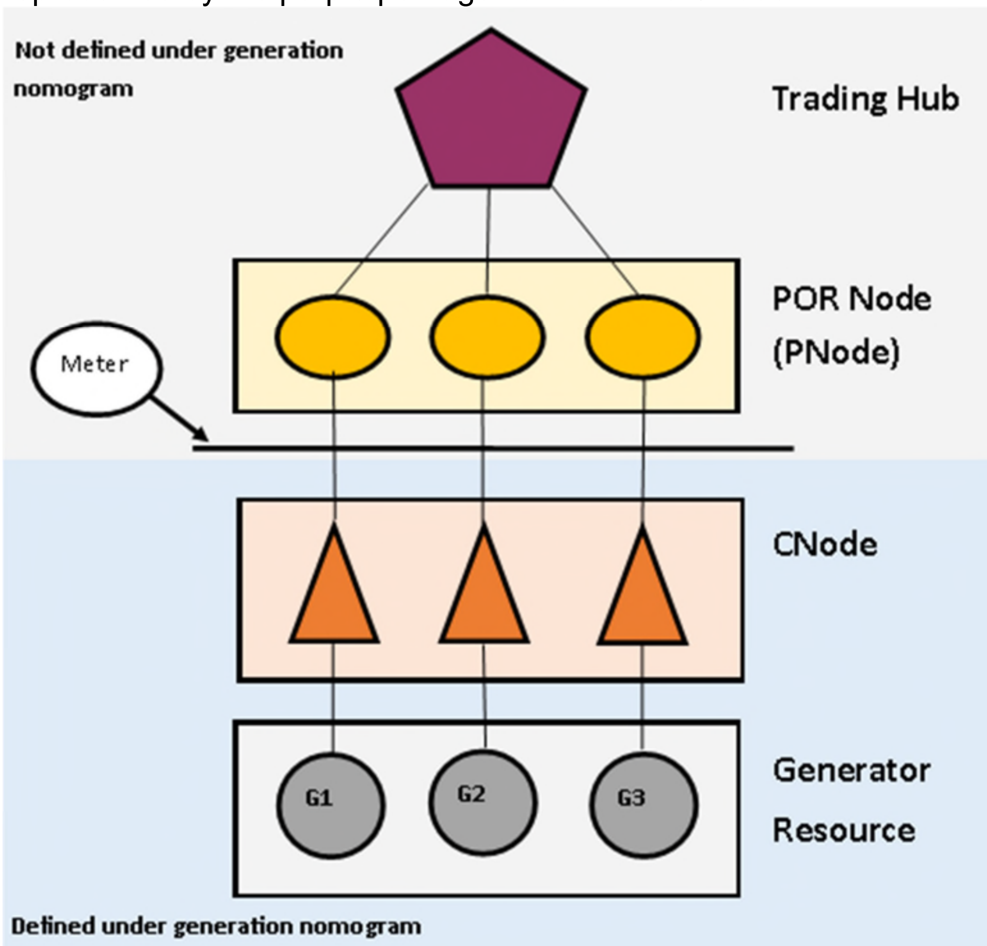
61 The new tariff provisions also specify how the CAISO will allocate any non-zero amounts that are attributable to the price differential between the marginal cost of congestion used for settling a generating unit's scheduled or dispatched amounts at their location and the marginal cost of congestion used for settling demand, virtual bids, or congestion revenue rights.

62 The full network model is composed of network connectivity Nodes (CNodes) interconnected with network branches. A CNode represents a connection point used to define the physical topological connectivity of the network and only one load or generation device can be connected to a CNode. Each piece of equipment has a CNode associated with it and rolls up into a bus which represents all the topological nodes associated with a generating resource.

bus pricing node (PNode) are unique. The figure below further shows the connection between the CNode and the PNode, which represents the point at which the injection is received into the CAISO controlled grid for supply, or withdrawal is delivered out of the CAISO controlled grid for demand. Generally, the PNode of a generating unit will coincide with the CNode and is where the relevant revenue quality meter is connected or compensated, and reflects the point at which the generating unit is connected to the CAISO balancing authority area. This location is referred to as the "Point Of Receipt" (POR) and is considered to be a PNode. However, the PNode and CNode can differ in the CAISO's network model.



With respect to aggregated locations such as trading hubs, the settlement of transactions using these locations would be based on price information from the PNodes that are aggregated into the aggregated pricing node (APNode), and do not use price information from the CNode(s). The figure below shows the relationship between the generators (grey circles), CNodes (orange triangles) and PNodes that are aggregated into the Trading Hub's APNode. The diagram illustrates that the PNode contributes to the pricing of the trading hub price represented by the purple pentagon and not the CNode.



The CAISO proposes to add tariff language authorizing it, during the critical summer period, to settle injections received into the CAISO Controlled Grid for Supply in the SoCalGas and SDG&E regions at prices that are influenced by the natural gas price constraint. That is accomplished by pricing such resources based on the resource-specific locational marginal prices at the CNode rather than the PNode prices. For all other transactions, the CAISO will continue to use the PNode-related prices. Consequently, only prices for generators on the affected gas systems at the specific resource location will reflect the cost of honoring the gas constraint and not prices used for settling virtual bids and congestion revenue rights, or prices used for trading hubs or load aggregation points.

This constraint will establish just and reasonable prices at affected generator locations because under a maximum gas burn limit the price should decrease in accordance with the constrained availability of gas available to fuel generating power at that location. This is similar to the manner in which a supply source behind a transmission constraint is priced higher to reflect the congestion cost associated with dispatching that supply. Similarly, the price of an affected generator under a minimum gas burn limit will increase to reflect the fact that a higher amount of gas needs to be burned to relieve pipeline pressures.

The price for load, virtual bids, and congestion revenue rights will not reflect the shadow price of the natural gas constraint. An incremental injection at the point of receipt locational marginal price is not assumed to come from the generators under this constraint that may reside at the point of receipt locations. Since the constraint depends only on the generation group under it and not on a general injection at that location, the nomogram does not change. In particular, if the incremental change in injection at the point of receipt location was actually an increment in load at the location, the generation group under the constraint would not change and therefore the impact of the constraint is not captured at the point of receipt locations. The point of receipt locational marginal prices should send accurate marginal price signals associated with the incremental change in injection or demand at that specific location.

It is reasonable to not reflect the shadow price of the natural gas constraint in the price of CRRs and virtual bids. If CRRs and virtual schedules settle on LMPs that reflect the shadow price of the gas usage constraint, financial entities may be able to take large positions at little or no cost from which the financial entities would profit at the expense of revenue inadequacy balancing accounts allocated largely to load serving entities.

When the gas usage constraint is binding in the day-ahead market, CRRs that source at a node impacted by the constraint and that sink at a node not impacted by the constraint would be paid based on the shadow price of the constraint. There are likely to be such source and sink node pairs with little to no other constraints creating price separation between the source and sink nodes. Therefore, large quantities of such CRRs could be obtained at little to no cost and with very little downside risk. When the gas usage constraint binds in the day-ahead market, these positions could be lucrative for the financial entities and costly for the load serving entities that would pay the revenue inadequacy uplift charges.

Also, when the gas usage constraint is enforced in the real-time market but not in the day-ahead market, virtual supply at a node whose settlement price is impacted by the constraint offset by virtual demand at a node whose settlement price is not impacted by the constraint would be paid based on the real-time shadow price of the constraint. As described in the paragraph above, there are likely to be node pairs with little to no other constraints creating price separation between the virtual supply and virtual demand nodes. Therefore, using the shadow price of the gas constraint to settle virtual bids could result in the ability to obtain large quantities of such offsetting virtual supply and demand schedules at little to no cost and with very little downside risk. When the gas usage constraint is binding in the real-time market, these offsetting virtual positions could be lucrative for the financial entities and costly for the load serving entities that would pay the imbalance energy uplift charges.

Because of the need to implement the natural gas constraint as promptly as possible (by early June), the CAISO will not be able to perform a market simulation prior to instituting the constraint. The CAISO has, however, performed internal testing of the constraint consistent with its standard software development process. Further, the CAISO will have the flexibility to modify the level of the constraint, or remove the constraint, if the CAISO determines that the constraint is leading to adverse market impacts.

In tandem with implementing the natural gas constraint, the CAISO also proposes to add provisions to the existing tariff language setting forth the criteria for designating a transmission constraint as competitive or non-competitive.[63] The new provisions state that, notwithstanding the existing criteria, when the CAISO enforces the natural gas constraint the CAISO may deem selected internal constraints to be non-competitive for specific days or hours based on its determination that actual electric supply conditions may be non-competitive due to anticipated electric supply conditions in the SoCalGas and SDG&E gas regions. These provisions will ensure the CAISO's ability to designate internal constraints as non-competitive when necessary.

The CAISO has included the provisions in this filing pursuant to a recommendation from DMM, which performed an analysis illustrating the CAISO's potential need to deem some transmission paths to be non-competitive due to the natural gas constraint. DMM concluded that, because the impact of the natural gas constraint on the assessment of competitive paths can only be assessed based on actual system conditions once the constraint is in place, the CAISO should have the authority to deem constraints within southern California to be non-competitive based on the actual system conditions.[64]

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63 Revised tariff section 39.7.2.2. The CAISO will also include implementation detail in the business practice manual regarding how it will apply the new provisions. These tariff revisions, and the tariff revisions to implement an increased gas price for southern California resources for the real-time market (see section III.C of this transmittal letter), are the only tariff changes proposed in this filing that apply solely to southern California.

64 DMM Comments at 10-12.

G. Expand the CAISO's Authority to Reserve Internal Transfer Capability by Adjusting Transmission Constraints

Due to the limited operability of Aliso Canyon, the CAISO anticipates needing flexibility to reserve sufficient internal transfer capability to ensure reliable grid operations during this summer, including meeting energy needs in southern California due to differences between day-ahead forecast of loads and real-time load (forecast error) and assuring deliverability of ancillary services. The CAISO especially expects to need this flexibility with regard to Path 26, but it may also need this flexibility to reserve capability on other internal transmission paths.

As noted above, the Inter-Agency Task Force concluded that the limited operability of Aliso Canyon creates the risk that daily imbalances between scheduled gas nominations and actual burns of gas may adversely affect gas pipeline operating pressures, thus undermining pipeline integrity and consequently having an adverse impact on electric reliability. Consequently, the CAISO could be limited in the amount of additional generation connected to the SoCalGas and SDG&E systems that the CAISO can dispatch to respond to increased southern California load relative to day-ahead CAISO market schedules. Reserving internal transfer capability will provide increased assurance that the CAISO can use generation outside of southern California to meet real-time energy needs in southern California.

One circumstance in which the CAISO might need to have transfer capability available to meet real-time energy needs is to ensure that operating reserves can be delivered to southern California if needed. Under its existing tariff authority, the CAISO may reduce the amount of ancillary services procured from resources in southern California, as appropriate, to ensure that the CAISO markets procure ancillary services from resources that have access to sufficient fuel to respond to a contingency event if needed. In conjunction with shifting ancillary services out of southern California, CAISO operators may need to reserve internal transfer capability to deploy operating reserves in other areas and deliver energy to southern California in response to a contingency event to meet that real-time energy demand.

For these reasons, the CAISO proposes to revise its tariff, on an interim basis, to state that it may adjust transmission constraints for the purpose of reserving internal transfer capability in the day-ahead market or real-time markets. The CAISO will determine whether such adjustments are necessary based on anticipated conditions on the natural gas delivery system, to reliably serve load in specific geographic regions of the CAISO balancing authority area or to assure deliverability of ancillary services.[65] DMM supports this proposal.[66]

The CAISO recognizes that there are trade-offs to reserving internal transmission capability in the day-ahead market. For example, although such reservations will allow the system to respond to real-time southern California load, they might also result in scheduling more southern California generation, which could increase gas usage. Consequently, CAISO operators will need to exercise discretion in enforcing the constraint. They will likely enforce the constraint in the day-ahead market when concerns relating to gas system conditions are more likely related to forecast error. For example, if the temperature on a particular day was roughly 84 degrees, and the forecast of load for that day was 40,000 MW but the actual load was 43,000 MW, the CAISO would have experienced a 7.5-percent forecast error. Given the anticipated limitations on the gas system, if the CAISO is not prepared to meet this 7.5-percent increase in demand across its transfer paths the CAISO might not be able to serve load if a gas limitation impacts resources in southern California and no local generation can be dispatched higher. If the temperature forecasted for the trading day is similar to 84 degrees and the operators have been observing this forecast error trend, the operators could adjust the transfer capability in anticipation of a similar forecast error to ensure that it the CAISO can meet the real-time energy needs of southern California, even with a gas system limitation in effect. This provision will enable the CAISO to alleviate the risk that it might not be able to serve load in the area, which would result in electric curtailments.

Similarly, there are trade-offs to releasing this reserved internal transfer capability in the real-time market. The CAISO expects that it would not release this reserved capability in the real-time market if it were reserving it to ensure the deliverability of operating reserves from outside southern California, unless conditions changed subsequent to the day-ahead market such that the reservation of capability was no longer necessary for this purpose. However, the CAISO would potentially release this reserved internal transmission capability in the real-time market if it reserved it in the day-ahead market in anticipation of forecast error to ensure it can meet southern California energy needs. Although this could result in the market increasing flows from north to south and using up the reserved transfer capability before any forecast error materialized, this would likely also result in generators in southern California being dispatched down in real-time, preserving the ability to meet increased southern California load. Also, routinely releasing this reserved internal transmission capability in the real-time

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[65] New tariff section 27.5.6(f). The CAISO will revise the business practice manual for the full network model to provide implementation detail regarding reservations of internal transfer capability (*e.g.*, on Path 26).

[66] DMM Comments at 14.

market could introduce systematic price differences between the day-ahead and real-time markets, potentially leading to adverse operational or market outcomes.

For these reasons, the CAISO is requesting discretion to determine whether or not to release the reserved transfer capability in real-time. Recognizing the trade-offs and that the exact outcome cannot be predicted in advance, the tariff revisions state that the CAISO may or may not release reserved internal transfer capability based on natural gas and electric system conditions or observed market inefficiencies. Pursuant to this tariff language, the CAISO will determine based on the system conditions and observed market outcomes whether it is optimal to (i) only manually release the reserved internal transfer capability in real-time if the transfer capability is needed to deliver energy to southern California or (ii) routinely release it.

The tariff language also specifies that the CAISO will provide a market notification if an adjustment to the transfer capability is made to the internal transfer paths pursuant to the authority requested herein. The market notification would explain the amount of the adjustment deemed necessary.

The CAISO also considered reserving transfer capability on interties with other balancing authority areas into southern California. However, because there are relatively limited amounts of real-time import bids on the interties, the CAISO anticipates the costs of withholding the transfer capability would exceed the benefit of reserving intertie capacity for use in real-time.

The CAISO is also evaluating the impact that reserving a portion of the available transfer capability on Path 26 and other internal transmission paths will have on CRR revenue sufficiency. Reserving internal transmission capability may reduce congestion revenues in the day-ahead markets that are used to pay CRRs. To ensure that the CAISO can prevent any potential negative impacts on CRR revenue sufficiency, the CAISO proposes to revise its tariff to permit it to adjust the amount of additional CRRs it releases in the monthly CRR auction and allocation processes to account for possible adjustments to the available transfer capability.[67] DMM supports this approach based on its observation that reservation of internal transmission capacity could cause the amount of CRRs allocated or sold by the CAISO to exceed the amount of transmission capacity actually available in the day-ahead market.[68]

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[67] Revised tariff section 36.4.

[68] DMM Comments at 14.

H. Provide the CAISO with the Authority to Suspend Convergence Bidding if the CAISO Determines It Is Adversely Impacting Market Efficiency

The CAISO will also monitor the impacts that virtual bidding has on the CAISO's use of reservations of available transfer capability. One example of virtual bidding activity that could reduce market efficiency is virtual supply downstream of reserved transfer capability and virtual demand upstream of reserved transfer capability. When the CAISO releases the reserved transfer capability in real-time, the day-ahead congestion price of the transfer path is likely to be higher than the real-time congestion price. Virtual supply placed downstream of the path and virtual demand placed upstream of the path could expect to profit from this difference in the path's congestion price. However, downstream virtual supply and upstream virtual demand would reduce the day-ahead schedules of downstream gas-fired generation and increase the day-ahead schedules of upstream generation.

The impact of such virtual schedules on day-ahead generation schedules is the opposite of the intended effects of reserving transfer capability. Such virtual schedules would therefore undermine the effectiveness of this reliability tool. Not routinely releasing the reserved transfer capability in real-time would reduce the likelihood of virtual schedules undermining the efficacy of the transfer reservation tool. However, continuing to withhold transfer capability in real-time, when the reliability benefits of reserving that capability in the day-ahead have been achieved, would be an inefficient use of available transmission capacity. The CAISO submits that it would not be reasonable to continue to withhold such capability merely to increase the chance that virtual schedules do not undermine the reliability benefits gained by the reservation.

In order to ensure that such virtual bidding cannot detrimentally affect the CAISO markets, the CAISO proposes to revise its tariff to explicitly state that its existing tariff authority to suspend or limit virtual bidding activities that can detrimentally affect system reliability or grid operations also includes the authority to suspend or limit virtual bidding activity that detrimentally affects CAISO market efficiency.[69] This new tariff provision is reasonable because virtual bidding behavior that adversely affects market efficiency can cause problems for system reliability, which the existing approved tariff language is expressly intended to protect. Implementing the tariff revision also accords with a recommendation from DMM that the CAISO have the authority to "prevent or protect against potential detrimental or inequitable market impacts" and should "closely monitor

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[69] New tariff section 7.9.2(d). The CAISO will also include implementation detail regarding this tariff authority in the business practice manual.

the impacts of virtual bidding and be prepared to quickly exercise this authority to suspend virtual bidding – including at specific locations or regions". DMM also identified an illustrative example of a virtual bidding strategy related to a CAISO reservation of internal transfer capability that could reduce market efficiency and thus warrant suspension of virtual bidding.[70] In the event the CAISO suspends or limits virtual bidding pursuant to this provision, the CAISO will file an informational report with the Commission explaining why it took such action.

I. Allow Resources to Seek After-the-Fact Cost Recovery from the Commission in a Section 205 Filing

The CAISO proposes to establish a procedure in its tariff whereby scheduling coordinators can seek to recover gas costs that are not recovered through the CAISO's tariff mechanisms pursuant to a section 205 filing submitted to the Commission.[71] This procedure was approved by the CAISO Board of Governors in March 2016, independent from the issues the CAISO expects to experience due to the limited availability of Aliso Canyon, and closely resembles a similar procedure accepted by the Commission for use in ISO New England's markets.[72] The CAISO proposes to implement this authority on an expedited basis because of concerns raised by market participants regarding the greater risk that they may not fully recover their fuel costs under the existing market rules when responding to a CAISO dispatch during the summer months.

Pursuant to the proposed procedure, if a scheduling coordinator representing a resource incurs but cannot recover through the CAISO's bid cost recovery process any actual marginal fuel procurement costs that exceed (1) the caps on bids for start-up costs, minimum load costs, or transition costs, (2) the incremental fuel cost calculated under the variable cost option for default energy bids, or (3) the incremental fuel cost calculated for generated bids, the resource

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[70] DMM Comments at 13-14.

[71] New tariff section 30.11. The process is also cross-referenced in new tariff sections 39.7.1.1.3 and 40.6.8.1.6. The CAISO and stakeholders developed an earlier version of this proposal in the Bidding Rules Enhancements stakeholder initiative until it was moved to and modified in the Aliso Canyon Gas Electric Coordination stakeholder initiative. As set forth in the Bidding Rules Enhancements initiative, the proposal would permit after-the-fact recovery of actual marginal fuel procurement costs not recovered through commitment costs, but did not extend to after-the-fact recovery of actual marginal fuel procurement costs under the variable cost option for default energy bids or calculated for generated bids. The CAISO and stakeholders extended the proposal to encompass default energy bids and generated bids in order to address better the risk presented by the limited operability of Aliso Canyon.

[72] *See* ISO New England Transmission, Markets, and Services Tariff, Market Rule 1, Appendix A, Section III.A.1, available on the ISO New England website at http://www.iso-ne.com/participate/rules-procedures/tariff.

may seek to recover those costs through a filing submitted to the Commission pursuant to section 205 of the FPA.[73] Because eligibility for a bid cost recovery uplift is contingent on a scheduling coordinator's costs exceeding its market revenues during the applicable period, a resource electing to utilize this process would need to demonstrate in its filing that it would have been entitled to a bid cost recovery uplift under the CAISO tariff in the first instance. The scheduling coordinator would have the burden of proving costs in excess of bid cost recovery and that it would be just and reasonable to provide cost recovery under all the facts and circumstances.

The scheduling coordinator must notify the CAISO within 30 business days after the operating day on which the resource incurred any costs that it believes were unrecovered , and must submit the filing to the Commission within 90 business days after that operating day. Within 60 business days after the scheduling coordinator provides the notice to the CAISO described above, the CAISO will provide the scheduling coordinator with a written explanation of any effect that events or circumstances in the CAISO markets may have had on the resource's inability to recover the costs on the operating day. These provisions will give the scheduling coordinator a reasonable amount of time to provide notice to the CAISO and file with the Commission, and for the CAISO to provide a written explanation regarding the applicable market conditions that the scheduling coordinator will provide to the Commission as part of the materials supporting its filing.

Each filing the scheduling coordinator submits to the Commission must include:

(1) Data supporting the scheduling coordinator's claim to the unrecovered costs it seeks, including invoices for the unrecovered costs;

(2) A description of the resource's participation in any gas pooling arrangements;

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[73] In the Bidding Rules Enhancements stakeholder initiative, the CAISO originally suggested that it, rather than the Commission, might be able to provide after-the-fact cost recovery. After additional review, however, the CAISO determined that it was not practicable to provide the cost recovery itself. To do so, the CAISO would have had to establish objective criteria to determine if a resource qualified for after-the-fact cost recovery and to specify that recovery. The CAISO does not believe this is practical, as it would be difficult to detail before the fact all of the situations in which a resource conducted prudent procurement practices but incurred gas procurement costs it could not recover under the tariff provisions. Also, determining incurred costs would require visibility to a market participant's full portfolio of gas transactions and hedging mechanisms, which the Commission has a greater ability than the CAISO to obtain.

(3) An explanation of why recovery of the costs is justified; and

(4) A copy of the written explanation from the CAISO to the scheduling coordinator described above.

The CAISO believes this is sufficient information for the scheduling coordinator to include in its filing. If the Commission requires additional materials to issue an order, it can request such materials from the scheduling coordinator.

To the extent that the Commission authorizes the scheduling coordinator to recover any costs pursuant to the scheduling coordinator's filing, the CAISO will pay the scheduling coordinator any amounts the Commission deems recoverable and will allocate such amounts pursuant to the existing tariff provisions regarding neutrality adjustments.[74]

Implementing this after-the-fact recovery provision on an expedited and interim basis for the summer 2016 period is just and reasonable. Although the CAISO is proposing in this filing to adopt a number of mechanisms that will improve the CAISO's market dispatches so that they are more efficient and reflective of gas system constraints, these mechanisms will not ensure resources' ability to fully recover their costs through the CAISO market. The gas system limitations resulting from the limited availability of Aliso Canyon have the potential to increase gas price volatility and/or result in higher commodity prices and penalties that require resources to incur gas-related costs that exceed the gas price values used in the CAISO markets. It is therefore necessary to allow resources to file for after-the-fact recovery of actual marginal fuel procurement costs that are not recovered through market revenues and which exceed the CAISO commitment cost bid cap, default energy bid or generated bids. This will provide market participants with stop-loss protection in the event of extreme conditions that lead to significant costs in excess of what can be recovered in the market.[75]

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[74] For an illustrative example of how the CAISO will pay the scheduling coordinator any amounts the Commission deems recoverable, see pages 15-16 of the Bidding Rules Enhancements Generator Commitment Cost Improvements Revised Draft Final Proposal (March 22, 2016).

[75] These three proposals can be implemented by June 1. In the stakeholder process, the CAISO also considered several options for including real-time price information in commitment costs and default energy bid costs under the variable cost option as the basis for the CAISO's cost estimates. Due to time constraints, however, the CAISO was obliged to table these proposals for future discussion with stakeholders. Revised Draft Final Proposal at 29.

IV. Stakeholder Issues

As explained above, stakeholders generally supported the CAISO's objective of implementing operational tools and market mechanisms this summer to mitigate the issues raised by the limited operability of Aliso Canyon.[76] Stakeholders also raised several issues as discussed below.

After the CAISO issued the Draft Final Proposal, several stakeholders requested that the CAISO provide further explanation and clarification on the details as to how the CAISO will implement the risk mitigation tools proposed in this filing. In response, the CAISO posted the Revised Draft Final Proposal to provide additional information. However, the CAISO cannot at this time explain in exact detail how and when it will use the operational tools and market mechanisms. The exact impacts of the limited operability of Aliso Canyon on the electric system under the various system conditions that may occur this summer are unknown. Consequently, it is imperative that the CAISO have sufficient implementation flexibility as to both the operational tools and the market mechanisms. Moreover, where practical, the CAISO has identified and included measures to provide transparency to market participants as to how and when the CAISO will utilize the tools proposed in this filing.

One stakeholder raised concerns that the proposed natural gas constraint would disproportionately affect certain small load-serving entities. This concern was based on the misunderstanding that the constraint would be uniformly applied to all generators in the affected area. The CAISO clarified, however, that the natural gas constraint will not be applied uniformly applied to all generators. Instead, the constraint will take into account local reliability needs, the efficiency of resources, and resource costs to enable the CAISO to most effectively and efficiently limit generation dispatch consistent with gas availability limitations.

Some stakeholders expressed concern that the proposed gas price increase mechanism for southern California resources for the real-time market will only apply to affected generators on the SoCalGas system. The stakeholders argued that the proposed provisions should apply to all gas generators in the CAISO system. In response, the CAISO stressed that the provisions are intended to be interim measures to address the immediate need to ensure reliable operations in southern California over the summer given the Aliso Canyon situation. The provisions are designed to apply only to the affected generators so that the market will limit their real-time dispatches for local reliability needs and in a manner that supports gas system limitations. This will mitigate the primary limitation of the gas system: using more gas over the real-

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[76] See section II.C of this transmittal letter.

time operating day than was scheduled for that day. There is no valid reason why the increased gas price needs to apply to all system resources.

A stakeholder expressed concern that the tariff revisions to permit resources to seek after-the-fact cost recovery from the Commission might go into effect too late to permit such filings to capture unrecovered costs incurred during the earlier part of the summer. To address this concern, the CAISO proposes to make the tariff revisions effective on the earliest effective date proposed in this filing – June 2, 2016, the day after the date by which the CAISO requests that the Commission issue an order accepting this filing.[77]

Some stakeholders requested that the CAISO commit to a process to replace the interim solutions included in the proposal with more market-based solutions. The CAISO has proposed a sunset date for the proposed provisions. The CAISO also notes that it has made several enhancements to its tariff provisions regarding bidding rules and the calculation of commitment costs, and will continue to pursue further enhancements to effectively allow accurate marginal costs to be fully reflected in CAISO market bids. Given the imminent risks to reliability facing the CAISO this summer, the interim nature of the proposal, and the limited time the CAISO has to develop and implement solutions, the CAISO submits that its proposals constitute an appropriate, just, and reasonable solution.

V. Effective Date and Requests for Expedited Treatment and Waiver of Notice Requirements

The CAISO respectfully requests that the Commission grant expedited treatment of the tariff revisions proposed in this filing. Implementing these tariff revisions starting this summer, when gas usage associated with electric generation is generally highest, is necessary to ensure that the CAISO has improved procedures and flexibility in place to timely address the risks presented by the limited operability of Aliso Canyon. Therefore, the CAISO requests that the Commission establish a comment date no later than May 16, 2016, and issue an order accepting this filing by June 1, 2016.

The CAISO also requests that the Commission grant waiver of its notice requirements to accept all of the tariff revisions contained in this filing effective June 2, 2016, except for the tariff revisions to implement an improved day-ahead gas price index and delete the gas price-spike provisions for the day-ahead market,[78] and the tariff revisions to allow the CAISO to increase the gas price

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[77] See section V of this transmittal letter.

[78] New tariff sections 39.7.1.1.1.3(a)-(c) and deleted tariff sections 30.4.1.2(b), 31.6.1(v),

applicable to commitment cost caps and default energy bids for resources on the SoCalGas and SDG&E systems for the real-time market,[79] for which the CAISO requests an effective date of July 6, 2016.[80] Good cause exists to grant this waiver in order to permit the tariff revisions to go into effect as soon as practicable to address the issues presented by the limited operability of Aliso Canyon this summer. Therefore, the Commission should grant the requested waiver.

VI. Interim Effectiveness of the Tariff Revisions Until November 30, 2016 to the Extent the Commission Does Not Permit Them to Remain in Effect Beyond November 30 Pursuant to a Subsequent CAISO Filing

The CAISO anticipates that some of the tariff revisions proposed in this filing may not be needed this winter, when gas usage associated with electric generation will likely decrease and the Aliso Canyon situation may be less of a concern due to the mitigation measures in place at that time or possibly greater operability of Aliso Canyon.[81] The CAISO will have a better understanding of which tariff revisions will no longer be needed after it evaluates the effects the proposed tariff revisions had on the CAISO markets over the summer and the potential effects such tariff revisions may have on the CAISO markets given predicted conditions for the winter. Further, the Commission and market participants will have transparency regarding the effects that the tariff revisions have had on the CAISO markets pursuant to the quarterly Reports on Market Issues and Performance that DMM issues.[82]

On the other hand, some of the proposed tariff provisions proposed are taken from existing stakeholder processes and were designed to be implemented on a permanent basis. These include the procedures for after-the-fact recovery

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and 39.7.1.1.1.3(b) (discussed in section III.B of this transmittal letter).

[79] New tariff section 39.7.1.1.1.3(d) (discussed in section III.C of this transmittal letter).

[80] Pursuant to Section 35.11 of the Commission's regulations, 18 C.F.R. § 35.11, the CAISO requests waiver of Section 35.3(a)(1) of the Commission's regulations, 18 C.F.R. § 35.3(a)(1), to permit the requested June 2 and July 6 effective dates. The CAISO plans to make expedited changes to the business practice manuals to implement the tariff revisions effective as of these dates.

[81] The CAISO anticipates, however, that it will need the tariff revisions originally proposed in the Bidding Rules Enhancements stakeholder initiative and modified for inclusion in this filing this winter and beyond. These tariff revisions allow resources to rebid commitment costs in the real-time market and seek after-the-fact cost recovery from the Commission. See sections III.D and III.I of this transmittal letter.

[82] These quarterly reports are available on the CAISO website at http://caiso.com/market/Pages/MarketMonitoring/MarketIssuesPerfomanceReports/Default.aspx.

for commitment costs, real-time rebidding of commitment costs and revisions to the pool of bids considered in the short-term unit commitment process. The CAISO is including these proposals in this filing rather than filing them in separate 205 filings because it has determined that they will prove helpful in addressing the limitations relating to Aliso Canyon this summer.

The CAISO recognizes that it is requesting substantially expedited comment and approval periods for this filing. For this reason, as well as the fact that some of the provisions may only be needed temporarily, the CAISO requests that the Commission approve all of the tariff modifications included herein on an interim basis. In order to implement this interim approach, the CAISO is submitting two sets of tariff records – one set that contains the proposed tariff revisions and shows the June 2 and July 6, 2016 effective dates discussed above, and a second set that contains the tariff sections revised by this filing as they read in the existing tariff (*i.e.*, omitting the tariff revisions) and shows an effective date of November 30, 2016 for all the tariff sections.[83] Pursuant to this approach, to the extent the Commission accepts the tariff revisions and does not later take action to continue their effectiveness beyond November 30, on that date the first set of tariff records will automatically be superseded by the second set of tariff records, and thus the tariff sections revised by this filing will revert to how they read before the CAISO submitted this filing.

The CAISO will provide transparency to market participants and the Commission as to whether the CAISO believes each of the tariff revisions should remain in effect beyond November 30. Prior to that date, the CAISO will submit another filing or filings pursuant to section 205 of the FPA that explains why each of the tariff revisions proposed in the instant filing should either: (1) automatically be superseded by the existing tariff effective November 30 as described above; (2) be permitted to remain in effect after November 30 with no modifications; or (3) be permitted to remain in effect after November 30 with modifications.[84]

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[83] The clean tariff sheets and red-lined document provided in attachments B and C to this filing reflect only the first set of tariff records described above.

[84] The FPA 205 filing or filings submitted will include a request that the Commission issue an order accepting them by November 29, 2016.

VII. Communications

Correspondence and other communications regarding this filing should be directed to:

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VIII. Service

The CAISO has served copies of this filing on the California Public Utilities Commission, the California Energy Commission, and all parties with scheduling coordinator agreements under the CAISO tariff. In addition, the CAISO has posted a copy of the filing on the CAISO website.

IX. Contents of Filing

In addition to this transmittal letter, this filing includes the following attachments:

Attachment A	Clean CAISO tariff sheets incorporating this tariff amendment
Attachment B	Red-lined document showing the revisions contained in this tariff amendment
Attachment C	Additional Background Regarding Aliso Canyon and CAISO Stakeholder Process
Attachment D	Revised Draft Final Proposal
Attachment E	Board Memorandum
Attachment F	DMM Comments

X. Conclusion

For the reasons set forth in this filing, the CAISO respectfully requests that the Commission establish a comment date in this proceeding of May 16, 2016, and issue an order by June 1, 2016 that accepts most of the tariff revisions proposed in the filing effective June 2, 2016 and the balance of the tariff revisions effective July 6, 2016, as discussed in this filing.

Respectfully submitted,

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Attachment A – Clean Tariff Records

Tariff Amendment to Enhance Gas-Electric Coordination to Address Risks Posed by Limited Operability of Aliso Canyon Natural Gas Storage Facility

California Independent System Operator Corporation

May 9, 2016

6.5.2.2 Communications With Scheduling Coordinators

6.5.2.2.1 Bid Adder Eligibility

6.5.2.2.1.1 By the 20th of each month, the CAISO will notify Scheduling Coordinators of Bid Adder eligibility, applicable Bid Adder value for the following month, and Frequently Mitigated Units that are eligible for a Bid Adder.

6.5.2.2.1.2 Scheduling Coordinators shall have one week to review Bid Adder information and provide comment back to the CAISO by the 27th of each month.

6.5.2.2.2 Day-Ahead Market Bid Submittal

Seven (7) days prior to any Trading Day, Scheduling Coordinators can begin submitting Bids for the DAM for that Trading Day,

6.5.2.2.3 Advisory Day-Ahead Market Results

The CAISO may provide to the responsible Scheduling Coordinator the MWh amounts scheduled in the preliminary RUC process the CAISO conducts two (2) days prior to the Trading Day, that is based on Bids and forecasts of system conditions as available in the CAISO Market systems at the time the CAISO conducts the preliminary RUC process. This information is for advisory purposes only and is not financially binding.

6.5.2.3 Public Market Information

6.5.2.3.1 Demand Forecasts

6.5.2.3.1.1 Beginning seven (7) days prior to the target Day-Ahead Market, and updated as necessary, the CAISO will publish the CAISO Forecast of CAISO Demand.

6.5.2.3.1.2 By 6:00 p.m. the day prior to the target Day-Ahead Market, the CAISO will publish the updated CAISO Forecast of CAISO Demand.

6.5.2.3.2 Network and System Conditions

By 6:00 p.m. the day prior to the target Day-Ahead Market, the CAISO will publish known network and system conditions, including but not limited to TTC and ATC, the total capacity of inter-Balancing Authority Area Transmission Interfaces, and the available capacity.

6.5.2.3.3 Ancillary Services Requirements

By 6:00 p.m. the day prior to the target Day-Ahead Market, the CAISO will publish forecasted Ancillary Services requirements and regional constraints by AS Region.

6.5.2.3.4 Greenhouse Gas Price Indices

The CAISO will publish daily greenhouse gas price indices when available.

6.5.2.3.5 Extremely Long-Start Unit Commitment

The CAISO will communicate commitment instructions to Scheduling Coordinators for Extremely Long-Start Resources by 3:00 p.m. two (2) days in advance of the Operating Day through a secure communication system.

6.5.2.3.6 Virtual Bid Reference Prices

The CAISO will publish Virtual Bid Reference Prices prior to the applicable reference period for the Virtual Bid Reference Prices.

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6.5.4.2.3 The CAISO will publish the natural gas price used for the Real-Time Market when available.

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7.9.2 Reasons for Suspension or Limitation

The CAISO may suspend or limit the ability of one or more Scheduling Coordinators to submit Virtual Bids of the CAISO determines that virtual bidding activities of one or more Scheduling Coordinators on behalf of one or more Convergence Bidding Entities detrimentally affect System Reliability or grid operations. Virtual bidding activities can detrimentally affect System Reliability or grid operations if such activities contribute to threatened or imminent reliability conditions, including but not limited to the following circumstances:

(a) Submitted Virtual Bids create a substantial risk that the CAISO will be unable to obtain sufficient Energy and Ancillary Services to meet Real-Time Demand and

Ancillary Service requirements in the CAISO Balancing Authority Area.

(b) Submitted Virtual Bids render the CAISO Day-Ahead Market software unable to process Bids submitted into the Day-Ahead Market.

