California Independent
System Operator Corporation

October 14, 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. ER17- ___-000

Filing to Maintain in Effect for One Year Certain Tariff Provisions Previously Accepted on an Interim Basis to Address Limited Operability of Aliso Canyon Facility

Dear Secretary Bose:

The California Independent System Operator Corporation (CAISO) submits this tariff amendment[1] to maintain in effect for an additional 12 months, with some modifications, certain measures the Commission previously approved to address market and operational issues arising from the inoperability of the Aliso Canyon gas storage facility (Aliso Canyon).[2] The CAISO also proposes to terminate some of the previously approved emergency measures. The CAISO submits this filing to ensure that for the next 12 months it will continue to have the set of tools it needs to mitigate reliability and market distortion risks posed by the expected limited operability of Aliso Canyon.

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[1] The CAISO submits this filing pursuant to section 205 of the Federal Power Act (FPA), 16 U.S.C. § 824d.

[2] *See Cal. Indep. Sys. Operator Corp.*, 155 FERC ¶ 61,224 (2016) (June 1 Order) (accepting tariff revisions to address risks posed by limited operability of Aliso Canyon). The June 1 Order addressed a tariff amendment the CAISO filed on May 9, 2016 in Docket No. ER16-1649-000 (May 9 Tariff Amendment).

Specifically, the CAISO requests authority to maintain in effect on an interim basis the following measures:

1) To maintain increased access to potentially useful market information prior to the CAISO day-ahead market, the CAISO proposes to continue 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. Although these advisory schedules are not financially or physically binding, they assist scheduling coordinators with gas procurement decisions and gas nomination processes.

2) Use more timely and 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 constraints occurring over the upcoming 12-month period, resulting in day-ahead schedules that are better aligned with actual gas system conditions.

3) Maintain an increased 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-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 to continue to 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) Maintain an existing 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 affect electric grid reliability. Through this additional operational tool, the CAISO market clearing process will continue to 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. This constraint will also allow CAISO operators to continue to minimize variations between day-ahead and real-time gas usage if such variations potentially can undermine gas and electric system reliability. Regarding the exercise of this constraint, the CAISO seeks continued authorization to suspend convergence bidding if the CAISO determines

that the constraint is adversely affecting market efficiency. The CAISO does not, however, propose to continue using the existing minimum natural gas constraint. In addition, the CAISO proposes to maintain the existing measures regarding designation of a transmission constraint as competitive or non-competitive when it enforces a natural gas constraint, and regarding suspension or limitation of virtual bidding activity related to enforcement of a natural gas constraint that detrimentally affects CAISO market efficiency.

5) Allow scheduling coordinators to seek after-the-fact fuel costs related to their default energy bids and generated bids from the Commission in a section 205 filing, to the extent they are otherwise unable to recover their costs through the CAISO's bid cost recovery mechanisms. This will augment the existing section 205 procedure the Commission has already approved.

The CAISO also proposes to discontinue use its expanded authority to reserve internal transfer capability by adjusting transmission constraints and to adjust the release of congestion revenue rights (CRRs).

The CAISO respectfully requests that the Commission accept the tariff provisions contained in this filing effective November 30, 2016, *i.e.*, the day the previously approved provisions are scheduled to expire pursuant to the June 1 Order. The CAISO also requests that the Commission accept the tariff provisions in this filing on a continued interim basis. Specifically, the CAISO is submitting tariff records in this filing that will cause the tariff provisions to revert automatically on November 30, 2017 (*i.e.*, one year after the requested effective date) to how they read before the tariff provisions the CAISO is submitting in this filing took effect. In order to ensure the CAISO and market participants are prepared to transition appropriately on November 30, 2016, the CAISO respectfully requests an order by November 28, 2016. This will provide the CAISO and market participants sufficient time to consider any Commission directives in this proceeding and to transition on November 30, 2016 accordingly.

Stakeholders and the CAISO's Department of Market Monitoring (DMM) either support or do not oppose extending these measures for another 12 months. Considering the particular challenges to reliability that may arise in the coming 12 months, the continued interim nature of the proposal, and the Commission's previous acceptance of similar provisions in the June 1 Order, the CAISO submits that its interim solution is just and reasonable and should be approved.[3]

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[3] *See ISO New England Inc., et al.*, 144 FERC ¶ 61,204, at PP 21, 42 (2013) (accepting ISO New England's Winter Reliability Program on an interim basis).

I. Background and Need for Filing

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 there is a sufficient supply of electricity to satisfy demand in the region while maintaining the reliability of the transmission system the CAISO operates (*i.e.*, 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 align better with actual physical conditions on that grid.[6] Market participants can engage in convergence bidding (also called virtual bidding) to speculate on price differences, hedge their physical market positions, and manage their exposure to differences between day-ahead and real-time prices.[7] The CAISO has the authority to suspend or limit virtual bidding activities that can detrimentally affect system reliability or grid operations.[8]

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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 30.9.

[8] Existing tariff section 7.9.

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.[9] 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.[10]

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 resources' market bids and 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 (IFM) and the residual unit commitment (RUC) process), the CAISO commits long-start units through the IFM and RUC and publishes a financially binding day-ahead schedule for IFM awards. 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),[11] and transition costs for resources that can operate in different configurations.[12]

To the extent resources do not recover their start-up costs, minimum load costs, and transition costs through the market, resources recover them through the bid cost recovery process based on the sum of cost components specified in the tariff that reflect the resources' unit-specific performance parameters relative to their market revenues for those cost components.[13] For natural gas-fired

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[9] Existing tariff section 39, *et seq.*

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

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

[12] The tariff refers to these resources as "multi-stage generating resources" (MSG resources). *See* tariff appendix A, existing definitions of "Multi-Stage Generating Resources" and "Transition Cost."

[13] Existing tariff sections 30.4.1.1.1(a), 30.4.1.1.2(a). Under the CAISO tariff, all resources except for those with use limitations recover their commitment costs pursuant to this "proxy cost

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.[14] Gas-fired and non-gas-fired resources can also submit daily bids for their start-up costs, minimum load costs, and transition costs that are between zero and a cap of 125 percent of the calculated proxy cost (the bid cap).[15]

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.[16] 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 (NGI), SNL Energy/BTU's Daily Gas Wire (SNL), Platt's Gas Daily, and the Intercontinental Exchange (ICE).[17] The CAISO uses this gas price index in the day-ahead market run for the following trading day.[18] 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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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. Existing tariff section 30.4.1.2.

[14] Existing tariff section 30.4.1.1.1(a).

[15] Existing tariff sections 30.4.1.1.1(b), 30.4.1.1.2(b), 30.4.1.1.5, 30.7.9(c), 30.7.10.

[16] *See* existing tariff section 39.7.1.1.1.3(a).

[17] All times listed in this transmittal letter are Pacific time.

[18] As discussed below, the tariff provisions approved in the June 1 Order included provisions to change how the CAISO calculates gas prices for the day-ahead market, but those provisions have not yet gone into effect.

[19] Existing tariff section 39.7.1.1.1.3(b). As discussed below, in the June 1 Order the Commission approved the CAISO's proposal to delete to gas price spike procedure in connection with the change in how the CAISO calculates gas prices for the day-ahead market, but the deletion has not yet gone into effect.

however, ICE 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, which are determined using the same tariff provisions that are used to determine the gas price under the proxy cost methodology as described above. All 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.[25]

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.

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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.

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 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. Like default energy bids under the variable cost option, generated bids include an adder of 10 percent.

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 Aliso Canyon

Please refer to attachment C to this filing for background information regarding the natural gas leak at Aliso Canyon and the implications thereof, including the risk posed to the reliability of electric service during the summer season and the upcoming winter season.

C. The May 9 Tariff Amendment

The CAISO filed the tariff revisions contained in the May 9 Tariff Amendment to provide the CAISO with a set of tools it could use in its markets on an interim basis to mitigate reliability and market distortion risks posed by the limited operability of Aliso Canyon. The CAISO requested that the Commission accept most of the tariff revisions effective June 2, 2016 and accept the balance of the tariff revisions effective July 6, 2016.

The CAISO also submitted tariff records for the revisions so they would automatically expire on November 30, 2016. Absent Commission action to

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

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

maintain their effectiveness beyond November 30, the revised tariff sections will revert to how they read before the CAISO submitted the May 9 Tariff Amendment.[28] The CAISO stated that prior to November 30, it would submit another section 205 filing or filings explaining why each of the tariff revisions should either: (i) automatically expire effective November 30; (ii) remain in effect after November 30 with no modifications; or (iii) remain in effect after November 30 with modifications.[29]

D. The June 1 Order

In the June 1 Order, the Commission accepted the tariff revisions contained in the May 9 Tariff Amendment effective June 2 and July 6, 2016, as requested by the CAISO, subject to the CAISO submitting a compliance filing within 30 days. The Commission also ordered a technical conference to be held several months after the CAISO implemented the revisions to discuss lessons learned and potential longer-term solutions.[30]

Specifically, the Commission accepted the CAISO's proposal to provide scheduling coordinators with advisory day-ahead commitment schedules produced in the residual unit commitment process on a two-day-ahead basis. The Commission found that this advisory information "can help scheduling coordinators make more informed gas procurement decisions and more closely match their gas procurement with their potential gas consumption by nominating an amount of gas to match their expected generation output for each hour."[31] The Commission stated that the information can thereby "help reduce gas and electric reliability risks associated with imbalances between the amount of gas that electric generators nominate and the amount of gas that they burn."[32] The Commission concluded that the CAISO's proposal was "just and reasonable and not unduly discriminatory in the interim period when there is uncertainty about the operation of Aliso Canyon and the associated impact on gas and electric system reliability."[33]

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[28] Transmittal letter for May 9 Tariff Amendment at 42.

[29] *Id.*

[30] *See* June 1 Order at PP 12-13, 104, and ordering paragraphs (A)-(D). The technical conference was held on September 16, 2016.

[31] June 1 Order at P 16.

[32] *Id.*

[33] *Id.* As discussed below in section II.A of this transmittal letter, the CAISO proposes in this filing to maintain these tariff revisions (with one clarification) for 12 months beyond November 30.