(c) Submitted Virtual Bids render the CAISO unable to achieve an alternating current (AC) solution in the Day-Ahead Market for an extended period of time.

(d) Submitted Virtual Bids detrimentally affect CAISO market efficiency.

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27.5.6 Management & Enforcement of Constraints in the CAISO Markets

The CAISO operates the CAISO Markets through the use of a market software system that utilizes various information including the Base Market Model, the State Estimator, submitted Bids including Self-Schedules, Generated Bids, and Transmission Constraints, including Nomograms and Contingencies transmission and generation Outages. The market model used in each of the CAISO Markets is derived from the most current Base Market Model available at that time. To create a more relevant time-specific network model for use in each of the CAISO Markets, the CAISO will adjust the Base Market Model to reflect Outages and derates that are known and applicable when the respective CAISO Market will operate, and to compensate for observed discrepancies between actual real-time power flows and flows calculated by the market software. Through this process the CAISO creates the market model to be used in each Day-Ahead Market and each process of the Real-Time Market. The CAISO will manage the enforcement of Transmission Constraints, including Nomograms and Contingencies, consistent with good utility practice, to ensure, to the extent possible, that the market model used in each market accurately reflects all the factors that contribute to actual Real-Time flows on the CAISO Controlled Grid and that the CAISO Market results are better aligned with actual physical conditions on the CAISO Controlled Grid. In operating the CAISO Markets, the CAISO may take the following actions so that, to the extent possible, the CAISO Market solutions are feasible, accurate, and consistent with good utility practice:

(a) The CAISO may enforce, not enforce, or adjust flow-based Transmission Constraints, including Nomograms and Contingencies, if the CAISO observes that the CAISO Markets produce or may produce results that are inconsistent with observed or reasonably anticipated conditions or infeasible market solutions either because (a) the CAISO reasonably anticipates that the CAISO Market run will identify Congestion that is unlikely to materialize in Real-Time even if the Transmission Constraint were to be ignored in all the markets leading to Real-Time, or (b) the CAISO reasonably anticipates that the CAISO Market will fail to identify Congestion that is likely to appear in the Real-Time. The CAISO does not make such adjustments to intertie Scheduling Limits.

(b) The CAISO may enforce or not enforce Transmission Constraints, including Nomograms and Contingencies, if the CAISO has determined that non-enforcement or enforcement, respectively, of such Transmission Constraints may result in the unnecessary precommitment and scheduling of use-limited resources.

(c) The CAISO may not enforce Transmission Constraints, including Nomograms and Contingencies, if it has determined it lacks sufficient visibility to conditions on transmission facilities necessary to reliably ascertain constraint flows required for a feasible, accurate and reliable market solution.

(d) For the duration of a planned or unplanned Outage, the CAISO may create and apply alternative Transmission Constraints, including Nomograms and Contingencies, that may add to or replace certain originally defined constraints.

(e) The CAISO may adjust Transmission Constraints, including Nomograms and Contingencies, for the purpose of setting prudent operating margins consistent with good utility practice to ensure reliable operation under anticipated conditions of unpredictable and uncontrollable flow volatility consistent with the requirements of Section 7.

(f) The CAISO may adjust Transmission Constraints for the purpose of reserving internal transfer capability in the Day-Ahead or Real-Time Markets, based on anticipated conditions on the natural gas delivery system, to reliably serve load in specific geographic regions of the CAISO Balancing Authority Area, or to assure deliverability of Ancillary

Services. The CAISO may or may not release such reserved internal transfer capability based on natural gas and electric system conditions, or observed market inefficiencies. Upon determining that an adjustment is necessary, the CAISO will issue a notification specifying the amount of the adjustment.

To the extent that particular Transmission Constraints, including Nomograms and Contingencies, are not enforced in the operations of the CAISO Markets, the CAISO will operate the CAISO Controlled Grid and manage any Congestion based on available information including the State Estimator solutions and available telemetry to Dispatch resources through Exceptional Dispatch to ensure the CAISO is operating the CAISO Controlled Grid consistent with the requirements of Section 7.

* * * *

27.11 Natural Gas Constraint

The CAISO may enforce constraints that limit the maximum or minimum amount of natural gas that can be burned by natural gas-fired resources, based on limitations in applicable gas regions anticipated by the CAISO during specific hours. In the event that such a constraint is binding, the Shadow Price of the constraint will only be reflected in the Marginal Cost of Congestion component of the Locational Marginal Prices of the affected natural gas-fired resources. The Shadow Price of the constraint will not be reflected in the Marginal Cost of Congestion component of the Locational Marginal Prices for purposes of settling cleared Demand, Virtual Bids, or Congestion Revenue Rights. The same Marginal Cost of Congestion used for settling Demand, Virtual Bids, or Congestion Revenue Rights is used for the calculation of the Real-Time Congestion Offset pursuant Section 11.5.4.1.1. The CAISO will allocate any non-zero amounts that are attributable to the price differential between the Marginal Cost of Congestion used for settling a Generating Unit’s scheduled or Dispatched amounts at their location and the Marginal Cost of Congestion used for settling Demand, Virtual Bids, or Congestion Revenue Rights pursuant to Section 11.5.4, except that for Day-Ahead settlements the CAISO will allocate the difference through the CRR Balancing Account pursuant to Section 11.2.4.5.

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30.4.1.2 Registered Cost Methodology

Under the Registered Cost methodology, the Scheduling Coordinator for a Use-Limited Resource may register values of its choosing for Start-Up Costs and/or Minimum Load Costs in the Master File subject to the maximum limit specified in Section 39.6.1.6. A Scheduling Coordinator for a Multi-Stage Generating Resource that is a Use-Limited Resource registering a Start-Up Cost must also register Transition Costs for each feasible MSG Transition, subject to the maximum limit specified in Section 39.6.1.7. For a Use-Limited Resource to be eligible for the Registered Cost methodology there must be sufficient information in the Master File to calculate the value pursuant to the Proxy Cost methodology, which will be used to validate the specific value registered using the Registered Cost methodology. Any such values will be fixed for a minimum of 30 days in the Master File unless: (a) the resource's costs for any such value, as calculated pursuant to the Proxy Cost methodology, exceed the value registered using the Registered Cost methodology, in which case the Scheduling Coordinator may elect to switch to the Proxy Cost methodology for the balance of any 30-day period, except as set forth in Section 30.4.1.2(b); or (b) any cost registered in the Master File exceeds the maximum limit specified in Section 39.6.1.6 or Section 39.6.1.7 after this minimum 30-day period, in which case the value will be lowered to the maximum limit specified in Section 39.6.1.6 or Section 39.6.1.7. If a Multi-Stage Generating Resource elects to use the Registered Cost methodology, that election will apply to all the MSG Configurations for that resource. The cap for the Registered Cost values for each MSG Configuration will be based on the Proxy Cost values calculated for each MSG Configuration, including for each MSG Configuration that cannot be directly started, which are also subject to the maximum limits specified in Sections 39.6.1.6 and 39.6.1.7.

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30.5 Bidding Rules

30.5.1 General Bidding Rules

(a) All Energy and Ancillary Services Bids of each Scheduling Coordinator submitted to the DAM for the following Trading Day shall be submitted at or prior to 10:00

a.m. on the day preceding the Trading Day, but no sooner than seven (7) days prior to the Trading Day. All Energy and Ancillary Services Bids of each Scheduling Coordinator submitted to the RTM for the following Trading Day shall be submitted starting from the time of publication, at 1:00 p.m. on the day preceding the Trading Day, of DAM results for the Trading Day, and ending seventy-five (75) minutes prior to each applicable Trading Hour in the RTM. Scheduling Coordinators may submit only one set of Bids to the RTM for a given Trading Hour, which the CAISO uses for all Real-Time Market processes. The CAISO will not accept any Energy or Ancillary Services Bids for the following Trading Day between 10:00 a.m. on the day preceding the Trading Day and the publication, at 1:00 p.m. on the day preceding the Trading Day, of DAM results for the Trading Day;

(b) Bid prices submitted by a Scheduling Coordinator for Energy accepted and cleared in the IFM and scheduled in the Day-Ahead Schedule may be increased or decreased in the RTM . Bid prices for Energy submitted but not scheduled in the Day-Ahead Schedule may be increased or decreased in the RTM. Incremental Bid prices for Energy associated with Day-Ahead AS or RUC Awards in Bids submitted to the RTM may be revised. A Scheduling Coordinator may submit in the Real-Time Market new daily Bids for Start-Up Costs, Minimum Load Costs, and Transition Costs for resources and MSG Configurations for which the Scheduling Coordinator previously submitted such Bids in the Day-Ahead Market, except for: (1) Trading Hours in which a resource or MSG Configuration has received a Day-Ahead Schedule or has received a Start-Up Instruction in RUC; and (2) Trading Hours that span the Minimum Run Time of the resource or MSG Configuration after the CAISO has committed the resource or the Scheduling Coordinator has self-committed the resource in the RTM. Scheduling Coordinators may revise ETC Self-Schedules for Supply in the RTM to the extent such a change is consistent with TRTC Instructions provided to the

CAISO by the Participating TO in accordance with Section 16. Scheduling Coordinators may revise TOR Self-Schedules for Supply only in the HASP to the extent such a change is consistent with TRTC Instructions provided to the CAISO by the Non-Participating TO in accordance with Section 17. Energy associated with awarded Ancillary Services capacity cannot be offered in the Real-Time Market separate and apart from the awarded Ancillary Services capacity;

(c) Scheduling Coordinators may submit Energy, AS and RUC Bids in the DAM that are different for each Trading Hour of the Trading Day;

(d) Bids for Energy or capacity that are submitted to one CAISO Market, but are not accepted in that market are no longer a binding commitment and Scheduling Coordinators may submit Bids in a subsequent CAISO Market at a different price;

(e) The CAISO shall be entitled to take all reasonable measures to verify that Scheduling Coordinators meet the technical and financial criteria set forth in Section 4.5.1 and the accuracy of information submitted to the CAISO pursuant to this Section 30; and

[No changes to the remainder of Section 30.5.1]

* * * *

30.11 Filings with FERC to Recover Actual Marginal Fuel Procurement Costs

If a Schedule Coordinator incurs but cannot recover through the Bid Cost Recovery process any actual marginal fuel procurement costs that exceed (i) the limit on Bids for Start-Up Costs set forth in Section 30.7.9, (ii) the limit on Bids for Minimum Load Costs set forth in Section 30.7.10, (iii) the limit on Bids for Transition Costs set forth in Section 30.4.1.1.5, (iv) the incremental fuel cost calculated under the Variable Cost Option for Default Energy Bids as set forth in Section 39.7.1.1.1, or (v) the incremental fuel cost calculated for Generated Bids as set forth in Sections 30.7.3.4, 39.7.1.1.1, and 40.6.8, the Scheduling Coordinator for the resource may seek to recover those costs through a FERC filing made pursuant to Section 205 of the Federal Power Act. The Scheduling Coordinator must notify the CAISO within thirty (30) Business Days after the Operating Day on which the resource incurred the unrecovered costs, and must submit the filing to FERC within ninety (90) Business Days after that Trading Day. Within sixty (60) Business Days after the Scheduling Coordinator provides notice to the CAISO per this Section, the CAISO will provide the Scheduling Coordinator with a written explanation of any effect that events or circumstances in the CAISO Markets and fuel market conditions may have had on the resource's inability to recover the costs on the Trading Day.

Each filing the Scheduling Coordinator submits to FERC must include:

(1) Data supporting the Scheduling Coordinator's claim to the unrecovered costs it seeks, including Invoices for the unrecovered costs;

(2) A description of the resource's participation in any gas pooling arrangements;

(3) An explanation of why recovery of the costs is justified; and

(4) A copy of the written explanation from the CAISO to the Scheduling Coordinator described above in this Section.

To the extent that FERC authorizes the Scheduling Coordinator to recover any costs pursuant to the Scheduling Coordinator's filing, the CAISO will pay the Scheduling Coordinator any amounts the Commission deems recoverable and will allocate such amounts pursuant to Section 11.14.

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31.6 Timing Of Day-Ahead Scheduling

31.6.1 Criteria For Temporary Waiver Of Timing Requirements

The CAISO may at its sole discretion implement any temporary variation or waiver of the timing requirements of this Section 31 and Section 6.5.3 (including the omission of any step) if any of the following criteria are met:

(i) such waiver or variation of timing requirements is reasonably necessary to preserve System Reliability, prevent an imminent or threatened System Emergency or to retain Operational Control over the CAISO Controlled Grid during an actual System Emergency.

(ii) because of error or delay, the CAISO requires additional time to fulfill its responsibilities;

(iii) problems with data or the processing of data cause a delay in receiving or issuing Bids or publishing information on the CAISO's secure communication system;

(iv) problems with telecommunications or computing infrastructure cause a delay in receiving or issuing Day-Ahead Schedules or publishing information on the CAISO's secure communication system.

* * * *

34.6 Short-Term Unit Commitment

Once per hour, near the top of each Trading Hour, immediately after the FMM and the RTUC for the same interval is completed the CAISO performs an approximately five (5) hour Short-Term Unit Commitment (STUC) run using SCUC and the CAISO Forecast Of CAISO Demand to commit Medium Start Units and Short Start Units with Start-Up Times greater than the time period covered by the RTUC described in Section 34.3. In any given Trading Hour, the STUC may commit resources for the third fifteen-minute interval of the current Trading Hour and extending into the next four (4) Trading Hours. The STUC looks ahead over a period of at least three (3) hours beyond the Trading Hour for which the RTUC optimization was run. STUC will utilize: (1) Bids previously submitted in the RTM by the Scheduling Coordinator for that Trading Hour; or (2) the Clean Bid from the Day-Ahead Market if the resource has a Day-Ahead Schedule or received a Start-Up Instruction in RUC for the Trading Hour, or if the resource has a Real-Time must-offer obligation for that Trading Hour. The CAISO revises these replicated Bids each time the hourly STUC is run, to utilize the most recently available Bids. Not all resources identified for need as a given STUC run will necessarily receive CAISO commitment instructions immediately, because during the Trading Day the CAISO may issue a commitment instruction to a resource only at the latest possible time that allows the resource to be ready to provide Energy when it is expected to be needed. A Start-Up Instruction produced by STUC is considered binding if the resource could not achieve the target Start-Up Time as determined in the current STUC run in a subsequent RTUC or STUC run as a result of the Start-Up Time of the resource. A Start-Up Instruction produced by STUC is considered advisory if it is not binding, such that the resource could achieve its target start time as determined in the current RTUC run in a subsequent STUC or RTUC run based on its Start-Up Time. A binding Dispatch Instruction produced by STUC that results in a change in Commitment Status will be issued, in accordance with Section 6.3, after review and acceptance of the Start-Up Instruction by the CAISO Operator. The STUC will only decommit a resource to the extent that resource's physical characteristics allow it to be cycled in the same approximately five (5) hour look-ahead time period for which it was previously committed. STUC does not produce Locational Marginal Prices for Settlement. A Day-Ahead Schedule or RUC Schedule for an MSG Configuration that is later impacted by the resource's derate or outages, will be reconsidered in the STUC process taking into consideration the impacts of the derate or outage on the available MSG Configurations.

* * * *

36.4 FNM For CRR Allocation And CRR Auction

When the CAISO conducts its CRR Allocation and CRR Auction, the CAISO shall use the most up-to-date DC FNM which is based on the AC FNM used in the Day-Ahead Market. The Seasonal Available CRR Capacity shall be based on the DC FNM, taking into consideration the following, all of which are discussed in the applicable Business Practice Manual: (i) any long-term scheduled transmission Outages, (ii) TTC adjusted for any long-term scheduled derates, (iii) a downward adjustment due to TOR or ETC as determined by the CAISO, and (iv) the impact on transmission elements used in the annual CRR Allocation and Auction of (a) transmission Outages or derates that are not scheduled at the time the CAISO conducts the Seasonal CRR Allocation or Auction determined through a methodology that calculates the breakeven point for revenue adequacy based on historical Outages and derates, and (b) known system topology changes, both as further defined in the Business Practice Manuals. The Monthly Available CRR Capacity shall be based on the DC FNM, taking into consideration: (i) any scheduled transmission Outages known at least thirty (30) days in advance of the start of that month as submitted for approval consistent with the criteria specified in Section 36.4.3, (ii) adjustments to compensate for the expected impact of Outages that are not required to be scheduled thirty (30) days in advance, including unplanned transmission Outages, (iii) adjustments to restore Outages or derates that were applied for use in calculating Seasonal Available CRR Capacity but are not applicable for the current month, (iv) any new transmission facilities added to the CAISO Controlled Grid that were not part of the DC FNM used to determine the prior Seasonal Available CRR Capacity and that have already been placed in-service and energized at the time the CAISO starts the applicable monthly process, (v) TTC adjusted for any scheduled derates or Outages for that month, (vi) a downward adjustment due to TOR or ETC as determined by the CAISO; (vii) adjustments for possible unscheduled flow at the Interties, and (viii) any adjustments necessary to account for possible adjustments to Transmission Constraints pursuant to Section 27.5.6 (f). For the first monthly CRR Allocation and CRR Auction for CRR Year One, to account for any planned or unplanned Outages that may occur for the first month of CRR Year One, the CAISO will derate all flow limits, including Transmission Interface limits and normal thermal limits, based on statistical factors determined as provided in the Business Practice Manuals.

* * * *

39.7.1.1.1.3 Calculation of Natural Gas Price

(a) The CAISO will use different gas price indices for the Day-Ahead Market and the Real-Time Market. If a gas price index is unavailable for any reason, the CAISO will use the most recently available gas price index as set forth in Section 39.7.1.1.1.3(c).

(b) For the Day-Ahead Market, the CAISO will use a gas price index reported by the Intercontinental Exchange between 8:00 and 9:00 Pacific Time, which is a volume-weighted average price calculated by the Intercontinental Exchange based on trades transacted on the Intercontinental Exchange during its next-day trading window.

(c) For the Real-Time Market, the CAISO will calculate a gas price index using at least two prices from two or more of the following publications: Natural Gas Intelligence, SNL Energy/BTU's Daily

Gas Wire, Platt's Gas Daily, and the Intercontinental Exchange. The CAISO will update gas price indices for the Real-Time Market between the hours of 19:00 and 22:00 Pacific Time using natural gas prices published one (1) day prior to the applicable Trading Day, unless gas prices are not published on that day, in which case the CAISO will use the most recently published prices that are available.

(d) For the Real-Time Market, the CAISO will increase the gas price calculated pursuant to Section 39.7.1.1.1.3(c) for resources receiving gas service from Southern California Gas Company and San Diego Gas & Electric Company by an amount that: (1) improves the dispatch of these resources so that they are more likely to be dispatched to address local needs rather than system needs; (2) better accounts for systematic differences between day-ahead and same-day natural gas prices; and (3) improves the ability to manage the generators' gas usage within applicable gas balancing rules. For applicable resources, the CAISO will initially increase the gas commodity price used in the calculation of Start-Up Costs, Minimum Load Costs, and Transition Costs pursuant to Section 30.4.1.1, and Generated Bids pursuant to Section 40.6.8, by seventy-five (75) percent, and may decrease this amount or increase it further by an amount not to exceed $2.50 plus two (2) times the next-day gas index price calculated pursuant to Section 39.7.1.1.1.3(b). For applicable resources, the CAISO will initially increase the gas commodity price used in the calculation of Default Energy Bids pursuant to Section 39.7.1.1 by twenty-five (25) percent, and may decrease this amount or increase it further by an amount not to exceed one hundred (100) percent. Upon determining that a subsequent increase in the gas price is necessary after the initial increase, the CAISO will issue a Market Notice specifying the amount of the increase.

* * * *

39.7.1.1.3 Filings with FERC to Recover Actual Marginal Fuel Procurement Costs

A Scheduling Coordinator for a resource subject to the Variable Cost Option may seek to recover actual marginal fuel procurement costs pursuant to a filing with FERC in accordance with Section 30.11.

* * * *

39.7.2.2 Criteria

(A) Notwithstanding the provisions in Section 39.7.2.2(B), when the CAISO enforces the natural gas constraint pursuant to Section 27.11, the CAISO may deem selected internal constraints to be non-competitive for specific days or hours based on its determination that actual electric supply conditions may be non-competitive due to anticipated electric supply conditions in the Southern California Gas Company and San Diego Gas & Electric Company gas regions.

(B) Subject to Section 39.7.3, for the DAM and RTM, a Transmission Constraint will be non-competitive only if the Transmission Constraint fails the dynamic competitive path assessment pursuant to this Section 39.7.2.2.

(a) Transmission Constraints for the DAM – As part of the MPM process associated with the DAM, the CAISO will designate a Transmission Constraint for the DAM as non-competitive when the fringe supply of counter-flow to the Transmission Constraint from all portfolios of suppliers that are not identified as potentially pivotal is less than the demand for counter-flow to the Transmission Constraint. For purposes of determining whether to designate a Transmission Constraint as non-competitive pursuant to this Section 39.7.2.2(a):

(i) Counter-flow to the Transmission Constraint means the delivery of Power from a resource to the system load distributed reference bus. If counter-flow to the Transmission Constraint is in the direction opposite to the market flow of Power to the Transmission Constraint, the counter-flow to the Transmission Constraint is calculated as the shift factor multiplied by the resource's scheduled Power. Otherwise, counter-flow to the Transmission Constraint is zero.

(ii) Fringe supply of counter-flow to the Transmission Constraint means all available capacity from internal resources not controlled by the identified potentially pivotal suppliers and all internal Virtual Supply Awards not controlled by the identified potentially pivotal suppliers that provide counter-flow to the Transmission Constraint. Available capacity reflects the highest capacity of a resource's Energy Bid adjusted for Self-Provided Ancillary Services and derates.

(iii) Demand for counter-flow to the Transmission Constraint means all internal dispatched Supply and Virtual Supply Awards that provide counter-flow to the Transmission Constraint.

(iv) Potentially pivotal suppliers mean the three (3) portfolios of net sellers that control the largest quantity of counter-flow supply to the Transmission Constraint.

(v) Portfolio means the effective available internal generation capacity under the control of the Scheduling Coordinator and/or Affiliate determined pursuant to Section 4.5.1.1.12 and all effective internal Virtual Supply Awards of the Scheduling Coordinator and/or Affiliate. Effectiveness in supplying counter-flow is determined by scaling generation capacity and/or Virtual Supply Awards by the shift factor from that location to the Transmission Constraint being tested.

(vi) A portfolio of a net seller means any portfolio that is not a portfolio of a net buyer. A portfolio of a net buyer means a portfolio for which the average daily net value of Measured Demand minus Supply over a twelve (12) month period is positive. The average daily net value is determined for each portfolio by subtracting, for each Trading Day, Supply from Measured Demand and then averaging the daily value for all Trading Days over the twelve (12) month period. The CAISO will calculate whether portfolios are portfolios of net buyers in the third month of each calendar quarter and the calculations will go into effect at the start of the next calendar quarter. The twelve (12) month period used in this calculation will be the most recent twelve (12) month period for which data is available. The specific mathematical formula used to perform this calculation will be set forth in a Business Practice Manual. Market Participants without physical resources will be deemed to be net sellers for purposes of this Section 39.7.2.2(a)(vi).

(vii) In determining which Scheduling Coordinators and/or Affiliates control the resources in the three (3) identified portfolios, the CAISO will include resources and Virtual Supply Awards directly associated with all Scheduling Coordinator ID Codes associated with the Scheduling Coordinators and/or Affiliates, as well as all resources that the Scheduling Coordinators and/or Affiliates control pursuant to Resource Control Agreements registered with the CAISO as set forth Section 4.5.1.1.13. Resources identified pursuant to Resource Control Agreements will only be assigned to the portfolio of the Scheduling Coordinator that has control of the resource or whose Affiliate has control of the resource pursuant to the Resource Control Agreements.

[No changes to the remainder of Section 39.7.2.2]

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40.6.3 Additional Availability Requirements For Resources that Are Not Long Start Units or Extremely Long Start Resources

A resource that is not a Long Start Unit or an Extremely Long Start Resource that is a Resource Adequacy Resource and that does not have an IFM Schedule or a RUC Schedule for any of its capacity for a given Trading Hour is required to participate in the Real Time Market in accordance with Section 40.6.2. Such a resource that is also a Use-Limited Resource subject to Section 40.6.4 is required, consistent with their applicable use plan, to submit Economic Bids or Self Schedules for Resource Adequacy Capacity into the Real Time Market.

The CAISO may waive these availability obligations for a resource that is not a Long Start Unit or an Extremely Long Start Resource that does not have an IFM Schedule or a RUC Schedule based on the procedure to be published on the CAISO Website.

* * * *

40.6.8.1.6 Filings with FERC to Recover Actual Marginal Fuel Procurement Costs

A Scheduling Coordinator for a resource subject to a Generated Bid may seek to recover actual marginal fuel procurement costs pursuant to a filing with FERC in accordance with Section 30.11.

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Attachment B – Marked Tariff Records

Tariff Amendment to Enhance Gas-Electric Coordination to Address Risks Posed by Limited Operability of Aliso Canyon Natural Gas Storage Facility

California Independent System Operator Corporation

May 9, 2016

6.5.2.2 Communications With Scheduling Coordinators

6.5.2.2.1 Bid Adder Eligibility

6.5.2.2.1.1 By the 20th of each month, the CAISO will notify Scheduling Coordinators of Bid Adder eligibility, applicable Bid Adder value for the following month, and Frequently Mitigated Units that are eligible for a Bid Adder.

6.5.2.2.1.2 Scheduling Coordinators shall have one week to review Bid Adder information and provide comment back to the CAISO by the 27th of each month.

6.5.2.2.2 Day-Ahead Market Bid Submittal

Seven (7) days prior to any Trading Day, Scheduling Coordinators can begin submitting Bids for the DAM for that Trading Day,

6.5.2.2.3 Advisory Day-Ahead Market Results

The CAISO may provide to the responsible Scheduling Coordinator the MWh amounts scheduled in the preliminary RUC process the CAISO conducts two (2) days prior to the Trading Day, that is based on Bids and forecasts of system conditions as available in the CAISO Market systems at the time the CAISO conducts the preliminary RUC process. This information is for advisory purposes only and is not financially binding.

6.5.2.3 Public Market Information

6.5.2.3.1 Demand Forecasts

6.5.2.3.1.1 Beginning seven (7) days prior to the target Day-Ahead Market, and updated as necessary, the CAISO will publish the CAISO Forecast of CAISO Demand.

6.5.2.3.1.2 By 6:00 p.m. the day prior to the target Day-Ahead Market, the CAISO will publish the updated CAISO Forecast of CAISO Demand.

6.5.2.3.2 Network and System Conditions

By 6:00 p.m. the day prior to the target Day-Ahead Market, the CAISO will publish known network and system conditions, including but not limited to TTC and ATC, the total capacity of inter-Balancing Authority Area Transmission Interfaces, and the available capacity.

6.5.2.3.3 Ancillary Services Requirements

By 6:00 p.m. the day prior to the target Day-Ahead Market, the CAISO will publish forecasted Ancillary Services requirements and regional constraints by AS Region.

6.5.2.3.4 ~~Natural Gas and~~ Greenhouse Gas Price Indices

The CAISO will publish ~~relevant natural gas price indices and~~ daily greenhouse gas price indices when available.

6.5.2.3.5 Extremely Long-Start Unit Commitment

The CAISO will communicate commitment instructions to Scheduling Coordinators for Extremely Long-Start Resources by 3:00 p.m. two (2) days in advance of the Operating Day through a secure communication system.

6.5.2.3.6 Virtual Bid Reference Prices

The CAISO will publish Virtual Bid Reference Prices prior to the applicable reference period for the Virtual Bid Reference Prices.

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6.5.4.2.3 The CAISO will publish the natural gas price used for the Real-Time Market when available.

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7.9.2 Reasons for Suspension or Limitation

The CAISO may suspend or limit the ability of one or more Scheduling Coordinators to submit Virtual Bids of the CAISO determines that virtual bidding activities of one or more Scheduling Coordinators on behalf of one or more Convergence Bidding Entities detrimentally affect System Reliability or grid operations. Virtual bidding activities can detrimentally affect System Reliability or grid operations if such activities contribute to threatened or imminent reliability conditions, including but not limited to the following circumstances:

(a) Submitted Virtual Bids create a substantial risk that the CAISO will be unable to obtain sufficient Energy and Ancillary Services to meet Real-Time Demand and Ancillary Service requirements in the CAISO Balancing Authority Area.

(b) Submitted Virtual Bids render the CAISO Day-Ahead Market software unable to process Bids submitted into the Day-Ahead Market.

(c) Submitted Virtual Bids render the CAISO unable to achieve an alternating current (AC) solution in the Day-Ahead Market for an extended period of time.

(d) Submitted Virtual Bids detrimentally affect CAISO market efficiency.

* * * *

27.5.6 Management & Enforcement of Constraints in the CAISO Markets

The CAISO operates the CAISO Markets through the use of a market software system that utilizes various information including the Base Market Model, the State Estimator, submitted Bids including Self-Schedules, Generated Bids, and Transmission Constraints, including Nomograms and Contingencies transmission and generation Outages. The market model used in each of the CAISO Markets is derived from the most current Base Market Model available at that time. To create a more relevant time-specific network model for use in each of the CAISO Markets, the CAISO will adjust the Base Market Model to reflect Outages and derates that are known and applicable when the respective CAISO Market will operate, and to compensate for observed discrepancies between actual real-time power flows and flows calculated by the market software. Through this process the CAISO creates the market model to be used in each Day-Ahead Market and each process of the Real-Time Market. The CAISO will manage the enforcement of Transmission Constraints, including Nomograms and Contingencies, consistent with good utility practice, to ensure, to the extent possible, that the market model used in each market accurately reflects all the factors that contribute to actual Real-Time flows on the CAISO Controlled Grid and that the CAISO Market results are better aligned with actual physical conditions on the CAISO Controlled Grid. In operating the CAISO Markets, the CAISO may take the following actions so that, to the extent possible, the CAISO Market solutions are feasible, accurate, and consistent with good utility practice:

(a) The CAISO may enforce, not enforce, or adjust flow-based Transmission Constraints, including Nomograms and Contingencies, if the CAISO observes that the CAISO Markets produce or may produce results that are inconsistent with observed or reasonably anticipated conditions or infeasible market solutions either because (a) the CAISO reasonably anticipates that the CAISO Market run will identify Congestion that is unlikely to materialize in Real-Time even if the Transmission Constraint were to be ignored in all the markets leading to Real-Time, or (b) the CAISO reasonably anticipates that the CAISO Market will fail to identify Congestion that is likely to appear in the Real-Time. The CAISO does not make such adjustments to intertie Scheduling Limits.

(b) The CAISO may enforce or not enforce Transmission Constraints, including Nomograms and Contingencies, if the CAISO has determined that non-enforcement or enforcement, respectively, of such Transmission Constraints may result in the unnecessary precommitment and scheduling of use-limited resources.

(c) The CAISO may not enforce Transmission Constraints, including Nomograms and Contingencies, if it has determined it lacks sufficient visibility to conditions on transmission facilities necessary to reliably ascertain constraint flows required for a feasible, accurate and reliable market solution.

(d) For the duration of a planned or unplanned Outage, the CAISO may create and apply alternative Transmission Constraints, including Nomograms and Contingencies, that may add to or replace certain originally defined constraints.

(e) The CAISO may adjust Transmission Constraints, including Nomograms and Contingencies, for the purpose of setting prudent operating margins consistent with good utility practice to ensure reliable operation under anticipated conditions of unpredictable and uncontrollable flow volatility consistent with the requirements of Section 7.

(f) The CAISO may adjust Transmission Constraints for the purpose of reserving internal transfer capability in the Day-Ahead or Real-Time Markets, based on anticipated conditions on the natural gas delivery system, to reliably serve load in specific geographic regions of the CAISO Balancing Authority Area, or to assure deliverability of Ancillary Services. The CAISO may or may not release such reserved internal transfer capability based on natural gas and electric system conditions, or observed market inefficiencies. Upon determining that an adjustment is necessary, the CAISO will issue a notification specifying the amount of the adjustment.

To the extent that particular Transmission Constraints, including Nomograms and Contingencies, are not enforced in the operations of the CAISO Markets, the CAISO will operate the CAISO Controlled Grid and manage any Congestion based on available information including the State Estimator solutions and available telemetry to Dispatch resources through Exceptional Dispatch to ensure the CAISO is operating the CAISO Controlled Grid consistent with the requirements of Section 7.

* * * *

27.11 Natural Gas Constraint

The CAISO may enforce constraints that limit the maximum or minimum amount of natural gas that can be burned by natural gas-fired resources, based on limitations in applicable gas regions anticipated by the CAISO during specific hours. In the event that such a constraint is binding, the Shadow Price of the constraint will only be reflected in the Marginal Cost of Congestion component of the Locational Marginal Prices of the affected natural gas-fired resources. The Shadow Price of the constraint will not be reflected in the Marginal Cost of Congestion component of the Locational Marginal Prices for purposes of settling cleared Demand, Virtual Bids, or Congestion Revenue Rights. The same Marginal Cost of Congestion used for settling Demand, Virtual Bids, or Congestion Revenue Rights is used for the calculation of the Real-Time Congestion Offset pursuant Section 11.5.4.1.1. The CAISO will allocate any non-zero amounts that are attributable to the price differential between the Marginal Cost of Congestion used for settling a Generating Unit's scheduled or Dispatched amounts at their location and the Marginal Cost of Congestion used for settling Demand, Virtual Bids, or Congestion Revenue Rights pursuant to

Section 11.5.4, except that for Day-Ahead settlements the CAISO will allocate the difference through the CRR Balancing Account pursuant to Section 11.2.4.5.

* * * *

30.4.1.2 Registered Cost Methodology

~~(a)~~Under the Registered Cost methodology, the Scheduling Coordinator for a Use-Limited Resource may register values of its choosing for Start-Up Costs and/or Minimum Load Costs in the Master File subject to the maximum limit specified in Section 39.6.1.6. A Scheduling Coordinator for a Multi-Stage Generating Resource that is a Use-Limited Resource registering a Start-Up Cost must also register Transition Costs for each feasible MSG Transition, subject to the maximum limit specified in Section 39.6.1.7. For a Use-Limited Resource to be eligible for the Registered Cost methodology there must be sufficient information in the Master File to calculate the value pursuant to the Proxy Cost methodology, which will be used to validate the specific value registered using the Registered Cost methodology. Any such values will be fixed for a minimum of 30 days in the Master File unless: (a) the resource's costs for any such value, as calculated pursuant to the Proxy Cost methodology, exceed the value registered using the Registered Cost methodology, in which case the Scheduling Coordinator may elect to switch to the Proxy Cost methodology for the balance of any 30-day period, except as set forth in Section 30.4.1.2(b); or (b) any cost registered in the Master File exceeds the maximum limit specified in Section 39.6.1.6 or Section 39.6.1.7 after this minimum 30-day period, in which case the value will be lowered to the maximum limit specified in Section 39.6.1.6 or Section 39.6.1.7. If a Multi-Stage Generating Resource elects to use the Registered Cost methodology, that election will apply to all the MSG Configurations for that resource. The cap for the Registered Cost values for each MSG Configuration will be based on the Proxy Cost values calculated for each MSG Configuration, including for each MSG Configuration that cannot be directly started, which are also subject to the maximum limits specified in Sections 39.6.1.6 and 39.6.1.7.

~~(b) If the alternative natural gas price set forth in Section 39.7.1.1.1.3(b) is triggered, and a Use-Limited Resource's Start-Up Costs or Minimum Load Costs calculated pursuant to the Proxy Cost methodology using the alternative gas price exceeds the value registered in the Master File, then~~

~~the CAISO will switch the Use-Limited Resource to the Proxy Cost methodology. Any Use-Limited Resource switched to the Proxy Cost methodology pursuant to this Section 30.4.1.2(b) will revert to the Registered Cost methodology when the Use-Limited Resource's alternative Proxy Cost calculation no longer exceeds the value registered using the Registered Cost methodology. These determinations will be made separately for both Start-Up Costs and Minimum Load Costs. The CAISO will not make a separate determination for Transition Costs but if a Start-Up Cost is switched to the Proxy Cost methodology, the Transition Costs of the Use-Limited Resource will also be switched to the Proxy Cost methodology.~~

* * * *

30.5 Bidding Rules

30.5.1 General Bidding Rules

(a) All Energy and Ancillary Services Bids of each Scheduling Coordinator submitted to the DAM for the following Trading Day shall be submitted at or prior to 10:00 a.m. on the day preceding the Trading Day, but no sooner than seven (7) days prior to the Trading Day. All Energy and Ancillary Services Bids of each Scheduling Coordinator submitted to the RTM for the following Trading Day shall be submitted starting from the time of publication, at 1:00 p.m. on the day preceding the Trading Day, of DAM results for the Trading Day, and ending seventy-five (75) minutes prior to each applicable Trading Hour in the RTM. Scheduling Coordinators may submit only one set of Bids to the RTM for a given Trading Hour, which the CAISO uses for all Real-Time Market processes. The CAISO will not accept any Energy or Ancillary Services Bids for the following Trading Day between 10:00 a.m. on the day preceding the Trading Day and the publication, at 1:00 p.m. on the day preceding the Trading Day, of DAM results for the Trading Day;

(b) Bid prices submitted by a Scheduling Coordinator for Energy accepted and cleared in the IFM and scheduled in the Day-Ahead Schedule may be increased or decreased in the RTM . Bid prices for Energy submitted but not scheduled in the Day-Ahead Schedule may be increased or decreased in the RTM. Incremental Bid prices for Energy associated with Day-Ahead AS or RUC Awards in Bids submitted to the RTM may be revised. A Scheduling Coordinator may submit in the Real-Time Market new daily Bids for Start-Up Costs, Minimum Load Costs, and Transition Costs for resources and MSG Configurations for which the Scheduling Coordinator previously submitted such Bids in the Day-Ahead Market, except for: (1) Trading Hours in which a resource or MSG Configuration has received a Day-Ahead Schedule or has received a Start-Up Instruction in RUC; and (2) Trading Hours that span the Minimum Run Time of the resource or MSG Configuration after the CAISO has committed the resource or the Scheduling Coordinator has self-committed the resource in the RTM. Scheduling Coordinators may revise ETC Self-Schedules for Supply in the RTM to the extent such a change is consistent with TRTC Instructions provided to the CAISO by the Participating TO in accordance with Section 16. Scheduling Coordinators may revise TOR Self-Schedules for Supply only in the HASP to the extent such a change is consistent with TRTC Instructions provided to the CAISO by the Non-Participating TO in accordance with Section 17. Energy associated with awarded Ancillary Services capacity cannot be offered in the Real-Time Market separate and apart from the awarded Ancillary Services capacity;

(c) Scheduling Coordinators may submit Energy, AS and RUC Bids in the DAM that are different for each Trading Hour of the Trading Day;

(d) Bids for Energy or capacity that are submitted to one CAISO Market, but are not accepted in that market are no longer a binding commitment and Scheduling Coordinators may submit Bids in a subsequent CAISO Market at a different price;

(e) The CAISO shall be entitled to take all reasonable measures to verify that Scheduling Coordinators meet the technical and financial criteria set forth in

Section 4.5.1 and the accuracy of information submitted to the CAISO pursuant to this Section 30; and

[No changes to the remainder of Section 30.5.1]

* * * *

30.11 Filings with FERC to Recover Actual Marginal Fuel Procurement Costs

If a Schedule Coordinator incurs but cannot recover through the Bid Cost Recovery process any actual marginal fuel procurement costs that exceed (i) the limit on Bids for Start-Up Costs set forth in Section 30.7.9, (ii) the limit on Bids for Minimum Load Costs set forth in Section 30.7.10, (iii) the limit on Bids for Transition Costs set forth in Section 30.4.1.1.5, (iv) the incremental fuel cost calculated under the Variable Cost Option for Default Energy Bids as set forth in Section 39.7.1.1.1, or (v) the incremental fuel cost calculated for Generated Bids as set forth in Sections 30.7.3.4, 39.7.1.1.1, and 40.6.8, the Scheduling Coordinator for the resource may seek to recover those costs through a FERC filing made pursuant to Section 205 of the Federal Power Act. The Scheduling Coordinator must notify the CAISO within thirty (30) Business Days after the Operating Day on which the resource incurred the unrecovered costs, and must submit the filing to FERC within ninety (90) Business Days after that Trading Day. Within sixty (60) Business Days after the Scheduling Coordinator provides notice to the CAISO per this Section, the CAISO will provide the Scheduling Coordinator with a written explanation of any effect that events or circumstances in the CAISO Markets and fuel market conditions may have had on the resource's inability to recover the costs on the Trading Day.

Each filing the Scheduling Coordinator submits to FERC must include:

(1) Data supporting the Scheduling Coordinator's claim to the unrecovered costs it seeks, including Invoices for the unrecovered costs;

(2) A description of the resource's participation in any gas pooling arrangements;

(3) An explanation of why recovery of the costs is justified; and

(4) A copy of the written explanation from the CAISO to the Scheduling Coordinator described above in this Section.

To the extent that FERC authorizes the Scheduling Coordinator to recover any costs pursuant to the Scheduling Coordinator's filing, the CAISO will pay the Scheduling Coordinator any amounts the Commission deems recoverable and will allocate such amounts pursuant to Section 11.14.

* * * *

31.6 Timing Of Day-Ahead Scheduling

31.6.1 Criteria For Temporary Waiver Of Timing Requirements

The CAISO may at its sole discretion implement any temporary variation or waiver of the timing requirements of this Section 31 and Section 6.5.3 (including the omission of any step) if any of the following criteria are met:

(i) such waiver or variation of timing requirements is reasonably necessary to preserve System Reliability, prevent an imminent or threatened System Emergency or to retain Operational Control over the CAISO Controlled Grid during an actual System Emergency.

(ii) because of error or delay, the CAISO requires additional time to fulfill its responsibilities;

(iii) problems with data or the processing of data cause a delay in receiving or issuing Bids or publishing information on the CAISO's secure communication system;

(iv) problems with telecommunications or computing infrastructure cause a delay in receiving or issuing Day-Ahead Schedules or publishing information on the CAISO's secure communication system.~~;~~

~~(v) the alternative natural gas price set forth in Section 39.7.1.1.1.3(b) is triggered.~~

* * * *

34.6 Short-Term Unit Commitment

Once per hour, near the top of each Trading Hour, immediately after the FMM and the RTUC for the same interval is completed the CAISO performs an approximately five (5) hour Short-Term Unit Commitment (STUC) run using SCUC and the CAISO Forecast Of CAISO Demand to commit Medium Start Units and Short Start Units with Start-Up Times greater than the time period covered by the RTUC described in Section 34.3. In any given Trading Hour, the STUC may commit resources for the third fifteen-minute interval of the current Trading Hour and extending into the next four (4) Trading Hours. The STUC looks ahead over a period of at least three (3) hours beyond the Trading Hour for which the RTUC optimization was run. STUC ~~, and~~ will utilize: (1) Bids previously submitted in the RTM by the Scheduling Coordinator for that Trading Hour; or (2) the Clean Bid from the Day-Ahead Market if the resource has a Day-Ahead Schedule or received a Start-Up Instruction in RUC for the Trading Hour, or if the resource has a Real-Time must-offer obligation for that Trading Hour~~available from other CAISO Markets for that Trading Hour for these additional hours~~. The CAISO revises these replicated Bids each time the hourly STUC is run, to utilize the most recently available Bids. Not all resources identified for need as a given STUC run will necessarily receive CAISO commitment instructions immediately, because during the Trading Day the CAISO may issue a commitment instruction to a resource only at the latest possible time that allows the resource to be ready to provide Energy when it is expected to be needed. A Start-Up Instruction produced by STUC is considered binding if the resource could not achieve the target Start-Up Time as determined in the current STUC run in a subsequent RTUC or STUC run as a result of the Start-Up Time of the resource. A Start-Up Instruction produced by STUC is considered advisory if it is not binding, such that the resource could achieve its target start time as determined in the current RTUC run in a subsequent STUC or RTUC run based on its Start-Up Time. A binding Dispatch Instruction produced by STUC that results in a change in Commitment Status will be issued, in accordance with Section 6.3, after review and acceptance of the Start-Up Instruction by the CAISO Operator. The STUC will only decommit a resource to the extent that resource's physical characteristics allow it to be cycled in the same approximately five (5) hour look-ahead time period for which it was previously committed. STUC does not produce Locational Marginal Prices for Settlement. A Day-Ahead Schedule or RUC Schedule for an MSG Configuration that is later impacted by the resource's derate or outages, will be reconsidered in the STUC process taking into consideration the impacts of the derate or outage on the available MSG Configurations.

* * * *

36.4 FNM For CRR Allocation And CRR Auction

When the CAISO conducts its CRR Allocation and CRR Auction, the CAISO shall use the most up-to-date DC FNM which is based on the AC FNM used in the Day-Ahead Market. The Seasonal Available CRR Capacity shall be based on the DC FNM, taking into consideration the following, all of which are discussed in the applicable Business Practice Manual: (i) any long-term scheduled transmission Outages, (ii) TTC adjusted for any long-term scheduled derates, (iii) a downward adjustment due to TOR or ETC as determined by the CAISO, and (iv) the impact on transmission elements used in the annual CRR Allocation and Auction of (a) transmission Outages or derates that are not scheduled at the time the CAISO conducts the Seasonal CRR Allocation or Auction determined through a methodology that calculates the breakeven point for revenue adequacy based on historical Outages and derates, and (b) known system topology changes, both as further defined in the Business Practice Manuals. The Monthly Available CRR Capacity shall be based on the DC FNM, taking into consideration: (i) any scheduled transmission Outages known at least thirty (30) days in advance of the start of that month as submitted for approval consistent with the criteria specified in Section 36.4.3, (ii) adjustments to compensate for the expected impact of Outages that are not required to be scheduled thirty (30) days in advance, including unplanned transmission Outages, (iii) adjustments to restore Outages or derates that were applied for use in calculating Seasonal Available CRR Capacity but are not applicable for the current month, (iv) any new transmission facilities added to the CAISO Controlled Grid that were not part of the DC FNM used to determine the prior Seasonal Available CRR Capacity and that have already been placed in-service and energized at the time the CAISO starts the applicable monthly process, (v) TTC adjusted for any scheduled derates or Outages for that month, (vi) a downward adjustment due to TOR or ETC as determined by the CAISO; ~~and~~ (vii) adjustments for possible unscheduled flow at the Interties, and (viii) any adjustments necessary to account for possible adjustments to Transmission Constraints pursuant to Section 27.5.6 (f). For the first monthly CRR Allocation and CRR Auction for CRR Year One, to account for any planned or unplanned Outages that may occur for the first month of CRR Year One, the CAISO will derate all flow limits, including Transmission Interface limits and normal thermal limits, based on statistical factors determined as provided in the Business Practice Manuals.

* * * *

39.7.1.1.1.3 Calculation of Natural Gas Price

(a) ~~Except as set forth in Section 39.7.1.1.1.3(b), t~~The CAISO will use different gas price indices for the Day-Ahead Market and the Real-Time Market~~ and a gas price index will be calculated using at least two prices from two or more of the following publications: Natural Gas Intelligence, SNL Energy/BTU's Daily Gas Wire, Platt's Gas Daily, and the Intercontinental Exchange~~. If a gas price index is unavailable for any reason, the CAISO will use the most recently available gas price index as set forth in Section 39.7.1.1.1.3(c).

(b) For the Day-Ahead Market, the CAISO will use a gas price index reported by the Intercontinental Exchange between 8:00 and 9:00 Pacific Time, which is a volume-weighted average price calculated by the Intercontinental Exchange based on trades transacted on the Intercontinental Exchange during its next-day trading window. ~~will update the gas price indices between 19:00 and 22:00 Pacific Time using natural gas prices published on the day that is two (2) days prior to the applicable Trading Day, unless gas prices are not published on that day, in which case the CAISO will use the most recently published prices that are available.~~

(c) For the Real-Time Market, the CAISO will calculate a gas price index using at least two prices from two or more of the following publications: Natural Gas Intelligence, SNL Energy/BTU's Daily Gas Wire, Platt's Gas Daily, and the Intercontinental Exchange. ~~t~~The CAISO will update gas price indices for the Real-Time Market between the hours of 19:00 and 22:00 Pacific Time using natural gas prices published one (1) day prior to the applicable Trading Day, unless gas prices are not published on that day, in which case the CAISO will use the most recently published prices that are available.

(d) For the Real-Time Market, the CAISO will increase the gas price calculated pursuant to Section 39.7.1.1.1.3(c) for resources receiving gas service from Southern California Gas Company and San Diego Gas & Electric Company by an amount that: (1) improves the dispatch of these resources so that they are more likely to be dispatched to address local needs rather than system needs; (2) better accounts for systematic differences between day-ahead and same-day natural gas prices; and (3) improves the ability to manage the generators' gas usage within applicable gas balancing rules. For applicable resources, the CAISO will initially increase the gas commodity price used in the calculation of Start-Up Costs, Minimum Load Costs, and Transition Costs pursuant to Section 30.4.1.1, and Generated Bids pursuant to Section 40.6.8, by seventy-five (75) percent, and may decrease this amount or increase it further by an amount not to exceed $2.50 plus two (2) times the next-day gas index price calculated pursuant to Section 39.7.1.1.1.3(b). For applicable resources, the CAISO will initially increase the gas commodity price used in the calculation of Default Energy Bids pursuant to Section 39.7.1.1 by twenty-five (25) percent, and may decrease this amount or increase it further by an amount not to exceed one hundred (100) percent. Upon determining that a subsequent increase in the gas price is necessary after the initial increase, the CAISO will issue a Market Notice specifying the amount of the increase.

~~(b) If a daily gas price reported by the Intercontinental Exchange on the morning of the Day-Ahead Market run exceeds one hundred twenty-five (125) percent of any natural gas price index calculated for the Day-Ahead Market between 19:00 and 22:00 Pacific Time on the preceding day, the CAISO will utilize the gas price reported by the Intercontinental Exchange in all CAISO cost formulas and market processes for that day's Day Ahead Market that would normally utilize the natural gas price index calculated pursuant to this Section 39.7.1.1.1.3.~~

* * * *

39.7.1.1.3 Filings with FERC to Recover Actual Marginal Fuel Procurement Costs

A Scheduling Coordinator for a resource subject to the Variable Cost Option may seek to recover actual marginal fuel procurement costs pursuant to a filing with FERC in accordance with Section 30.11.

* * * *

39.7.2.2 Criteria

(A) Notwithstanding the provisions in Section 39.7.2.2(B), when the CAISO enforces the natural gas constraint pursuant to Section 27.11, the CAISO may deem selected internal constraints to be non-competitive for specific days or hours based on its determination that actual electric supply conditions may be non-competitive due to anticipated electric supply conditions in the Southern California Gas Company and San Diego Gas & Electric Company gas regions.

(B) Subject to Section 39.7.3, for the DAM and RTM, a Transmission Constraint will be non-competitive only if the Transmission Constraint fails the dynamic competitive path assessment pursuant to this Section 39.7.2.2.

(a) Transmission Constraints for the DAM – As part of the MPM process associated with the DAM, the CAISO will designate a Transmission Constraint for the DAM as non-competitive when the fringe supply of counter-flow to the Transmission Constraint from all portfolios of suppliers that are not identified as potentially pivotal is less than the demand for counter-flow to the Transmission Constraint. For purposes of determining whether to designate a Transmission Constraint as non-competitive pursuant to this Section 39.7.2.2(a):

(i) Counter-flow to the Transmission Constraint means the delivery of Power from a resource to the system load distributed reference bus. If counter-flow to the Transmission Constraint is in the direction opposite to the market flow of Power to the Transmission Constraint, the counter-flow to the Transmission Constraint is calculated as the shift factor multiplied by the resource's scheduled Power. Otherwise, counter-flow to the Transmission Constraint is zero.

(ii) Fringe supply of counter-flow to the Transmission Constraint means all available capacity from internal resources not controlled by the identified potentially pivotal suppliers and all internal Virtual Supply Awards not controlled by the identified potentially pivotal suppliers that provide counter-flow to the Transmission Constraint. Available capacity reflects the highest capacity of a resource's Energy Bid adjusted for Self-Provided Ancillary Services and derates.

(iii) Demand for counter-flow to the Transmission Constraint means all internal dispatched Supply and Virtual Supply Awards that provide counter-flow to the Transmission Constraint.

(iv) Potentially pivotal suppliers mean the three (3) portfolios of net sellers that control the largest quantity of counter-flow supply to the Transmission Constraint.

(v) Portfolio means the effective available internal generation capacity under the control of the Scheduling Coordinator and/or Affiliate determined pursuant to Section 4.5.1.1.12 and all effective internal Virtual Supply Awards of the Scheduling Coordinator and/or Affiliate. Effectiveness in supplying counter-flow is determined by scaling generation capacity and/or Virtual Supply Awards by the shift factor from that location to the Transmission Constraint being tested.

(vi) A portfolio of a net seller means any portfolio that is not a portfolio of a net buyer. A portfolio of a net buyer means a portfolio for which the average daily net value of Measured Demand minus Supply over a twelve (12) month period is positive. The average daily net value is determined for each portfolio by subtracting, for each Trading Day, Supply from Measured Demand and then averaging the daily value for all Trading Days over the twelve (12) month period. The CAISO will calculate whether portfolios are portfolios of net buyers in the third month of each calendar quarter and the calculations will go into effect at the start of the next calendar quarter. The twelve (12) month period used in this calculation will be the most recent twelve (12) month period for which data is available. The specific mathematical formula used to perform this calculation will be set forth in a Business Practice Manual. Market Participants without physical resources will be deemed to be net sellers for purposes of this Section 39.7.2.2(a)(vi).

(vii) In determining which Scheduling Coordinators and/or Affiliates control the resources in the three (3) identified portfolios, the CAISO will include resources and Virtual Supply Awards directly associated with all Scheduling Coordinator ID Codes associated with the Scheduling Coordinators and/or Affiliates, as well as all resources that the Scheduling Coordinators and/or Affiliates control pursuant to Resource Control Agreements registered with the CAISO as set forth Section 4.5.1.1.13. Resources identified pursuant to Resource Control Agreements will only be assigned to the portfolio of the Scheduling Coordinator that has control of the resource or whose Affiliate has control of the resource pursuant to the Resource Control Agreements.

[No changes to the remainder of Section 39.7.2.2]

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40.6.3 Additional Availability Requirements For Resources that Are Not Long Start Units or Extremely Long Start ~~Short Start~~ Resources~~Units~~

A resource that is not a Long Start Unit or an Extremely Long Start ~~Short Start~~ Resource~~Unit~~ that is a Resource Adequacy Resource and that does not have an IFM Schedule or a RUC Schedule for any of its capacity for a given Trading Hour is required to participate in the Real Time Market in accordance with Section 40.6.2. Such a resource that is also a Use-Limited Resource subject to Section 40.6.4 is required, consistent with their applicable use plan, to submit Economic Bids or Self Schedules for Resource Adequacy Capacity into the Real Time Market.

The CAISO may waive these availability obligations for a resource that is not a Long Start Unit or an Extremely Long Start~~Short Start~~ Resource~~Unit~~ that does not have an IFM Schedule or a RUC Schedule based on the procedure to be published on the CAISO Website.

* * * *

40.6.8.1.6 Filings with FERC to Recover Actual Marginal Fuel Procurement Costs

A Scheduling Coordinator for a resource subject to a Generated Bid may seek to recover actual marginal fuel procurement costs pursuant to a filing with FERC in accordance with Section 30.11.

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Attachment C – Additional Background Information Regarding Aliso Canyon and CAISO Stakeholder Process

Tariff Amendment to Enhance Gas-Electric Coordination to Address Risks Posed by Limited Operability of Aliso Canyon Natural Gas Storage Facility

California Independent System Operator Corporation

May 9, 2016

ATTACHMENT C

ADDITIONAL BACKGROUND INFORMATION REGARDING ALISO CANYON AND CAISO STAKEHOLDER PROCESS

I. Implications Regarding the Natural Gas Leak at the Aliso Canyon Gas Storage Facility

A. The Aliso Canyon Facility

Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) own and operate an integrated gas transmission system located in southern California, for which SoCalGas is responsible. Using a network of transmission pipelines and four interconnected storage fields, SoCalGas and SDG&E deliver natural gas to more than five million business and residential customer accounts, which equals approximately 21 million residents.[1]

The largest of the gas storage fields is the Aliso Canyon facility (Aliso Canyon) located near Los Angeles.[2] Aliso Canyon an integral part of the gas and electric system and is used year round. For summer operations, the SoCalGas Control department strives to completely fill Aliso Canyon to provide firm injection services to customers and prepare for the upcoming winter. Aliso Canyon's withdrawal capabilities are also used an average of approximately 10 days during each summer month to provide gas supply to meet the hourly peak electric generation demand that occurs throughout the day, when that demand cannot be met quickly enough by flowing supplies.[3]

Aliso Canyon is integral to the reliable operation of the electric grid and infrastructure in California that the CAISO operates. Its gas storage acts as a shock absorber for the real-time dynamic variations in electric demand. Aliso Canyon also provides additional gas delivery capacity when gas demand exceeds the amount of flowing supply and provides a place to inject unutilized gas when electric demand is less than expected. The Inter-Agency Task Force's risk assessment focused on summer 2016 and indicates that the Aliso Canyon facility supports gas and electric reliability when there are significant differences

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1 Aliso Canyon Risk Assessment Technical Report Prepared by the Staff of the California Public Utilities Commission, California Energy Commission, the California Independent System Operator, the Los Angeles Department of Water and Power, and Southern California Gas Company, at 5-7 (Apr. 5, 2016) (Risk Assessment Report). The Risk Assessment Report is available on the CAISO website page dedicated to the Aliso Canyon Gas Electric Coordination stakeholder initiative that resulted in this filing, http://www.caiso.com/informed/Pages/StakeholderProcesses/AlisoCanyonGasElectricCoordination.aspx.

2 Risk Assessment Report at 7. The other three gas storage fields are the Honor Rancho, La Goleta, and Playa del Rey facilities. *Id.*

3 *Id.* at 7-8.

between flowing gas supply and actual gas demand. Such differences are due either to unexpected changes between the amount of gas scheduled the day before and the actual gas demand occurring in real-time, or to commercial practices and incentives regarding gas procurement that can result in low flowing supply.[4]

B. The Gas Leak at Aliso Canyon, Subsequent Events, and Potential Consequences of Limited Operability of Aliso Canyon

On October 23, 2015, a significant gas leak was detected at Aliso Canyon, which was not sealed until February 18, 2016. Currently, 15 billion cubic feet of gas are being held at Aliso Canyon as an actual working gas inventory.[5] SoCalGas currently has only limited ability to withdraw gas from Aliso Canyon.

On January 6, 2016 the Governor of California issued an Emergency Proclamation that included a number of directives related to the leak, including the continuation of a moratorium on gas injections into Aliso Canyon established following the leak until a comprehensive review of the "safety of the storage wells and the air quality of the surrounding community is completed," and a directive that the CPUC and the CEC, in coordination with the CAISO, "shall take all actions necessary to ensure the continued reliability of natural gas and electricity supplies in the coming months during the moratorium."[6] Among the actions taken pursuant to the latter directive were the organization of an Inter-Agency Task Force and the preparation and issuance of the Risk Assessment Report and the Reliability Action Plan by the members of the Inter-Agency Task Force – the CPUC, CEC, CAISO, SoCalGas, and the Los Angeles Department of Water and Power (LADWP).

Gas pipeline companies impose daily gas balancing requirements, based on the difference between nominated gas flows and actual gas demand (*i.e.*, burned gas), that are commonly referred to in southern California as operational flow orders (OFOs) and emergency flow orders (EFOs). Gas customers that exceed the balancing requirements by a specified tolerance band may have to pay penalties.[7] Gas-fired resources often manage these gas balancing

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4 *Id.* at 10.

5 Aliso Canyon Action Plan to Preserve Gas and Electric Reliability for the Los Angeles Basin Prepared by the Staff of the California Public Utilities Commission, California Energy Commission, the California Independent System Operator, and the Los Angeles Department of Water and Power, at 20 (Reliability Action Plan). The Reliability Action Plan is available on the same CAISO website page as the Risk Assessment Report.

6 Emergency Proclamation at ¶¶ 7, 10. The Emergency Proclamation is available at https://www.gov.ca.gov/news.php?id=19264.

7 A gas pipeline company will issue a "high" OFO or EFO when the gas pipeline pressure is increasing because the amount of nominated gas is higher than the actual gas demand; to enable the pipeline to balance the pressure at a more sustainable level, gas customers must

requirements in part by bidding their commitment costs and energy offers into the CAISO real-time market at levels intended to ensure that the gas burns resulting from CAISO acceptance or non-acceptance of their bids will allow them to stay within the tolerance band, thus avoiding such penalties. For example, in situations in which a resource receives an OFO or EFO that puts the resource at risk of incurring a penalty if the resource burns an amount of gas above the tolerance band, the resource may seek to hold or decrease its gas burn by bidding higher costs into the CAISO real-time market, so that the CAISO real-time market is less likely to dispatch the resource up. Conversely, in situations where a resource receives an OFO or EFO that puts the resource at risk of incurring a penalty if the resource burns an amount of gas below the tolerance band, the resource will seek to not be dispatched down so that it does not decrease its gas burn, by bidding lower costs into the CAISO real-time market.

The limited operability of Aliso Canyon has caused gas-balancing conditions in southern California to become more strained, over both the SoCalGas and SDG&E gas systems, and these conditions are expected to worsen this summer. On March 1, SoCalGas and SDG&E filed a joint motion with the CPUC in which they proposed interim daily gas balancing and penalty rules to address the gas balancing conditions in southern California. SoCalGas, SDG&E, and other parties in the proceeding subsequently entered into settlement discussions. On April 29, the parties filed with the CPUC a joint motion for adoption of a settlement agreement containing a proposed interim set of gas balancing rules.[8] The settlement agreement is currently pending CPUC review. Regardless of whatever rules the CPUC adopts, gas-fired resources will continue to apply the approach to managing gas-imbalance risk described above.

The Commission has also recognized the seriousness of the impacts that may result from the limited operability of Aliso Canyon. At the Commission meeting held on March 17, Commission Staff presented its annual State of the Markets Report, which included the following discussion:

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either decrease their nominated flows or reduce their demand. Conversely, a gas pipeline company will issue a "low" OFO or EFO when the gas pipeline pressure is decreasing because the amount of nominated gas is lower than the actual gas demand; to enable the pipeline to balance the pressure at a more sustainable level, gas customers must either increase their nominated flows or increase their demand.

[8] Joint Motion of Southern California Gas Company (U 904 G), San Diego Gas & Electric Company (U 902 G), and the Indicated Parties for Adoption of Daily Balancing Proposal Settlement Agreement, CPUC Proceeding No. A.15-06-020 (Apr. 29, 2016). The settlement agreement provides that during the settlement term, which will end no later than November 30, 2016, SoCalGas and SDG&E will deal with supply shortages and surpluses using OFO tariff procedures rather than daily balancing procedures. To facilitate this approach, the settlement agreement provides that, during the settlement term, SoCalGas and SDG&E will make a number of temporary changes to their existing high and low OFO tariff provisions, including tightening the existing 110-percent high-OFO tolerance level to a default 105-percent tolerance level that can be changed back to a 110-percent tolerance level at the sole discretion of SoCalGas and SDG&E.

> Aliso Canyon represents 63 percent of SoCal's storage, and could be shut down for the foreseeable future. The closure is having impacts on SoCal's system reliability, flexibility, and prices. Moreover, natural gas forward prices in California have risen steadily since November 2015 due to expectations that increased spot gas purchases will be necessary to substitute for the lost Aliso Canyon storage withdrawals during next winter's peak demand season. There are also concerns regarding the impact on power generation this summer, since nearby plants rely on Aliso Canyon storage to meet peak requirements.[9]

The Risk Assessment Report and the Reliability Action Plan include analyses of the likely impacts if Aliso Canyon is unavailable for summer 2016. The analyses calculate a potential for 23 to 32 days in 2016 during which the SoCalGas and SDG&E systems will be under significant stress without Aliso Canyon in operation, placing uninterrupted service to power plants and other non-core gas customers – whose gas service is always curtailed before service to core gas customers – at risk.[10] Seventeen gas-fired power plants, with a combined capacity of 9,838 megawatts (MW), are most directly served by withdrawals of gas from Aliso Canyon.[11] Most of this capacity is dispatched on hot days, when electricity demand rises due to increased use of air conditioning. SoCalGas relies on Aliso Canyon during these days to meet hourly changes in gas requirements of these gas-fired resources as the resources start up and operate during hours of peak generating and demand. Moreover, some of these resources must be available to produce power quickly in the event of outages on the transmission system.[12]

The analyses estimate that, assuming no gas is withdrawn from Aliso Canyon, gas curtailments can be expected during 16 days this summer, with 14 of those summer days being likely to have a large enough impact to interrupt much of the power generation located in the Los Angeles Basin and potentially

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9 *State of the Markets Report 2015*, Docket No. AD06-3-000, at 11 (Mar. 17, 2016). This report is available on the Commission's website.

10 *See* Risk Assessment Report at 32-41. Pursuant to CPUC directives, gas utility customers are split into two basic groups: core customers and non-core customers. Core customers consist of homes, small commercial operations, and small industrial customers, all of which typically receive their gas-related services from the gas utility. Core customers are the last customers to be curtailed in the event that there is insufficient supply in the system. Non-core customers consist mainly of large industrial and commercial customers, including power plants, which procure their own natural gas supplies and use SoCalGas's system to transport the gas supply they purchase elsewhere. Reliability Action Plan at 11-12.

11 Although there are seventeen generators in the Los Angeles Basin most directly impacted by the limited operability of Aliso Canyon, SoCalGas indicates that if issues arise with respect to maintaining pressures due to mismatches in scheduled and actual gas demand, such issues can have an impact on generators throughout southern California.

12 Reliability Action Plan at 9-10.

the broader southern California region, thus affecting both the CAISO and LADWP.[13] In addition, the analyses indicate that, during a typical high-demand summer day, the limited supply of gas due to the unavailability of Aliso Canyon would likely cause load curtailments that could affect as many as 3.36 million core customers.[14]

Importing power from more northerly sources into southern California may alleviate some of the effects of the unavailability of Aliso Canyon on gas-fired resources, and thus on electric customers. However, imports of power from more northerly resources into the Los Angeles Basin are bottlenecked by the limited power transfer capability of Path 26, a set of three 500-kilovolt (kV) transmission lines located primarily in Los Angeles County, that is used to convey power from northern California to southern California (or vice versa). Path 26 has 4,000 MW of total transfer capability when all three transmission lines are in service.[15]

Based on its analyses, the Inter-Agency Task Force identified four major risks to the SoCalGas operating region starting in the summer of 2016:

1. Daily imbalances between the amount of gas nominated and the amount of gas burned that exceed 150 million cubic feet can affect operating pressures, thus undermining pipeline integrity.

2. Planned and unplanned outages or curtailments on the gas system often limit pipeline and other storage availability.

3. Rapid ramping of electric generation can exceed the dynamic capability of the gas system, thus affecting recovery from contingencies and renewable generation following.

4. Cold weather in the east can reduce gas supplies for California.[16]

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13 *Id.* at 20-23.

14 Risk Assessment Report at 49-52.

15 *Id.* at 43 n.8, 46. The Risk Assessment Report also explains that there is approximately 10,100 MW of east-to-west transmission capability between the southwestern United States (Nevada and Arizona) and the CAISO, but the real-time ability to increase power delivery from the southwest is limited by the small amount of supply available and remaining unused transfer capability. Further, there is approximately 3,000 MW of transfer capability between LADWP and the CAISO, but in the summer typically 2,500 MW of that transfer capability is used to convey power from LADWP resources located outside the Los Angeles Basin, leaving only 500 MW available for other imported power. In addition, because transmission throughout the system can become congested during times of high imports, its effectiveness to mitigate the effects of gas curtailments when electricity demand is high may be limited. *Id.* at 46.

16 *See Aliso Canyon's Impact on Electric Reliability Technical Analysis and Action Plan*, at page 10 (presentation delivered at joint agency workshop held on April 8, 2016), available on the CEC's website at http://www.energy.ca.gov/2016_energypolicy/documents/2016-04-

To address these risks posed by the limited operability of Aliso Canyon, the Reliability Action Plan set forth 18 mitigation measures to reduce the need for and magnitude of natural gas curtailments. Some of the mitigation measures have already been implemented, others are still under consideration, and still others are standby measures that may be implemented in the future if needed.[17] This suite of mitigation measures includes establishing an interim set of tighter gas balancing rules, which are currently pending review by the CPUC as described above. The mitigation measures also include:

- Efforts to explore the use of remaining gas in Aliso Canyon to prevent electric service interruptions this summer.

- Efforts to efficiently complete the required safety review at Aliso Canyon to allow for safe use of the storage field.

- The CPUC is examining whether any gas maintenance tasks on SoCalGas's system can be safely deferred.

- The CPUC has authorized funding to create a gas conservation messaging campaign.

- The CPUC is working to expand energy efficiency and demand response programs in the Los Angeles Basin.

- The CAISO and SoCalGas have enhanced their coordination efforts by refining information they exchange on expected system conditions and expected gas burns.

- The CAISO, LADWP, and SoCalGas have scheduled tabletop exercises to manage gas pipeline outages as well as to address emergency procedures in the event of a gas curtailment on the SoCalGas system.

- The CAISO is working with Peak Reliability to assess whether it can increase emergency ratings on transmission paths that serve the Los Angeles Basin, and is working with its participating transmission owners to utilize remedial action schemes if necessary to maximize use of these transmission paths during emergency conditions.

08_presentations.html.

17 Reliability Action Plan at 24-32. The mitigation measures are grouped into five general categories: (1) prudent use of Aliso Canyon; (2) tariff changes (both state and federal); (3) coordination; (4) LADWP operations; and (5) reduction of natural gas and electricity use. *Id.* at 24.

- The CAISO is working to operationalize its Flex Alert program this summer to encourage electricity conservation.

The CAISO expects that these various measures will prove instrumental in mitigating the challenges posed by the limited operability of Aliso Canyon. Nevertheless, significant electric grid reliability concerns remain, stemming from the interaction between gas pipeline balancing requirements and the reliance on natural gas generating resources to serve load in southern California, particularly during peak summer periods. After careful consideration, the CAISO has concluded that the tariff modifications described herein are necessary both to address these reliability concerns proactively and successfully, in terms of both ensuring uninterrupted electric service in the Los Angeles Basin and the greater southern California area, and to not exacerbate an already constrained gas system. These modifications represent a significant undertaking by the CAISO and its stakeholders, and the Commission should promptly approve them so they can be implemented for the summer season.

II. CAISO Stakeholder Process

The CAISO established the Aliso Canyon Gas Electric Coordination stakeholder initiative on an expedited basis on March 16, 2016.[18] The CAISO posted an issue paper in the initiative for stakeholder review on March 17, held a stakeholder conference call regarding the issue paper on March 23, and requested the submission of written stakeholder comments on the issue paper by March 30.

The CAISO held a working group meeting in the stakeholder initiative on April 6 to discuss CAISO market mechanisms or tools that might be appropriate to address the limited operability of Aliso Canyon. On April 15, the CAISO posted for stakeholder review and comment a Straw Proposal regarding potential means of addressing the Aliso Canyon situation. On April 19, the CAISO's Market Surveillance Committee (MSC) held a conference call that included discussion of the Straw Proposal and the opportunity for stakeholders to provide verbal comments. Stakeholders provided written comments on the Straw Proposal on April 21.

The CAISO issued a Draft Final Proposal on April 26 and discussed it with stakeholders on a conference call held on April 27. Stakeholders submitted written comments on the Draft Final Proposal on April 28. The CAISO posted

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[18] *See* http://www.caiso.com/informed/Pages/StakeholderProcesses/AlisoCanyonGasElectricCoordination.aspx. In addition, as discussed below in the transmittal letter, some of the proposals contained in this filing are based on proposals originally developed in the CAISO's pre-existing Bidding Rules Enhancements stakeholder initiative. Materials from that stakeholder initiative are available on the CAISO website at http://www.caiso.com/informed/Pages/StakeholderProcesses/BiddingRulesEnhancements.aspx.

draft tariff revisions to implement the Draft Final Proposal on April 29 and requested that stakeholders submit written comments on the draft tariff revisions prior to May 3 or share them on a conference call that the CAISO held on that date to discuss the draft tariff revisions. The CAISO issued a Revised Draft Final Proposal on May 4.[19]

Stakeholders generally supported the objective of implementing operational tools and market mechanisms this summer to mitigate the issues raised by the limited operability of Aliso Canyon. The CAISO addresses specific issues raised by stakeholders in section IV of the transmittal letter for this filing. In addition, the CAISO Department of Market Monitoring (DMM) submitted written comments on the Revised Draft Final Proposal explaining that DMM worked closely with the CAISO in developing and that DMM supports the key elements of the proposals finalized in the Revised Draft Final Proposal.[20]

The CAISO Governing Board (Board) authorized the filing of this tariff amendment at its May 4, 2016 meeting.[21]

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[19] The Revised Draft Final Proposal is provided in attachment D to this filing.

[20] DMM comments on Revised Draft Final Proposal at 1 (May 6, 2016) (DMM Comments). The DMM Comments are provided in attachment F to this filing.

[21] Materials related to the Board's authorization to submit this filing are available on the CAISO website at http://www.caiso.com/informed/Pages/BoardCommittees/Default.aspx. The materials include a memorandum to the Board from Keith Casey, Vice President, Market & Infrastructure Development (Board Memorandum), which is provided in attachment E to this filing.

Attachment D – Revised Draft Final Proposal

Tariff Amendment to Enhance Gas-Electric Coordination to Address Risks Posed by Limited Operability of Aliso Canyon Natural Gas Storage Facility

California Independent System Operator Corporation

May 9, 2016

Aliso Canyon Gas-Electric Coordination

Revised Draft Final Proposal

May 04, 2016

Table of Contents

1. Executive Summary

In October 2015, the Aliso Canyon natural gas storage facility in Southern California experienced a large gas leak significantly affecting gas markets and many of the people that live and work in the area. The facility is a key part of the gas system, serving gas customers in the Los Angeles Basin, including gas-fired power plants.