The Commission found the tariff revisions not expressly discussed in the June 1 Order, which consisted of revisions regarding the gas price index used to calculate commitment costs, default energy bids, and generated bids in the day-ahead market, real-time rebidding of commitment costs, and the short-term unit commitment process, to be "just and reasonable because they constitute appropriate improvements upon CAISO's current tariff provisions that should enable CAISO to address limitations in the natural gas delivery system in southern California and facilitate fuel cost recovery by generators."[34] Therefore, the Commission accepted them on an interim basis without further modification.[35]

The Commission conditionally accepted the CAISO's proposed tariff provisions to increase (or decrease) as needed the gas price that is used to calculate commitment costs and generated and default energy bids for gas-fired resources served by the Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) gas systems.[36] The Commission found that the "CAISO has devised a system to increase or decrease the price of gas a generator may include as part of its bid as a means to allow these resources to manage gas balancing requirements under the tightened balancing tolerance bands," and that "the proposed reform should improve a generator's ability to recover fuel costs during this interim period of potential volatility."[37]

The Commission conditionally accepted the CAISO's proposal to institute maximum and minimum natural gas constraints in its market solution to reflect gas limitations under certain conditions.[38] The Commission found that this

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[34] June 1 Order at P 12 & n.13.

[35] As discussed below in section I.E of this transmittal letter, the CAISO has already submitted a tariff amendment to permanently maintain the tariff revisions regarding real-time rebidding of commitment costs and the short-term unit commitment process. As discussed below in section II.B of this transmittal letter, the CAISO proposes in the instant filing to maintain substantially the same tariff revisions regarding the gas price index for the day-ahead market for 12 months beyond November 30.

[36] The condition was that the CAISO specify on compliance the unit of gas to which the $2.50 adder set forth in the tariff provisions applies. June 1 Order at P 35. The CAISO revised tariff section 39.7.1.1.1.3(d) in its compliance filing to specify that the applicable unit of gas is $2.50 per therm.

[37] June 1 Order at P 29. As discussed below in section II.C of this transmittal letter, the CAISO proposes to maintain these tariff revisions for 12 months beyond November 30.

[38] The Commission conditioned its acceptance of the tariff provisions on the CAISO's submittal of two further tariff changes on compliance. The first of these compliance directives was that the CAISO specify in the tariff the type of information it will make available regarding enforcement of the gas constraint and how and when it will make this information available. June 1 Order at P 49. The CAISO revised tariff section 27.11 to comply with this directive. The second compliance directive was that the CAISO include in its tariff a mechanism to provide scheduling coordinators responsible for bidding generating resources into the CAISO markets

proposal "is a reasonable measure to ensure the reliable operation of the electric grid within the bounds necessarily imposed on it by the operation of the natural gas system, which is outside of CAISO's control."[39] The Commission "agree[d] with CAISO that these measures are necessary because electric reliability could be compromised if market inputs do not accurately reflect gas system constraints," and found that the CAISO's "proposed method of using generator nomograms with a penalty factor is an appropriate interim means to achieve this goal."[40]

In conjunction with the CAISO's proposal to enforce the gas constraint, the Commission also accepted the CAISO's proposed tariff provisions allowing it to designate a transmission constraint as non-competitive when necessary based on actual system conditions. The Commission found that "CAISO has provided sufficient justification for this measure because, as CAISO explains, actual electric supply conditions may be non-competitive when the natural gas constraint is enforced due to anticipated electric supply conditions in the SoCalGas and SDG&E gas regions."[41] In this regard, the Commission agreed with DMM's analysis finding that "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."[42]

The Commission conditionally accepted the CAISO's proposed tariff provisions authorizing the CAISO to suspend virtual bidding when and if it determines that such trading runs counter to market economic efficiency.[43] The Commission found that "during the interim period, with the limited operability of Aliso Canyon and the operational steps that CAISO may undertake to address electric and gas reliability, there may be times when promoting price

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with their respective resource-specific pricing data. *Id.* at P 51. The CAISO revised tariff section 6.2.1.3 to comply with this directive.

[39] June 1 Order at P 48.

[40] *Id.* As discussed below in section II.D of this transmittal letter, the CAISO proposes to maintain the tariff revisions regarding the maximum gas constraint for 12 months beyond November 30, but does not propose to maintain the minimum gas constraint.

[41] June 1 Order at P 52.

[42] *Id.* As discussed below in section II.E of this transmittal letter, the CAISO proposes to maintain these tariff revisions for 12 months beyond November 30.

[43] The condition was that the CAISO clarify on compliance that it may only suspend virtual bidding for market efficiency purposes related to a reservation of internal transfer capability or enforcement of a natural gas constraint pursuant to the tariff. June 1 Order at P 80. The CAISO revised tariff section 7.9.2(d) to comply with this directive.

convergence may run contrary to the efficient economic solution of the market."[44] The Commission also stated that there may be "sustained differences in prices between locations and between day-ahead and real-time markets that could be exploited by virtual bidders without yielding any market benefits."[45] Further, the Commission explained that "[g]iven the uncertainty surrounding the extent to which CAISO may have to use internal transfer capability or enforce the gas constraint to address threats to reliability, or the impact that these actions will have on market outcomes, we find that CAISO has demonstrated a potential need for limited intervention in market outcomes to ensure these measures achieve their stated objectives."[46]

The Commission conditionally accepted the CAISO's proposed procedures for filings seeking after-the-fact recovery of fuel-related commitment costs and incremental fuel costs associated with default energy bids under the variable cost option and with generated bids.[47] The Commission found that "because of the uncertainty and potential price volatility introduced into the market due to the limited operability of Aliso Canyon, there remains the possibility that fuel costs may exceed the amounts recoverable under CAISO's normal cost recovery provisions."[48] Although the Commission noted that "after-the-fact cost recovery cannot be a substitute for properly functioning markets," the Commission explained that "given the situation facing CAISO and the need to ensure reliable operation of the grid at just and reasonable rates, we find reasonable the interim solution to improving a scheduling coordinator's ability to recover fuel costs."[49]

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[44] June 1 Order at P 80.

[45] *Id.*

[46] *Id.* at P 83. As discussed below in section II.E of this transmittal letter, the CAISO proposes to maintain these tariff revisions for 12 months beyond November 30.

[47] June 1 Order at PP 91-96. The Commission conditioned its acceptance of the tariff provisions on the CAISO's submittal of two further tariff changes on compliance. The first of these compliance directives was that the CAISO specify in the tariff that participants in the Energy Imbalance Market (EIM) are eligible to seek such after-the-fact cost recovery from the Commission. *Id.* at P 94. The CAISO proposed to revise tariff section 30.11 to comply with this directive, and also filed a separate motion for clarification and, in the alternative, request for rehearing regarding the directive. In its order on clarification and compliance the Commission found that it was not necessary for the CAISO to make that revision. *Cal. Indep. Sys. Operator Corp.*, 156 FERC ¶ 61,135, at P 8 (2016). The second compliance directive was that the CAISO revise the timeline for the after-the-fact cost recovery process to state that the CAISO will provide a written explanation to the scheduling coordinator within 60 days after the trading day on which the scheduling coordinator's unrecovered costs were incurred. June 1 Order at P 95. The CAISO revised tariff section 30.11 to comply with this directive.

[48] June 1 Order at P 91.

[49] *Id.* at P 92. *See also id.* at P 104. As discussed below in section I.E of this transmittal

The Commission accepted the CAISO's proposal to reserve internal transmission transfer capability based upon anticipated conditions on the natural gas delivery system. The Commission found that this proposal "constitutes a proactive approach that should assist CAISO in managing reliability this summer in a flexible manner that can react to day-to-day and hour-to-hour changes on the gas system."[50] The Commission also accepted the CAISO's proposal to limit the release and allocation of monthly congestion revenue rights related to the reserved transfer capability.[51]

The Commission acknowledged the CAISO's commitment to make "a section 205 filing with the Commission before the [November 30, 2016] automatic expiration date to either confirm that it has determined the provisions should expire, or to explain why the provisions should remain in effect in some form."[52]

E. Events Following Issuance of the June 1 Order

The CAISO implemented the tariff revisions accepted in the June 1 Order effective on the dates authorized by the Commission, except as discussed below.

On June 29, 2016, the CAISO filed a motion for clarification and, in the alternative, request for rehearing of the June 1 Order. On June 30, 2016, the CAISO submitted its filing to comply with the directives in that order. On August 26, 2016, the Commission issued an order granting the CAISO's motion for clarification and accepting its compliance filing.[53]

On July 1, 2016, the CAISO filed a petition for limited tariff waiver to suspend the effectiveness of the tariff revisions regarding use of more timely and accurate gas commodity prices for commitment costs bid caps, default energy bids, and generated bids in the day-ahead market until August 5, 2016. The

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letter, the CAISO has already submitted a tariff amendment to permanently maintain the tariff revisions regarding the procedure after-the-fact recovery of fuel-related commitment costs. As discussed below in section II.F of this transmittal letter, the CAISO proposes in the instant filing to augment the tariff revisions regarding the procedure for after-the-fact recovery of incremental fuel costs associated with default energy bids and generated bids for 12 months beyond November 30.

[50] June 1 Order at P 63.

[51] *Id.* at P 69. As discussed below in section II.G of this transmittal letter, the CAISO proposes to discontinue the use of these tariff revisions.

[52] June 1 Order at P 13.

[53] *Cal. Indep. Sys. Operator Corp.*, 156 FERC ¶ 61,135.

Commission granted the petition on August 4.[54] On August 5, the CAISO filed a petition for extension of the limited tariff waiver, this time to suspend the effectiveness of the tariff revisions until no later than two business days after the Commission rules on a motion for clarification, or in the alternative, petition for limited waiver that the CAISO had filed on August 3, regarding a statement in the June 1 Order potentially affecting the implementation of the tariff provisions. The effectiveness of these tariff revisions remains suspended pending Commission action on the August 3 and August 5 filings.

On August 19, 2016, the CAISO filed a tariff amendment (August 19 Tariff Amendment) to maintain on a permanent basis, after November 30, certain of the tariff provisions approved in the June 1 Order.[55] Specifically, the CAISO proposed to make permanent the Commission-approved tariff provisions to: allow scheduling coordinators to seek after-the-fact recovery of unrecovered commitment costs that exceed the commitment cost bid cap as a result of actual marginal fuel procurement costs pursuant to an FPA section 205 filing submitted to the Commission; allow resources to rebid commitment costs in the CAISO real-time market if they were not committed in the day-ahead market; and ensure the CAISO short-term unit commitment process does not commit resources that did not submit bids into the real-time market unless they were scheduled or committed in the day-ahead or had a real-time must-offer obligation.[56] The CAISO explained that it had designed these tariff provisions in a separate CAISO stakeholder process but had asked the Commission to accept them (and other tariff revisions) on an expedited and interim basis in the May 9 Tariff Amendment. Commission action on the August 19 Tariff Amendment is pending.