In response, the ISO is participating in an inter-agency task force with California Energy Commission (CEC), California Public Utility Commission (CPUC), Los Angeles Department of Water and Power (LADWP), and Southern California Gas (SoCalGas) to assess the risks of the limited operability of Aliso Canyon introduces to the gas and electric markets. Besides assessing these new reliability risks of gas curtailments or electric market load interruption measures, the task force is discussing possible mitigation measures. On March 1, 2016 SoCalGas and San Diego Gas & Electric (SDG&E) submitted a joint motion (motion) at CPUC proposing daily balancing requirements[1] in response to the abrupt change in its gas storage capacity at its Aliso Canyon storage facility. On April 2016, the inter-agency task force published its Technical Assessment Report which identified four major risks to the SoCalGas operating region beginning summer 2016.

The ISO initiated this stakeholder process to explore market mechanisms or other tools the ISO may consider, including the possible mitigation measures explored by the task force, to mitigate the risks to gas and electric markets to avoid electric service interruptions to the extent possible. Under this stakeholder process, the ISO seeks to:

(1) Evaluate reliability risks emerging from abrupt change in gas storage capacity at the Aliso Canyon storage facility,

(2) Evaluate how gas balancing rules regardless of the penalty structure adopted by SoCalGas and SDG&E might affect resources' ability to manage their generation assets,

(3) Identify and develop market mechanisms or tools to support reliability and ensure markets are not adversely affected.

A balancing requirement over a day will require resources to manage their gas procurement and subsequent pipeline nomination so the amount of nominated gas is within a tolerance band (expressed in percentage) of its actual gas burn. These strict gas balancing requirements support gas system reliability by signaling to gas customers when their gas deviations over the day are outside the tolerance band and imposing a charge associated with such deviations. The penalties associated with the violating either a daily balancing requirement or an

[1] San Diego Gas & Electric Company, Southern California Gas Company, Application of Southern California Gas Company (U904G) and San Diego Gas & Electric Company (U902G) for Authority to Revise their Curtailment Procedures. Available at: http://delaps1.cpuc.ca.gov/CPUCProceedingLookup/f?p=401:56:12698212606868::NO:RP,57,RIR:P5_PROCEEDING_SELECT:A1506020

operational flow order introduces a new risk to gas customers including electricity generators in the ISO markets that may affect traded prices of natural gas.

The ISO understands that the gas balancing rules should mitigate risk to reliability on the gas system. Any measures designed to reduce reliability risks on the gas system will also reduce the risk of events that adversely impact electric reliability system. The ISO manages the dispatch of several generators dependent on gas coming from the SoCalGas system. The ISO recognizes concerns that its commitment or dispatch instructions, especially in real-time, could cause generators under a daily balancing requirement or an operational flow order to violate these tolerance bands and potentially incur costs. Among other concerns, the ISO does not currently:

- Coordinate ISO market instructions or exceptional dispatches with daily balancing requirements.

- Include mechanisms to reflect intraday prices reflecting strained gas condition in commitment cost and mitigated incremental energy bids.

In Section 5 of this proposal, the ISO discusses its evaluation of the issues affecting gas and electric service under the constrained conditions due to limited operability of Aliso Canyon. In this proposal, the ISO identifies and proposes measures to mitigate the inter-agency task forces identified risks, which include:

- In Section 6, the ISO discusses measures to mitigate the risk where planned and unplanned outages on gas system often limit pipeline and other storage availability that impact gas availability.

- In Section 7, the ISO discusses measures to mitigate the risk where daily imbalances exceeding 150 million cubic feet (MMcf) affecting operating pressures that undermine pipeline integrity and to address the risk that the electric system could be adversely impacted when its rapid ramping can exceed dynamic capability of gas system i.e. contingency recovery, renewable generation following, or significant changes in load.

Besides addressing the risks raised by the task force, the ISO identified the need to propose changes to its day-ahead gas price index used to determine its cost estimates. There has been a change to the timing when Intercontinental Exchange (ICE) is releasing the next day index used for the ISO's manual price spike procedure, which would require re-opening the day-ahead market window around 11:30AM PST and likely publishing roughly by 3:45PM PST to continue the procedure. Given the increased need to include accurate gas price information in both day-ahead and real-time under these constrained conditions, the ISO is addressing long term enhancements to the price used in its cost estimates in Section 7.3.

2. Plan for Stakeholder Engagement

Stakeholder process is targeting implementing improvements, if any, identified through the process by summer 2016. The current schedule for this initiative is shown below.

Milestone	Date
Issue Paper Posted	3/17/16
Stakeholder Call	3/23/2016
Stakeholder Written Comments Due	3/30/2016
Working Group Stakeholder Meeting	4/06/2016
Straw Proposal Posted	4/15/2016
Market Surveillance Meeting discussion item	4/19/2016
Stakeholder Written Comments Due	4/21/2016
Draft Final Proposal Posted	4/26/2016
Stakeholder Call	4/27/2016
Stakeholder Written Comments Due	4/28/2016
Draft Tariff Language Posted	4/29/2016
Stakeholder Call	5/03/2016
Revised Draft Final Proposal Posted	5/04/2016
Board of Governors Meeting	5/04/2016

3. Changes to the Proposal

Changes from the Draft Final Proposal are as follows:

- Section 6 has been revised to contain the ISO proposals to request tariff authority expanding the operational tools at the ISO operators' disposal to manage electric service in light of gas system conditions.
    - Section 6.1 has been revised to more generally propose gas constraint(s) the ISO operators would have the authority to enforce to better reflect gas system limitations either in day-ahead and/or real-time and provides details as to how the constraint(s) would be enforced. As a part of this revision, the ISO has revised its proposal to reinclude ability to manage changes in generators' gas usage relative to day-ahead energy schedules (and presumably relative to gas

nominations submitted in the day-ahead timeframe) through a minimum and/or maximum gas burn constraint in the ISO real-time market. The ISO continues to believe its proposal to pursue increased flexibility in its bidding rules discussed in Section 7.2 is the primary tool that best supports the ability of generators to reflect the gas company's balancing mechanisms in ISO market bids to support gas and electric reliability. After further evaluation of stakeholder feedback on removing the authority to enforce a gas constraint to manage this risk, the ISO is revising its Draft Final Proposal to propose the authority to enforce a gas constraint in anticipation of gas system conditions being compromised in real-time if needed.

  - Section 6.3, 6.4, and 6.5 have been included to make clearer to stakeholders the proposed clarifications or new authority the ISO is seeking to allow operators to have sufficient tools to manage the electric system through summer 2016.
- Section 7.2 has been updated to more clearly explain the proposals both to bidding rule pieces being accelerated from the *Commitment Cost Bidding Improvements* board approved policy as well as to the proposed scalars on the commodity price portion of the gas price index.
- Appendix C has been added to include details on the gas constraint and its pricing impact.
- Appendix D has been added to provide calculations demonstrating the proposed changes to the commitment cost and default energy bid calculations as result of applying a scalar to the commodity price portion of the gas price index.

4. Background

4.1. Aliso Canyon Impact

In October 2015, the Aliso Canyon natural gas storage facility in Southern California experienced a large gas leak significantly affecting gas markets and many of the people that live and work in the area. The facility is a key part of the gas system, serving gas customers in the LA Basin, including gas-fired power plants. On January 6, Governor Brown issued a Proclamation of a State of Emergency that included two directives related to possible impacts on the electric system:

- The Division of Oil, Gas and Geothermal Resources is to continue its prohibition on injecting gas into the storage facility until a comprehensive review of the storage and wells and air quality in the area is complete; and

- The CPUC and CEC are to coordinate with the ISO to "take all actions necessary to ensure the continued reliability of natural gas and electricity supplies… during the moratorium on injections…"

On April 5, 2016 the ISO, CPUC, CEC, SoCalGas Company, and the Los Angeles Department of Water and Power Balancing Authority released their Technical Assessment Report[2] and associated Action Plan[3] for addressing reliability risks associated with Aliso Canyon limited operability. At an oversight hearing held by the Assembly Utilities and Commerce Committee on January 21, 2016, the CPUC's representative emphasized the benefit of this work done with the ISO, CEC and others to plan for reliable electric operations in light of Aliso Canyon limited operability. This action plan identified summer 2016 and/or winter 2016-2017 gas or electric reliability risks.

There are four identified risks to the SoCalGas operating region for summer 2016:

1. Daily imbalances exceeding 150 million cubic feet (MMcf) affecting operating pressures that undermine pipeline integrity.

2. Planned and unplanned outages on gas system often limit pipeline and other storage availability

3. Rapid ramping of electric generation can exceed dynamic capability of gas system i.e. contingency recovery, renewable generation following.

4. Cold weather to east can reduce gas supplies for California

On February 18, 2016, state regulators confirmed the leaking gas facility had been sealed. SoCalGas may not inject new gas from the Aliso Canyon natural gas storage facility until completing inspections by the Division of Oil, Gas, and Geothermal Resources of California's Department of Conservation.[4] SoCalGas has limited ability to withdraw gas from the storage facility. Under these strained conditions, pipelines will impose daily balancing requirements based on the difference between nominated gas flows and actual gas demand commonly referred to in Southern California as operational flow order (OFO) and emergency flow orders (EFO). Due to limited operability of Aliso Canyon, Southern California will be under these strained conditions on a more frequent basis when nominated gas flow does not match actual gas demand. By summer 2016, if left to existing practices there is high risk of gas curtailments to gas-fired resources in Southern California due to constraints at the Aliso Canyon storage facility. Depending on the magnitude and timing of such gas curtailment to the electric generators, there is increased risk to electric service reliability.

To mitigate the risk of gas curtailments and impacts to electric reliability because of Aliso Canyon, SoCalGas and SDG&E filed the motion for Interim Order Establishing Temporary Daily Balancing Requirements at the CPUC.[5] The motion proposed to impose an interim daily gas

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[4] *See* California Department of Conservation, Division of Oil, Gas, and Geothermal Resources, Requirements of Comprehensive Safety Review of the Aliso Canyon Natural Gas Storage Facility http://www.conservation.ca.gov/index/Documents/Comprehensive%20Safety%20Review%20Aliso%20Canyon.pdf

[5] Application 15-06-020.

balancing penalty of 150% of daily gas indices for daily gas deviations where the difference between nominated gas flows and actual gas demand (burned gas) falls outside a 5% tolerance band, which if approved by CPUC will be effective May 1, 2016.

Since filing the joint motion for daily balancing, SoCalGas and SDG&E have noticed a settlement conference on April 28, 2016. SoCalGas and SDG&E''s customers will need to balance their nominated flows within a tolerance band of their actual gas burn or face potential penalties regardless of whether SoCalGas:

(1) implements its daily balancing proposal,

(2) uses its existing OFO authority, or,

(3) implements an alternative balancing mechanism.

As result of the settlement conference, SoCalGas and SDG&E filed with the CPUC on April 30, 2016 a Joint Motion for Adoption of Settlement Agreement on the daily balancing scope of the Gas Curtailment Procedures Application (A.15-06-020) on behalf of SoCalGas, SDG&E, and twenty-four other parties. The Settlement Agreement covers the issue of the need for tighter balancing requirements while the use of the Aliso Canyon storage field is limited. The Settlement could allow the temporary requirements to be in place as early as June 1.

During the Settlement term, which would end no later than November 30, 2016 (earlier if certain operational capacities are recovered at Aliso Canyon), SoCalGas and SDG&E will deal with supply shortages and surpluses using Operational Flow Order (OFO) tariff procedures rather than daily balancing procedures. A number of temporary changes will be made to the existing low and high OFO tariff provisions to facilitate this, including changing the existing 110% high OFO tolerance to a default of 105% that can be changed to 110% at SoCalGas and SDG&Es sole discretion and revising the current Low OFO formula so that the balancing trigger is based on operational constraints. Given this change, the ISO believes it is appropriate to evaluate the risks to gas reliability differently depending on the direction to which the pipeline pressure is moving outside of reliable bounds and adjust operations accordingly.

4.2. FERC Order 809

FERC released a final order on April 16, 2015 (Order 809, RM14-2) establishing new times for nomination practices used by the interstate pipelines to nominate natural gas transportation.[6] Table 1 below compares the current (black font) and revised or additional (red bolded font) nomination timelines in Central Clock Time (CCT). These changes will take effect on April 1, 2016.

Table 1: Current and FERC Order 809 gas nomination deadlines (PST)

[6] Federal Energy Regulatory Commission, Docket No. RM14-2-000; Order No. 809, April 16, 2015.

Nomination Cycle	Nomination Deadline (PST)	Notification of Nominate (PST)	Nomination Effective (PST)	Bumping of interruptible transportation
Timely	9:30 a.m. **11:00 a.m.**	2:30 p.m. **3:00 p.m.**	7:00 a.m. Next Day	N/A
Evening	4:00 p.m.	8:00 p.m. **7:00 p.m.**	7:00 a.m. Next Day	Yes **Yes**
Intra-day 1	8:00 a.m.	12:00 p.m. **11:00 a.m.**	3:00 p.m. Current Day **12:00 p.m. effective**	Yes **Yes**
Intra-day 2	3:00 p.m. **12:30 p.m.**	7:00 p.m. **3:30 p.m.**	7:00 p.m. Current Day **4:00 p.m. effective**	No **Yes**
Intra-day 3	**5:00 p.m.**	**8:00 p.m.**	**8:00 p.m. effective**	**No**

The ISO provided an update to stakeholders on the impacts of FERC No. 809 on June 19, 2015.[7] The ISO did not discover sufficient benefits to gas-fired generators to justify the costs of moving the day-ahead market run time window to earlier in the day. In a stakeholder process, the ISO considered three alternatives and found Alternative 2, to not move the day-ahead market window, to be the most effective design.[8] This was because at the time obtaining gas nominations on the pipelines serving California generators was not a problem. There was sufficient access to storage and stakeholders stated there was enough notice for procurement during evening nomination cycle for gas flows beginning 7AM PST on the electric operating day.

Besides the order, FERC issued a companion section 206 proceeding requiring ISOs and RTOs to propose changes to their electric market nominating timelines, or to demonstrate why changes are unnecessary after adoption of the final rule in RM14-2. The filing was due 90 days after April 16, 2015. The ISO filed its response to FERC's 206 proceeding in EL14-22 asking the Commission to find the ISO did not need to move the timing of its current day-ahead close and

[7] See Proposal – FERC Order No. 809 available at: http://www.caiso.com/Documents/Proposal_FERCOrderNo809.pdf.
[8] See Straw Proposal at 15 available at: http://www.caiso.com/Documents/StrawProposal_BiddingRulesEnhancements.pdf

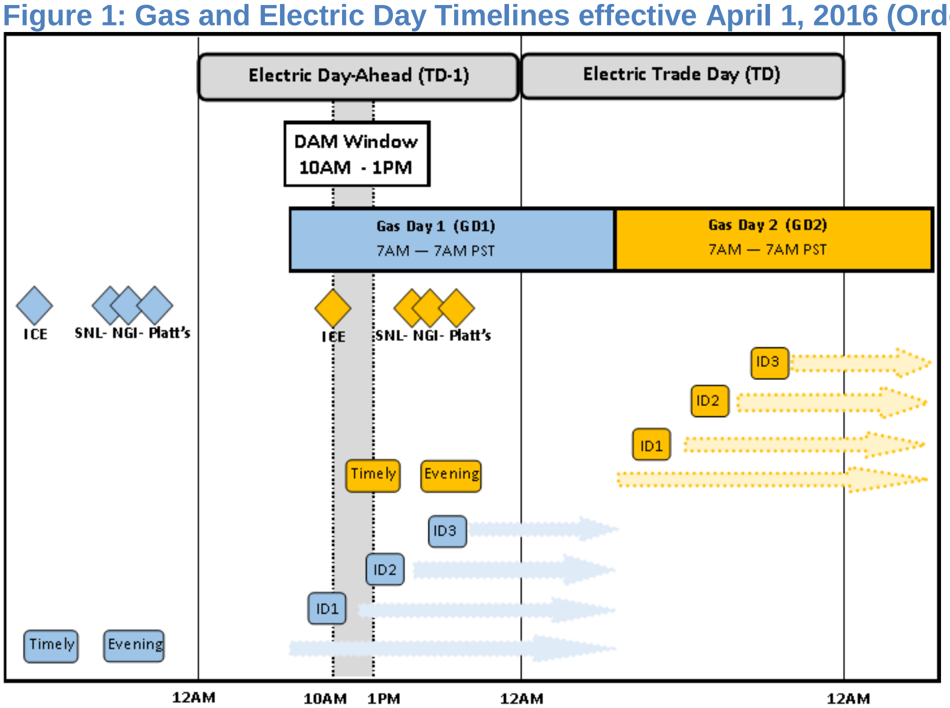
publication of market results forward.[9] FERC accepted the ISO's proposal to not change the day-ahead market window.

In light of reduced access to storage due to limited operations of Aliso Canyon, the ISO evaluated whether its decision made in coordination with its stakeholders to not move the day-ahead market timeline remained the best solution. The ISO understands from discussion with stakeholders and review of comments that the reliability risk is driven by uncertainty of incremental changes to day-ahead schedules in real-time. This risk would not be addressed by moving the day-ahead market timeline. The price risk associated with having to submit day-ahead bids prior to procurement when procurement would occur during less liquid trading would be alleviated by moving the day-ahead market window.

4.3. Alignment of natural gas and electric markets

The ISO acknowledges that the hours of the gas day and the electric day are not aligned. This imposes challenges for gas procurement and nominations to meet ISO commitments or dispatches since the day-ahead market publication time of 1PM PST can result in resources procuring gas to meet schedules at more illiquid trading periods to the extent they did not anticipate day-ahead market schedules and procure gas in the more liquid trading period prior to the day-ahead market. Figure 1 illustrates the interaction of gas day and electric day timelines where the electric days, Gas Day 1 (GD1) and Gas Day 2 (GD2) flows are represented by the colors gray, blue and orange respectively. The discussion in this section uses GD1 and GD2 as defined in Figure 1.

Figure 1: Gas and Electric Day Timelines effective April 1, 2016 (Order 809)



[9] See EL14-22 Filing, July 23, 2015 at 15 available at: http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13939292

The ISO market uses a daily gas price index (GPI) to calculate proxy commitment costs, to generate energy bids, and to create variable cost option default energy bids. The day-ahead market uses a GPI based on the gas price for GD1 traded on the day prior to the day on which the day-ahead market is run. GD1 comprises delivery beginning 7 AM in the day-ahead through 7 AM on the operating day. The gas price used is an average of natural gas day-ahead indices for gas flowing on GD1[10], shown in Figure 1 by blue diamonds.

There is an exception to this. If a natural gas price spike occurs spike in which prevailing gas prices increase to at least 125 percent of the GD1 index. Here, the ISO uses a manual process to update the market with the ICE GD2 index that ICE publishes at 10 AM on the day the day-ahead market is run.

The impact of using the GD1 price is that the gas price for purchases on the day the day-ahead market is run may not be fully reflected in the ISO's variable cost option default energy bid or its commitment cost calculations resulting in commitment cost bid caps that may not be fully reflective of expected market conditions. The gas price indices that reflect expected market conditions for the majority of ISO's operating day are shown as orange diamonds in Figure 1. The corresponding gas day is also shown in orange.

The ISO averages natural gas day-ahead prices published in ICE, SNL Energy/BTU daily, NGI, or Platt's Gas Daily indices to determine its GPI. Table 2 shows the earliest and latest available times for each publication. These publications and their earliest time available are the gas price indices shown as diamonds in Figure 1.

Table 2: Natural gas day-ahead indices publication times[11]

Source	Earliest Time Available (PST)	Latest Time Available (PST)
ICE	10:00 AM	12:00 PM
SNL Energy/BTU Daily	16:00 PM	19:00 PM
NGI	19:00 PM	2:00 AM (flow date)
Platt's	17:00 PM	19:00 PM

The ISO's cost estimates use a next day gas price index, which is the volume weighted average of gas transactions during the timely procurement with a deadline for eligibility around 9:30AM PST (timely deadline)[12]. ISO's commitment cost estimates used in both day-ahead and real-time markets are based on next day gas price index for GD1. Default energy bids are currently determined for day-ahead using GD1 index and for real-time using GD2 index.

[10] ISO tariff section 30.4 and 39.7.1.1.1.3.
[11] Market Instruments BPM at 191.
[12] Cut off for eligibility varies by publisher but all are set to end with timely deadline.

Under *Bidding Rules Enhancements - Generator Commitment Cost Improvements,* the ISO proposed at its March board meeting to allow resources without day-ahead schedules to submit commitment costs in the real-time market based on next day gas price index for GD2. As discussed in section 7.2, the ISO will propose to allow all resources, including those with a day-ahead schedule or a binding start up instruction, to resubmit commitment costs to the real-time market. The ISO will continue to evaluate these bidding rule changes and may revise them in the future through other stakeholder processes.

Any change in traded gas prices between the day-ahead timely cycle and procurement for evening, intraday 1, intraday 2, or intraday 3 nomination cycles may not be fully reflected in ISO's cost estimates since all published indices are based on timely trading. If there is strained market conditions such as risk of penalties from deviations from a daily balancing requirement, the traded gas prices during these procurement and nomination periods are expected to increase relative to timely trading. If this occurs, the ISO has limited ability to model resources' costs in the market efficiently. This could lead to inefficient real-time commitments and dispatches and insufficient cost recovery.

Because the market cannot always consider the actual fuel costs generators would face, the ISO market's solution (including prices) in these circumstances would not reflect the marginal cost of serving load. Generators would face the dilemma of either facing the daily imbalance charges or uninstructed imbalance energy costs if they do not deliver their energy commitment. This could lead to the need for out-of-market actions by the ISO to re-dispatch the system manually to account for their lack of performance to avoid causing a system reliability issue on the electric grid.

5. Identified Issues

Besides the issues evaluated under this stakeholder initiative, other measures such as use of flex alerts and demand response measures are also being considered by ISO operations to support reliability.

5.1. Timing of Day-ahead results relative to GD1 or GD2 liquid trading

As shown in Figure 1, the day-ahead market publication is released after all but one nomination cycle deadline for GD1 and after the timely cycle deadline for GD2, which increases the risk of a mismatch of nominated gas flow and actual gas demand triggering deviations from daily balancing requirement. If resources wait for ISO day-ahead schedules for the early hours of its operating day, hours ending 1 through 7 associated with last hours of GD1 nominations, if not purchased before the day-ahead market publication would be procured and nominated during the last and most illiquid procurement and nomination cycle, intraday 3. The day-ahead market also does not inform timely gas procurement or pipeline nominations for its operating day hours ending 8 through 24 since the first cycle of gas nomination for GD2 concludes at 11AM PST TD-1.[13]

The ISO explored how the daily balancing requirements impact resources ability to manage their gas procurement for GD1 and GD2 hours to manage the difference between gas nominations and burns within the tolerance band and to respond to ISO instructions. Specifically, how market mechanisms or other tools could be improved to better align nominations with real-time gas burn to help mitigate reliability concerns for summer 2016.

The ISO learned through conversations with SoCalGas and its stakeholders that generators do not have a requirement to adjust their nominations to reflect day-ahead schedules for the first 6 hours of the electric operating day by the 5th and final gas nomination cycle (ID3) due to the manner that balancing is evaluated. Generators are evaluated for balancing within their tolerance band by comparing the metered gas burn across the calendar day (Midnight to Midnight) to the final nominated amounts including all adjustments beginning at 7AM PST through 7AM PST the next day. This misalignment provides some benefit to generators so that there is more time to adjust their nominations to focus on the primary reason electric generators may have difficulty balancing - the real-time re-dispatch significantly differs from their day-ahead schedule.

The ISO understands from discussion with stakeholders and review of comments that the reliability risk is driven by uncertainty of incremental changes to day-ahead schedules in real-time. This risk would not be addressed by moving the day-ahead market timeline. The price risk associated with having to submit day-ahead bids prior to procurement when procurement would occur during less liquid trading would be alleviated by moving the day-ahead market window. However, the ISO proposes in Section 7.1 to increase generators access to information prior to day-ahead in efforts to improve their ability to prudently procure gas.

5.2. Real-time commitments and dispatch might need to be constrained to reflect gas balancing limitations

While the day-ahead schedule is financially binding, it is not a binding start-up instruction for medium, short, or fast start units under current ISO operations. Since the ISO's real-time processes re-optimize unit commitments to find the least cost, security constrained solution,[14] these types of resources have a risk they may receive a day-ahead market schedule but then not receive a binding start-up instruction to start up by the real-time market. The ISO is concerned with the impacts on medium, short and fast start units of these daily gas balancing requirements.

Further, once a binding start-up instruction has been received by a resource, there is still a risk the ISO real-time processes could cause dispatch instructions that would cause a difference between nominated gas flows and actual gas burn. The ISO is concerned with the impacts to

[13] Discussion assumes FERC Order 809 is effective so timing will be reflective of April 1, 2016.
[14] Real-time processes that can result in changes to unit commitments are the short-term unit commitment (STUC) process, hour ahead scheduling process (HASP), and fifteen minute market (FMM).

all committed resources of its issuing real-time dispatch instructions different than day-ahead schedules or earlier real-time market non-binding solutions.

Given this uncertainty in the volume of gas needed to meet ISO commitment and dispatch instructions, the ISO explored with its stakeholders how, if at all, the ISO could change its operations or provide resources with tools to support their gas management in a manner that supports gas system reliability and enables them to respond to ISO instructions. Resources will likely incur higher gas costs when procuring additional gas to reduce the deviation created due to the ISO's instruction, which costs would not be reflected in ISO's cost estimates. Thus, might not be able to be reflected through their commitment cost bid cap or any mitigated incremental energy offers.

Stakeholders have communicated to the ISO that sometimes gas cannot be procured because they might not be able to find a seller. Under this scenario, the ISO instruction could cause resources to incur gas balancing charges for operating outside the gas tolerance band to follow the instruction.

The ISO explored how the daily balancing requirements impact resources ability to manage their gas procurement during real-time to manage the difference between gas nominations and burns within the tolerance band and to respond to ISO instructions. Specifically, whether changes to market mechanisms or available tools are necessary to address the concerns. The ISO evaluated what market improvements could better enable either the ISO or resources to manage the risks of deviations so they are managed within the tolerance band supporting gas system reliability while allowing ISO to efficiently dispatch its market to support electric reliability.

ISO understands from discussion with stakeholders and review of comments that this risk is most severe for Scheduling Coordinators managing generators largely dispatched and relied on as peaker units to respond to ISO's flexibility needs or mitigated resources that cannot manage gas limitations effectively through incremental energy offers.

Section 6 and 7 discuss both the operational tools and market mechanisms the ISO is proposing to mitigate reliability risks that could arise if real-time commitments and dispatch do not reflect gas system limitations such as a limited imbalance tolerance.

5.3. Commitment cost bid cap and mitigated energy bids may not reflect real-time market gas prices and gas availability

Under strained gas conditions, intra-day gas availability is likely to decrease and procurement costs will likely increase due to the costs associated with managing gas supply within a daily balancing tolerance band. The ISO's cost estimates do not currently include price information from on availability and prices from intra-day gas markets. Consequently, both the commitment proxy cost bid cap and mitigated energy bids might be restricted from reflecting changes to availability and prices. There is a risk fuel costs might exceed the commitment cost bid cap driving commitment costs to exceed the current day's bid cap that provides 25% headroom on

ISO's commitment cost estimates. There is a higher risk due to the 10% margin of error used in calculating the default energy bid that resources mitigated to their variable cost option default energy bids would be mitigated to costs below its short-run marginal costs, reflective of deviation charges.

When intra-day gas prices are high enough relative to the next day gas index to not be able to be reflected in the default energy bid or commitment cost bid cap, the change in marginal costs that are not modelled and the ISO's markets could experience less efficient commitments, dispatches, and insufficient cost recovery beginning summer 2016. These modelling concerns affect resources' commitment costs and any mitigated incremental energy offers[15]. The primary concern is that generators affected by the Aliso Canyon situation will not be able to reflect limited gas availability in real-time market bids and consequently could be dispatched for system needs and not local needs.

The ISO explored with its stakeholders if market mechanisms or other tools are necessary to address this issue and whether incentives are improved through intra-market or after-the-fact solutions. Specifically two questions were discussed:

(1) Is there a need for adjustments to ISO's ability to model resources marginal costs and compensate resources for the additional short-run marginal costs associated with generator's managing their balancing requirements?

(2) Is there a need for other tools to ensure proper incentives are maintained in ISO's market such as an after-the-fact cost recovery of verifiable costs?

The ISO understands from discussions with stakeholders and review of comments there is broad agreement there exists a market design gap in which the ISO's commitment cost bid cap and mitigated energy offers may not allow generators to fully reflect costs. The concern surrounding this gap is exacerbated due to Aliso Canyon as this gap affects all generators across the footprint including Energy Imbalance Market participating generators. To ensure the ISO's dispatch in real-time is efficient and reliable, these cost estimates will be evaluated consistent with the change to the gas market structure. The ISO believes it is especially important for Southern California resources to be able to reflect real-time gas limitations in bids this summer so they are only dispatched for local needs and not system needs. Section 7.2 discusses the ISO proposal to improve the ability for generators to reflect the expectation of marginal procurement costs in real-time only for affected generators.

[15] Modelling concerns affect commitment costs and any mitigated incremental energy offers which are mitigated to the default energy bid. Most resources are under either the proxy cost option for commitment costs or the variable cost option for default energy bids which do not include real-time gas price information or risk of incurred deviation charges.

6. Proposals for operational tools

6.1. Introduce gas constraints

6.1.1. Problem statement

The ISO supports exploring measures that can ensure gas system limitations are reflected in its markets both day-ahead and/or real-time in time for summer 2016 to help mitigate the anticipated concerns associated with the limited operability of Aliso Canyon storage facilities. Based on the inter-agency technical assessment report to which the ISO contributed, and the ISO's discussion with stakeholders under this effort, the ISO understands the two primary factors that can adversely impact the gas system reliability, and consequently electric system reliability, are:

1. Capacity reduction limitations from storage outages, pipeline outages, or curtailments: Whether planned or unplanned, outages or curtailments will restrict the availability of gas to affected generators. A plant level limitation reflecting an agreed upon maximum allowable gas burn could be reflected in ISO markets so the ISO can more efficiently dispatch the generators under the limitation.

2. System imbalance limitation where large imbalances between gas nominations and actual gas burn could compromise gas reliability: Electric operations can affect gas reliability if electric market outcomes result in instructing affected generators to increase or decrease their gas imbalances to respond to ISO instructions. For example, a significant change in the dispatch of generators in the SoCalGas and SDG&E gas system between the real-time dispatch and day-ahead market schedules could exacerbate the decline (for low operating pressure condition) or the increase (for high operating pressure condition) of operating pressure if generators are not able to adjust either their nominations or their gas burn to a level more supportive of gas system conditions. The technical assessment concluded that daily gas imbalances greater than 150 MMcf[16] in either direction significantly increase risk of gas curtailments that could result in electric service interruptions.

Discussion on (1) capacity reduction limitations

Current ISO policy in the event of a reduction in gas system capacity or deliverability capability is to allow generators to manage their output so that it reflects the reduction from gas outages and/or curtailments.

For outages, the ISO's policy is that once these outages are made public by the gas company, the generators are responsible for submitting its plant level limitation through the outage management system using the appropriate nature of work. The ISO's current policy places the responsibility on the generator to ensure it submits an outage card to the ISO's outage management system reflecting a limitation it might expect unless timing precludes the outage

[16] The ISO will continue to explore with SoCalGas its understanding of the exact constraint and in the meantime uses 150 MMcf for the purpose of describing the proposed priced constraint.

card from being reflected in the market. While an outage may be public, it may be unclear to generators exactly what their plant level limitation will be until the curtailment or their inability to procure gas occurs. While it would improve electric market outcomes if generators submitted outage cards reflecting their share of the gas limitation as result of outage, generators might not be able to translate the outage information to a plant level limitation. Further once a notification is issued for curtailments, the ISO is evaluating whether operations could be improved through using the gas constraint to reflect curtailments instead of issuing exceptional dispatches when timing does not allow outage cards to be reflected in the current market run.

For curtailments, operating procedure 4120 (OP 4120) details the communication and actions taken to ensure curtailments are reflected to support gas and electric reliability. ISO policy for addressing curtailments outlined in OP 4120 is that if time allows, the gas company is responsible for communicating plant level limitations and the generator is responsible for submitting these plant level limitations to the ISO outage management system with a nature of work 'ambient not due to temperature'. If an outage card is submitted later than 37.5 minutes prior to the real-time market interval, the real-time market run for that interval will not reflect the limitation. In this instance, the ISO will issue exceptional dispatches so the plant level limitations consistent with what gas curtailment notifications would have been received by the generator are reflected in the market.

If determined the ISO has more latitude to allocate curtailment amount across its electric generator's based on more refined criteria rather than a pro rata curtailment, the ISO would enforce a gas constraint to reflect the capacity reduction limitation in its markets where the constraint would limit the maximum allowable gas burn for the affected area in each market run based on an hourly limit provided to it by SoCalGas. For example, SoCalGas might notify the ISO of curtailment notification such that they would specify the gas operating zone(s) affected, the hours the curtailment will be in place (e.g. HE15 – HE18), and the maximum allowable burn for the hours which could vary across hours (e.g. 1 BCF for HE15, 1 BCF for HE16, 1 .5 BCF for HE17, and 1.5 BCF for HE18).

<u>Discussion on (2) system imbalance limitations</u>

According to the technical assessment report, the constraint on the gas system is not a flexible constraint once certain conditions are present and in those instances the range should not exceed the identified range that can be supported by the gas company. The conservative range noted in the report was 150 MMcf which is the amount the gas system can support on days with high demand usage relative to its overall system capacity. Gas operations with its day-ahead demand forecast can inform the extent to which this range can widen to support more imbalances.

As mentioned in the ISO's Draft Final Proposal, if the gas reliability concern likely to impact electric service is anticipated to be a daily concern the ISO would default to enforcing a limit on gas burn in real-time until operability of Aliso Canyon is improved or other gas market structural changes are made to increase the ability of the gas system to support larger imbalances over a day. On the other hand, if the risk to reliability imposed by large imbalances is only present on days when certain fundamental factors are present the enforcement of this constraint would be triggered based on the fundamental factor(s). As seen in SoCalGas's settlement process with the most recent filing on April 30th, the conversation has evolved to note that factors can provide more information as to the severity of the imbalance limitation as well as to when it is of paramount concern. The ISO commits to coordinate with the gas company through the summer and would apply limitations to its market based on anticipated needs.

To increase the affected generators ability to respond to electric service needs in the real-time when most needed by the system, the ISO would need to allocate any daily range across hours based on the expected load shape.

6.1.2. Constraint details

The ISO proposes to implement a constraint in its day-ahead or real-time market, or both, that would limit the affected area gas burn to a gas burn limitation reflecting gas system limitations for either capacity reduction limitations or system imbalance limitations. If ISO operations determined additional generation from the affected generators is needed beyond the limits of the constraint enforced, the additional generation could only be dispatched through exceptional dispatches once coordinated with the gas system operator.

Defining affected generators under gas constraint(s)

This gas constraint will be implemented using generation nomograms where the generation nomogram is defined by the set of generators each with a unity shift factor (dfax=1) to the transmission paths within the area so the nomogram limits the area's generators to either a minimum or maximum gas burn level. In Appendix C: Nomogram Constraint, the nomogram functionality is described in detail where the nomogram variable type used for this constraint is V_3.

The affected area, or the set of generators included under the gas constraint(s), will be the gas fired generation within the SoCalGas and SDG&E gas operating zone(s) identified by SoCalGas or SDG&E as under the maximum gas burn limitation. If the entire system is affected, the constraint would encompass the entire SoCalGas and SDG&E system.

Depending on which gas operating zones are under restricted system limitations, the affected area could be one gas operating zones, a selection of gas operating zones, or the entire gas system. The ISO will define a generation nomogram for each of the 6 gas operating zones under its tariff. A 7th generation nomogram will be defined to include all generators within the ISO's portion of the SoCalGas and SDG&E system. If gas system limitation is anticipated or identified that would impact more than one gas operating zone but not inclusive of the system-wide generation nomogram, the ISO will allocate the multi-zone limitation to the individual gas operating zones.

General constraint formulation

This gas constraint appears in Equation 1 as a two sided constraint but in practice the ISO would likely choose one side of the constraint to enforce depending on gas system limitations. The ISO believes there is a higher need to enforce the upper bound (i.e. right hand side) limit as it anticipates gas and electric needs will mostly call for ISO imposing limitations on the maximum gas burn level which the electric market is limited in reflecting higher costs to manage maximum burn levels. Situations calling for the need to enforce the lower bound (i.e. left hand side) limit to minimum gas burn levels could arise but would be more infrequent as generators can submit bid prices at low enough levels to manage their burn at higher output levels to support gas system reliability.

Equation 1: Gas Constraint(s)

$$LHS_t \leq \sum_{i \in S} \alpha_i \left(G_{i,t}\right) \leq RHS_t$$

S	Set of generators in affected area (1 or more gas operating zones)
G	Power output (MW)
$\propto_i$	Energy (MW) to million cubic feet (MMcf) gas conversion factor (Masterfile heat rate value at given MW output * unit conversion factor)
LHS_t	Left hand side limit enforcing lower bound constraint, limit formulation described in **Error! Reference source not found.**
RHS_t	Right hand side limit enforcing upper bound constraint, limit formulation described in **Error! Reference source not found.** and **Error! Reference source not found.** depending on the type of system limitation

The criteria for enforcing the limits would differ depending on whether (1) it's a total gas burn limitation (absolute) versus incremental gas burn limitation (relative), (2) daily or hourly limitation, and (3) limit provided by the gas company or default value. The details for the left hand side and right hand side limits for the first condition, total or incremental, are discussed below and reflected in Equation 2 and Equation 3 respectively.