Please refer to attachment C hereto for background information regarding the CAISO's stakeholder process leading up to this filing.[57]

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[54] *Cal. Indep. Sys. Operator Corp.*, 156 FERC ¶ 61,093 (2016).

[55] *See* Docket No. ER16-2445-000. The CAISO filed minor corrections to the August 19 Tariff Amendment on August 23, 2016.

[56] Because the CAISO has already submitted these tariff provisions in its August 19 Tariff Amendment currently pending before the Commission, the CAISO has not also included them in the instant filing. However, as discussed below, the CAISO does propose in this filing to augment the procedure allowing a scheduling coordinator to seek after-the-fact recovery of fuel-related costs associated with default energy bids. In the event that the Commission does not issue an order accepting the August 19 Tariff Amendment by about October 25, 2016, the CAISO will make any filings necessary to temporarily extend the tariff provisions set forth in the August 19 Tariff Amendment from November 30, 2016 until the earlier of: (i) the effective date of the tariff provisions set forth in a Commission order accepting the August 19 Tariff Amendment; or (ii) the same November 30, 2017 reversion date that the CAISO proposes for the tariff provisions contained in the instant filing.

[57] As discussed in attachment C hereto, the materials provided in the stakeholder process

F. Need to Extend the Tariff Provisions

As discussed in attachment C hereto, the CAISO expects that Aliso Canyon will not be operational during the bulk of 2017. The Inter-Agency Task Force[58] recently performed analyses that identify the risks presented by the limited operability of Aliso Canyon this coming winter.[59] In particular, the CAISO and LADWP used gas curtailment estimates to determine how much of a gas curtailment the electric generators could absorb and whether electric service interruptions could occur. Their analysis concluded that, although the risk to electric reliability is expected to be less than it was this past summer, challenges for electric reliability will continue this winter due to the limited operability of Aliso Canyon.

Specifically, the analysis found that gas-fired electric generation could be susceptible to gas curtailments during the winter without Aliso Canyon under certain conditions. Although electric load is generally lower in the winter compared with the summer, the availability of electric generation supply may be reduced during the winter due to the commitment of fewer generators on-line and outages for scheduled maintenance. The analysis determined that any gas curtailments occurring this winter are not expected to result in electric load interruption, even with reduced availability of electric generation, so long as gas supply and receipt point utilization remains approximately 84 percent or higher (corresponding to a system capacity of 4.1 billion cubic feet per day (Bcfd) of gas) on peak gas demand days. At or above this 84-percent level, the CAISO and LADWP are expected to be able to secure sufficient generation outside of

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included a Draft Final Proposal (attachment D hereto) and comment on the Draft Final Proposal submitted by DMM (attachment E hereto). In addition, attachment F hereto contains a memorandum provided to the CAISO Governing Board to support Board authorization of the instant filing.

[58] The members of the Inter-Agency Task Force are the California Public Utilities Commission (CPUC), California Energy Commission (CEC), CAISO, SoCalGas, and the Los Angeles Department of Water and Power (LADWP).

[59] See the Aliso Canyon Winter 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 (Aug. 22, 2016) (Winter Risk Assessment Report) and the Aliso Canyon Gas and Electric Reliability Winter Action Plan 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 (Aug. 22, 2016) (Winter Action Plan), both available on the CAISO website page dedicated to the Aliso Canyon Gas-Electric Coordination stakeholder initiative, http://www.caiso.com/informed/Pages/StakeholderProcesses/AlisoCanyonGasElectricCoordination.aspx.

the SoCalGas and SDG&E service territories to avoid interrupting electric load. If, however, the gas supply and receipt point utilization falls below the 84-percent level or gas supply limitations are affecting electric generation supply external to the SoCalGas system, there is a risk that system capacity will not be sufficient to source gas to meet all customer needs. In that event, absent withdrawal of sufficient gas from Aliso Canyon to make up the shortfall, gas curtailment of electric generation may occur, potentially interrupting service to electric load.[60]

The CAISO and LADWP analyzed their ability to absorb a potential gas curtailment of 0.7 billion cubic feet (Bcf), which is the amount that would need to be curtailed if a 1-in-10-year winter peak demand event occurred based on SoCalGas's planning criteria for meeting gas demand of all customers (core and non-core). The analysis found that the CAISO and LADWP could absorb most but not all of a potential 0.7 Bcf gas curtailment, if: (1) electric transmission import capability remains unimpaired, (2) no gas-fired generation that is needed outside of the SoCalGas service area is out of service, and (3) every generating resource that the CAISO and LADWP seeks to use has natural gas to operate.[61]

The CAISO and LADWP would need a small amount of additional gas to support minimum generation requirements, such as those requirements needed to maintain transmission system reliability or respond to local contingencies. There also remains some risk of electric service interruption due to reliability rules that require balancing authorities such as the CAISO and LADWP to maintain operating reserve margins. Gas-fired resources are normally used to maintain these operating reserves because they can respond rapidly to operating instructions. Even if the CAISO and LADWP can serve all electricity demand without using gas-fired resources, they need some gas to serve resources providing the operating reserves. If the CAISO and LADWP have no natural gas because of a gas curtailment, they could be required to shed load, thus resulting in the curtailment of electricity service to meet the operating reserve requirement.[62]

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[60] Winter Risk Assessment Report at 30-40. This analysis assumes that multiple outages do not occur on the electric and gas system. *Id.* at 40. The Winter Risk Assessment Report also discusses the consequences of various scenarios with levels of system capacity different from the 4.1 Bcfd amount discussed above.

[61] Winter Action Plan at 4-5, 17-18.

[62] *Id.* at 5. The risks related to gas capacity limitations discussed above are a primary driver of the threat to electric reliability this winter. A lesser though still-present risk is that posed by gas imbalances from non-core customers for gas, which include gas-fired electric generators. The majority of demand for gas shifts in the winter from non-core customers to core customers (*i.e.*, residential and small commercial and industrial customers), with core customers using approximately 60 percent of gas supply. Also, demand for electricity is lower in the winter and there is more flexibility to shift responsibility to resources located outside of southern California for

In addition to the mitigation measures for the summer referenced above, the Winter Action Plan "identifie[d] 10 new measures to help reduce, but not eliminate, the possibility of gas curtailments large enough to cause electricity service interruptions this winter":

- SoCalGas establishing a gas demand response program.
- Further efforts by SoCalGas to establish a gas conservation messaging campaign.
- Continuing a set of tighter gas balancing rules for non-core customers that was established pursuant to a settlement approved by the CPUC and that is currently scheduled to expire on November 30, 2016.
- Establishing gas balancing rules applicable to SoCalGas core customers.
- SoCalGas submitting reports to the CPUC describing rapid process in restoring pipeline service during maintenance outages.
- Exploring the feasibility of purchasing liquefied natural gas for delivery into the SDG&E system.
- Exploring what, if anything, natural gas producers can do to increase deliveries into the SoCalGas system.
- The CPUC updating a protocol that will apply if and when some of the gas stored currently being held at Aliso Canyon is withdrawn.
- The CEC monitoring refinery gas use and operations and California Attorney General monitoring gasoline prices for potential price manipulation.
- The CAISO using a maximum limit on electric generator gas burns in advance of very cold days.[63]

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providing electricity into southern California, subject to transmission and generation outages. Non-core electric generators will, however, be the first to be curtailed if on-system gas is needed to meet core demand in the winter. *See* Winter Risk Assessment Report at 6-7, 14-16; Winter Action Plan at 10-12, 17-20.

[63] Winter Action Plan at 5, 20-25.

The CAISO believes that maintaining its existing, maximum natural gas constraint will allow the CAISO to use the constraint in advance of very cold days as recommended in the Winter Action Plan. The Winter Action Plan also recognized that efforts to make changes to the CAISO market to improve gas-electric coordination are ongoing.[64] The instant tariff filing includes such changes.

II. Proposed Tariff Revisions

Through the stakeholder process for the May 9 Tariff Amendment, the CAISO developed tariff provisions to mitigate the risks posed by the limited operability of Aliso Canyon during the summer. After the release of winter assessment by the Inter-Agency Task Force, the CAISO conducted a subsequent stakeholder process to consider which of the previously filed and approved measures it needed to retain to address the issues identified in the report. The CAISO proposes to maintain, with some modifications, certain of those tariff provisions for 12 months to provide the CAISO with the necessary 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.[65] These tools will continue to ensure that the CAISO markets consider generator bids and produce prices that reflect gas system limitations, thereby reducing the chance that CAISO dispatches could affect gas system reliability adversely. These measures will continue to position the CAISO to operate its system reliably, in light of the challenges for winter identified by the Inter-Agency Task Force. Below the CAISO discusses the measures it proposes to maintain in effect and any appropriate modifications.

A. Maintain the Effectiveness of the Tariff Provisions the CAISO Uses to Give Generators Advisory Information Regarding Their Potential Day-Ahead Commitments Prior to the Day-Ahead Market Run

The CAISO proposes to maintain the effectiveness of the tariff provisions accepted in the June 1 Order, under which the CAISO helps scheduling coordinators make more informed gas procurement decisions by providing them with advisory information regarding their resources' potential commitment in the day-ahead market that the CAISO produces through its existing two-day-ahead

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64 *Id.* at 24.

65 The May 9 Tariff Amendment implemented phase 1 of the CAISO's ongoing Aliso Canyon Gas-Electric Coordination stakeholder initiative. The instant filing will implement phase 2 of that initiative.

process.[66] This involves the CAISO running the commitment process based on available bids and estimates of system conditions at that time. As the CAISO currently does, the CAISO will provide this information to scheduling coordinators only to advise them of their potential commitments; the information 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 continue to 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.[67] The CAISO communicates the advisory resource-specific RUC schedule to each scheduling coordinator for its resources through the CAISO's secure communication system and does not include pricing information.[68] Although the precise constraints 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 believed that providing scheduling coordinators with the two-day-ahead residual unit commitment process results would improve their ability to plan for gas procurement. The Commission reached the same conclusion in the June 1 Order, finding that this information would help reduce gas and electric reliability risks and that the tariff provisions are just and reasonable in the interim period when there is uncertainty about the operation of Aliso Canyon and the associated impact on gas and electric system reliability.[69] Those same reasons support retention of this mechanism for another 12 months.