<u>Total gas burn limitation due to reduction in capacity or deliverability</u>

Error! Reference source not found. in Appendix C defines the constraint limits for **Error! Reference source not found.**a maximum allowable total gas burn due to reductions in system capacity. The upper bound limit defines the maximum allowable total gas burn generally communicated to the ISO from the gas company When this maximum limit is enforced and ISO operations determines additional generation from the affected generators is needed above this limit for electric reliability, the additional generation would only be dispatched through exceptional dispatches once coordinated with the gas system operator.

The upper bound constraint used to reflect gas system limitations due to outages or curtailments could either reflect a gas system limitation daily or hourly depending on the type of capacity reduction. A system capacity reduction from outages could tend to last for several days and appear as a daily limitation where a system capacity reduction from curtailments or emergency flow orders issued to respond to deteriorating system conditions generally occur for specific hours at hourly amounts.

The ISO would distribute the daily limitation across the hours based on a ratio of hourly load forecast to daily load forecast to support greater electric flexibility, if provided an hourly burn limit the value would be input individually for each hour. To further enhance the flexibility of this constraint, the ISO proposes to have the flexibility to recapture portions of the allocated range unused for earlier intervals if necessary. For example, if balancing range allocated to the first 4 hours of the day was unused, the gas burn associated with that allocation would be recaptured and used to increase the allowable range for later periods consistent with expected load shape.

Equation 2: Gas Capacity Reduction Limitation

$$Where\ limit\ is\ set\ as\ follows:$$

$$RHS_t = \gamma_t\, R_h$$

$$\sum_{1}^{N} \gamma_t = 1$$

R_h	Gas system limitation which could be a MMcf/day limitation on pipeline capacity as result of planned outages provided by the gas company (if not provided ISO will default to gas system design capacity) or an hourly value in MMcf provided by gas company generally in instance of curtailments
γ_t	Allowance distribution coefficients associated with upper bound limit that distributes a MMcf/day amount over the intervals of a trading day based on ratio of hourly load forecast to daily load forecast, if provided an hourly burn limit and not a daily limitation this value will be 1

The ISO proposes to request authority to enforce the gas constraint[17] in its markets when SoCalGas notifies the ISO of a concern with its fuel supply or access to fuel based on its system conditions. This constraint would not be enforced daily but instead enforced in the market when the gas company notifies the ISO of the limitation and its details: (1) affected area, (2) affected hours, and (3) maximum allowable gas burn for each hour. For example, if the gas company notifies the ISO it will have an outage on its pipelines reducing the availability of fuel in a defined zone to an expected maximum amount prior to the day-ahead market close, the constraint would be enforced in both day-ahead and real-time. If an unplanned outage occurs after day-

[17] Constraint names are illustrative for the purpose of this draft final proposal but might alter to better reflect formula in next iteration.

ahead or curtailment is issued during real-time, the constraint could be enforced in real-time market run.

Incremental gas burn limitation

Error! Reference source not found. in Appendix C defines the constraint limits for **Error! Reference source not found.**a maximum allowable incremental gas burn due to concerns about deteriorating pipeline pressure on the gas system. The upper bound limit defines the maximum allowable incremental gas burn the gas system can support and maintain reliable operations, generally communicated to the ISO from the gas company. When this maximum incremental limit is enforced and ISO operations determines additional generation from the affected generators is needed above this limit for electric reliability, the additional generation would only be dispatched through exceptional dispatches once coordinated with the gas system operator.

The lower or upper bound constraint used to reflect gas system limitations due to anticipated gas and electric system conditions that would lead to deterioration of pipeline operating pressures would define the limit on either side based on a daily MMcf amount. A significant change in the ISO's dispatch from day-ahead to real-time if generators are not successful in adjusting nominations to compensate for change can lead to compromising the gas operating pressures. This constraint, since it is relative to the day-ahead schedule, would be enforced in real-time as a daily limitation representing the incremental amount (MMcf/day) the real-time dispatch can deviate from the day-ahead schedule.

The ISO would distribute the daily limitation across the hours based on a ratio of hourly load forecast to daily load forecast to support greater electric flexibility, if a value is not provided by SoCalGas a default value of 5% relative to the area's day-ahead schedule burn. To further enhance the flexibility of this constraint, the ISO proposes to have the flexibility to recapture portions of the allocated range unused for earlier intervals if necessary. For example, if balancing range allocated to the first 4 hours of the day was unused, the gas burn associated with that allocation would be recaptured and used to increase the allowable range for later periods consistent with expected load shape.

Equation 3: Gas System Imbalance Limitation

$$Where\ limits\ are\ set\ as\ follows:$$

$$LHS_t = \beta_t \left[R_l + \sum_{i \in S} \alpha_i \left(\overline{G}_{i,t} \right) \right]$$

$$RHS_t = \gamma_t \left[R_h + \sum_{i \in S} \alpha_i \left(\overline{G}_{i,t} \right) \right]$$

$$\sum_{1}^{N} \beta_t = \sum_{1}^{N} \gamma_t = 1$$

S	Set of generators in affected area
$\bar{G}$	Day-ahead market schedule
$\propto_i$	Energy (MW) to million cubic feet (MMcf) gas conversion factor (Masterfile heat rate value at given MW output * unit conversion factor)
R_l	Daily lower bound deviation allowance relative to day-ahead market schedule
R_h	Daily upper bound deviation allowance relative to day-ahead market schedule
β_t	Allowance distribution coefficients associated with upper bound limit that distributes a MMcf/day amount over the intervals of a trading day based on ratio of hourly load forecast to daily load forecast
γ_t	Allowance distribution coefficients associated with upper bound limit that distributes a MMcf/day amount over the intervals of a trading day based on ratio of hourly load forecast to daily load forecast

The ISO would enforce this constraint for:

- Real-time hours once the gas company has issued or anticipates issuing an operational flow order. The ISO would enforce the side of the constraint of the OFO. For a low operational flow order, the right hand side limit would be enforced so that the maximum gas burn would be maintained at a supportable level. For a high operational flow order, the left hand side limit would be enforced so that the minimum gas burn would be maintained at supportable level (e.g. day-ahead schedule burn +/- 5%). The ratio the gas system can support would be dynamic if provided by the gas company, if not would default to 5%.

- For days where the ISO anticipates its load forecast may have a large error resulting in significant re-dispatches in the real-time market. The magnitude of such re-dispatch especially if day-ahead gas demand forecast is high implying a smaller imbalance tolerance, the ISO needs the authority to limit the re-dispatch in real-time as a preventive measure. By limiting the re-dispatch the ISO would not be issuing real-time dispatch instructions that could compromise the gas system reliability. Used in such a manner, the electric operator would be enforcing the constraint to avoid gas system conditions that could result in curtailments. The ratio the gas system can support would be dynamic if provided by the gas company, if not would default to 5%.

6.1.3. Pricing impacts

The nomogram segment would have a shadow price associated with it reflective of a penalty price associated with relaxing the constraint. If the market cannot come to a feasible solution without violating the constraint, then the LMP for generators subject to the constraint will reflect the constraint penalty price. The ISO will establish this penalty price to function appropriately relative to the other penalty prices used by the market.

The constraint parameter establishing the penalty price for the gas constraint is a "penalty factor," which is associated with constraints on the optimization and which govern the conditions under which constraints may be relaxed and the setting of market prices when any constraints are relaxed. Importantly, the magnitude of the penalty factor values for each constraint for each market reflects the hierarchical priority order in which the associated constraint may be relaxed in that market by the market software relative to other constraints. A negative penalty price is used to reflect the need to reduce supply, a positive price is used to reflect the need for demand reduction, and for some constraints either a negative and positive price could be used.

The ISO believes the gas constraint should ideally have a lower priority than the electric transmission constraints. Table 3 below shows the ideal relative priority of the gas constraint to the other constraints market parameters described in the Market Operations BPM[18]. If changing the relative priority of generation group nomogram for gas purposes versus electric purposes is not implementable by June 1, the ISO will relax the gas constraint consistent with electric generation group nomograms seen in lines describing "Transmission constraints: Intertie scheduling, branch, corridor, **nomogram** (base case and contingency analysis)."

Table 3: Relative priority of relaxation of gas constraint

Market	Penalty Price Description	Scheduling Run Value	Pricing Run Value	Comment
IFM	Transmission constraints: Intertie scheduling, branch, corridor, nomogram (base case and contingency analysis)	5000	1000	Intertie scheduling constraints limit the total amount of energy and ancillary service capacity that can be scheduled at each scheduling point. In the scheduling run, the market optimization enforces transmission constraints up to a point where the cost of enforcement (the "shadow price" of the constraint) reaches the parameter value, at which point the constraint is relaxed. Ideally electric transmission constraints would have

[18] Market Operations BPM on Pages 179 – 186, available at: https://bpmcm.caiso.com/BPM%20Document%20Library/Market%20Operations/Market%20Operations%20BPM%20Version%20%2045_clean.doc.

				higher priority than the gas burn transmission constraint.
	Transmission constraints: gas burn nomogram			
	Ancillary Service Region Regulation-up and Regulation-down Minimum Requirements	2500	250	In the event of bid insufficiency, AS minimum requirements will be met in preference to serving generic Self-Scheduled demand, but not at the cost of overloading transmission into AS regions.
RUC	Transmission constraints: branch, corridor, nomogram (base case and contingency analysis)	1250	250	These constraints affect the final dispatch in the Real-Time Market, when conditions may differ from Day-Ahead.
	Transmission constraints: gas burn nomogram			
	Limit on quick-start capacity scheduled in RUC	250	0	Limits the amount of quick-start capacity (resources that can be started up and on-line within 5 hours) that can be scheduled in RUC. For MRTU launch the limit will be set to 75%.
RTM	Transmission constraints: branch, corridor, nomogram (base case and contingency analysis)	1500	1000	Scheduling run penalty price will enforce internal transmission constraints up to a re-dispatch cost of $ of congestion relief in $1500 per MWh. Energy bid cap as pricing run parameter consistent with the value for energy balance relaxation under a global energy supply shortage.
	Transmission constraints: gas burn nomogram			
	Ancillary Service Region Maximum Limit on Upward Services	1500	250	Scheduling run penalty price is lower than those for minimum requirements to avoid otherwise system-wide shortage by allowing sub-regional relaxation of the maximum requirement. AS market bid cap as pricing run to reflect the otherwise system-wide shortage.

Due to the ISO's market design and the functionality of a generation group nomogram, described in Appendix C, the constraint will affect the resource specific price at the connectivity node (CNode) used to dispatch affected generators. The affected generators will settle off of the resource specific price at the CNode where the penalty price reflected in the CNode LMP when relaxed will ensure the generation under the nomogram will not be dispatched higher or lower than the constraints' limits. When relaxed:

- For a maximum gas burn limit, the CNode LMP will be lowered to ensure the necessary supply reduction occurs.
- For a minimum gas burn limit, the CNode LMP will be increased to ensure the necessary supply increase occurs.

During Summer 2016 until any approved tariff provisions expire at the end of November 2016, all generators in the SoCalGas and SDG&E area will not be able to be settled off of their Point of Delivery (POD) LMP, the POD is the same FNM node as the POR Pnode. All other market participants will be settled off of the pricing node locational marginal prices. The nomogram segment shadow price is not included in the pricing node locational marginal prices used for settling:

- Injections received into the CAISO Controlled Grid for Supply **[Affected generators will not be eligible to receive this price through end of November 2016]**,
- Withdrawals delivered out of the CAISO Controlled Grid for Demand,
- Virtual bids or congestion revenue rights for those injection and withdrawal locations, and (CRR).

In short, the nomogram constrains only the specific resources it applies to; it does not apply to any other injection at the same location, thus its shadow price is not reflected in the PNode LMP, but only in the CNode. As discussed in Appendix C, this is because for nomogram variables with aggregate generating resource output (i.e. V_3) the shift factor is set to 0 and will not be included in the locational marginal price at the PNode. This is similar to the difference between the SP-TIE price for an intertie schedule and the SP LMP for load at that location. The SP-TIE LMP includes contributions from constraints that apply only to the intertie schedule, but not the load.

6.2. Reserve internal transfer capability

The ISO anticipates needing the flexibility to reserve internal transfer capability (e.g. on Path 26) ensuring there is sufficient transfer capability in real-time to support reliable grid operations including meeting incremental energy needs in Southern California or assuring deliverability of contingency reserves.[19] The ISO would reduce transfer capability in the day-ahead and potentially also in the real-time market.

There are trade-offs to reserving this transmission capacity in the day-ahead market. Although it will allow the system to respond to greater real-time changes in Southern California's load, it might result in scheduling more Southern California generation, increasing gas usage. The ISO will establish the amount of transfer capability reserved each day based on the anticipated gas or electric conditions. Also, the ISO will determine based on system conditions whether it is

[19] Note: Path 26 is used an example but the proposed authority would apply to any internal transmission path.

optimal to only manually release the transfer capability in real-time if the transfer capability is needed to deliver energy to Southern California or to routinely release it.

The ISO also considered reserving transfer capability on interties with other balancing areas into Southern California. However, because there are relatively limited amounts of real-time import bids on the interties, the ISO believes the costs of withholding the transfer capability would exceed the benefit of reserving the capacity for use in real-time.

With decreased flexibility of affected generation to respond to electric contingencies and a risk that the day-ahead market schedules Path 26 to its transfer capability limit, the ISO is concerned that without the ability to reserve some of Path 26's, or other internal path's, transfer capability its ability to reliably deliver energy into Southern California would be compromised. One scenario of concern is whether ISO's ability to procure deployable operating reserves could be undermined. For example, given the constrained nature of the Southern California area, it is foreseeable that if a contingency event occurred in the region this reserved transfer capability would enable operating reserves in other areas to deliver energy to Southern California.

The CAISO will consider limiting a corresponding amount of additional congestion revenue rights it releases in the monthly allocation process. In conjunction with using this tool, the ISO would potentially limit the amount of congestion revenue rights it releases in the monthly allocation and auction to be consistent with the reduced transfer capability.

6.3. Reduce ancillary service procurement

The ISO proposes to seek authority to reduce the amount of ancillary services procured from resources in southern California to ensure the ISO markets procure ancillary services that have access to sufficient fuel to respond to a contingency event if needed. The ISO operators would adjust the amount of reserves the markets procure from resources in southern California based on anticipated gas and electric system conditions. ISO operators might implement this tool in conjunction with reserving internal transfer capability (Section 6.2) to ensure reserves shifted to northern California can be delivered to southern California.

6.4. Deem internal paths uncompetitive

The ISO proposes to seek tariff authority to deem selected internal constraints uncompetitive for specific hours or days when the proposed constraint limiting the affected area's gas burn in southern California is enforced in the ISO market processes.

The determination will be based on whether or not the actual electric supply conditions may be uncompetitive during periods when the gas constraint (Section 6.1) is enforced.

6.5. Clarify authority to suspend virtual bidding

The ISO proposes to seek clarification that it has authority to suspend virtual bidding in the event the CAISO identifies market inefficiencies. The ISO will monitor the impacts virtual bidding has on market quality and if for example transfers of payment are identified the CAISO may need to exercise this authority.

7. Proposals to improve market mechanisms

7.1. Increase access to information prior to day-ahead

Through discussions with stakeholders, the ISO and stakeholders agreed that increased information prior to the day-ahead market (DAM) publication time at 1PM PST would be helpful to generators for planning gas purchases. The identified gap is while market participants can plan based on expectations of where economics will place them in the supply stack through forward planning based on a combination of fundamentals and market signals, they do not have visibility into DAM schedules resulting from inclusion of constraints such as the minimum online constraint.

The ISO discussed with stakeholders methods of increasing the information to market participants to help mitigate this gap. The first method discussed was moving the day-ahead market window earlier so it published the results so the DAM results can inform procurement and nominations during the timely nomination cycle for flows beginning 7AM PST during electric operating day. However, the risk of increased forecast error from moving market earlier exacerbates the risk that real-time re-dispatch would differ significantly from the DAM schedule would likely reverse the benefits received from changing the ISO's DAM timelines. The ISO believes moving its DAM timeline would not provide sufficient benefit to warrant cost to the ISO or its market participants of such a change.

The second method discussed was providing advisory information to market participants on DAM results prior to the close of the timely nomination cycle. Currently the ISO runs a two day-ahead (2DA) RUC process, which provides advisory results. These results are used by ISO operations for its planning purposes in advance of the DAM. While the precise constraints used change between market runs until the final set of constraints used in the real-time market, these results would provide information not currently available to the market. The ISO proposes to release the 2DA advisory results to its market participants to improve market participants' ability to plan.

The ISO evaluated whether changes to this market run must be made to ensure there are sufficient bids used to clear the market in a manner that produces meaningful information for market participants. An open question was whether market participants support ISO using the most recent bids used for day-ahead market run in its 2DA run so bids would reflect prior trade day or if ISO should continue to use submitted bids for operating day of the 2DA run. ISO notes the results of this 2DA run will only be as meaningful as there are available bids in the ISO's systems to represent clearing the 2DA market on bid-in supply and bid-in demand.

The ISO proposes to run the 2DA RUC run consistent with its current practice so it will only use bids in the bid stack present at the time the process is run to provide informational results that are neither financially or operationally binding. ISO stresses to stakeholders that bids for the operating day must be submitted prior to 10AM 2 days before the operating day to include those bids in the 2DA RUC run. These bids can be resubmitted and updated up until 10AM day-ahead.

7.2. Increase ability of generators to reflect real-time marginal costs in its offers under the ISO's market design

When generators are under a balancing requirement across a day, the penalty for violating the tolerance band allowed is intended to make the generators view the costs of gas differently. The ISO believes the change in economics introduced by the risk of noncompliance with a gas balancing requirement is intended to incentive certain behavior that supports the reliable operation of the gas system. These incentives, combined with where a generator expects to operate within its tolerance band, are price information that contributes to the valuation of the generator's expectations of its marginal costs to generate power. The ISO believes generators should be allowed to reflect their expectations of marginal costs in their commitment cost and energy offers. In this way, the incentives designed by the gas markets could be reflected in the electric markets so that the incremental gas burn of generators is in a direction supportive of gas reliability.

Under a high OFO, the pipeline pressure is increasing because nominated gas is higher than the actual gas demand driving up that pressure. To balance the pressure at a more sustainable level, customers need to either decrease their nominated flows or increase their demand. If a customer had an imbalance outside the tolerance band and is unable to sell gas off system or to another customer on system and adjust its nominations accordingly to reduce this imbalance, the customer would need to either increase its gas burn or incur a noncompliance penalty. For electric generator customers, the generator could bid to increase its burn by bidding at lower costs in the ISO real-time market so the generator appears more economic and can be incrementally dispatched.

Under a low OFO, the pipeline pressure is dropping because nominated gas is lower than the actual gas demand driving down that pressure. To balance the pressure at a more sustainable level, customers need to either increase their nominated flows or reduce their demand. If a customer had an imbalance outside the tolerance band and is unable to procure and nominate flow to reduce this imbalance, the customer would need to either reduce its gas burn or incur a noncompliance penalty. For electric generator customers, the generator could reduce its burn by bidding into the market at higher costs so the generator appears less economic and can be decremented down. Under current bidding rules, when these costs exceed either 25% of the estimated commitment costs or 10% of estimated incremental energy costs for mitigated energy costs, generators are prevented from reflecting the economic incentives imposed by the gas company in its production costs.

Market prices that reflect the constrained conditions in Southern California will only be possible dependent on the accuracy of the bid prices submitted into the ISO market. This is important for generators to be able to manage their gas usage through their ISO market bids. For example, a short-start unit that did not receive a day-ahead schedule may not line up gas and should be able to reflect this unavailability through its bids.

The commitment cost bid cap set at 125% of ISO's proxy cost calculation for start-up, transition or minimum load costs under the changed gas market conditions is expected to no longer capture real-time price volatility on all days. The ISO also believes it may be insufficient to allow generators to manage their gas burn within the gas company's balancing requirements through avoiding or increasing real-time dispatches in gas constrained areas in order to operate within the gas tolerance bands sets for reliability purposes.

While generators have the ability to increase or reduce incremental energy offers in the real-time as long as they are not mitigated, currently they do not have the ability to update commitment costs in real-time to reflect changes in expectations of marginal fuel procurement costs. Due to these commitment cost bid caps, the generator is less able to manage gas usage by submitting higher priced bids when their dispatch needs to be reduced to operate within the tolerance band therefore they are more likely to violate its tolerance band under that situation. This exacerbates the gas reliability issue when the pressure is dropping since the generators burn would increase since it appears more economic widening its imbalance driving pressure lower. This limitation may decrease the efficiency of commitments for medium, short or fast start units, which do not receive binding commitments until real-time.

Further, all generators who have their incremental energy offers mitigated are also constrained since default energy bids only contain a 10% input for incidental costs other than the fuel proxy costs. While the market design gap where the mitigated energy costs is also a concern it is the lesser concern since absent mitigation the costs can be reflected.

In its Straw Proposal, the ISO proposed to increase the accuracy of its cost estimates for commitment costs and incremental energy used in the real-time market to estimates based on a valuation of real-time gas prices. Two potential options proposed for estimating commitment and incremental energy costs based on a valuation of real-time gas prices were:

1. Gas price submitted by generators reflecting marginal cost of gas
2. Rolling volume weighted average price of exchange traded intraday and same day transactions for each commodity trading hub defined within a fuel region

The ISO evaluated the implementation feasibility of the options to increase the accuracy of its commitment cost and default energy bid cost estimates. The ISO's objective is to select a design option that can be implemented by this summer. Given this objective, the ISO proposes to not propose a long-term market design solution to include real-time price information as basis for its cost estimates but instead to postpone these proposals for future stakeholder discussions.

In the short term and just for generators in the affected Southern California area, the ISO proposes it have the flexibility to apply a scalar to the commodity price used to determine the gas price index for the SoCalGas and SDG&E generators to allow commitment cost offers and mitigated energy offers to better reflect both (1) the changed economics due to economic incentives associated with gas balancing imposed on generators and (2) intraday gas price variations relative to the gas price index. The scalar will be different for estimating commitment costs and incremental energy costs. In either case, the ISO will have the authority to adjust the scaling of the gas commodity price in the event that it is too high or too low based on observed electric and gas market outcomes based on the criteria below. If such an adjustment is made, the ISO will release a market notice including the adjusted amount if the ISO takes that action. The scalar will be determined based on its ability to manage the following criteria:

- Sufficient to enable the ISO market to dispatch generators on the Southern California Gas Company and SDG&E systems only for local electricity needs and not system electricity needs;

- Accounts for systematic differences between actual day-ahead and same day gas prices that are likely to be more volatile for same day purchases on the constrained gas systems; and

- Needed to improve generators' ability to manage gas company requirements on the constrained systems to limit differences between individual generator's gas schedules and usage (i.e., gas balancing requirements).

For the commitment cost bid cap used by the real-time market, the commitment cost bid cap is currently 125 percent of calculated costs under the proxy cost option. The ISO proposes to increase the commitment cost bid cap by adjusting the gas price index used as an input into the commitment cost bid cap. The gas price index used in the commitment cost proxy cost calculation would initially be set to scale the gas commodity price to 175 percent of the gas commodity price and any adjustments made by the ISO would not exceed roughly the price of noncompliance with a Stage 5 OFO order. Stage 5 OFO penalty is $2.50 plus the next day gas index price rounded up to the nearest dollar. The ISO estimates a scalar approximating the commodity cost of the gas plus this noncompliance charge is roughly $2.50 plus 2 times the next day gas index price or roughly a 200 percent increase over current gas prices assuming next day gas prices around $2.50. Appendix D contains the equations for this process.

For the default energy bids used by the real-time market, the ISO proposes to increase the default energy bid by adjusting the gas price index used in its calculation. The default energy bid scalar is currently 10 percent and applies to the entire default energy bid estimate. The gas price index used in the default energy bid calculation would initially be set to scale the gas commodity price to 125 percent of the gas commodity price and will be capped at 200 percent of the gas commodity price. Appendix D contains the equations for this process.

While generators have the ability to increase or reduce incremental energy offers in the real-time as long as they are not mitigated, currently they do not have the ability to update commitment costs in real-time to reflect changes in expectation of marginal procurement costs and gas availability. The ISO proposes to expand its board approved policy from *Commitment Cost Bidding Improvements* to allow resources to rebid their commitment costs in the real-time market to all resources regardless of whether it received a day-ahead schedule or received binding start-up instruction. The board approved policy did not allow generators to rebid their commitment costs if they had a day-ahead schedule or after the real-time market committed them as follows:

- When a resource has not been committed in the day-ahead market for specific hours, the CAISO will propose that a resource may re-bid its commitment costs for those hours.
- Resources would not be able to re-bid commitment costs in the real-time market once operating and subject to a minimum run time constraint.
- ISO will implement in two phases where phase 1 will include tariff rule detailing the eligibility for rebidding commitment costs in real-time and phase 2 will fully automate validation rules that ensure within the market systems the commitment costs will not be accepted unless the criteria is met.

Another provision the Board also approved at its March meeting from *Commitment Cost Bidding Improvements* is that the ISO market will no longer automatically insert bids into the real-time market for resources that had bid into the day-ahead market but did not receive a day-ahead schedule and that do not have a real-time must offer obligation. This will ensure the real-time market will not consider bids from generators that did not have an obligation to plan for gas procurement to operate in real-time from neither receiving a day-ahead schedule nor having a real-time must offer obligation.

Finally, the ISO proposes to expand its board approved policy providing the opportunity to seek after-the-fact commitment cost recovery to include a cost recovery filing opportunity for incurred marginal procurement costs associated with providing incremental energy, in addition to the previous board approved policy addressing commitment costs. The ISO also proposes to adjust the reimbursement method proposed for any incurred costs determined by FERC. At the March Board meeting, the ISO proposed to reimburse the FERC-approved costs through its bid cost recovery mechanism. The ISO is revising its proposal to adjust the reimbursement method to allocate costs the Commission finds to be just and reasonable to measured demand.

7.3. Proposal to routinely use improved day-ahead gas price index

As discussed in Section 4.3, there are two gas operating days overlapping the electric operating day where the second day or gas day 2 begins at 7AM PST. Currently, the ISO relies on its manual price spike procedure to allow it to reopen its DAM for generators to resubmit commitment cost offers under a bid cap using the GD2 next day index if the GD2 next day index is at least 25% higher than GD1 next day index. The GD2 next day index is the Intercontinental Exchange published next day index for gas traded today for delivery tomorrow beginning at 7AM PST. This printed index price is a volume weighted average price of trades done during ICE's next day window. Prior to April 1, 2016 ICE has been providing this printed index to the ISO around 10AM PST.

The ISO recently learned that the Intercontinental Exchange (ICE) has changed its publication time to 11:30 PST. This change in timing makes it infeasible to continue the manual price spike procedure through receipt of printed index from ICE as it would require reopening day-ahead bidding after 11:30AM PST. Given this timing, the ISO would likely be able to close the market again around 12:45 PM PST and publish its day-ahead results by 3:45 PM PST. The ISO believes holding back the DAM window that late would be moving the timeline back to a time that would adversely impact gas fired generators ability to prudently procure and nominate gas to meet ISO dispatch.

The ISO proposes to implement a next day index for gas procured the morning on the day prior to its electric operating day for gas day beginning at 7AM PST during the operating day as the basis for its gas price index the day-ahead market. The ISO proposes to calculate an approximation of the ICE next day gas price index. Additionally, the ISO proposes to update the manual price spike procedure to allow it to base a determination of a gas price spike based on an approximation of the ICE next day gas price index currently used in the procedure.

The ISO proposes to upgrade its functionality to calculate a volume weighted average price (VWAP) using trades observed on ICE during the ICE next day trading window. The VWAP would be calculated consistently with ICE's VWAP calculation.

This next day gas index would be used for calculating proxy commitment costs and default energy bids. The approximation would be made and used in determining the ISO's cost estimates prior to the close of the day-ahead market at 10AM PST. The ISO is still evaluating when it can implement this functionality. In the interim, if necessary, the ISO proposes to continue to use the manual gas price spike procedure based on an ISO estimate of gas prices based on trades observed on ICE.

8. Next Steps

No stakeholder comments are requested for this Revised Draft Final Proposal. The ISO will present its proposal to its Board on May 4, 2016.

Appendix A: Gas Electric Coordination Process

The ISO created a process flow based on Operating Procedure 4120 as well as some additional actions taken prior to initiating this procedure to support gas-electric coordination. The process flow is available in pdf format at: http://www.caiso.com/Documents/AlisoCanyonGasElectricCoordination_GasElectricCoordinationProcess.pdf.

The ISO is evaluating the following changes to its current procedure:

1. After receiving a curtailment notification, the ISO will perform assessment of curtailments impact on electric reliability and determine preferred allocation of curtailment across affected generators in a manner that supports reliability in both gas and electric systems.

2. At the time ISO provides pro rata curtailment amounts for each generator under its control to SoCalGas it will also provide a second set of curtailment amounts reflecting the preferred allocation of curtailment amounts across affected generators and request the gas company issue its curtailments based on these amounts instead of pro rata given electric reliability needs.

3. Explore how both SoCalGas and the ISO could formalize its joint procedure for various types of events so that affected generators would have one resource to consult to understand the procedure and the roles of each entity under this procedure.

4. Host a joint training prior to summer 2016 where both SoCalGas and ISO staff will ensure all generators have been fully briefed on the appropriate procedures for each event and can field questions at that time.

ISO understands from discussions with its stakeholders one of the concerns with the current process is that gas system operators are not the staff communicating with the electric generators under one of these events but instead the communications come from client representatives. Operating Procedure 4120 currently contemplates that the individuals communicating with affected electric generators would have the authority to adjust the curtailment amount based on feedback from generators. The ISO is concerned as to whether this portion of the process flow is functional, especially under a tight timeline for effecting curtailments, if the communication is managed by an intermediary rather than the operators. Accordingly, the ISO will further explore this item with SoCalGas.

Appendix B: Issue Paper Discussion Items

Initial questions for discussion under this initiative to begin the dialogue include:

(1) How, if at all, could the ISO provide additional information to generators prior to the intraday 3 for GD1 and the timely for GD2 gas nomination deadlines?

(2) What market changes or other tools, if any, could improve resources' ability to procure and nominate gas for GD1 and GD2 earlier to alleviate reliability and price risk?

(3) How do resources especially medium, short, or fast start units procure gas to meet ISO instructions in light of the risk of deviating from daily gas balancing requirements? Is there a difference in procurement practices depending on whether a binding start up instruction is issued versus if only advisory start up instructions have been issued?

(4) What market changes or tools, if any, would support gas system reliability while efficiently dispatching resources to support electric system reliability in the real-time?

(5) What market changes, if any, could improve ISO's ability to better model and compensate resources for the higher costs associated with committing or dispatching these resources identified in Section 5.3?

(6) How, if at all, the ISO should address or coordinate gas curtailments that effect ISO generation?

Appendix C: Nomogram Constraint

Introduction

A nomogram is a set of piece-wise linear inequality constraints relating transmission corridor MW flows and MW generation. (Note that if one wanted to use the MW flow on a single branch as part of a nomogram definition then a single branch transmission corridor would need to be defined.) Resource statuses cannot be part of the nomogram model. The constraints must be piecewise linear defining a convex set. **Nomograms can consist of a family of piecewise linear constraint curves. The constraint curve that is active for a given Trading Hour (or set of Trading Hours) is manually selected by the user prior to the optimization.**

An individual nomogram variable can be one of the following:

a) A transmission corridor MW flow value.

b) A Nomogram Generation Group MW output value. This is the sum of the MW output of the individual market generating resources or aggregate market generating resources that make up the nomogram generation group.

The following are examples of typical nomogram variable combinations:

a) Transmission Corridor MW Flow vs. Transmission Corridor MW Flow.

b) Transmission Corridor MW Flow vs. Area MW Generation.

The nomogram constraint presents a family of piecewise linear curves relating one or more nomogram variables. The Nomogram constraints relating variables $V_n\,;\;\; where,\; n=1,2,...,N$ imposed by $k=1,2,...,K$ linear segments of an active piecewise linear nomogram curve can be expressed as follows:

$$a_1^k \cdot V_1 + a_2^k \cdot V_2 + ... + a_n^k \cdot V_n + ... + a_N^k \cdot V_N \le b^k; \quad k=1,2,...,K$$

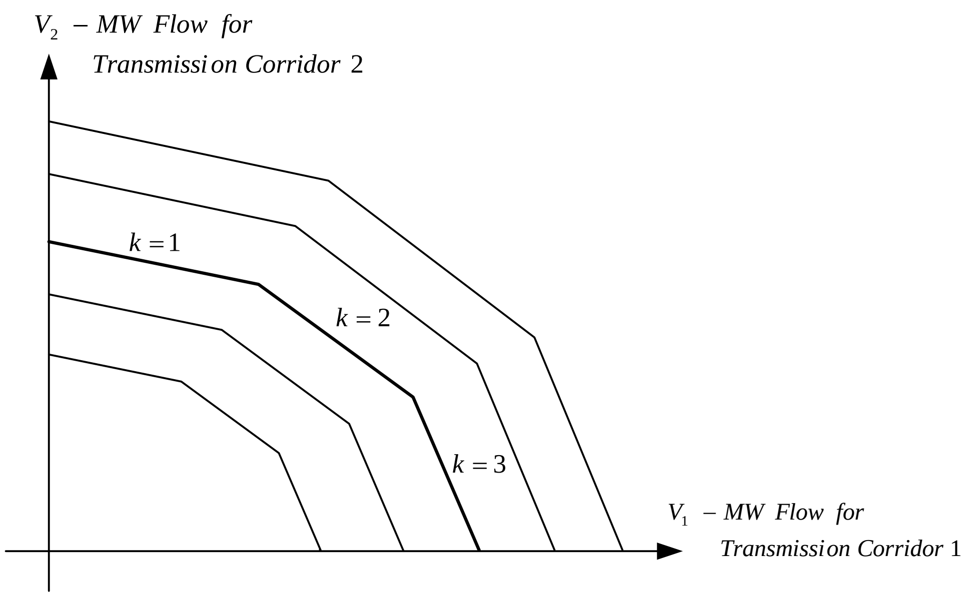


Figure 1. A Typical Nomogram Constraint

For example, the nomogram shown on above diagram relates a transmission corridor (corridor 1) MW Flow variable:

$$V_1 = Flow_{corr1}^{base,t} + \Delta Flow_{corr1}^{t} = Flow_{corr1}^{base,t} + \sum_{node \in corr1} SF_{corr1}^{node} \cdot \left(P_{node}^{t} - P_{node}^{base,t}\right)$$

To another transmission corridor (corridor 2) MW Flow variable:

$$V_2 = Flow_{corr2}^{base,t} + \Delta Flow_{corr2}^{t} = Flow_{corr2}^{base,t} + \sum_{node \in corr2} SF_{corr2}^{node} \cdot \left(P_{node}^{t} - P_{node}^{base,t}\right)$$

For a selected nomogram constraint curve the following three segments are specified:

$a_1^1 \cdot V_1 + a_2^1 \cdot V_2 \le b^1$ for segment *k* = 1,

$a_1^2 \cdot V_1 + a_2^2 \cdot V_2 \le b^2$ for segment *k* = 2,

$a_1^3 \cdot V_1 + a_2^3 \cdot V_2 \le b^3$ for segment *k* = 3.

The active nomogram constraint curve is manually selected by the user prior to the optimization process from a pre-specified set of piecewise linear curves.

Other nomogram variables can be the energy generation of some group of generating units:

$$V_3 = \sum_{unit \in G} En_{unit}^{t}$$

No other types of variables are supported.