Without this information, scheduling coordinators would be required to wait until 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 that 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

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[66] New tariff section 6.5.2.2.3. The new tariff section in this filing is similar to the same new section approved in the proceeding on the May 9 Tariff Amendment, with one minor modification to clarify that the scheduling coordinator receives "its" MWh amounts scheduled in the preliminary RUC process.

[67] Based on a comment provided in the stakeholder process for this filing, the CAISO plans to also include unit-specific gas burn data in the advisory information. However, including this additional data does not require any changes to the tariff provisions. *See* Draft Final Proposal, attachment D hereto, at 7-8.

[68] 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.

[69] *See* June 1 Order at P 16.

and bilateral gas and electric market activity and can 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 such schedules are also affected by the numerous constraints modeled by the CAISO market. Continuing the advisory schedules will enable scheduling coordinators to make more informed decisions regarding gas procurement.

The CAISO will continue to provide advisory information 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 the scheduling coordinators for these resources are the entities that must ensure they have procured and nominated sufficient gas to perform consistent with expected CAISO dispatches.[70] The Commission found in the June 1 Order that it is just and reasonable to provide the information only to the responsible scheduling coordinator,[71] and should find the same here.

B. Maintain the Tariff Provisions to Implement an Improved Day-Ahead Gas Price Methodology

The CAISO proposes to maintain the tariff provisions accepted in the June 1 Order to improve the accuracy of the gas commodity price indices the CAISO previously used 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.[72] Using information that more

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[70] During the stakeholder process for the May 9 Tariff Amendment, 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, and continues to believe, that moving the day-ahead market timeline would be unnecessary and counterproductive.

[71] June 1 Order at P 17.

[72] As discussed above, the Commission has not yet issued an order on the CAISO's August 3 motion for clarification, or in the alternative, petition for limited waiver of the June 1 Order. Therefore, the effectiveness of these tariff provisions remains suspended pursuant to the CAISO's August 5 petition for extension of limited tariff waiver. Nevertheless, the CAISO proposes to maintain the provisions in the tariff on an interim basis after November 30. If and when the Commission issues an order granting the relief requested in the CAISO's August 3

accurately reflects prevailing gas commodity costs will enhance the day-ahead market's ability to dispatch resources efficiently. Also, it will ensure that resources cleared in the day-ahead market will be compensated based on fuel prices that better reflect their actual costs of procurement.[73] The CAISO expects that maintaining the tariff provisions will be particularly helpful in continuing to reflect constrained gas conditions resulting from the limited operability of Aliso Canyon. However, these tariff provisions will continue to 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 maintain the tariff provisions stating that, for the day-ahead market, the CAISO will use a volume-weighted average price reported between 8:00 a.m. and 9:00 a.m. 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.[74] 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.[75] For example, if the CAISO cannot obtain price data on a particular day, it will use the prior evening's price index.

In the June 1 Order, the Commission found that this new procedure constituted a just and reasonable improvement upon the CAISO's existing tariff provisions that should enable the CAISO to address limitations in the natural gas delivery system in southern California and to facilitate fuel cost recovery by generators.[76] Maintaining the tariff provisions proposed in the May 9 Tariff Amendment will allow them to continue serving these purposes.

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filing, the CAISO will make the tariff provisions effective within two business days after issuance of that order. If, on the other hand, the Commission denies the relief requested in the August 3 filing, presumably the CAISO will not be able to maintain the provisions, at least in their current form.

[73] 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.

[74] New tariff section 39.7.1.1.1.3(b). The new tariff section in this filing is substantially the same as the corresponding new section approved in the proceeding on the May 9 Tariff Amendment. As it did in that earlier tariff amendment, the CAISO has broken section 39.7.1.1.1.3 out into new subsections (a) through (d) to make the organization of the provisions in the section more clear. New subsection (d) is discussed below in section II.C of this transmittal letter.

[75] New tariff section 39.7.1.1.1.3(a). In addition, the CAISO proposes to maintain the effectiveness of the tariff provisions regarding public market information that were revised in the May 9 Tariff Amendment to clarify that the CAISO will publish daily greenhouse gas price indices and the natural gas price used for the real-time market when available. Revised tariff sections 6.5.2.3.4, 6.5.4.2.3.

[76] June 1 Order at P 12 & n.13.

Also, in the June 1 Order, the Commission accepted "CAISO's proposal to use an ICE-generated index" in implementing its proposed tariff revisions to improve the accuracy of the natural gas price index the CAISO uses to calculate commitment costs, generated bids, and default energy bids in the day-ahead market, to be effective on an interim basis from July 6, 2016 until November 30, 2016.[77] Under the revised tariff provisions, the CAISO would calculate these amounts using a volume-weighted average gas price that is reported by ICE between 8:00 a.m. and 9:00 a.m., *i.e.*, prior to the running of the CAISO's day-ahead market. The Commission noted, however, that "in order to use an index reported by ICE, the index must conform" to the Commission's policy statement on price indices.[78]

On July 1, 2016, the CAISO filed in this proceeding a petition for limited tariff waiver to suspend the effectiveness of these tariff revisions while it evaluated whether the volume-weighted gas price the CAISO plans to draw from the ICE system between 8:00 a.m. and 9:00 a.m. conforms to the Commission's policy statement.

As the CAISO explained in its July 1 filing, it is not in a position to represent that the volume-weighted average price it will draw from ICE between 8:00 a.m. and 9:00 a.m. "conforms" to the policy statement. However, the volume-weighted average price is based on cleared gas trades that are executed on ICE's platform up until the time that the CAISO draws the volume-weighted price from ICE. ICE has informed the CAISO that it calculates the volume-weighted price in the same manner as the "official" index it publishes at 11:30 a.m., which ICE has publicly represented complies with the policy statement. Therefore, there is no reason to believe that the volume-weighted average price is any less robust than ICE's other indices, which the CAISO and other market operators have used and continue to use in their markets. Moreover, as the CAISO demonstrates in this tariff amendment, there are clear benefits to using the volume-weighted average price reported between 8:00 a.m. and 9:00 a.m. For these reasons, the CAISO requests that the Commission clarify in this proceeding as well that the CAISO is authorized to implement the interim tariff revisions relating to the improved gas price calculation process.

The procedure set forth in the proposed tariff provisions revises and replaces the CAISO's current day-ahead procedure. The current procedure requires the CAISO to calculate its day-ahead gas price index two days prior to the applicable trading day using at least two or more of the following publications:

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[77] *Id.* at P 12 & nn.13-14.

[78] *Id.* at P 12 n.14.

NGI, SNL, Platt's Gas Daily, and ICE.[79] The market data from the summer shown in Figure 1 below supports using the revised procedure as an improvement upon the current procedure.[80] In Figure 1, the CAISO calculated the premium needed to reflect the highest traded price relative to the next-day index used by the day-ahead market and by the real-time market.[81] For the day-ahead market, the CAISO calculated the percent difference between (i) the highest prices for trades on or reported by NGI, SNL, or ICE and (ii) ICE's next-day gas price index published for the following day (depicted as green circles). For the real-time market, the CAISO calculated the percent difference between (i) the highest prices traded on ICE and (ii) ICE's next-day gas index published on the morning of the day-ahead market (depicted as yellow dots).

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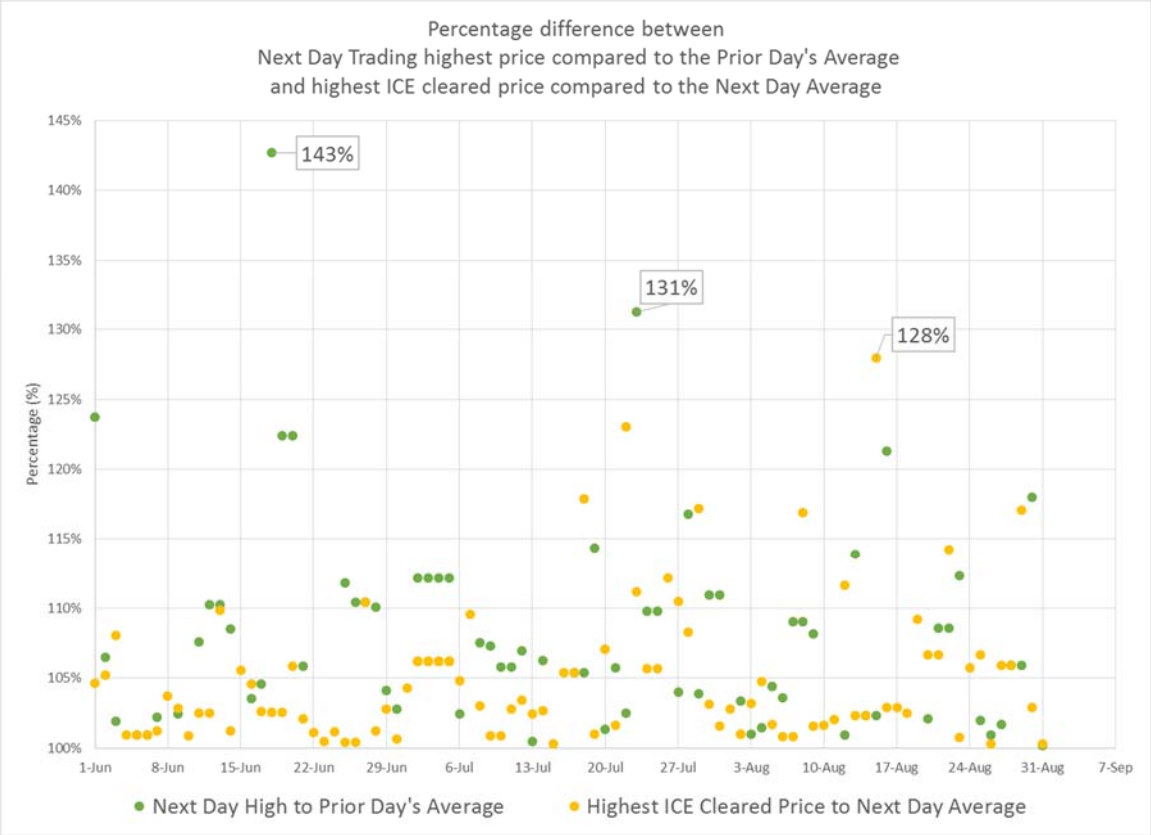
[79] The revised day-ahead procedure that the CAISO proposes to maintain in this filing does not affect the calculation of the real-time gas price index, which will continue to be based on two or more of these publications.