Notation

The notation used for these equations is the same as used in the IFM DDS with the following extensions for nomograms:

t	time interval index
node	node index
unit	generating unit or import system resource index
load	dispatchable load or export system resource index
line	network branch (line or corridor) constraint index
nm	is a subscript referring to a particular nomogram
nv	is a subscript referring to a particular nomogram variable for a particular nomogram
nc	is a subscript referring to the active curve for a particular nomogram at time *t*. For every nomogram there may be multiple curves defined but only one of them can be active in a given Trading Hour.
ns	is a subscript referring to a particular nomogram segment for a particular active nomogram curve for a particular nomogram
ntc	is a subscript referring to a particular transmission corridor that is associated with a nomogram variable
$a_{nv}^{nm,nc,ns}$	is the coefficient of segment *ns* of the active curve *nc* of nomogram *nm* that corresponds to the nomogram variable *nv*

$b^{nm,nc,ns}$	is the right hand side value of segment *ns* of the active curve *nc* of nomogram *nm*
$SF_{nm,nv}^{node}$	is a shift factor indicating how the nomogram variable *nv* of nomogram *nm* changes due to an incremental injection into the system at the pnode location *node*.
$SF_{nm,nc,ns}^{node}$	is a shift factor indicating how the left hand side value of segment *ns* of the active curve *nc* of nomogram *nm* changes due to an incremental injection into the system at the pnode location *node*.
$NSCP_{nm,nc,ns}^{t}$	is the nomogram segment clearing price (i.e., shadow price) for the nomogram segment *ns* of the active curve *nc* of nomogram *nm* at time *t*
$\overline{P}_{nm,nc,ns}^{viol;t}$	is the violation or infeasibility slack variable for segment *ns* of the active curve *nc* for nomogram *nm* at time *t*
$C(\overline{P}_{nm,nc,ns}^{viol;t})$	is the contribution to the objective function for the infeasibility slack variable for segment *ns* of the active curve *nc* for nomogram *nm* at time *t*
p_{NM}^{viol}	is the infeasibility slack variable penalty price for nomograms
GG	refers to the set of generation resources that make up a specific generation group
NN	refers to the set of nodes.
T	refers to the time horizon
G	refers to the set of generating units or import system resources
L	refers to the set of dispatchable loads or export system resources
LL	refers to the set of network branch (line or corridor) constraints
NM	refers to the set of all nomograms
NMV_{nm}	refers to the set of nomogram variables associated with nomogram *nm*
$NMS_{nm,nc}$	refers to the set of nomogram segments associated with active curve *nc* of nomogram *nm*
P_{node}	is the energy injection at node *node*
En	is the energy schedule of a given resource
$V_{nm,nv}^{t}$	is the value of the nomogram variable corresponding to nomogram *nm* and variable *nv* for time *t*
MCP	is the shadow price of the power balance constraint
pf_{node}	is the loss penalty factor at node *node*
TCP	is the shadow price of a network constraint on a transmission branch or corridor

Generation Group Nomogram Variable Equation

This section provides the formulation details for generation groups that are defined as a nomogram variable. Basically this nomogram variable consists of the sum of the MW outputs of a subset of generation resources within the system. There are some key observations to make regarding this definition. The first relates to which generation resources are part of the subset. The following restrictions should be made on the subset:

- Permitted values within a generation group
    - Individual generation resources
    - Aggregate generation resources. If an aggregate generation resource is defined as part of a generation group then all of the members of the aggregate resource will be part of the generation group.

System Resources (import/exports) will not participate in nomograms, but transmission corridors defined for inter-ties can be defined as nomogram variables.

- Values not permitted within a generation group
  - Only a subset of the units in an aggregate generation resource. Either the entire aggregate generation resource should be included within a generation group or none if it should be.

The equation for a generation group nomogram variable can be written as follows:

$$V_{nm,nv}^{t} = \sum_{unit \in GG} En_{unit}^{t}; \quad nm \in NM; nv \in NMV_{nm}; t \in T$$

We want to know how the variable associated with a nomogram changes due to an increment of load at each pnode. For a generation group nomogram variable this can be written as follows:

$$SF_{nm,nv}^{node} = \frac{\Delta V_{nm,nv}^{t}}{\Delta P_{node}} = 0$$

There is a subtlety to note here. The subtlety is that an incremental injection at this pnode is not assumed to come from the portion of a generation group that may reside at this pnode. Since the nomogram variable depends only on the generation group resources and not on a general injection at the pnode then the nomogram variable does not change. In particular, if the incremental change in injection at the pnode was actually an increment in load at the pnode the generation group nomogram variable would not change and therefore the shift factor term is zero.

Nomogram Segment Equation

For every segment of the active curve for each nomogram for each time period an equation should be added to the model. This section will discuss the form of the equation to be added.

$$a_{1}^{nm,nc,ns} \cdot V_{nm,1}^{t} + a_{2}^{nm,nc,ns} \cdot V_{nm,2}^{t} + \ldots + a_{n}^{nm,nc,ns} \cdot V_{nm,n}^{t} \le b^{nm,nc,ns}; \quad nm \in NM; ns \in NMS_{nm,nc}; t \in T$$

This can be written in a more compact notation as follows:

$$\sum_{nv \in NMV_{nm}} a_{nv}^{nm,nc,ns} \cdot V_{nm,nv}^{t} \le b^{nm,nc,ns}; \quad nm \in NM; ns = \in NMS_{nm,nc}; t \in T$$

There are several observations to be made here. First, according to the table definitions, the equation can be one of the following relationships: $\le, =, \ge$. The equation above used $\le$ for convenience sake. Second the number of equations being described here should not be missed. The form shown above looks pretty simple however the total number of equations represented is given by

$$NumEqs = T \cdot \sum_{nm \in NM} NMS_{nm,nc}$$

An infeasibility slack variable should be included in the nomogram segment inequality constraint. This is similar to the slack variable processing that is done for other constraints. In particular this has the following form:

$$\sum_{nv \in NMV_{nm}} a_{nv}^{nm,nc,ns} \cdot V_{nm,nv}^{t} \le b^{nm,nc,ns} + \overline{P}_{nm,nc,ns}^{viol,t}; \quad nm \in NM; ns = \in NMS_{nm,nc}; t \in T$$

The infeasibility slack variable should be a non-negative value, i.e.,

$$\overline{P}_{nm,nc,ns}^{viol,t} \geq 0; \quad nm \in NM; ns \in NMS_{nm,nc}; t \in T$$

There is a penalty function associated with the infeasibility slack variable. This penalty function needs to be included as part of the objective function.

$$C(\overline{P}_{nm,nc,ns}^{viol;t}) = p_{NM}^{viol} \cdot \overline{P}_{nm,nc,ns}^{viol;t}; \quad p_{NM}^{viol} >> 1$$

It should be remembered that the nomogram segment constraint be any one of the types $\leq, =, \geq$. The exact form of the infeasibility slack variable term will depend on the specific form being used.

Following the solution, the nomogram segments that are binding will provide a contribution to the congestion component of the LMP for every price node. Let us consider this contribution in more detail here. First let us consider the equation for LMP values without any contribution from nomograms, namely:

$$LMP_{node}^{En;t} = MCP^{En;t} / pf_{node}^{t} + \sum_{line \in LL} SF_{line}^{node} \cdot TCP_{line}^{t}$$

Where the index *node* refers to every price node. If we extend this to include the effect of nomograms we can write

$$LMP_{node}^{En;t} = MCP^{En;t} / pf_{node}^{t} + \sum_{line \in LL} SF_{line}^{node} \cdot TCP_{line}^{t} + \sum_{nm \in NM} \sum_{ns \in NMS_{nm,nc}} SF_{nm,nc,ns}^{node} \cdot NSCP_{nm,nc,ns}^{t}$$

The nomogram segment shadow price $NSCP_{nm,nc,ns}^{t}$ will be a byproduct of the optimization. Let us turn our attention to how to determine the term $SF_{nm,nc,ns}^{node}$. This can be written as follows:

$$SF_{nm,nc,ns}^{node} = \sum_{nv \in NMV_{nm}} a_{nv}^{nm,nc,ns} \cdot SF_{nm,nv}^{node}$$

Where as described in the previous section:

$$SF_{nm,nv}^{node} = \begin{cases} SF_{ntc}^{node} & \text{if } nv \text{ is transmission corridor } ntc \text{ flow} \\ 0 & \text{if } nv \text{ is an aggregate generating resource output} \end{cases}$$

Specifically for Aggregate Generating Resources that are variables in a given nomogram, an additional marginal congestion component contribution exists because of the restriction that that particular nomogram imposes on the Aggregate Generating Resource:

$$LMP_{V_{nm,nv}}^{En;t} = MCP^{En;t} / pf_{node}^{t} + \sum_{line \in LL} SF_{line}^{node} \cdot TCP_{line}^{t} + \sum_{ns \in NMS_{nm,nc}} a_{nv}^{nm,nc,ns} \cdot NSCP_{nm,nc,ns}^{t}$$

Where the node is the aggregate node (ANode) of the aggregate generating resource and the shift factor is the aggregate shift factor that corresponds to that aggregate node.

Note that this additional marginal congestion component applies only to the Aggregate Generating Resources that are variables in a nomogram; it does not apply to other resources, even if connected to the same node(s).

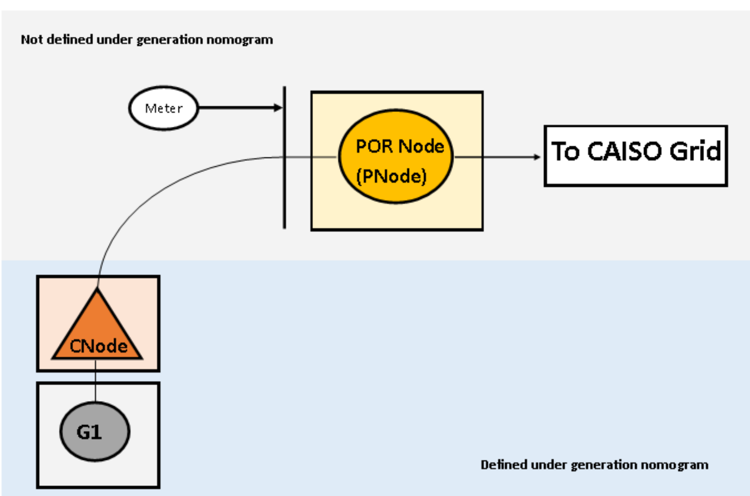
Impact on nodal prices

As stated in the ISO's Managing Full Network Model (FNM) Business Practice Manual[20], "The operation of the CAISO's Markets, which includes the determination and mitigation of transmission congestion and the calculation of LMPs, requires a network model [Full Network Model] that provides a detailed and accurate representation of the power system included in the CAISO Markets."

The FNM is composed of network connectivity Nodes[21] (CNodes) interconnected with network branches. A CNode represents a connection point used to define the physical topological connectivity of the network where only one load or generation device can be connected to a CNode. Each terminal of equipment is connected to a CNode. Each piece of equipment has a CNode associated with it and roles up into a bus which represents all the topological nodes associated with a generating resource. Below in Figure 2, the grey circle represents generator 1 (G1)'s physical topological connection point of the terminal of the equipment to a network node, the connectivity node (CNode). In this example, there is only one piece of equipment which is connected to a CNode so the CNode and bus are the same.

Figure 2 further shows the connection between the CNode to the Pricing Node (PNode), which represents the point at which the injection is received into the CAISO Controlled Grid for Supply, or withdrawal is delivered out of the CAISO Controlled Grid for Demand. Generally, the PNode of a generating unit will coincide with the the CNode where the relevant revenue quality meter is connected or compensated, to reflect the point at which the Generating Units are connected to the CAISO Balancing Authority Area. This Location is referred to as the "Point Of Receipt" (POR) and is considered to be a PNode. However, the PNode and CNode can differ in the FNM.

Figure 2: Simple generating unit with one CNode and Pnode



[20] Available on Page 11 at https://bpmcm.caiso.com/BPM%20Document%20Library/Managing%20Full%20Network%20Model/Managing%20Full%20Network%20Model%20BPM%20Version%208_clean.docx.

[21] The CAISO BPMs have adopted "Connectivity Node" or CNode as an alternative expression of "Node".

The diagram shows the pieces of the FNM that would be variables under the generation group nomogram where the nodes in the blue box would be defined as variable and the nodes in the grey box would not be defined as variable under the generation group nomogram. As discussed in detail in the Generation Group Nomogram Variable Equation

This section provides the formulation details for generation groups that are defined as a nomogram variable. Basically this nomogram variable consists of the sum of the MW outputs of a subset of generation resources within the system. There are some key observations to make regarding this definition. The first relates to which generation resources are part of the subset. The following restrictions should be made on the subset:

- Permitted values within a generation group
    - Individual generation resources
    - Aggregate generation resources. If an aggregate generation resource is defined as part of a generation group then all of the members of the aggregate resource will be part of the generation group.

  System Resources (import/exports) will not participate in nomograms, but transmission corridors defined for inter-ties can be defined as nomogram variables.

- Values not permitted within a generation group
    - Only a subset of the units in an aggregate generation resource. Either the entire aggregate generation resource should be included within a generation group or none if it should be.

The equation for a generation group nomogram variable can be written as follows:

$$V_{nm,nv}^{t} = \sum_{unit \in GG} En_{unit}^{t}; \quad nm \in NM; nv \in NMV_{nm}; t \in T$$

We want to know how the variable associated with a nomogram changes due to an increment of load at each pnode. For a generation group nomogram variable this can be written as follows:

$$SF_{nm,nv}^{node} = \frac{\Delta V_{nm,nv}^{t}}{\Delta P_{node}} = 0$$

There is a subtlety to note here. The subtlety is that an incremental injection at this pnode is not assumed to come from the portion of a generation group that may reside at this pnode. Since the nomogram variable depends only on the generation group resources and not on a general injection at the pnode then the nomogram variable does not change. In particular, if the incremental change in injection at the pnode was actually an increment in load at the pnode the generation group nomogram variable would not change and therefore the shift factor term is zero.

Nomogram Segment Equation

For every segment of the active curve for each nomogram for each time period an equation should be added to the model. This section will discuss the form of the equation to be added.

$$a_1^{nm,nc,ns} \cdot V_{nm,1}^{t} + a_2^{nm,nc,ns} \cdot V_{nm,2}^{t} + ... + a_n^{nm,nc,ns} \cdot V_{nm,n}^{t} \le b^{nm,nc,ns}; \quad nm \in NM; ns \in NMS_{nm,nc}; t \in T$$

This can be written in a more compact notation as follows:

$$\sum_{nv \in NMV_{nm}} a_{nv}^{nm,nc,ns} \cdot V_{nm,nv}^{t} \leq b^{nm,nc,ns}; \quad nm \in NM; ns = \in NMS_{nm,nc}; t \in T$$

There are several observations to be made here. First, according to the table definitions, the equation can be one of the following relationships: $\leq, =, \geq$. The equation above used $\leq$ for convenience sake. Second the number of equations being described here should not be missed. The form shown above looks pretty simple however the total number of equations represented is given by

$$NumEqs = T \cdot \sum_{nm \in NM} NMS_{nm,nc}$$

An infeasibility slack variable should be included in the nomogram segment inequality constraint. This is similar to the slack variable processing that is done for other constraints. In particular this has the following form:

$$\sum_{nv \in NMV_{nm}} a_{nv}^{nm,nc,ns} \cdot V_{nm,nv}^{t} \leq b^{nm,nc,ns} + \overline{P}_{nm,nc,ns}^{viol,t}; \quad nm \in NM; ns = \in NMS_{nm,nc}; t \in T$$

The infeasibility slack variable should be a non-negative value, i.e.,

$$\overline{P}_{nm,nc,ns}^{viol,t} \geq 0; \quad nm \in NM; ns \in NMS_{nm,nc}; t \in T$$

There is a penalty function associated with the infeasibility slack variable. This penalty function needs to be included as part of the objective function.

$$C(\overline{P}_{nm,nc,ns}^{viol;t}) = p_{NM}^{viol} \cdot \overline{P}_{nm,nc,ns}^{viol;t}; \quad p_{NM}^{viol} >> 1$$

It should be remembered that the nomogram segment constraint be any one of the types $\leq, =, \geq$. The exact form of the infeasibility slack variable term will depend on the specific form being used.

Following the solution, the nomogram segments that are binding will provide a contribution to the congestion component of the LMP for every price node. Let us consider this contribution in more detail here. First let us consider the equation for LMP values without any contribution from nomograms, namely:

$$LMP_{node}^{En;t} = MCP^{En;t} / pf_{node}^{t} + \sum_{line \in LL} SF_{line}^{node} \cdot TCP_{line}^{t}$$

Where the index *node* refers to every price node. If we extend this to include the effect of nomograms we can write

$$LMP_{node}^{En;t} = MCP^{En;t} / pf_{node}^{t} + \sum_{line \in LL} SF_{line}^{node} \cdot TCP_{line}^{t} + \sum_{nm \in NM} \sum_{ns \in NMS_{nm,nc}} SF_{nm,nc,ns}^{node} \cdot NSCP_{nm,nc,ns}^{t}$$

The nomogram segment shadow price $NSCP_{nm,nc,ns}^{t}$ will be a byproduct of the optimization. Let us turn our attention to how to determine the term $SF_{nm,nc,ns}^{node}$. This can be written as follows:

$$SF_{nm,nc,ns}^{node} = \sum_{nv \in NMV_{nm}} a_{nv}^{nm,nc,ns} \cdot SF_{nm,nv}^{node}$$

Where as described in the previous section:

$$SF_{nm,nv}^{node} = \begin{cases} SF_{ntc}^{node} & \text{if } nv \text{ is transmission corridor } ntc \text{ flow} \\ 0 & \text{if } nv \text{ is an aggregate generating resource output} \end{cases}$$

Specifically for Aggregate Generating Resources that are variables in a given nomogram, an additional marginal congestion component contribution exists because of the restriction that that particular nomogram imposes on the Aggregate Generating Resource:

$$LMP_{V_{nm,nv}}^{En;t} = MCP^{En;t} / pf_{node}^{t} + \sum_{line \in LL} SF_{line}^{node} \cdot TCP_{line}^{t} + \sum_{ns \in NMS_{nm,nc}} a_{nv}^{nm,nc,ns} \cdot NSCP_{nm,nc,ns}^{t}$$

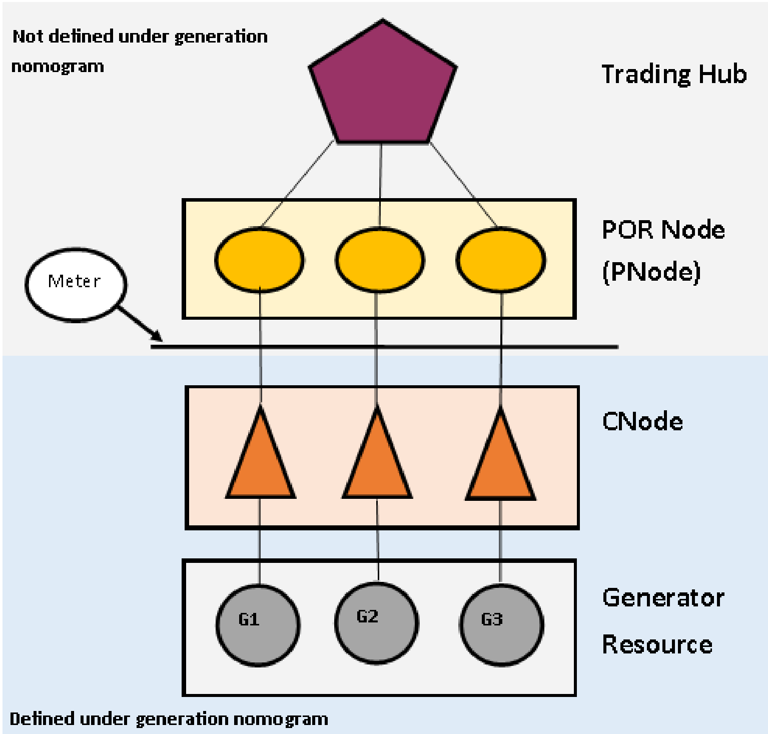
Where the node is the aggregate node (ANode) of the aggregate generating resource and the shift factor is the aggregate shift factor that corresponds to that aggregate node.

Note that this additional marginal congestion component applies only to the Aggregate Generating Resources that are variables in a nomogram; it does not apply to other resources, even if connected to the same node(s).

section of Appendix C while the nomogram segment shadow price is a natural byproduct of the optimization, the shift factor indicating how the nomogram variable nv of nomogram nm changes due to an incremental injection into the system at the PNode location node ($SF_{nm,nv}^{node}$) is 0 so that the PNode LMP does not contain the nomogram segment shadow price. Whereas, the shift factor indicating how the nomogram variable nv of nomogram nm changes due to an incremental injection into the system at the CNode location node ($SF_{nm,nv}^{node}$) is 1 so that the CNode LMP associated with each element of the nomogram does contain the nomogram segment shadow price.

As another example, any transactions settling off of a trading hub would contain the price information from the Pnodes that are aggregated into the aggregated pricing node (APNode) also called Trading Hub. Figure 3 shows the relationship between the generators (grey circles), CNodes (orange triangles) to the PNodes that are aggregated into the Trading Hub's APNode.

Figure 3: Relationship of nodes to aggregate pricing nodes



The diagram shows the pieces of the FNM that would be variables under the generation group nomogram where the nodes in the blue box would be defined as variable and the nodes in the grey box would not be defined as variable under the generation group nomogram. As shown in Figure 3 only the CNodes are variables under the generation group nomogram so that only the impact of the nomogram segment shadow price is reflected in the CNode LMP whereby the shift factor to the PNodes, shown in the grey box, is 0 and the shadow price is not captured in these prices. Because the shadow price is not captured in the PNode LMPs, the impact of the shadow price does not get reflected in the APNodes either since they are based on PNode LMPs.

Appendix D: Gas Price Index Details

The GPI formulation just for the SCE and SDGE fuel regions. There will be scalars applied to the commodity price (relevant next day gas index) to get to a different GPI for energy versus commitment cost estimates. Every other fuel region will remain unaffected and the gas price indices are the same for commitment costs and default energy bid calculation (i.e. $GPI_{Commitment} = GPI_{Energy}$). These scalars would be used to formulate the two different GPIs for the SoCalGas and SDG&E fuel regions every day. If adjusted up or down there would be a market notice specifying the new scalars.

Equation 4: GPI Formulation

$$GPI_{Commitment} = (Commodity\ Price * \text{Scalar}_{Commitment}) + Transportation\ Rate$$

$$GPI_{Energy} = \left(Commodity\ Price * \text{Scalar}_{Energy}\right) + Transportation\ Rate$$

Where:

$\text{Scalar}_{Commitment} = 1.75$, Fuel Region is eligible for scalar

$\text{Scalar}_{DEB} = 1.25$, Fuel Region is eligible for scalar

In the following cost estimate equations, the ISO highlights the portion of the calculations affected and clarifies which GPI is used for which cost estimate.[22]

Equation 5: Proxy Start-Up Costs

$$\text{Start-up Cost} = \begin{cases} \text{Start-up Fuel Cost} + \text{Start-up Energy Cost} + \text{GMC Adder}, & GHG_{COMPLIANCE} = 'N' and\ MMA = 0 \\ \text{Start-up Fuel Cost} + \text{Start-up Energy Cost} + \text{GMC Adder} + \text{GHG Cost}, & GHG_{COMPLIANCE} = 'Y' and\ MMA = 0 \\ \text{Start-up Fuel Cost} + \text{Start-up Energy Cost} + \text{GMC Adder} + \text{GHG Cost} + MMA, & GHG_{COMPLIANCE} = 'Y' and\ MMA \neq 0 \end{cases}$$

Where:

$\text{Start-up Fuel Cost} = STRT\_STARTUP\_FUEL * GPI_{Commitment}$
$\text{Start-up Energy Cost} = STRT\_STARTUP\_AUX * EPI$

$$\text{GMC Adder} = Pmin * (STARTUP\_RAMP\_TIME/60min) * \frac{GMC}{2}$$

$\text{GHG Cost} = STRT\_STARTUP\_FUEL * \text{Emissions Rate} * \text{GHG Allowance Rate}$

Equation 6: Proxy Minimum Load Costs

[22] The equation for transition costs is not included but the $GPI_{Commitment}$ would be used to determine the proxy transition cost estimate.

Minimum Load Cost

$$= \begin{cases} \text{Minimum Load Fuel Cost} + \text{VOM} + \text{GMC Adder}\,, & GHG_{COMPLIANCE} =' N' and\ MMA = 0 \\ \text{Minimum Load Fuel Cost} + \text{VOM} + \text{GMC Adder} + \text{GHG Cost}\,, & GHG_{COMPLIANCE} =' Y' and\ MMA = 0 \\ \text{Minimum Load Fuel Cost} + \text{VOM} + \text{GMC Adder} + \text{GHG Cost} + MMA\,, & GHG_{COMPLIANCE} =' Y' and\ MMA \neq 0 \end{cases}$$

Where:

$\text{Minimum Load Fuel Cost} = Unit\ Conversion * \text{Heat\_Rate} * Pmin * \ GPI_{Commitment}$

$\text{VOM} = \text{VOM} * \text{Pmin}$
$\text{GMC Adder} = Pmin * GMC$

$\text{GHG Cost} = Unit\ Conversion * \text{Heat\_Rate} * Pmin * \text{Emissions Rate} * \text{GHG Allowance Rate}$

Equation 7: Default Energy Bid Costs

Default Energy Bid Cost

$$= \begin{cases} \text{Segment's Fuel Cost} + \text{VOM} + \text{GMC Adder} + Scalar, & GHG_{COMPLIANCE} =' N' and\ DEBA = 0 \\ \text{Segment's Fuel Cost} + \text{VOM} + \text{GMC Adder} + \text{GHG Cost} \ + Scalar, & GHG_{COMPLIANCE} =' Y' and\ DEBA = 0 \\ \text{Segment's Fuel Cost} + \text{VOM} + \text{GMC Adder} + \text{GHG Cost} + DEBA + Scalar\,, & GHG_{COMPLIANCE} =' Y' and\ DEBA \neq 0 \end{cases}$$

Where:

$\text{Individual Segment's Fuel Cost} = Unit\ Conversion * \text{Heat\_Rate} * \ GPI_{Energy}$

$\text{GHG Cost} = Unit\ Conversion * \text{Heat\_Rate} * \text{Emissions Rate} * \text{GHG Allowance Rate}$

$\text{Scalar} = 1.1$

Attachment E – Memorandum to ISO Board of Governors

Tariff Amendment to Enhance Gas-Electric Coordination to Address Risks Posed by Limited Operability of Aliso Canyon Natural Gas Storage Facility

California Independent System Operator Corporation

May 9, 2016

Memorandum

To: ISO Board of Governors

From: Keith Casey, Vice President, Market & Infrastructure Development

Date: May 2, 2016

Re: **Decision on Aliso Canyon gas-electric coordination proposal**

This memorandum requires Board action.

EXECUTIVE SUMMARY

In October 2015, the Aliso Canyon natural gas storage facility in southern California experienced a large natural gas leak significantly affecting many of the people that live and work in the area as well as the gas balancing tools available to gas users. The storage facility is a significant part of the gas system serving customers in the Los Angeles Basin and San Diego, including gas-fired electric generation. The leak has resulted in a dramatic reduction in the use of the storage facility, greatly limiting the flexibility of the Southern California Gas Company (SoCalGas) and San Diego Gas and Electric Company (SDG&E) systems to serve gas-fired generators in the area. The limitations resulting from the loss of the Aliso Canyon storage facility are expected to stress the gas system this summer when electric loads increase in times where scheduled flowing gas does not match actual gas demand. Curtailment of significant amounts of gas to electric generators may occur when such conditions overlay with planned or unplanned outages to the SoCalGas system, which could lead to electric service interruptions in the area.[1] In connection with the limitations on injections and withdrawals at the Aliso Canyon natural gas storage facility, Management initiated an expedited process to work with stakeholders to develop market mechanisms and operational tools to mitigate the risks to natural gas and electric markets to avoid electric service interruptions to the extent possible.

Management proposes a coordinated set of operational tools and market enhancements to address limitations resulting from the loss of the Aliso Canyon storage facility. The operational tools will enable ISO operators to manage gas usage resulting from generation

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[1] See Aliso Canyon Action Plan to Preserve Gas and Electric Reliability for the Los Angeles Basin posted at: http://www.energy.ca.gov/2016_energypolicy/documents/2016-04-08_joint_agency_workshop/Aliso_Canyon_Action_Plan_to_Preserve_Gas_and_Electric_Reliability_for_the_Los_Angeles_Basin.pdf and Aliso Canyon Risk Assessment Technical Report posted at http://www.energy.ca.gov/2016_energypolicy/documents/2016-04-08_joint_agency_workshop/Aliso_Canyon_Risk_Assessment_Technical_Report.pdf

dispatches in southern California to address reliability issues on the gas system. These tools are designed to reflect gas limitations in the ISO market and to minimize electric generation dispatch that would otherwise operate outside gas system limitations. This will avoid further exacerbating gas system conditions and contributing to the likelihood that gas curtailments will result in the disruption of electric service in the area. The market enhancements will provide generators greater ability to reflect gas system limitations and gas prices in their bids submitted to the ISO market. These enhancements will result in the ISO market dispatching generation in a way that is consistent with gas system limitations to maintain reliability.

Upon Board approval, Management will submit tariff revisions to the Federal Energy Regulatory Commission seeking expedited consideration of mitigation measures with an effective date in early June. Given the short timeframe to develop these provisions and the request for expedited consideration by the Commission, Management proposes that the provisions proposed in this memorandum expire on December 1, 2016.

> ***Moved, that the ISO Board of Governors approves the Aliso Canyon gas electric coordination proposal, as described in the memorandum dated May 2, 2016; and***
>
> ***Moved, that the ISO Board of Governors authorizes Management to make all necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the proposed tariff change.***

DISCUSSION AND ANALYSIS

Management proposes several measures to mitigate reliability risks to the natural gas and electric systems caused by limitations on injections and withdrawals at the Aliso Canyon natural gas storage facility. These measures address gas system limitations over this summer, one of the major limitations being the amount of gas the system can deliver in real-time relative to the amount of gas that was scheduled on the system. The measures minimize the adverse impact real-time electric generation redispatch can have on the gas system, especially in the event there are gas system outages.

Management initiated an expedited stakeholder process to develop measures to help support gas system reliability and ensure electric system reliability over the summer. The stakeholder process focused on the following two policy objectives:

- Ensure ISO markets produce prices that reflect gas system limitations so that the risk that ISO dispatch could adversely impact gas operators' efforts to manage reliability is mitigated, and

- Provide operational tools that can be used through the market clearing process at ISO operators' discretion if needed to mitigate the risk of operating outside gas system limitations that are severely constrained due to the limited operability of Aliso Canyon to avoid electric service interruptions to the extent possible.

Operational tools

Management proposes several operational tools to be implemented in the market clearing process, largely at the discretion of the ISO operators, to ensure the market dispatches do not exacerbate gas system conditions that could in turn compromise electric system reliability.

The first operational tool is a constraint in ISO market processes that will limit the affected area gas burn to a maximum and/or minimum limit. The ISO will coordinate with the gas company to the extent possible in setting gas burn limitations of the constraint. The ISO operators will enforce this gas burn constraint in its markets when gas system limitations exist or they have a concern that electric system redispatches could compromise gas system conditions which in turn could compromise electric grid reliability. Depending on gas system limitations, they will have the ability to apply this constraint in either, or both, of the day-ahead and real-time markets. They will also have the ability to apply the constraint for individual or groups of zones defined by the gas system. The constraint, when binding, will limit the dispatch of generators subject to the constraint and will affect resource-specific prices used for dispatch and settlement purposes. However, it will not impact the locational marginal price used for other purposes including load, congestion revenue rights, and virtual bids settlement.

The second operational tool is to provide ISO operators with the authority to reserve transfer capability on internal transmission paths. ISO operators may need to reserve internal transfer capability to ensure there is sufficient transfer capability in real-time to support reliable grid operations, including meeting incremental energy needs in southern California or assuring deliverability of contingency reserves. This would provide operators the ability to reserve transfer capability in either, or both, of the day-ahead and real-time markets. The ISO will consider limiting a corresponding amount of additional congestion revenue rights it releases in its monthly allocation process. In conjunction with using this tool, the ISO would potentially limit the amount of congestion revenue rights it releases in the monthly allocation and auction to be consistent with the reduced transfer capability.

The third operational tool is to reduce the amount of ancillary services procured from resources in southern California to ensure the ISO markets procure ancillary services that have access to sufficient fuel to respond to a contingency event if needed. The ISO operators would adjust the amount of reserves the markets procure from resources in southern California based on anticipated gas and electric system conditions. ISO operators might implement this tool in conjunction with reserving internal transfer capability to ensure reserves shifted to northern California can be delivered to southern California.

Finally, Management proposes tariff authority to deem selected internal transmission paths competitive or uncompetitive when the proposed constraint limiting the affected area's gas burn in southern California is enforced in the ISO market processes based on a determination that the actual electric supply conditions may be uncompetitive.

ISO market modifications

In addition to the operational tools described above, Management proposes several ISO market modifications to ensure ISO markets produce prices that reflect gas system limitations so that the risk that ISO dispatch could adversely impact gas operators' efforts to manage reliability is mitigated.

The first of these market modifications is to increase the gas cost estimate that is used to calculate the ISO real-time market commitment cost bid cap and default energy bids for generators on the Southern California Gas Company and SDG&E systems. This modification will allow these generators' real-time bid prices to better reflect gas system limitations and gas prices. This greater bidding flexibility will increase the likelihood that the ISO market will only dispatch these generators for local needs and not for system energy that can be provided by generators not subject to gas limitations in other areas of the electric grid. This modification is designed to increase the likelihood that the ISO markets will only dispatch individual generators to serve local needs in areas that could adversely impact gas reliability.

The gas cost estimates used by the ISO real-time market currently reflect prices for gas purchased for next day delivery. For generators on the Southern California Gas Company and SDG&E systems, Management proposes to increase these gas cost estimates in the real-time market by an amount that is:

- Sufficient to enable the ISO market to dispatch generators on the Southern California Gas Company and SDG&E systems only for local electricity needs and not system electricity needs;

- Accounts for systematic differences between actual day-ahead and same day gas prices that are likely to be more volatile for same day purchases on the constrained gas systems; and

- Needed to improve generators' ability to manage gas company requirements on the constrained systems to limit differences between individual generator's gas schedules and usage (*i.e.*, gas balancing requirements).

The amount used in the commitment cost proxy cost calculation would initially be set to scale the gas commodity price to 175 percent of the gas index price. The ISO will monitor whether this level is effective in ensuring that the ISO market dispatches generators in the affected areas only for local needs and adequately accounts for gas prices and balancing requirements. Management proposes to have the authority to adjust the scaling of the gas commodity price in the event that it is too high or too low based on observed electric and gas market outcomes. The adjustment to the gas commodity price used in the commitment cost proxy cost calculation would be capped at $2.50 plus two times the next day gas index price, which is the price a generator would pay for gas if it violated a gas company operational flow order based on the current gas company tariffs. This is likely to be the highest real-time gas prices rise to in southern California.

Management also proposes to adjust the gas price used to calculate default energy bids, which are the incremental energy bids used when a generator's bid is mitigated in local market power mitigation. Management proposes to initially scale the gas price used in the default energy bid calculation to 125 percent of the gas commodity price. Similar to the proxy cost calculation, Management proposes to have the authority to adjust the scaling of the gas price used for default energy bid calculations up or down based on observed electric and gas market outcomes. The gas commodity price for default energy bids would be capped at 200 percent of the gas commodity price.

Management also proposes a second market modification, applicable to all gas-fired generators, not just those in the affected area, to improve the gas price information used by the ISO day-ahead market to establish commitment cost bid caps and default energy bids for mitigated energy offers. The gas price information currently used by the day-ahead market is based on gas trading occurring the previous day and consequently does not align with gas trading for the majority of the operating day for which the ISO's day-ahead market is being run. The gas trading for the majority of the operating day occurs in the morning before the ISO runs the day-ahead market. The ISO currently manually adjusts its gas prices in the event of a large gas price increase relative to the previous day based on an updated index price received from the Intercontinental Exchange. Because the Intercontinental Exchange recently started publishing this updated index price at a time later in the day that makes this process infeasible, Management proposes to develop its own next day index for gas that approximates the Intercontinental Exchange next day gas price index. The ISO would do this by calculating a volume weighted average price using trades observed during the Intercontinental Exchange next day trading window.

The third market modification involves two provisions that the Board already approved but are mentioned here for the sake of describing the entire mitigation plan for Aliso Canyon. The first of these is to allow resources to re-bid commitment costs in the real-time market for hours for which they did not receive a day-ahead schedule. Resources would not be able to re-bid commitment costs in the real-time market once operating and subject to a minimum run-time constraint. The Board already approved this element at its March 2016 meeting, however, Management will include this provision in the FERC filing for expedited treatment and implementation. Second, Management will include a provision the Board also approved at its March meeting that will result in the ISO market no longer automatically inserting bids into the real-time market for resources that had bid into the day-ahead market but did not receive a day-ahead schedule and that do not have a real-time must offer obligation. This will ensure the real-time market will not consider bids from generators that did not have an obligation to plan for gas procurement to operate in real-time from neither receiving a day-ahead schedule nor having a real-time must offer obligation.

Management proposes a fourth market modification to make two day-ahead advisory market results available with the clarification that they are not financially binding and for information purposes only. Currently, the ISO runs a two day-ahead market, which provides advisory results. The ISO uses these results for internal planning purposes only. The ISO would provide advisory information to market participants on estimates of their day-ahead market schedules so that they can consider this information in purchasing gas in the next day gas trading that primarily occurs before ISO day-ahead market results are available.

The final market modification is to permit market participants to file with the Federal Energy Regulatory Commission to have the opportunity to recover incurred commitment costs that exceed the commitment cost bid cap not recovered through market revenues as the result of high marginal fuel procurement costs not being fully reflected in the bid cap. The Board previously approved this measure at its March Board meeting. However, in light of the Aliso Canyon situation, Management proposes to expand this measure to also allow an opportunity for market participants to seek recovery for marginal fuel procurement costs associated with providing incremental energy and to modify its reimbursement method. The expanded measure will permit market participants to file with the Federal Energy Regulatory Commission to have the opportunity to recover incurred incremental energy costs that exceed the default energy bid not recovered through market revenues as the result of high marginal fuel procurement costs not being fully reflected in default energy bid. At the March Board meeting, Management proposed to reimburse the FERC-approved costs through its bid cost recovery mechanism. Management now proposes to adjust the reimbursement method to allocate costs the Commission finds to be just and reasonable to measured demand.

POSITIONS OF THE PARTIES

Stakeholders support Management's objective to quickly develop market and operational tools to mitigate the reliability issues raised by the limited operability of the Aliso Canyon gas storage facility. Stakeholders generally support the provisions to provide more flexibility to accurately reflect gas prices and to provide ISO operators with additional tools to manage electric system dispatch impacts on the SoCalGas and SDG&E systems. However, several stakeholders requested that Management provide further explanation and clarification on the details as to how the proposed provisions would be designed and implemented. In response, Management posted a revised draft final proposal that includes additional details. However, Management cannot at this time explain in exact detail how and when the operational tools would be used. The specific impacts of the limited operability of the Aliso Canyon facility on the electric system under various system conditions this summer are unknown. Consequently, implementation flexibility will be critical for both the market provisions and the application of the new operational tools.

Six Cities raised concerns that the proposed gas availability constraint would disproportionately impact certain small load serving entities. This concern was based on the understanding that the constraint would be uniformly applied to all generators in the affected area. Management clarifies that the constraint is not uniformly applied. It takes into account local reliability needs, efficiency of units, and resource costs to most effectively and efficiently limit generation dispatch consistent with gas availability limitations.

Some stakeholders are concerned that the real-time pricing provisions in Management's proposal only apply to affected generators on the SoCalGas system. They argue that the proposed provisions should apply to all gas generators in the ISO system. The pricing provisions in Management's proposal are intended to be short-term measures to address the immediate needs of the system to provide reliable operations in southern California over the summer. The pricing provisions are designed to only be applied to the affected generators so that the market will limit real-time dispatches of these generators for local reliability needs and in a manner supportive of gas system limitations. This will mitigate the primary limitation of the gas system—using more gas over the real-time operating day than that which was scheduled for that day.

Finally, some stakeholders also urged Management to commit to a process to replace the short-term solutions included in the proposal with more market-based solutions. Management has made several enhancements to its bidding rules and commitment cost market designs and will continue to pursue further enhancements to effectively address issues related to allowing accurate marginal costs to be fully reflected into ISO market bids.

CONCLUSION

Management requests Board approval of the proposal discussed above. The proposed market and operational tools will provide important functionality to mitigate the reliability impacts of the limited operability of the Aliso Canyon natural gas storage facility. The proposal includes flexibility so that the ISO can adjust the use of the new tools in line with market and reliability needs.

Attachment F – DMM Comments

Tariff Amendment to Enhance Gas-Electric Coordination to Address Risks Posed by Limited Operability of Aliso Canyon Natural Gas Storage Facility

California Independent System Operator Corporation

May 9, 2016

Comments on Final Aliso Canyon Gas-Electric Coordination Proposal

Department of Market Monitoring

May 6, 2016

The Department of Market Monitoring (DMM) has worked closely with the ISO in developing the ISO's Final Proposal for Aliso Canyon Gas-Electric Coordination. DMM supports the key elements of the ISO's final proposal, which was modified and expanded over the course of the stakeholder process based on input from DMM. DMM provided input through written comments, as well as by directly working with ISO staff.[1] Section 1 of these comments summarizes DMM's recommendations and analysis of key elements of the ISO proposal. Section 2 provides a more detailed analysis performed by DMM to assess and recommend the 75 percent adder being proposed for gas price indices used to calculate bid caps for commitment costs for resources in the Southern California Gas Company (SoCalGas) and San Diego Gas and Electric (SDG&E) service areas (collectively referred to as the SoCal gas system in these comments).

1. Key provisions of proposal

1.1 Increase in gas prices used for commitment costs

Background

Currently, start up and minimum load bids in the real-time market for most gas-fired capacity in the ISO system are capped at 125 percent of estimated costs. These cost-based caps are based on an index of gas prices for gas purchases in the market for next day delivery. Thus, these prices may not reflect actual prices for any gas that is purchases in the same day market as a result of resources being committed in the real-time energy market. In addition, generators cannot submit bids in excess of these cost-based caps as a means of managing how units are committed or dispatched in the real-time market in order to avoid gas imbalances and potential imbalance penalties or charges.

Because of the special gas balancing provisions and restrictions being implemented in the SoCal gas system, the ISO is proposing to increase the gas index used in calculating these commitment cost bid caps in the real-time market for resources in these areas. Under the ISO's proposal, the level by which the current gas price indices for the SoCal gas system would be increased is based on the following objectives:

- Enable the ISO market to dispatch generators served by the SoCal gas system only for local electricity needs and not for system electricity needs that can be met by other resources;
- Account for any systematic premium for gas procured in the same day market relative to the next day delivery gas prices used to calculate bid caps; and

[1] *Comments on Aliso Canyon Gas-Electric Coordination Straw Proposal*, Department of Market Monitoring, April 22, 2016, http://www.caiso.com/Documents/DMMComments_AlisoCanyonGasElectricCoordinationStrawProposal.pdf.

Comments on Aliso Canyon Gas-Electric Coordination Draft Final Proposal, Department of Market Monitoring, April 29, 2016, http://www.caiso.com/Documents/DMMComments_AlisoCanyonGas_ElectricCoordinationDraftFinalProposal.pdf

- Improve generators' ability to manage gas company requirements on the constrained systems to limit differences between individual generator's gas schedules and usage (i.e., gas balancing requirements).

Analysis by DMM indicates that prices for gas in the same day market in the SoCal gas area have not, on average, historically exceeded prices in the market for next day delivery and that same day prices have significantly exceeded next day prices on a very small portion of days.[2] The extent to which the additional gas restrictions created by Aliso Canyon may increase same day prices relative to next day prices is uncertain and cannot be estimated at this time. Therefore, DMM has recommended that the initial increase in gas price indices used for commitment cost bids be based on a level designed to enable the ISO market to dispatch generators on the SoCal gas system only for local electricity needs and not system electricity needs that can be met by other resources.

Units are committed (or kept on-line for additional hours) in the real-time market by the market optimization based on a combination of three-part bids: start-up, minimum load and energy.[3] Generators can affect unit commitment decisions by submitting energy bids up to the $1,000/MW energy bid cap. To avoid additional commitment and dispatch of resources in the real-time market within a gas constrained area for system needs that could be met by other resources, it is only necessary that total costs for resources in the gas constrained area (based on three part bids) be marginally higher than total costs for resources in the non-gas constrained areas.

To help determine how to set the initial value by which gas prices may be increased under this framework to limit real-time unit commitments in the SoCal gas system for local area needs, DMM assessed the degree that commitment cost bid caps for these resources might need to be increased so that most of this gas-fired capacity is slightly higher in the economic merit order than other units that could be committed to meet system needs. Based on this analysis, DMM recommended that an increase in the gas indices for units in the SoCal gas system of 75 percent appears sufficient to achieve this objective.

Figure 1-1 shows the economic merit of gas-fired capacity within the SoCal gas system relative to resources within the rest of the ISO system based on minimum load cost caps with current gas price indices. Figure 1-2 shows how this merit order changes with the initial 75 percent increase in the gas cost indices being proposed for units in the SoCal gas system. As illustrated by these results, the proposed 75 percent adder ensures that most capacity in the SoCal gas area will have a higher minimum load bid cost cap than gas-fired capacity located elsewhere in the ISO system. Detailed results of this analysis are provided in Section 2 of these comments.

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[2] *Report on natural gas price volatility at western trading hubs,* Department of Market Monitoring, May 14, 2015: http://www.caiso.com/Documents/DMMReport-GasPriceAnalysis.pdf

Report on natural gas price volatility, Department of Market Monitoring, September 21, 2015: http://www.caiso.com/Documents/DMMReport-gas_price_analysis_september2015.pdf

[3] Once a unit is on-line start-up bids are treated as a "sunk" cost.

Figure 1-1. Minimum load proxy cost caps (No SoCal gas adder)
All gas-fired resources

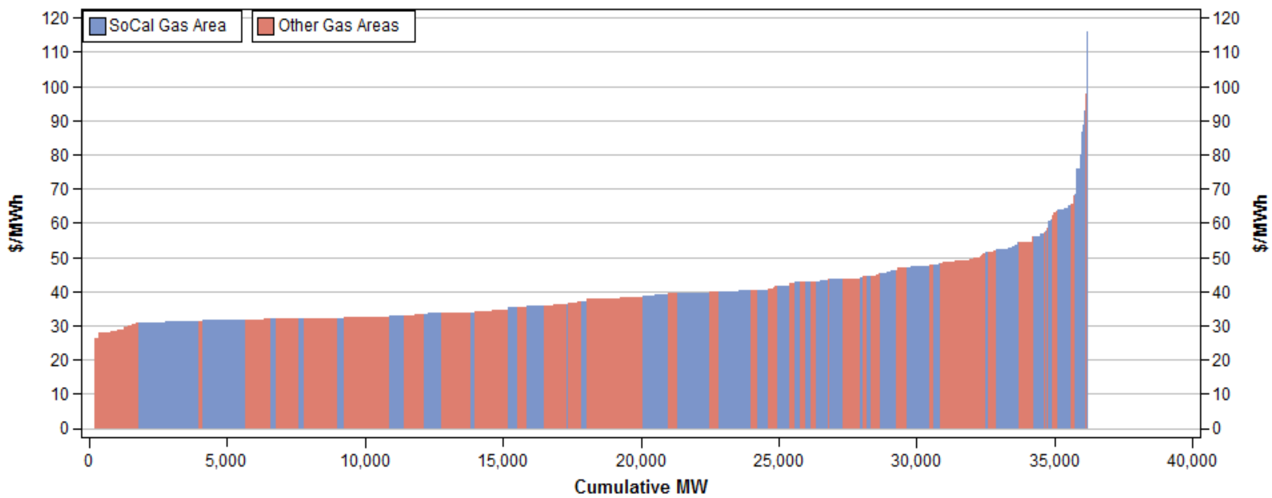
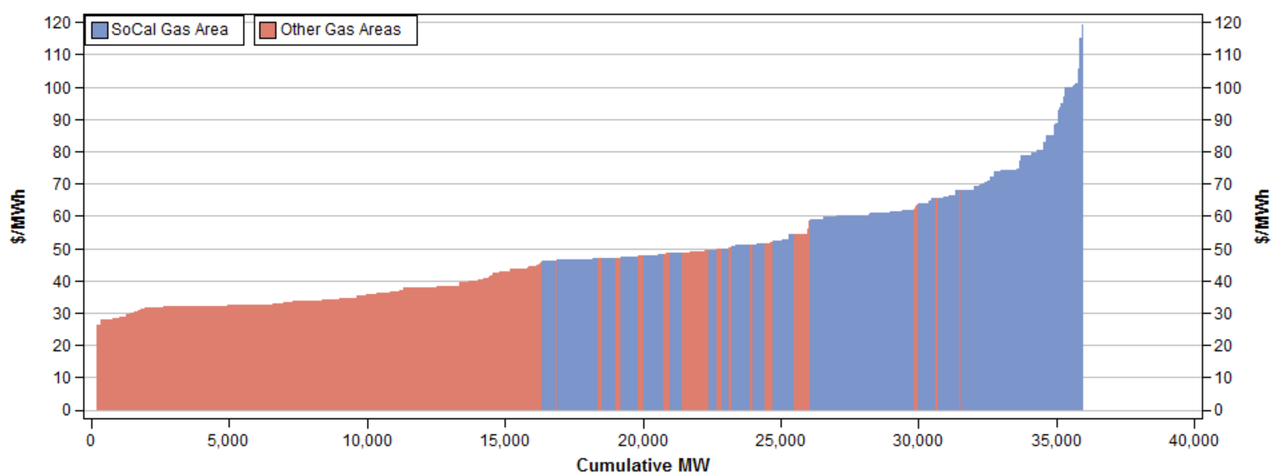


Figure 1-2. Minimum load proxy cost caps (75 percent SoCal gas adder)
All gas-fired resources



DMM strongly recommends that the ISO should have the flexibility necessary to adjust the gas price level used in calculating commitment cost bids caps based on observed market conditions and outcomes. However, DMM does not believe that the ISO should set the maximum value of the commitment cost cap up to the cost of an operational flow order penalty. Based on current gas prices, when combined with the 25 percent headroom already applied to commitment costs, this would represent an increase of over 300 percent in the gas prices used in calculating commitment cost bid caps to 4 times the gas price index value.[4] This is discussed in Section 1.2 below.

[4] The ISO's cap is proposed to be $2.50 plus two times the next day gas index. Prevailing natural gas prices at the SoCal Citygate are currently around $2.10/MMBtu. This results in an adder of $2.50 + $2.10 *2 = $6.70/MMBtu. Combined with

1.2 Basing commitment cost caps on gas penalties

In its filing, the ISO seeks to have the authority to set the gas indices used in calculating commitment costs up to a level that could effectively be more than enough to cover potential operational flow order penalties.[5]

As previously noted, DMM is not supportive of increasing gas prices used in calculating commitment cost bid caps to a level that could cover potential operational flow order penalties. This would simply remove the incentive for generators to avoid penalties and be likely to result in much higher bid cost recovery payments – without decreasing the amount of generation (and gas) actually needed to meet local needs within non-competitive areas.

Setting commitment cost caps to cover potential gas imbalance penalty prices essentially represents a worst case scenario and could reduce the incentive to avoid such penalties. DMM also notes that under the ISO's proposal, any commitment costs that are not recovered through the market or through bid cost recovery should be recoverable as part of the ISO's proposal on after-the-fact bid cost recovery. While DMM agrees that cost-based bid caps should be set high enough to result in efficient unit commitment and dispatch – and recover full cost under most cases – these caps also need to be set at levels that protect against excessive costs for consumers.

DMM has recommended that the ISO explicitly address whether any penalties should be eligible for inclusion in cost recovery. DMM supports explicit provisions on allowing recovery of gas penalties which are incurred as a direct result of (1) an ISO real-time commitment, (2) exceptional dispatch or (3) real-time energy dispatch when a unit was subject to bid mitigation. This approach provides more protection against local market power, potential gaming of commitment costs, and excessive costs to consumers in excess of actual incurred gas procurement costs.

1.3 Increase in gas prices used for Default Energy Bids

While commitment cost bids submitted by generators are currently capped at 125 percent of estimated costs based on the price of gas in the next day market, generators can submit energy bids up to the $1,000/MW energy bid cap. These energy bids are only subject to mitigation in the event that congestion occurs and the supply that can relieve this congestion is deemed uncompetitive under the

the current adder of 125 percent this would result in a total fuel cost of ($6.70/MMBtu * 1.25) = $8.375/MMBtu. This is an increase of about 300 percent of a $2.10/MMBtu gas price.

[5] The ISO has proposed a cap that is similar to a stage 5 operational flow order penalty on the SoCal gas systems. For example, assume gas prices of $2.50/MMBtu. The ISO's proposed cap increase would be $2.50 plus $2.50/MMBtu times two which would be $7.50/MMBtu. After factoring in the current 125 adder on proxy costs, the total fuel cost adder would be $7.50 * 1.25 = $9.375/MMBtu. We understand that the stage 5 operational flow order penalty in the SoCalGas system is $2.50 plus the daily balancing standby rate, which is equivalent to the InterContinental Exchange (ICE) Day-Ahead Index (including FF&U and brokerage fee) for the SoCal-Citygate, rounded up to the next whole dollar (see Sheet 12 https://www.socalgas.com/regulatory/tariffs/tm2/pdf/4822.pdf). Thus, if the gas price was $2.50/MMBtu, the stage 5 operational flow order penalty would be $2.50 plus $2.50 rounded up to the nearest dollar, which would be about $8/MMBtu ($5 + $3). Thus, in this example, the ISO's total fuel cost cap would be $9.375/MMBtu, which would be higher than the emergency flow order penalty of about $8/MMBtu plus the including FF&U and brokerage fee.

ISO local market power mitigation procedures.[6] When subject to mitigation, market bids submitted by generators are capped at the higher of competitive market prices or Default Energy Bids (DEBs) based on estimated marginal costs.

Like commitment cost bids caps, Default Energy Bids for the real-time market must be calculated in advance based on the price of gas in the next day market. However, unlike commitment costs, energy bids submitted by participants are only subject to mitigation and can only be dispatched based on a mitigated bid if they are needed to meet a local need within an uncompetitive area. Since units can only be dispatched based on Default Energy Bids for local needs, DMM believes it is unnecessary to inflate Default Energy Bids in the SoCal gas system to avoid having units in this area dispatched for system rather than local needs. Increasing Default Energy Bids above actual cost in this situation is likely to simply raise prices, without decreasing the amount of additional generation (and gas) needed from suppliers within the uncompetitive area to relieve congestion and ensure local reliability.

In addition, it is important to note that – unlike commitment costs—energy bids set the market price for the entire market. Generators would earn this higher price for all sales, but may incur an actual penalty only on the incremental amount of gas burned in excess of the tolerance band incorporated in the SoCal gas operational flow order or daily imbalance provisions. In addition, higher prices in the real-time market can raise prices in the day-ahead market, especially if virtual bidding is allowed.

For these reasons, DMM recommended that a different price index and criteria be used to determine any increase in Default Energy Bids than are used for commitment costs. Specifically, DMM suggests that it is only appropriate to increase the gas price index for Default Energy Bids to (1) reflect any systematic premium observed in same day gas prices relative to next day prices used to calculated Default Energy Bids, or (2) allow generators with units in the SoCal gas region to manage the merit order of resources that can meet local needs in the SoCal gas area to avoid potential penalties.

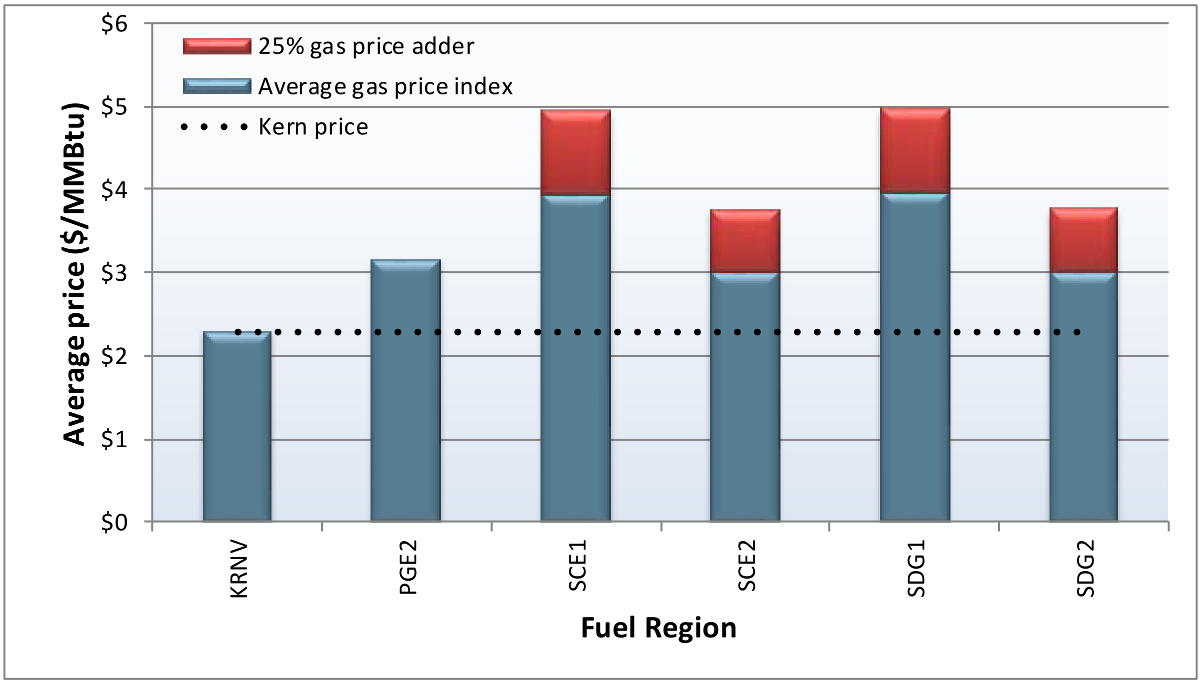
As noted in Section 1.1, the extent to which the additional gas restrictions created by Aliso Canyon may increase same day prices relative to next day prices is uncertain and cannot be estimated at this time. Therefore, DMM has recommended that the initial increase in gas price indices used for Default Energy Bids be based on a level that will allow generators with units in the SoCal gas region to manage the merit order of resources that can meet local needs in the SoCal gas area to avoid potential penalties. In addition, DMM also noted that the gas index used in calculating Default Energy Bids in the SoCal gas area would need to be inflated by a much lower amount than the gas index used in calculating commitment costs to achieve this objective.

Based on this recommendation, the ISO's final proposal was modified so that gas prices used in calculating Default Energy Bids for units in the SoCal gas area would be increased by a lower level than ISO has proposed for commitment cost bids. The ISO is proposing to initially increase gas prices used to calculate Default Energy Bids for these units by 25 percent, with a maximum increase of 100 percent.

[6] When bids are subject to mitigation, bids are frequently not mitigated down to cost-based Default Energy Bids, but are instead lowered only to a competitive market price that is usually greater than the cost-based Default Energy Bids of many units.

DMM believes the 25 percent increase proposed by the ISO is sufficient to achieve the goals of this increase. Figure 1-3 shows average gas prices from January 2015 to May 2016 for the various regions in the ISO used in calculating commitment cost caps and Default Energy Bids. These prices include gas commodity prices plus application of distribution charges for the applicable gas region.

Figure 1-3. Comparison of average gas price indices (January 2015 – May 2016)



As shown in Figure 1-3, gas prices for the Kern River pipeline (KRNV), which serves some generators in Southern California, are significantly lower than gas price indices for the areas served by the SoCal gas system (SCE1, SCE2, SDGE1, SDGE2). Over 1,600 MW of highly efficiency combined cycle gas-fired capacity is served by the Kern River pipeline south of Path 26 in SP15. The lower gas prices in this area – combined with the additional 25 percent adder proposed for units in the SoCal gas areas – should ensure that when congestion occurs in the north-to-south direction on Path 26, gas-fired capacity in the Kern area that is available in the real-time market should be available for dispatch to meet any real-time demand in the Southern California area outside of the gas-constrained areas in the SoCal gas system. At the same time, this provides further assurance that that the 25 percent adder proposed for units in the SoCal gas system will cause units in this gas-constrained area to be dispatched for additional energy in the real-time only when needed to meet demand within these areas.

1.4 Cost adders based on same day gas prices

Analysis by DMM indicates that historically the same day market in the SoCal gas area is very thin and that prices do not tend to exceed next day prices on average – and have significantly exceeded next day prices on a very small portion of days.[7] DMM believes it is uncertain whether the additional gas restrictions created by Aliso Canyon will change this historical trend and the degree to which available data on same day trades will provide a basis for determining if same day prices are systematically higher than next day prices. However, to the extent that there is an actual market for same day gas (for which reliable price data are available), DMM agrees Default Energy Bids should reflect this price.

Following implementation of new gas balancing rules in the SoCal gas area, DMM is prepared to work with the ISO to assess available data on same day gas trades to determine if same day prices are systematically higher than next day prices. Based on this analysis, DMM is also prepared to work with the ISO to determine how this might warrant increasing gas price adders used in determining commitment cost and Default Energy Bids.

1.5 Improved day-ahead gas price index

The ISO proposes to improve the day-ahead gas price index used in the day-ahead market. Currently, the ISO uses an index developed from a set of price indices from the market for next day delivery. However, due to the timing of the release of these indices, the ISO uses prices from delivery on the prior day. The ISO is proposing tariff revisions so that prices used in the day-ahead market would be based on an index calculated by the ISO based on data from the Intercontinental Exchange (ICE) that are available in the morning prior to the start of the day-ahead market. This will eliminate the one-day lag in the next day market gas prices currently used for the ISO's day-ahead market.

The ISO's proposal indicates the index calculated by the ISO will be a volume weighted average price consistent with the methodology that ICE uses to calculate its own gas index. During the stakeholder process, the ISO indicated this enhancement would only be implemented once it was "completely automated." DMM expressed concern that complete automation of this process may not be completed in the time frame in which the ISO's proposal is intended to be implemented.

Consequently, DMM has recommended that the ISO maintain flexibility to use an estimate of next day price based on available ICE data even if full automation or the calculation of a weighted average price is not in place. For instance, if prices appear to be about 20 percent higher and the ISO can reasonably estimate this 20 percent increase based on ICE data, the ISO should have authority to increase the gas prices used in the day-ahead market using its best estimate based on available gas market price data.[8]

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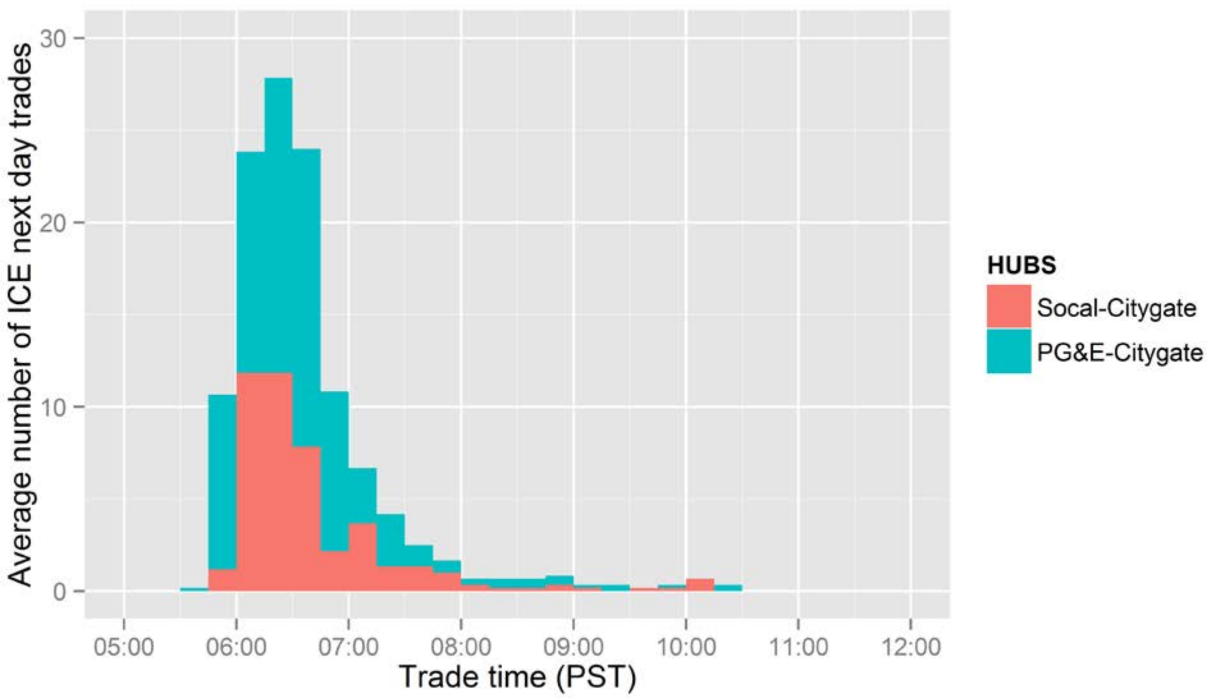
[7] *Report on natural gas price volatility at western trading hubs,* Department of Market Monitoring, May 14, 2015: http://www.caiso.com/Documents/DMMReport-GasPriceAnalysis.pdf

Report on natural gas price volatility, Department of Market Monitoring, September 21, 2015: http://www.caiso.com/Documents/DMMReport-gas_price_analysis_september2015.pdf

[8] DMM notes that this approach would appear to be at least as accurate and involve even less discretionary judgement as approaches used by some other ISOs, under which generators submit their own cost-based bids, subject to review by the ISO. When reviewing such bids, ISOs would need to routinely rely on rough comparisons

Figure 1-4 provides an example of the timing and volume of trades on ICE for the gas market for next day delivery during a typical period (flow dates April 1-8, 2016). As shown in Figure 1-4, the bulk of trades on ICE for the gas market for next day delivery are concluded by 8 a.m. PST. Thus, it appears that when there is a significant change in prices from the prior day in next day gas prices, even a reasonable approximation of the final ICE index could be developed that is much more accurate than the gas price indices for the prior day that would otherwise be used.

Figure 1-4. Timing and volume of next day ICE gas trades (April 1 - 8, 2016)



of bid prices to gas market prices during the gas trading period, and these accepted bid prices would be used in the market.

1.6 Rebidding of commitment costs in the real-time market

The ISO proposes to allow generators to re-bid commitment costs in the real-time market. This change would allow generators to utilize the higher caps on commitment costs being allowed in the real-time market. Allowing generators to change commitment cost bids throughout the operating day in real time will create significant new opportunities for generators with intertemporal constraints (such as minimum up and minimum down times) to exploit bid cost recovery. This could result in generators receiving payments in excess of the generators' actual commitment costs. This potential for exploiting bid cost recovery will be further exacerbated by the ISO's proposal to increase the commitment cost caps above 125 percent of proxy costs.

Therefore, DMM has encouraged the ISO to develop real-time commitment cost bidding guidelines that strike a balance between allowing flexibility for generators to bid costs they would expect to incur if dispatched and safeguarding against unreasonable bid cost recovery uplift payments.

The ISO has proposed versions of the following real-time commitment cost bidding guidelines:

1) No changing of day-ahead commitment costs in real-time for trading hours in which the generator has a day-ahead award; and
2) No changing of real-time commitment costs for the duration of the minimum up time of a unit (or configuration) after the unit (or configuration) has been committed in real time.

DMM supports these rules. However, market participants and FERC should be aware that the second rule above is unlikely to be able to be automatically enforced by the ISO's software. Therefore, market participants will be *physically* able to adjust a generator (or configuration) commitment cost in real-time during the generator's (or configuration's) minimum up time. The adjusted commitment cost will be used by the optimization and in settlements. However, DMM understands that it will be considered to be a tariff violation for the scheduling coordinator to execute this change to the generator's real-time commitment cost.

DMM will be closely scrutinizing changes to commitment costs in real time that coincide with bid cost recovery payments. However, DMM notes there are inherent difficulties and shortcomings in relying on behavioral monitoring to differentiate between (1) legitimate uses of real-time commitment cost bidding flexibility; and (2) potential exploitative uses of real-time commitment cost flexibility to inflate bid cost recovery payments. In this case, DMM supports relying on monitoring of real-time market bidding behavior during the interim period – as opposed to more restrictive rules -– in order to allow the potential benefits of re-bidding of higher real-time commitment costs that include gas cost adders.

DMM also notes the potential for behavior designed to trigger excessive bid cost recovery due to the provision allowing re-bidding of commitment costs in real time would be exacerbated if the ISO inflated the gas index used to calculate commitment cost caps to higher levels (e.g. significantly more than the 75 percent level incorporated in the ISO proposal). This would be of particular concern to DMM if the

ISO inflated this gas index to a much higher level based on potential penalties for excessive gas imbalances.

1.7 Authority to deem constraints uncompetitive based on gas limitations

The ISO's current local market power mitigation procedures are triggered based on an automated assessment of the structural competitiveness of each constraint on which congestion is projected to occur. However, this procedure will not incorporate the impact of special gas usage constraints being proposed on restricting the actual amount of gas-fired generation available in Southern California to relieve congestion and meet local needs. As a result, constraints such as Path 26 could be deemed competitive when in fact the amount of supply in Southern California that can be dispatched to relieve congestion on these constraints is more restricted and uncompetitive. Thus, DMM has recommended that the ISO seek special tariff authority to deem selected constraints uncompetitive based on a determination that actual supply conditions may be uncompetitive due to special gas usage constraints being imposed on gas-fired units in the SoCal gas system.

Background

The ISO's local market power mitigation provisions involve several steps. First, when congestion is projected to occur on a constraint, the constraint is designated as either *competitive* or *non-competitive* using the *dynamic competitive path assessment* (DCPA). If a constraint that is projected to be congested is found to be structurally non-competitive based on this automated test, then resources that can relieve congestion on this constraint are subjected to potential bid mitigation.

The DCPA measures the competitiveness of each constraint using a residual supply index (RSI) based on supply and demand of counter-flow from internal resources that can relieve congestion on each binding constraint. The RSI is the ratio of competitive supply of counter-flow compared to total demand for counter-flow for the constraint. When this ratio is greater than 1.0, the constraint is considered to be competitive. If the RSI is less than 1.0, the constraint is considered non-competitive and can trigger bid mitigation.

The automated DCPA procedure incorporated in the ISO's market software does not incorporate the impact of special gas usage constraints being proposed on restricting the actual amount of gas-fired generation available in Southern California. This gas usage constraint will cause the amount of generation capacity available to relieve congestion and meet local needs in Southern California to be lower than the amount included in the DCPA. As a result, constraints such as Path 26 could be deemed competitive when in fact the amount of supply in Southern California that can be dispatched to relieve congestion on these constraints is more restricted and uncompetitive.

Analysis

To illustrate the ISO's potential need to deem some paths non-competitive due to the gas usage constraint, DMM has analyzed the results of the DCPA for Path 26 in the 15-minute market. Figure 1-5 shows a histogram of how frequently the RSI fell within different ranges when congestion has been projected to occur in the north-to-south direction on Path 26 over the two year period from May 2014 to May 2016. For example, the RSI was between 1.0 and 1.03 during over 19 percent of the 15-minute intervals during which congestion was projected to occur during this period.

As illustrated in Figure 1-5, when Path 26 has been congested in the north-to-south direction, this constraint has usually been deemed structurally competitive based on an RSI greater than 1.0. However, during many of these intervals, the RSI has been relatively close to the 1.0 threshold below which the constraint would be deemed noncompetitive. In other words, the RSI is often above 1 but usually not very far above 1.0. This indicates that when the gas usage constraint being proposed is binding and reducing the actual real available supply of competitive counter-flow, results of the automated DCPA may indicate the constraint is competitive when it may in fact be structurally non-competitive.

These findings are further illustrated in Figure 1-6. This figure shows the amount by which residual supply of competitive counter flow exceeded the demand for counter-flow for the intervals when congestion was projected to occur in the north-to-south direction on Path 26 and this constraint was deemed structurally competitive during this two year period. This highlights the sensitivity of the DCPA results from any overestimation of the actual supply of available counter-flow due to the gas usage constraint.

For example, during about 43 percent of the intervals in which Path 26 was projected to be binding, the competitive supply of counter-flow exceeded demand by less than 200 MW. If the gas usage constraint were in place in those intervals and decreased the competitive supply of 15 minute counter-flow by 200 MW or more, the constraint would be structurally non-competitive. However, since the DCPA cannot account for the impact of the gas usage constraint, the automated DCPA results would indicate the constraint is structurally competitive and bid mitigation would not be triggered. This could lead to unmitigated high bids setting prices.

Both of these analyses show that Path 26, like other constraints in the ISO system, is often close to the threshold between competitive and non-competitive. The impact of the gas usage constraint may be enough to change the competitive status of constraints at times, but cannot be incorporated into the DCPA. While this analysis centers on Path 26, the gas usage constraint may cause the DCPA to overestimate the competitiveness of a variety of constraints within Southern California.

At this time, the impact of the gas usage constraint on the DCPA cannot be determined or estimated. This can only be assessed based on actual system conditions once the constraint is in place. Because of this, DMM is recommending that the ISO have the authority to deem constraints within Southern California for which the RSI is affected by the gas usage constraint to be non-competitive during some days or hours. The type of analysis provided in this section provides an example of how the ISO may assess whether to deem a constraint non-competitive.