[80] *See* Draft Final Proposal, attachment D hereto, at 8-10 (discussing the data presented in Figure 1).

[81] The next section of this transmittal letter concerns the tariff provisions the CAISO proposes to maintain regarding the real-time gas price. The discussion in that next section also references Figure 1.

Figure 1



As shown in Figure 1, of the 92 days from June through August, there were 19 days where the highest traded gas price was more than 110 percent higher than the next-day gas index price published the day prior to the CAISO's day-ahead market. If the revised procedure had been in effect, such price increases would have occurred on only 12 of the days. Using the revised procedure would have substantially improved resources' ability to reflect their actual costs in default energy bids under the variable cost option and generated bids, which equal 110 percent of such costs (including the 10-percent adder set forth in the tariff).[82] Also, from June through August, there were two days (June 18 and July 23) on which the highest traded price was more than 125 percent higher than the next-day gas index price published the day prior to the day-ahead market. This means the CAISO's commitment cost cap (equal to 125 percent of calculated costs) would not have accounted for the highest traded price without the CAISO's manual gas price spike procedure. If the revised procedure had

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82 See sections I.A.2.b-I.A.2.c of this transmittal letter.

been in effect, however, the CAISO's 125 percent commitment cost cap would have accounted for the highest traded price in all days during this time period.

As reflected in Figure 1, using the more up-to-date price data produced by ICE pursuant to the revised procedure will account for fuel cost increases that may develop on a given day, better reflecting resources' actual fuel costs when they purchase gas for the operating day. This, in turn, will result in a more efficient and informed day-ahead market dispatch because the bids will incorporate more timely information regarding the resource's actual gas costs. Using the gas price index reported by ICE on the morning of the day-ahead market reflects gas trading for the next operating day. As DMM noted in its comments attached to the May 9 Tariff Amendment, the bulk of gas trading for delivery the next day occurs by 8 a.m.[83]

In its latest comments submitted to the Aliso Canyon phase 2 stakeholder process, DMM supports this change and further recommends that the CAISO permanently include in its tariff a feature to eliminate the current one-day lag in gas prices used in the day-ahead market. In this filing, the CAISO proposes to include such a measure in the tariff for the next 12 months. The CAISO is considering various means of determining the gas costs used in the day-ahead market as part of a stakeholder initiative it expects to initiate in the fourth quarter of 2016. The CAISO and stakeholders will review DMM's suggestion as part of this initiative along with other options that may be appropriate to permanently retain. The CAISO and stakeholders, including DMM, will have an opportunity to opine on this matter during the upcoming stakeholder process and the CAISO will submit new tariff amendments to implement any changes that come out of that process.[84]

Using the revised procedure will also obviate the need for the CAISO to retain the manual gas price spike procedure it currently employs, which authorize 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.[85] 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.[86] As of April 1, 2016,

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[83] See page 8 of the DMM comments provided in attachment F to the May 9 Tariff Amendment.

[84] See DMM Comments, attachment E hereto, at 1, 7-8.

[85] *See* tariff section 39.7.1.1.1.3(b) as deleted in the May 9 Tariff Amendment and in this filing.

[86] See section I.A.2.a of this transmittal letter.

however, ICE began publishing 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 because it will delay the ability of gas-fired resources to prudently procure and nominate gas to meet CAISO dispatch instructions. For this reason, and because the CAISO will now 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.[87]

C. Maintain the Effectiveness of the Tariff Provisions Implementing an Increased Gas Price Applicable to Commitment Cost Caps and Default Energy Bids for the Real-Time Market

The CAISO proposes to maintain the effectiveness of the tariff provisions allowing an increased (or decreased) gas price used to calculate the commitment costs for gas-fired resources subject to the proxy cost methodology,[88] generated bids for resource adequacy resources, and default energy bids under the variable cost option used for mitigation. The tariff provisions permit such an increase or decrease by an amount necessary to ensure the real-time market appropriately recognizes the increased constraints of resources in the southern California region. As the Commission found in the June 1 Order, the tariff provisions allow resources to manage gas balancing requirements under the tightened balancing tolerance bands and to better recover fuel costs during the current interim period of potential volatility.[89]

For the real-time market, the CAISO uses a gas price index based on at least two gas commodity prices from 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. Default energy bids

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[87] 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). The May 9 Tariff Amendment included all of these same deletions.

[88] Resources subject to the proxy cost methodology are permitted to submit daily 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. Existing tariff sections 30.4.1.1.1(b), 30.4.1.1.2(b), 30.4.1.1.5, 30.7.9(c), 30.7.10.

[89] June 1 Order at P 29.

under the variable cost option and generated bids include an adder of 10 percent to the CAISO's calculation of costs based on the gas price indices.[90] The CAISO proposes to continue using the increased gas price component of these formulas in the real-time market to reflect the constraints on the southern California gas system arising from the limited operability of Aliso Canyon.

Based on the winter assessment, and as was the case over this past summer, the CAISO anticipates that (1) Aliso Canyon will have only limited operability, (2) intra-day (*i.e.*, real-time) gas availability will likely decrease, and (3) there will be tightened gas balancing requirements. The CAISO expects that the current commitment costs, generated bids, and default energy bids likely will not fully accommodate these conditions. Because the CAISO's current calculation of the gas commodity price is based on trading for next-day delivery, it does not include information from the intra-day gas commodity markets regarding gas prices or risk of noncompliance with gas balancing rules. Therefore, absent the tariff provisions that the CAISO proposes to maintain in this filing, the resulting commitment costs, generated bids, and default energy bids may not allow resources 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.

Further, the limited operability of Aliso Canyon means a lack of nearby gas storage to respond to electric ramping needs and, when there is a deterioration of gas pipeline pressures, limited ability for SoCalGas and 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 is better for the CAISO real-time market to dispatch generators on these gas systems only to meet local electrical needs and avoid dispatching them to meet general CAISO system needs that could be met by resources not subject to these strict gas limitations. Absent the tariff provisions that the CAISO proposes to maintain herein, 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 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, potentially preventing the CAISO from economically dispatching a generator on the affected gas system for system needs. When generators on the affected gas system are under tightened gas balancing requirements, they will presumably reflect these tightened balancing requirements in their bids, which will likely achieve the desired result of the real-time market dispatching these resources only for local electrical needs.

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[90] See sections I.A.2.a-I.A.2.c of this transmittal letter.

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 their gas balancing requirements under tightened balancing tolerance bands. This can occur even if 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 enforces the proposed gas constraint, it is preferable for the CAISO to be able to differentiate between generators that are at risk of violating balancing rules and those that have gas available to respond to dispatch. This allows the market dispatches and prices to reflect the resource's expected costs.

As an example of how these circumstances can occur, under a low-operational flow order (OFO) scenario,[91] the pipeline pressure drops because nominated gas is lower than the actual gas demand. To balance the pressure at a more sustainable level, customers either must increase their nominated flows or reduce their demand. If a customer has 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. Under the tariff provisions the CAISO proposes to maintain, 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 and reflect expectations regarding real-time commodity prices, the CAISO proposes to maintain the effectiveness of the tariff provisions to increase the gas commodity price for resources connected to either the SoCalGas or the SDG&E system for purposes of determining the CAISO's real-time gas price indices.[92] 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) improve the ability to manage the generators' gas usage within applicable gas balancing rules. Maintaining these tariff provisions will enable the real-time market clearing process to continue to avoid dispatching these resources for

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91 Background information regarding OFOs is provided in attachment C hereto.

92 New tariff section 39.7.1.1.1.3(d). The new tariff section in this filing is identical to the same new section approved in the proceeding on the May 9 Tariff Amendment. Aside from the continued use 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.

system needs, so it is likely only to dispatch the resources to address local needs, not system needs. The increased amount should also be sufficient to continue 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 continue to provide additional headroom to reflect costs of generators operating within the applicable gas balancing rules.

To achieve these goals, for resources connected to the SoCalGas or SDG&E systems for the real-time market, the CAISO will maintain its existing initial increase of the gas commodity price used for determining commitment costs by 75 percent, *i.e.*, the gas commodity price will remain 75 percent higher than it would have been absent the maintained increase. The CAISO will also maintain the ability to 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, or whether a greater or lesser increase is necessary. However, any increase in the commitment cost gas price will remain capped at $2.50 per therm, plus two times the next-day gas index price. The CAISO will continue to use this same procedure to determine default energy bids under the variable cost option, except that the initial increase will remain 25 percent, and any increase in the generated or default energy bid gas commodity price will be capped at 100 percent.[93]

Using a 75-percent increase of the gas commodity price to determine the commitment cost proxy cost continues to be just and reasonable. As DMM indicated in its comments on the May 9 Tariff Amendment, it analyzed how effective amounts added to the gas commodity price for resources in the SoCalGas and SDG&E gas areas would be in affecting the 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, 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.[94] 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 caps based on observed market conditions and outcomes."[95] The CAISO agrees that this flexibility is necessary because if a 75-percent increase no longer makes the affected resources sufficiently more costly

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[93] Such increases above existing gas commodity prices are sometimes called scalars, *e.g.*, the 75-percent initial increase of the gas commodity prices for the commitment cost proxy cost constitutes a 75-percent scalar.

[94] See pages 1-3 and 17-25 of the DMM comments provided in attachment F to May 9 Tariff Amendment.

[95] See page 3 of the DMM comments provided in attachment F to May 9 Tariff Amendment.

than other resources for purposes of system-wide dispatch, the CAISO should be able to recalibrate the price increase to an amount that accomplishes that goal. However, the CAISO sees no evidence suggesting that DMM's initial analysis supporting use of 75 percent is no longer valid.

The cap on the amount by which the gas commodity price is increased for use in determining commitment cost proxy cost ($2.50 per therm plus two times the next-day gas index price) is also just and reasonable because this cap level equals the price that a generator would pay for gas if it violated an OFO based on the current SoCalGas and SDG&E gas tariffs.[96] 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. The adjustment to the gas commodity price will ensure that commitment costs remain within the zone of reasonableness.[97] 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 continue to 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 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.