Figure 1-5. Residual supply index for Path 26 (north-to-south) during congested 15-mintue intervals (May 2014 to May 2016)

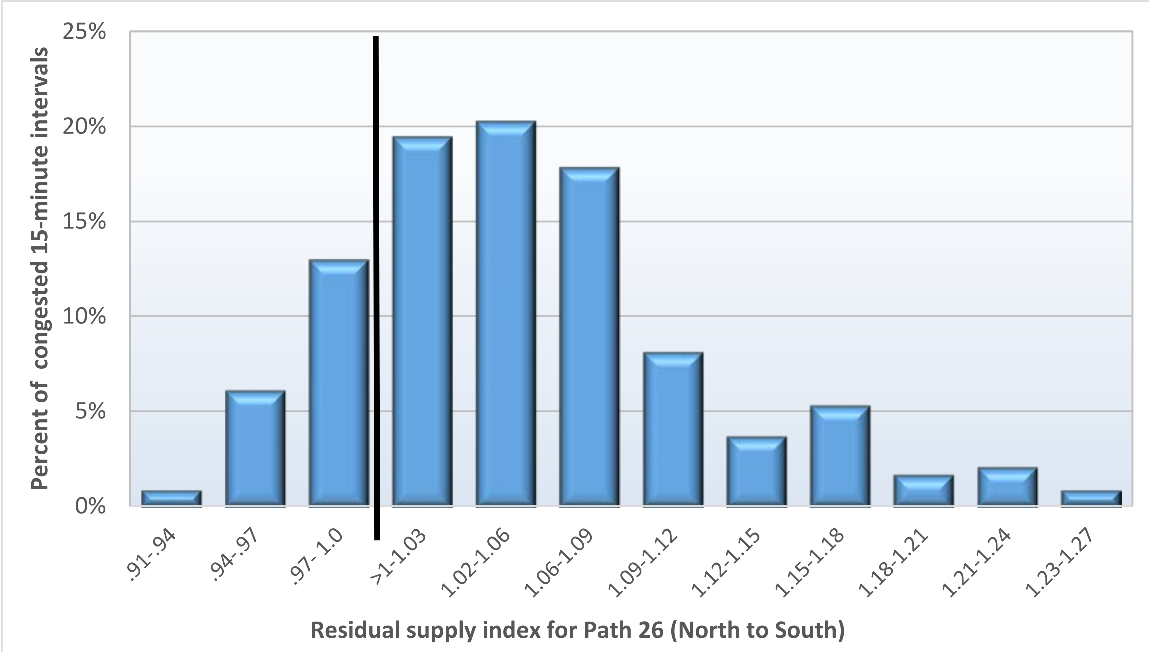
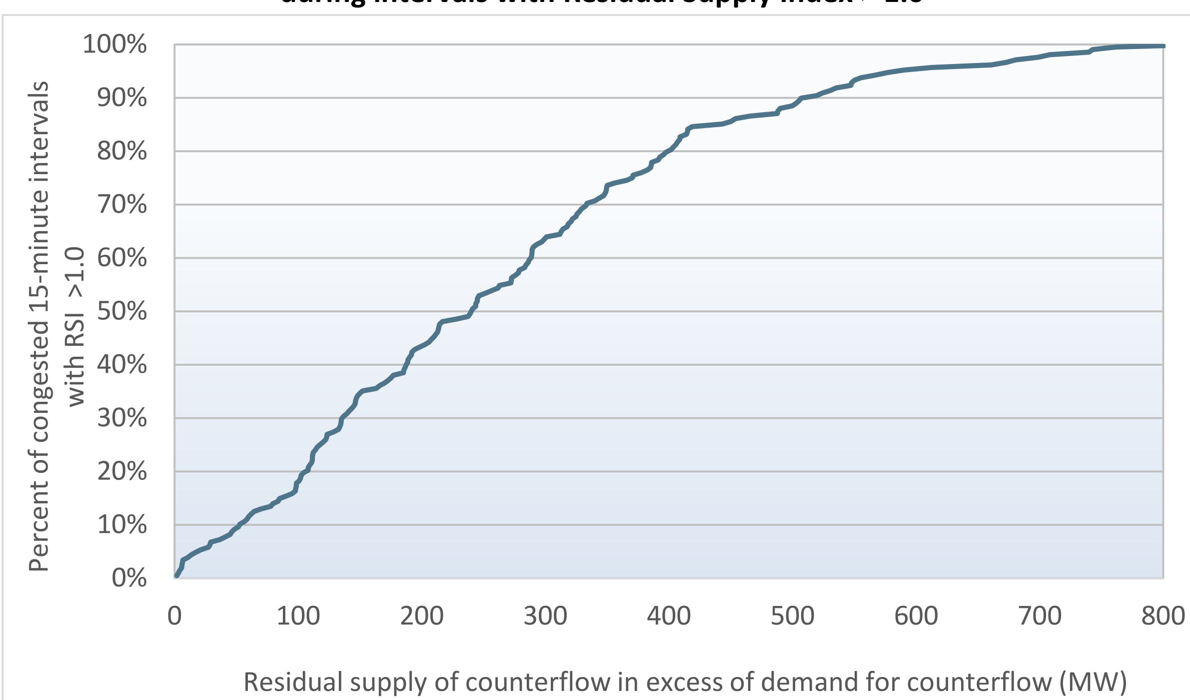


Figure 1-6. Sensitivity of residual supply index results to supply of counter flow on Path 26 during intervals with Residual Supply Index > 1.0



1.8 Expand authority to limit virtual bidding based on market impacts

The ISO tariff currently outlines the reasons for suspension of convergence bidding related to System Reliability or grid operations "if such activities contribute to threatened or imminent reliability conditions."[9]

As a general principle, DMM believes that when modeling, structural or market rule differences exist between the day-ahead and real-time markets, virtual bidding can often be profitable but provide little or no benefits – and can actually decrease market efficiency, make it more difficult to manage system reliability and result in inequitable market outcomes. Consequently, DMM strongly recommends the ISO modify its tariff to clarify its authority to suspend or limit virtual bidding – including at specific locations or regions – to prevent or protect against potential detrimental or inequitable market impacts.

One example of a virtual bidding strategy that could reduce market efficiency is related to the ISO's proposal to reserve transfer capability into a gas-constrained region in the day-ahead market. When the ISO releases the reserved transfer capability in real time, the day-ahead congestion price of the transfer path is likely to be higher than the real-time congestion price. Virtual supply placed downstream of the path and virtual demand placed upstream of the path could expect to profit from this difference in the path's congestion price.

However, downstream virtual supply and upstream virtual demand would reduce the day-ahead schedules of downstream gas-fired generation and increase the day-ahead schedules of upstream generation. The impact of such virtual schedules on day-ahead generation schedules is the opposite of the intended effects of reserving transfer capability. Such virtual schedules would therefore undermine the effectiveness of this reliability tool.

Although this virtual supply may cause more physical capacity within the SoCal system to be scheduled in the residual unit commitment (RUC) process, this is a much less efficient process for scheduling of electric supply. Additional capacity can be committed by the RUC process based on start-up and minimum load bids. However, most RUC requirements are met by capacity above minimum load for units that are committed in the day-ahead market or by the RUC process. This capacity is not awarded based on energy bid prices. Instead, RUC capacity bids are used, with most RUC awards being met by resource adequacy capacity, which is required to bid into the RUC process at a price of $0/MW.

The RUC process is also less efficient and effective from the perspective of maximizing the scheduling of gas prior to the real-time market. Since minimum load schedules for any long start units committed through the RUC process are financially and physically binding, generators may be expected and able to schedule gas for these commitments. However, since RUC schedules for capacity above minimum load and for all short-start units are not financially binding, generators may not be expected to schedule gas for this capacity. Thus, in the event virtual bidding increased reliance on the RUC process, this would

[9] See ISO tariff Section 7.9.2.

also undermine the goal of maximizing the scheduling of both electric supply and the needed gas on a day-ahead basis within the SoCal gas system.

Meanwhile, not routinely releasing the reserved transfer capability in real time would reduce the likelihood of such virtual schedules. However, not releasing the transfer capability in real time would be an inefficient use of available transmission capacity if most of the reliability benefits of reserving transfer capability in the day-ahead market can be achieved while still releasing the transfer capability in the real-time market.

DMM also recommends that the ISO closely monitor the impacts of virtual bidding and be prepared to quickly exercise this authority to suspend virtual bidding – including at specific locations or regions.

1.9 Limit sale of congestion revenue rights

DMM supports the proposal to reserve transmission capacity into the SoCal gas area in the day-ahead market to help limit gas imbalances in the real-time market. However, DMM has noted that this could cause the amount of congestion revenue rights (CRRs) allocated or sold by the ISO to exceed the amount of transmission capacity actually available in the day-ahead market. This causes CRR revenue inadequacy that is allocated to load-serving entities.

Given the uncertainty about the capacity into the SoCal gas area that will actually be available, DMM has recommended that the ISO carefully assess the amount of capacity that may be unavailable due to outages and any transmission reserved in the day-ahead market due to gas limitations in Southern California.

Path 26 is the most widely discussed example of a transmission path on which the ISO may reserve transmission capacity in the day-ahead market. Based on discussions with ISO staff, DMM understands that about 65 to 70 percent of the 4,000 MW of capacity in the north-to-south direction on Path 26 during the summer months (July to September) has already been allocated to load-serving entities or sold through prior auctions. Before additional capacity on Path 26 is made available in the monthly auctions for these months, DMM recommends the ISO assess the amount of additional transmission capacity that will be available with a high level of confidence, taking into account the following factors:

- **Transmission reservations.** The upper range of the amount of transmission capacity the ISO may reserve in the day-ahead market to help manage additional gas usage from real-time commitments and dispatches of electric generation capacity in the SoCal area.
- **Base flows.** The amount of capacity that may be needed to accommodate base flows in the day-ahead market created by the ISO's full network model, which represent unscheduled flows (or loop flows) created by energy and loads in other balancing areas.
- **Outages.** Potential unplanned transmission outages and de-rates.

Since the bulk of CRRs are purchased by purely financial entities, auctioning off more CRRs would appear to provide few benefits to participants interested in purchasing CRRs as a hedge for physical load or generation. In addition, entities interested in purchasing CRRs as a hedge for physical load or generation are free to contract directly with other parties for such hedges.

1.10 Limit time period of proposed actions

The ISO intends to sunset the provisions in its proposal by December 1 and reevaluate the effectiveness and the need for continuing the provisions moving forward. We agree with the ISO's proposal and recognize that some elements of the ISO's proposal could translate into more permanent changes.

2. Analysis of gas price adder for minimum load costs

This section summarizes analysis of how an extra fuel cost adder for commitment costs for resources in the SoCalGas areas would affect the likely system-wide dispatch order. The analysis shows that, if the objective is to make most these resources have a higher commitment cost than most resources outside the SoCalGas areas, then a 75 percent adder appears to be a reasonable starting point.

The ISO market software is designed to minimize total system bid-costs subject to both system-wide and resource-specific constraints. Therefore, the probability that a unit is committed (or kept on-line) in the real-time market depends on all three bid components (start-up, minimum load and incremental energy), as well as any resource-specific characteristics or constraints (e.g. start-time, minimum up time, minimum down time). Because of this complexity, it is not possible to precisely estimate how a gas-adder for commitment costs would influence the order in which resources would be committed for system needs.

This analysis focuses on one of the commitment cost bid components: the minimum load cost. This represents a major component affecting whether a unit is committed (or kept on-line) in the real-time market which can be directly compared across resources.

2.1 Comparison of minimum load costs

For this analysis, minimum load proxy cost caps are compared across resources by dividing the minimum load proxy cost cap by the resource's minimum operating level (or Pmin).[10] For multi-stage generators, this is done at the configuration level with the configuration-specific minimum load proxy cost cap and Pmin.[11] Only gas fired resources under the proxy cost option are included. These resources are grouped into two categories based on the resource's elected Master File fuel region:

- **SoCal gas area:** This includes gas resources in the SCE1, SCE2, SDG1 or SDG2 fuel regions, excluding resources identified by the ISO to be served by the Kern River Gas Transmission Company.
- **Other gas areas:** This includes gas resources in the CISO and PGE2 fuel regions as well as resources identified by the ISO to be served by the Kern River Gas Transmission Company.

Figure 2-1 shows the current ordering of minimum load cost bid caps for the set of resources described above without any extra gas adder.[12] Each bar represents one resource (or configuration), with the height of the bar reflecting the minimum load proxy cost bid cap per Pmin MWh, and the width representing the Pmin MW capacity. The resources are sorted by minimum load proxy cost cap per Pmin MWh from low to high. Blue bars represent resources in the SoCal gas area and red bars represent other gas area resources. As seen in this figure, the SoCal gas area resources are fairly evenly distributed across the stack of resources.

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[10] This analysis excludes the use-limited resources that are under the registered cost option. These resources have the option of switching to the proxy cost option. Moreover, these use-limited resources do not have the same must offer obligation as other resources.

[11] Including all configurations of all resources will result in some double-counting of capacity for multi-stage generating resources.

[12] This is as of May 1, 2016.

Figure 2-2 shows the same data as in Figure 2-1, except that a 75 percent adder has been added to the fuel cost component of the minimum load proxy bid cap for the SoCal gas area resources. With a 75 percent adder, the ordering changes such that SoCal gas area resources have a higher proxy cost cap than the majority of other resources.

Figure 2-1 Minimum load proxy cost caps (No SoCal gas adder)
All gas-fired resources

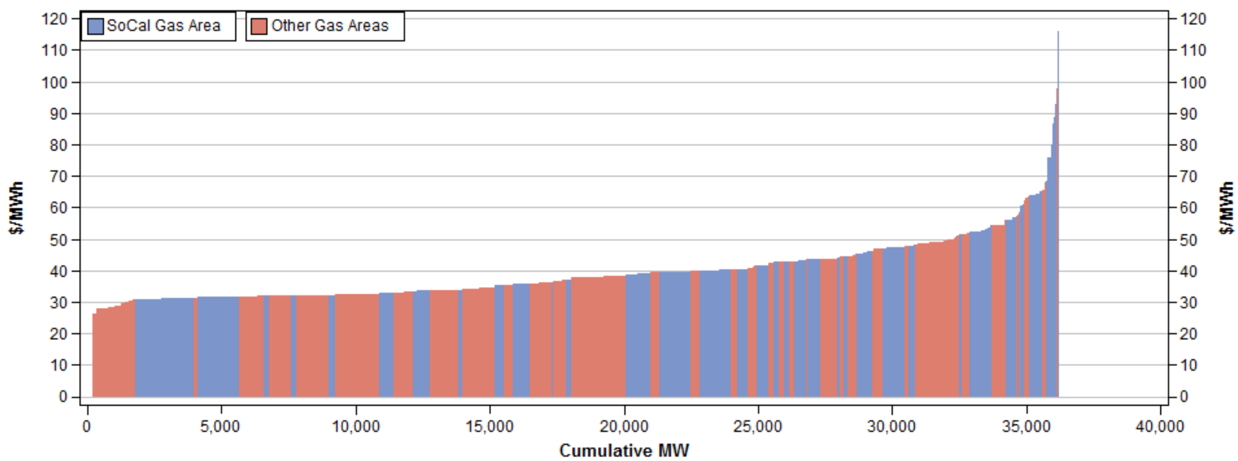
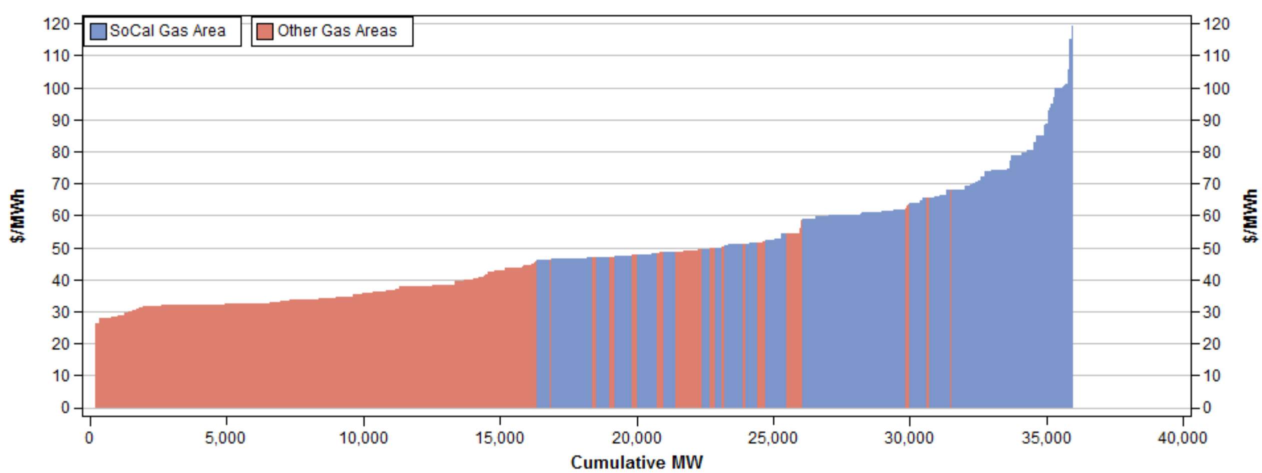


Figure 2-2 Minimum load proxy cost caps (75 percent SoCal gas adder)
All gas-fired resources



To compare the percentage of SoCal gas area resources that are higher than other gas area resources that is achieved using different adders, we have constructed the following methodology:

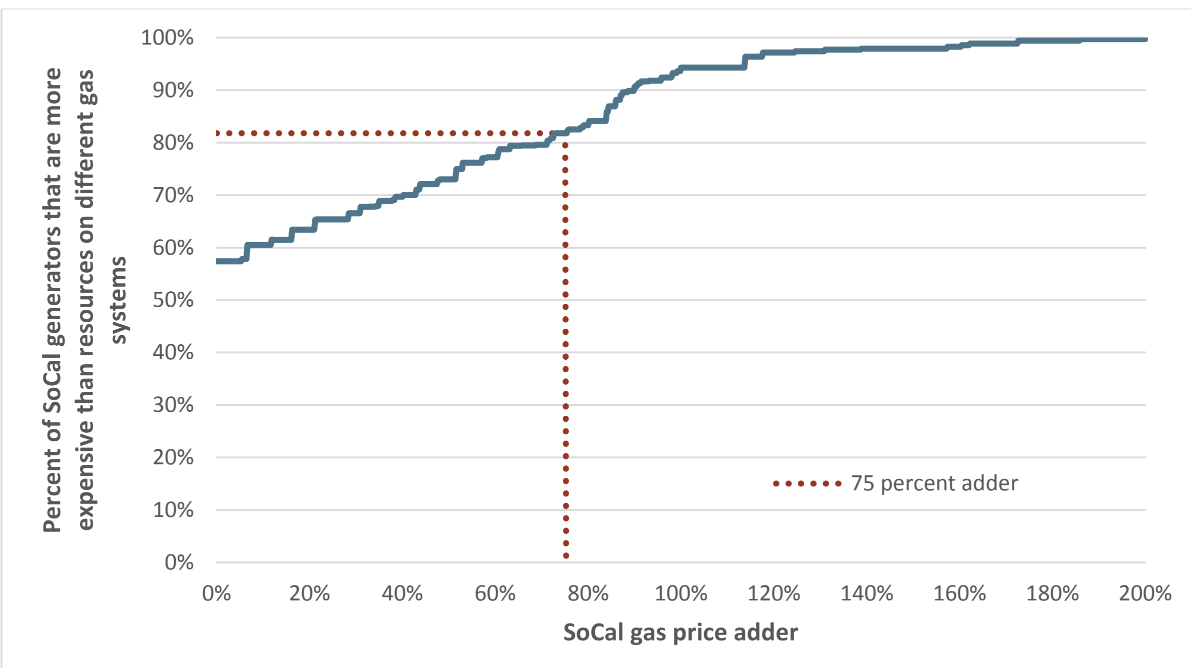
1. We first calculate the cumulative MW point at which all resources in the SoCal gas area have a higher cap than all other resources. This ordering defines a cut-off point between the two categories. This cut-off point is necessary because the quantity of resources in the affected SoCal gas areas are not the same total quantity as resources in other gas areas.

2. We then calculate the ordering of resources using different SoCal gas adders.

3. Using the ordering from step 2, we consider only the quantity of resources that are above the cut-off point defined in step 1. We then calculate the percent of this capacity that are SoCal gas area resources.

The resulting measure can be interpreted as the percent of SoCal gas generators that have higher minimum load bid caps than resources on other gas systems. Figure 2-3 shows this percent (y-axis) as a function of the SoCal gas adder (x-axis). As indicated by the red dashed line, a 75 percent adder results in about 82 percent of SoCal gas generation having higher minimum load bid caps than gas-fired capacity in the rest of the ISO system.

Figure 2-3 Percent of capacity in SoCal gas area with minimum load costs caps that are higher than resources in rest of ISO system (All gas-fired units)



This analysis is inclusive of all natural gas-fired generator types including combustion turbines, combined cycles and steam generators. While there may be times that the different resource types may compete with each other, it is likely that not all resources compete with each other at any given time because of differing operational parameters such as start-up times and ramp rates, and also because of different day-ahead commitment decisions. Thus, in the subsequent sections of this report, we provide the results of the same analysis performed in this section by gas-fired resource type.

Steam turbine resources

Figures 2-4, 2-5 and 2-6 are equivalent to Figures 2-1, 2-2 and 2-3 but only includes steam turbine units. As seen in these figures, using a 75 percent adder will result in about 97 percent of Southern California steam turbines having higher minimum load bid caps compared to steam turbines in other areas of the ISO.

Figure 2-4 Minimum load proxy cost caps (No SoCal gas adder) Steam Turbines

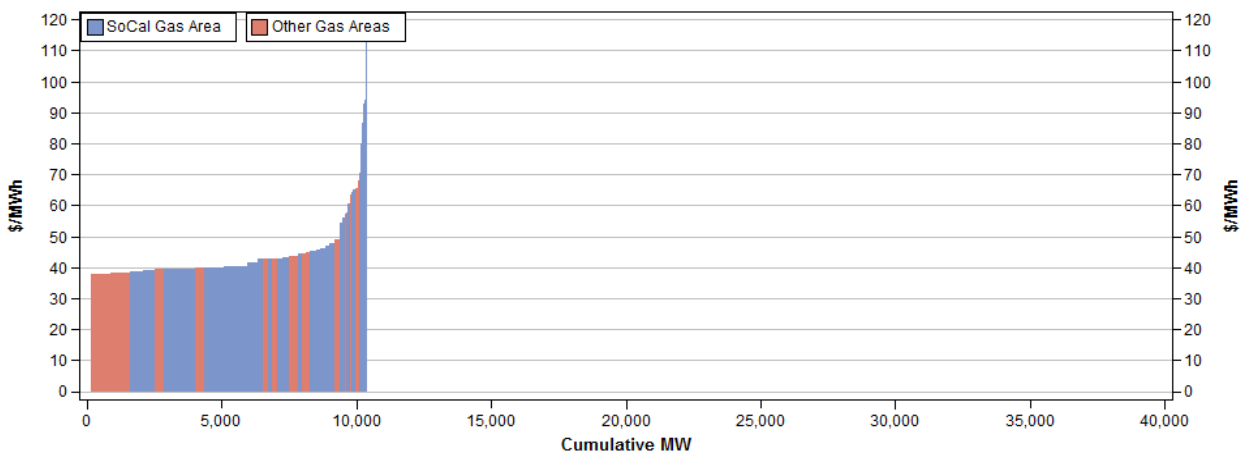


Figure 2-1 Minimum load proxy cost caps (75 percent SoCal gas adder) Steam Turbines

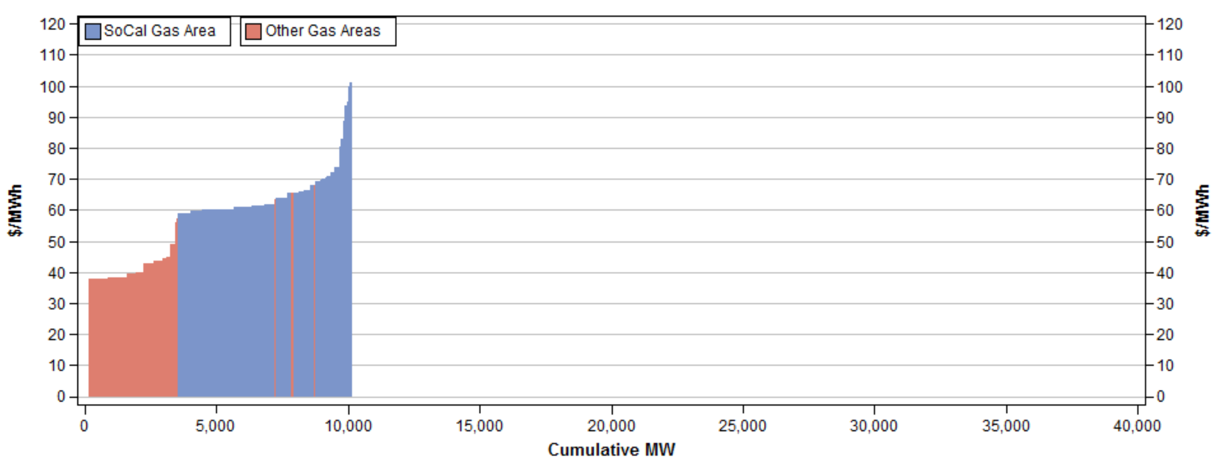
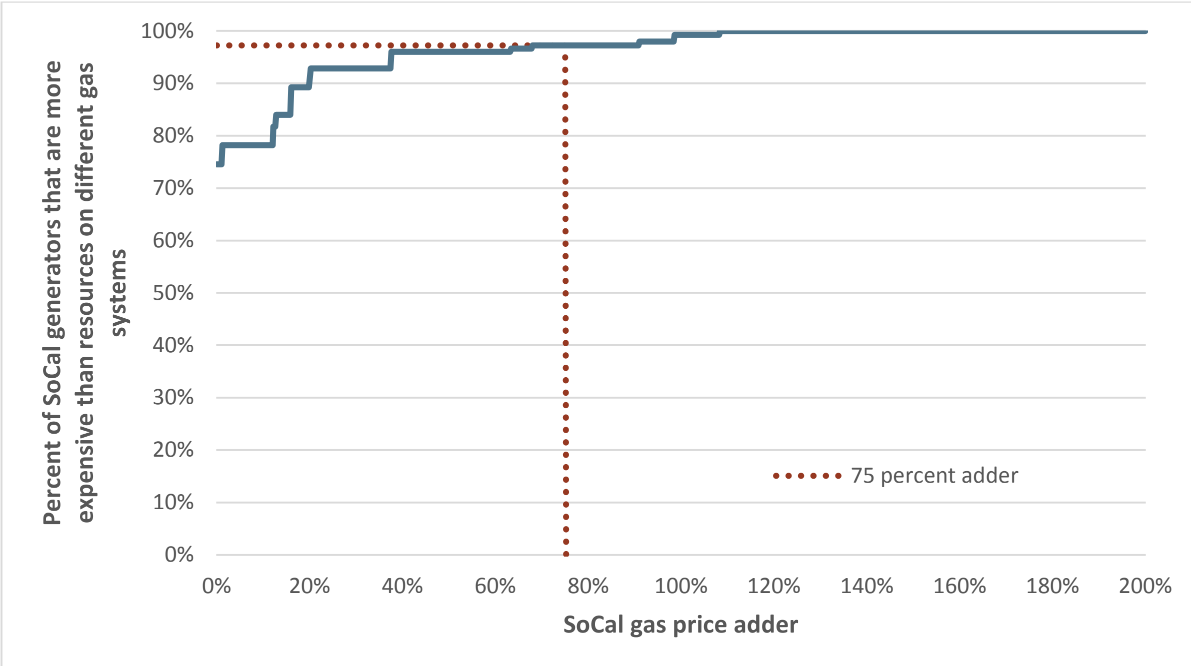


Figure 2-2 Percent of capacity in SoCal gas area with minimum load costs caps that are higher than resources in rest of ISO system (Steam Turbines)



Combined cycle resources

Figures 2-7, 2-8 and 2-9 include only combined cycle resources. As seen in these figures, using a 75 percent adder will result in about 95 percent of Southern California combined cycle configurations having higher minimum load cost than combined cycle capacity in other systems. With a 35 percent adder, about 92 percent of combined cycle capacity in Southern California capacity would have higher minimum load bid caps compared to combined cycle capacity in other areas.

Figure 2- 3 Minimum load proxy cost caps (No SoCal gas adder)
Combined Cycle units

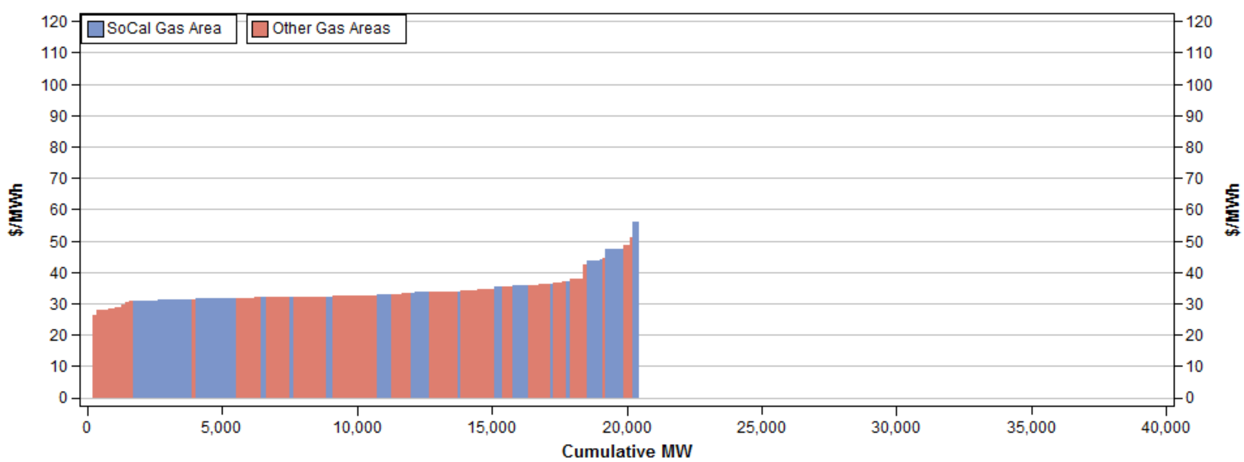


Figure 2- 4 Minimum load proxy cost caps (75 percent SoCal gas adder)
Combined Cycle units

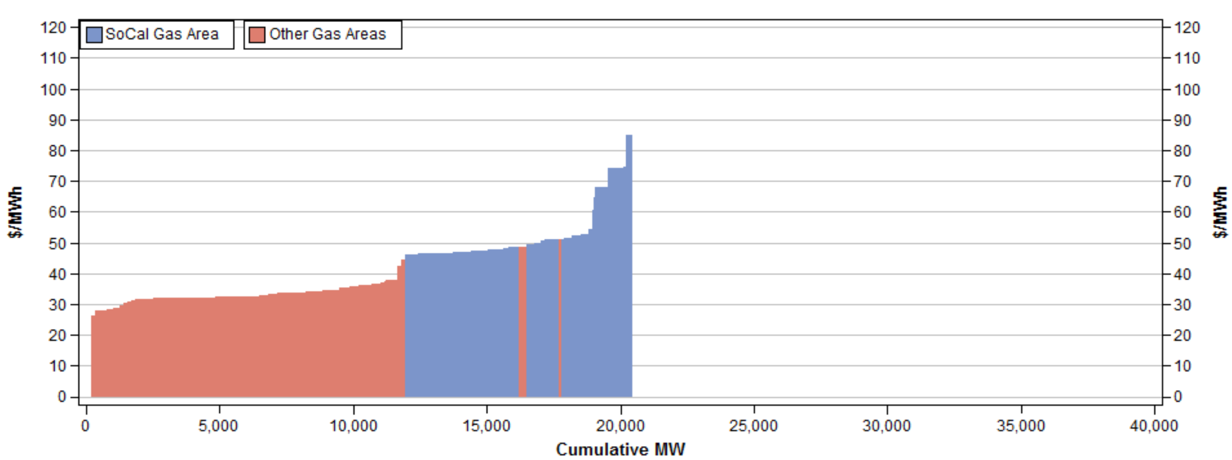
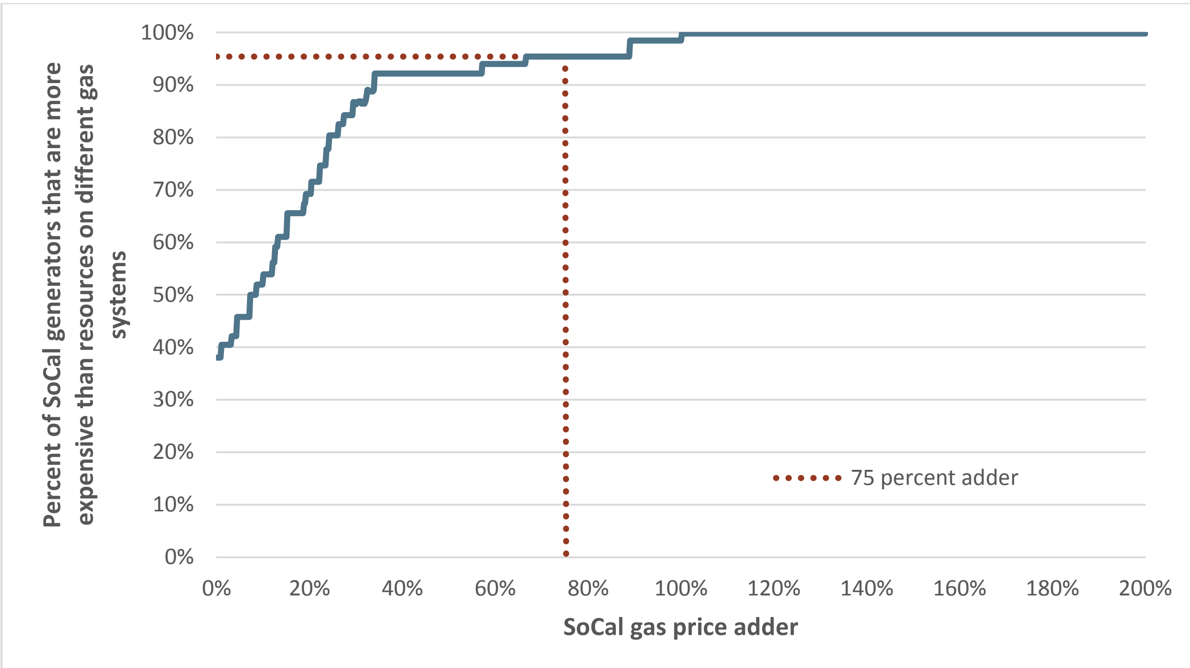


Figure 2- 5 Percent of capacity in SoCal gas area with minimum load costs caps that are higher than resources in rest of ISO system (Combined Cycle units)



Gas turbines

Figures 2-10, 2-11 and 2-12 include only gas turbines. As seen in these figures, using a 75 percent adder will result in about 98 percent of Sothern California gas turbine capacity having a higher minimum load bid cap than gas turbines in other systems. Since the Southern California gas turbines tend to have relatively high minimum load costs, an 8 percent adder is sufficient to cause almost 90 percent of this peaking capacity to have higher minimum load bid caps compared to peaking capacity in the rest of the system.

Figure 2-6 Minimum load proxy cost caps
Gas Turbines (No SoCal gas adder)

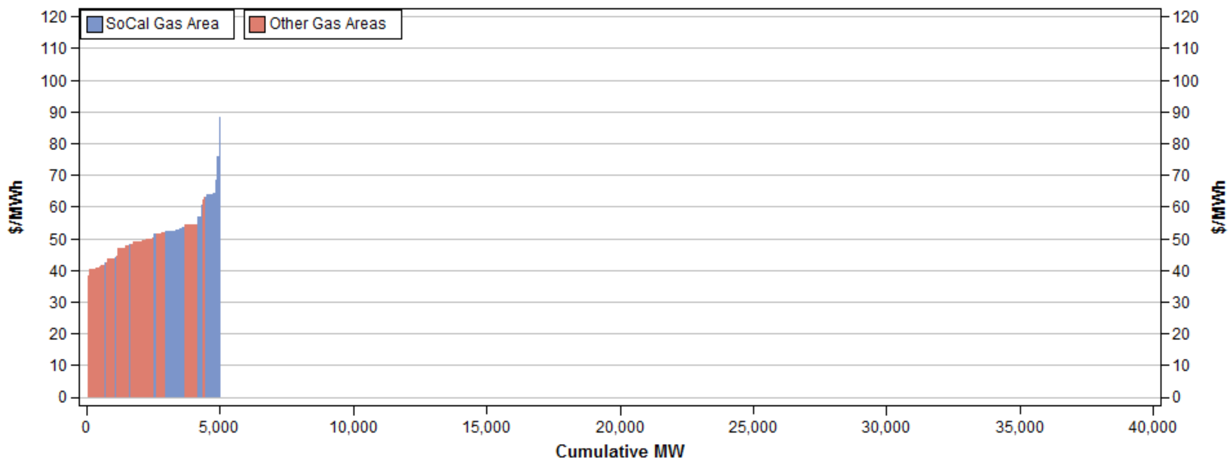


Figure 2-7 Minimum load proxy cost caps
Gas Turbines (75 percent SoCal gas adder)

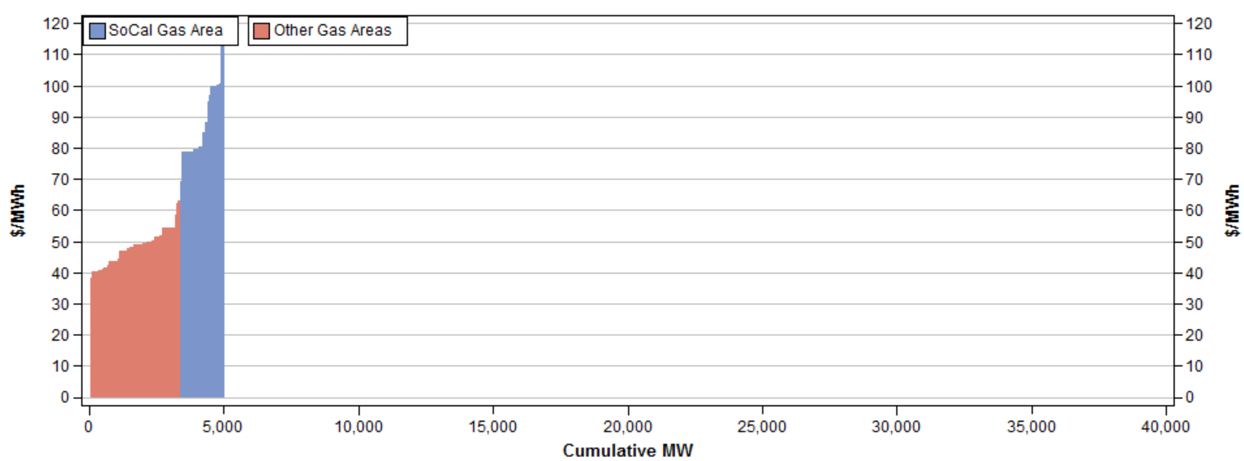


Figure 2-8 Percent of capacity in SoCal gas area with minimum load costs caps that are higher than resources in rest of ISO system (Gas Turbines)