Maintaining the existing initial increase of 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 on the May 9 Tariff Amendment, 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

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96 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.

97 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).

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.[98] 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 stated 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."[99]

It is just and reasonable to continue using a smaller initial increase in the gas commodity price for determining the default energy bids as compared to commitment costs, because even though it provides less ability for generators to manage gas imbalances, 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 a smaller impact on a resource's ability to manage its gas imbalances than do commitment costs. Because the price established pursuant to this mechanism 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 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.[100] 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

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[98] Existing tariff section 39.6.1.1.

[99] See pages 4-5 of the DMM comments provided in attachment F to the May 9 Tariff Amendment.

[100] See pages 5-6 of the DMM comments provided in attachment F to the May 9 Tariff Amendment.

used for determining default energy bids is just and reasonable. The CAISO sees no evidence that DMM's initial analysis of the 25 percent increase is no longer valid.

Figure 1 (provided in the immediately preceding section of this transmittal letter) demonstrates that the 75-percent and 25-percent increases continue to be just and reasonable based on this summer's gas price data. As shown in Figure 1, of the 92 days from June through August, the CAISO saw 12 days on which the highest traded ICE price for the day-ahead market was more than 110 percent higher than the next-day gas index price published the morning of the CAISO day-ahead market. There was also only one day (August 15) on which an increase of more than 125 percent occurred. Thus, the 75-percent and 25-percent increases would have allowed resources in the SoCalGas and SDG&E gas regions to recover their fuel costs related to commitment cost bids and the default energy and generated bids to the extent that they used the flexibility to increase their bid-in costs by the needed amounts. The 75-percent increase also would have provided the benefit of allowing resources to reflect gas system constraints so that suppliers could manage their resources within applicable gas balancing rules to the extent it was necessary for resources to use it in those regions.

The CAISO recognizes that it might need to adjust the increase in the gas price levels up or down in the future based on conditions arising at that time, but it is impossible to predict such level now. DMM supports the CAISO's proposal "to extend – but not modify – the current gas cost scalars used to increase commitment cost and default energy bid caps used in the real-time market at this time."[101] DMM states that its analysis of market data does not indicate that these allowable increases have played a significant role in helping participants manage real-time gas usage. However, because DMM has not observed any significant detrimental impacts of the increased gas price amounts in terms of market power and excessive or unnecessary market uplift costs, DMM supports extending this measure, provided that if significant detrimental cost impacts were to occur without any evidence the increases were providing significant benefits, DMM would recommend lowering the amounts by which the fuel costs could be increased in both cases.[102]

The CAISO agrees with DMM that it is important to monitor the performance of these two allowable increases and commits to continue evaluating the market to determine whether they remain effective in achieving the three goals expressly stated in the tariff provisions or whether either or both of

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101 DMM Comments, attachment E hereto, at 1.

102 *Id.* at 1-7.

the amounts should be adjusted to achieve those objectives. The CAISO would discuss any such changes with the DMM and stakeholders prior to making them. Pursuant to the proposed tariff provisions, upon determining that a change in the gas commodity price is necessary, the CAISO would issue a market notice specifying any change in the allowable increases in the fuel costs.[103]

D. Maintain the Effectiveness of the Tariff Provisions Allowing the CAISO to Implement a Maximum Natural Gas Constraint to Better Ensure that Dispatches Are Consistent with Gas System Limitations

The CAISO proposes to maintain the effectiveness of tariff provisions implementing a constraint in the CAISO markets that constrains the maximum 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.[104] Although the bidding rules and measures specified above provide an opportunity for better visibility of the impacts of the constrained gas system on the electric system, additional tools are necessary to ensure that CAISO operators can maintain the system reliably. Continuing the natural gas constraint will permit CAISO operators to enforce in the day-ahead and real-time markets a constraint(s) 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.[105] The constraint(s) will also continue to limit CAISO market dispatch of the affected generators in the real-time market to a maximum 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.[106]

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[103] *See* new tariff section 39.7.1.1.1.3(d). The CAISO notes that in response to stakeholder requests the CAISO agreed to provide notice of any price change and not just an increase as was previously stated in the tariff.

[104] New tariff section 27.11. The new tariff section in this filing is identical to the same new section approved in the proceeding on the May 9 Tariff Amendment, except as noted below. This filing also includes tariff section 6.2.1.3 as approved in the proceeding on the May 9 Tariff Amendment.

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

[106] In addition to the maximum gas constraint, the May 9 Tariff Amendment included tariff revisions to allow the CAISO to implement a minimum gas constraint, *i.e.*, a constraint on the minimum amount of gas that can be burned by resources based on limitations in applicable gas regions anticipated by the CAISO during specific hours. The CAISO does not propose to include in this filing the minimum gas constraint. Based on summer performance observations, resources have the ability to meet imbalance limitations requiring them to burn a minimum amount of gas by lowering their bid prices or by self-scheduling into the CAISO markets. Thus, the CAISO does

Consistent with the findings in the June 1 Order, the tariff provisions remain a reasonable and necessary measure to ensure the reliable operation of the electric grid within the bounds imposed on the CAISO by the operation of the natural gas system.[107] Maintaining the tariff provisions will also allow the CAISO to use the maximum gas constraint in advance of very cold days, as recommended in the Winter Action Plan issued by the Inter-Agency Task Force.[108] As the Inter-Agency Task Force found, gas-fired electric generation is still susceptible to gas curtailments during the winter without Aliso Canyon under certain conditions. However, during the winter fewer generators are on-line, and generators typically take their scheduled maintenance outages during the winter months to avoid service disruptions during the peak summer months. The Inter-Agency Task Force's analysis concluded that as long as gas supply and receipt point utilization remains approximately 84 percent or higher (corresponding to a system capacity of 4.1 billion cubic feet per day of gas) on peak gas demand days, gas curtailments occurring this winter should not result in electric load interruption because the CAISO and LADWP should be able to secure enough generation outside of the SoCalGas and SDG&E service territories to avoid interruption of electric load. If, however, the gas supply and receipt point utilization falls below the 84-percent level or gas supply limitations are affecting electric generation supply external to the SoCalGas system, it creates a risk that system capacity will not be sufficient to source gas to meet all customer needs. In that event, absent withdrawal of sufficient gas from Aliso Canyon to make up the shortfall, gas curtailment of electric generation may occur, potentially interrupting service to electric load. To ensure it can access resources outside the SoCalGas and SDG&E areas successfully if such situations arise, the CAISO can use the gas constraint to dispatch resources in needed locations in a timely manner and position the system to serve load reliably, without interruption.

As is currently the case, the CAISO will enforce the maximum 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 maximum 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

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not propose to retain the minimum gas constraint authority in its tariff.

107 *See* June 1 Order at P 48.

108 *See* attachment C hereto at 5-6.

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 enforce the constraint in the real-time market run. Similarly, the CAISO may enforce the constraint if it anticipates that large imbalances between gas schedules and gas consumed could compromise gas reliability and electric system reliability. As it does today, the CAISO will retain 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.

Maintaining the tariff provisions will allow the CAISO to respond to gas system conditions proactively as they develop, better ensuring that market dispatches reflect actual gas system conditions. It is critical for purposes of both gas and electric system reliability that the CAISO have the authority to act ahead of such occurrences to ensure that its dispatch reflects as much as possible the conditions on the natural gas system. Given the expectation of tight constraints caused by the limited operability of Aliso Canyon, the potential for such constraints to arise quickly is still likely. Over-dispatching resources in gas-constrained regions could negatively impact pipeline conditions, exacerbating existing gas system limitations. This, in turn, potentially could 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 experiences limitations affecting specific regions of the CAISO grid, but the CAISO market system is unable to capture those limitations through market constraints, the market could clear generation based on submitted bids and system conditions that do not account for gas system limitations. This could potentially occur in the CAISO real-time market even if the bids of generators on the affected systems reflect tightened gas balancing requirements. Such dispatches could aggravate already constrained gas system conditions compromising gas reliability, resulting in gas curtailments because gas generators cannot 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, electric curtailments likely will result.

When binding, the maximum gas constraint ensures that generation in the day-ahead or real-time market is dispatched taking into consideration gas system limitations. Because the CAISO cannot predict at this time exactly how and when the gas system will be constrained over the winter period, it seeks continued 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.[109]

The CAISO will continue to implement the maximum gas constraint using generation nomograms that include the generators within the affected areas.[110] The nomogram will affect the congestion component of the relevant generators' locational marginal prices and have a relaxation parameter value (*i.e.*, a "penalty price") associated with relaxing the gas constraint. The CAISO will continue to apply this parameter to function appropriately relative to the parameters for other constraints enforced in the market and has specified the parameter in the business practice manual for market operations.[111] Continued use of the constraint parameter in this manner is consistent with the finding in the June 1 Order that using generator nomograms with a penalty factor is an appropriate interim means of employing the gas constraint to ensure electric reliability.[112]

The CAISO may limit the enforcement of the gas constraint to specific affected area(s) and hours, and maximum gas burn for each hour based on information it obtains through coordination with the gas company. The CAISO clarifies that it will only apply the constraint for issues related to the SoCalGas

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[109] The CAISO provides a detailed mathematical description of the constraint on pages 18-23 of the Revised Draft Final Proposal, which is contained in attachment D to the May 9 Tariff Amendment. The CAISO has included relevant implementation detail in the business practice manual. As explained in the Draft Final Proposal provided in attachment D to the instant filing, the CAISO will revise the detail in the business practice manual and/or its operating procedures to: (1) clarify that the CAISO will use the maximum gas constraint based on its system needs in light of concerns with gas supply; (2) clarify that the CAISO's implementation of the constraint will include managing the electric system in response to a gas company issuing a curtailment watch; and (3) automate the ability of CAISO operators to distribute either a capacity or imbalance limitation across hours as deemed appropriate. Draft Final Proposal, attachment D hereto, at 14, 17-19

[110] 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 contained in attachment D to the May 9 Tariff Amendment.

[111] 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 has updated to provide detail regarding the constraint parameter. A detailed description of how the CAISO establishes the penalty price relative to other penalty prices used in the market is provided on pages 23-25 of the Revised Draft Final Proposal contained in attachment D to the May 9 Tariff Amendment.

[112] *See* June 1 Order at P 49.

and SDG&E gas systems.[113] Stakeholders have asked whether the CAISO would apply the constraint for gas related issues on other parts of the system, and the CAISO believes this could be a tool to be used address gas related issues elsewhere. However, because of the abbreviated stakeholder process leading to this filing, the CAISO does not propose at this time to extend the use of the gas constraint to other parts of the gas system. The CAISO will consider such enhancement in a future stakeholder process regarding gas and electric systems coordination. If 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 tariff provisions the CAISO proposes to maintain in this filing, when the maximum gas 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 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, including trading hub and other aggregated locations, and will not be reflected in locational marginal prices used for settling supply other than the affected generators, load, virtual bids, or congestion revenue rights.[114] The CAISO will continue to implement this approach by applying the constraint only to the resource-specific price at the network connectivity node (CNode)[115] used to dispatch affected generators but not to the bus location reflecting the point of delivery or receipt on the CAISO controlled grid.[116] 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 participants subject to the gas limitations. When the constraint is binding, the market will ensure generation subject to the constraint will not be dispatched

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113 *See* new tariff section 27.11.

114 The tariff provisions also specify how the CAISO will allocate any non-zero amounts 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.

115 Although this transmittal letter uses the capitalized term "CNode" as a convenient shorthand signifying a network connectivity node, that term is not defined in the tariff.

116 The full network model is composed of 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.

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.

During the September 16, 2016 technical conference in Docket No. ER16-1649, one of the topics for discussion was whether the CAISO used "any measures other than those accepted in the June 1 Order to manage reliability in the Southern California region, *e.g.*, exceptional dispatch or coordination with interstate pipelines."[117] The CAISO explained at the technical conference that over the summer it issued two sets of exceptional dispatches related to gas and electric system coordination.

The CAISO issued the first set of exceptional dispatches on June 19, 2016, in response to gas system curtailments due to operational issues on the Blythe compressor station used to support the SoCalGas system. Through close coordination with the gas company, the CAISO determined which resources the gas company was going to curtail and consistent with its communication with the gas company, the CAISO exceptionally dispatched down two resources. In this case, the CAISO did not believe enforcing the maximum generation constraint was appropriate because the issue was isolated to two resources, and the exceptional dispatches were related to specific gas curtailments issued to those two units.

On July 21, 2016, the CAISO issued exceptional dispatches to three resources after communicating with the gas company and learning that a curtailment watch was in place and curtailments were likely the next day. The CAISO notified market participants through a market notification system message that (1) it had confirmed with SoCalGas that there was a gas delivery system limitation in effect impacting the San Diego area from hour ending 18 until notified and (2) to mitigate impacts to electric system reliability, the CAISO had exceptionally dispatched the affected electrical generators for up to 12 hours from the time of the notice, or until the generators received an updated available gas limitation from SoCalGas, whichever came first. These exceptional dispatches helped relieve pressure on the affected system, and later that day, SoCalGas confirmed that the system issues were relieved.

Commission staff also asked whether the CAISO would have had the authority to employ the gas constraint in either of these cases instead of issuing exceptional dispatches. The CAISO explained that it has a number of tools available to address issues identified through its coordination with the gas

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[117] Supplemental Notice of Agenda and Discussion Topics for Staff Technical Conference, Docket No. ER16-1649-000, at 3 (Aug. 17, 2016).

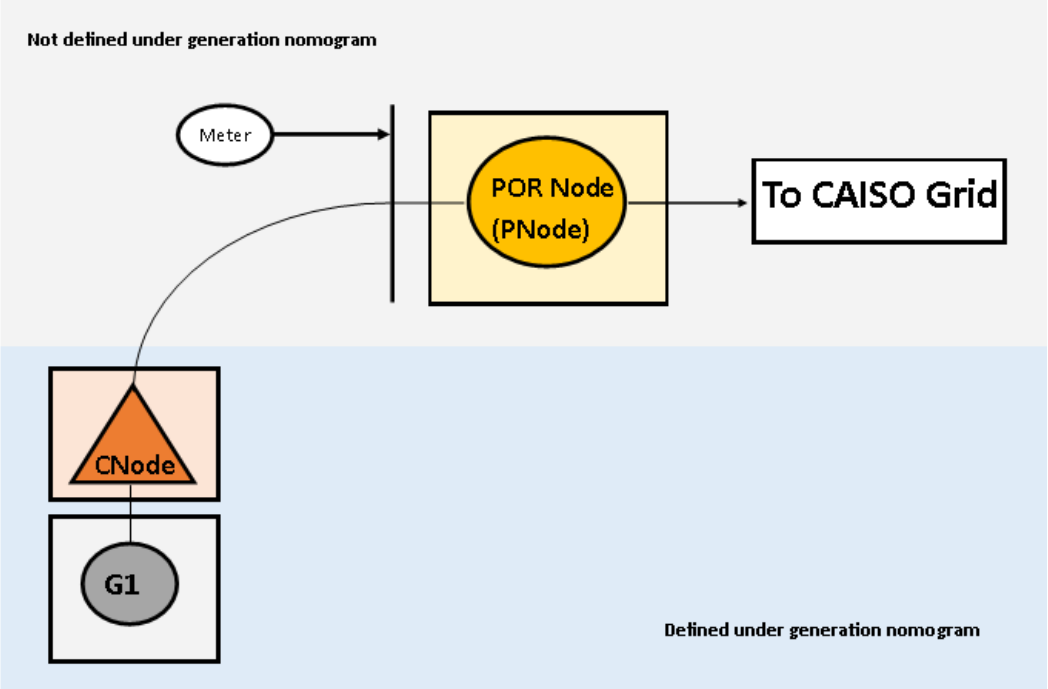
companies, and exceptional dispatch is one of those tools. As further discussed below, the CAISO believes that although it had tariff authority to apply the gas constraint to address these issues, it was inappropriate to do so at that time.

Regarding the June 19 events, when the CAISO needs to curtail specific generators based on its communications with the gas company, it is best to use exceptional dispatch rather than the constraint because the constraint may not be as effective in obtaining the desired curtailments. Thus, in such circumstances the CAISO will use exceptional dispatches rather the constraint.

Regarding the July 21 exceptional dispatches, in retrospect and after further examination of the circumstances, the CAISO could have implemented the constraint to effectuate the outcome intended with the exceptional dispatches. However, at the time it issued the exceptional dispatches, the CAISO had developed procedures to only apply the constraint it perceived the problem would have been resolved if the Aliso Canyon facility was fully functional. The CAISO has subsequently concluded that applying this rule is unnecessarily restrictive, and the question of whether the availability of Aliso Canyon could have resolved the issue is not always immediately obvious at the time the CAISO must make the decision to use the constraint or other means. The CAISO has revised its procedures and will apply the constraint if, based on the totality of the circumstances, and using the guidelines described above, the CAISO determines it is the best tool to use at that time. However, it is possible that based on the specific circumstances, the CAISO may choose to use exceptional dispatch and not the constraint to effectuate a reduction in generation in a given area. It is not the CAISO's intent to replace all exceptional dispatches resulting from gas operational issues with the maximum generation constraint. CAISO operators must retain the flexibility they have within the existing tariff authority to use the best tool available consistent with good utility judgment to maintain reliability depending on the circumstances.

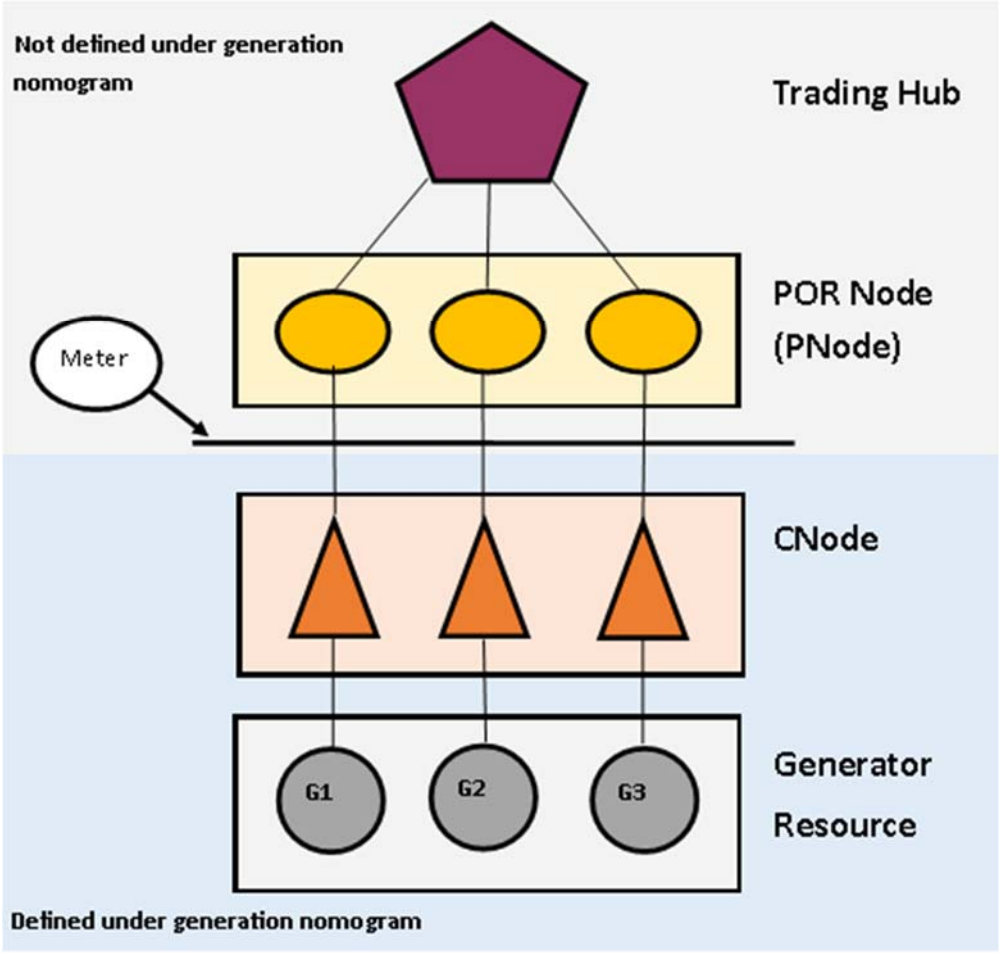
In Figure 2 below, the grey circle represents a generator's (G1)'s physical topological connection to a network node, the CNode. In this example, there is only one piece of equipment connected to a CNode. Therefore, the CNode and bus pricing node (PNode) are unique. Figure 2 also shows the connection 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.

Figure 2



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). Figure 3 below shows the relationship between the generators (represented by grey circles), CNodes (represented by orange triangles), and PNodes that are aggregated into the Trading Hub's APNode. Figure 3 illustrates that the PNode contributes to the pricing of the trading hub price represented by the purple pentagon and not the CNode.

Figure 3



The CAISO proposes to maintain the tariff language authorizing it to settle injections into the CAISO controlled grid in the SoCalGas and SDG&E gas regions at prices influenced by the maximum gas constraint. The CAISO accomplishes this 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 constraint.

The maximum gas constraint will continue to establish just and reasonable prices at affected generator locations, because under a maximum gas burn limit the price should decrease according to the constrained availability of gas available to fuel generating power at that location. This is similar to how a supply source behind a transmission constraint is priced higher to reflect the congestion cost associated with dispatching that supply.

The price for load, virtual bids, and congestion revenue rights will continue not to reflect the shadow price of the maximum 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. Because 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 locational marginal prices for the point of receipt should send accurate marginal price signals associated with the incremental change in injection or demand at that specific location.

It is reasonable not to reflect the shadow price of the maximum gas constraint in the price of CRRs and virtual bids. If CRRs and virtual schedules settle on locational marginal prices (LMPs) that reflect the shadow price of the constraint, financial entities might be able to take large positions at little or no cost from and inappropriately profit at the expense of revenue inadequacy balancing accounts allocated largely to load serving entities.

When the maximum gas constraint is binding in the day-ahead market, CRRs that source at a node impacted by the constraint and sink at a node not impacted by the constraint will continue to be paid based on the shadow price of the constraint. There likely will be such source and sink node pairs with little to no other constraints creating price separation between the source and sink nodes. Therefore, market participants could obtain large quantities of such CRRs 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 maximum gas 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 will continue to 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 or no other constraints creating price separation between the virtual supply and virtual demand nodes. Therefore, using the shadow price of the constraint to settle virtual bids could result in market participants obtaining large quantities of offsetting virtual supply and demand schedules at little to no cost and with very little downside risk. When the 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.

E. Maintain Measures to Address Market Issues Related to the Enforcement of the Maximum Gas Constraint

In tandem with maintaining the maximum gas constraint, the CAISO also proposes to maintain the tariff provisions regarding two related features to address potential market issues. First, the CAISO proposes to maintain the criteria for designating a transmission constraint as competitive or non-competitive.[118] The tariff 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. Maintaining these tariff provisions is consistent with the finding in the June 1 Order that such provisions are a reasonable measure to address actual electric supply conditions that are found to be non-competitive when the constraint is enforced due to anticipated electric supply conditions in the SoCalGas and SDG&E gas regions.[119]

Second, consistent with the June 1 Order,[120] to ensure that virtual bidding cannot detrimentally affect the CAISO markets, the CAISO proposes to maintain the effectiveness of the tariff provisions allowing the CAISO to suspend or limit virtual bidding activities in circumstances where submitted virtual bids detrimentally affect CAISO market efficiency related to enforcement of a natural gas constraint.[121] Maintaining these tariff provisions is reasonable because virtual bidding behavior that adversely affects market efficiency can cause problems for system reliability, which the existing approved tariff language is

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[118] Revised tariff section 39.7.2.2. The tariff section as revised in this filing is identical to the same revised section approved in the proceeding on the May 9 Tariff Amendment. The CAISO has included implementation detail in the business practice manual regarding how it applies the tariff provisions, and plans to include additional detail to the business practice manual. Draft Final Proposal, attachment D hereto, at 19-20. These tariff provisions, and the provisions to implement an increased gas price for southern California resources for the real-time market (see section II.C of this transmittal letter), are the only provisions proposed in this filing that apply solely to southern California.

[119] *See* June 1 Order at P 52.

[120] *See id.* at PP 80, 83.

[121] New tariff section 7.9.2(d). The tariff section as revised in this filing is identical to the same revised section approved in the proceeding on the May 9 Tariff Amendment, except that the CAISO has omitted the provision allowing suspension or limitation of virtual bidding activity related to a reservation of internal transfer capability. As discussed below in section II.G of this transmittal letter, the CAISO proposes to discontinue its authority pursuant to the May 9 Tariff Amendment to reserve internal transfer capability.

expressly intended to protect.[122] Further, as the Commission recognized in the June 1 Order, during the interim period, with the limited operability of Aliso Canyon and the measures that CAISO may have to undertake to address electric and gas reliability, there may be times when promoting price convergence may run contrary to the efficient economic solution of the market. There may also be sustained differences in prices between locations and between day-ahead and real-time markets that could be exploited by virtual bidders without yielding any market benefits.[123] Maintaining the tariff provisions will allow the CAISO to address these issues, which can occur during the winter period as identified in the winter assessment.

As is the case today, if the CAISO suspends or limits virtual bidding pursuant to the tariff provisions, the CAISO will file an informational report with the Commission explaining why it took such action. The CAISO has included detail regarding this tariff authority in the business practice manual. Further, the CAISO has committed to issue a technical bulletin justifying any general suspension or limitation of virtual bidding it might need to implement.[124]

F. Augment the Tariff Provisions that Allow Resources to Seek After-the-Fact Cost Recovery from the Commission Pursuant to a Section 205 Filing

In the June 1 Order, the Commission accepted, on an interim basis, procedures that permit scheduling coordinators to seek after-the-fact recovery of both fuel-related commitment costs and incremental fuel costs associated with default energy bids under the variable cost option and with generated bids by submitting section 205 fi to the Commission. Subsequently, the CAISO submitted the August 19 Tariff Amendment, in which it proposed to maintain in effect on a permanent basis the procedures regarding recovery of fuel-related commitment costs, but not the procedures regarding recovery fuel-related costs associated with default energy bids under the variable cost option or generated bids. The August 19 Tariff Amendment is pending before the Commission.

In addition, the CAISO proposes in this filing to continue allowing scheduling coordinators, on an interim basis, to seek after-the-fact recovery for costs relating to default energy bids and generated bids. The CAISO also proposes to permit scheduling coordinators to seek after-the-fact recovery of incremental fuel costs associated with *all* types of default energy bids (*i.e.*, not

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122 *See* existing tariff section 7.9.2.

123 June 1 Order at P 80.

124 Draft Final Proposal, attachment D hereto, at 20.

just default energy bids under the variable cost option, per the May 9 Tariff Amendment) on an interim basis.[125] Augmenting the procedures in this manner will allow the CAISO and stakeholders to better address the risk presented by the limited operability of Aliso Canyon.

As the Commission recognized in the June 1 Order, the procedures permitting section 205 filings to recover incremental fuel costs, including fuel costs associated with default energy bids under the variable cost option and generated bids, address the possibility that fuel costs may exceed the amounts recoverable under the CAISO's normal cost recovery provisions due to the uncertainty and potential price volatility introduced into the market by the limited operability of Aliso Canyon.[126] The Commission also found that permitting such section 205 filings is a reasonable interim solution given the situation facing CAISO and the need to ensure reliable operation of the grid at just and reasonable rates.[127]

Given the unlikelihood that Aliso will not be fully functional in the next 12 months, these same considerations will remain equally valid after November 30. The CAISO anticipates that scheduling coordinators will, in almost all circumstances, be able to recover their fuel-related costs pursuant to the normal tariff provisions allowing cost recovery.[128]

The CAISO and stakeholders are considering additional measures to improve recovery of costs by resources, including fuel cost recovery, in ongoing and planned stakeholder initiatives evaluating long-term market solutions for bid cost modeling of gas-fired resources, market mechanisms to improve market efficiency and support sufficient cost recovery, and coordination between the electric and gas markets.[129] The CAISO and stakeholders participating in these initiatives will be able to incorporate the discussion and information gathered from the September 16 technical conference to develop long-term solutions. The CAISO anticipates that it will complete these initiatives by the third quarter of

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[125] New tariff section 30.12. *See also* new tariff sections 39.7.1.7, 40.6.8.1.6 (both cross-referencing tariff section 30.12).

[126] June 1 Order at P 91.

[127] *Id.* at P 92.

[128] The normal tariff provisions are designed to provide resources with adequate compensation for their fuel-related default energy bid costs. *See, e.g.*, *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at PP 1004-14, 1033-71.

[129] These stakeholder processes include a commitment cost and default energy bid enhancements initiative, and a future initiative on gas-electric coordination to consider long-term policies to replace the interim measures adopted pursuant to the current Aliso Canyon Gas-Electric Coordination initiative.

2017 and implement any long-term solutions the following quarter. Nevertheless, the CAISO recognizes that unexpected events can lead to situations in which scheduling coordinators cannot recover all of their fuel-related costs associated with their default energy bids. In these situations, the additional tariff procedures proposed in its filing will serve as an appropriate backstop measure if a scheduling coordinator cannot recover its fuel-related costs associated with default energy bids through the normal tariff mechanisms.[130]

During the October 6, 2016 stakeholder meeting to review the draft tariff language, stakeholders sought certain clarifications that the CAISO subsequently included in the proposed tariff provisions. First, DMM and stakeholders asked the CAISO to clearly state whether the measures would apply to scheduling coordinators or to EIM participating resource scheduling coordinators required by Commission order to submit bids no greater than their default energy bid. The CAISO clarified that it perceived these resources to be mitigated and, consistent with the intent that this provision apply to all mitigated resources, it clarified that such entities can apply for cost recovery. Second, a stakeholder asked the CAISO to clarify that an entity can apply for recovery under this section if the entity is subject to exceptional dispatch mitigation, even if the entity does not submit a bid and is paid at the LMP. Third, DMM asked the CAISO to clarify that if a scheduling coordinator submits a bid that is less than its default energy bid, the entity is not eligible to apply for recovery under this section. The CAISO made this clarification and revised the draft tariff language to state that the resource must have been mitigated to its bid.[131]

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[130] The CAISO notes that it has other Commission-approved procedures that allow suppliers to make limited cost justification filings to the Commission in the rare instance that the applicable cap or administrative price is insufficient to compensate the supplier for its actual costs *See* existing tariff section 43.7.2.1.1(containing a capacity procurement mechanism (CPM) capacity price higher than the administrative price set forth in the tariff); existing tariff section 43A.4.1.1.1 (provision expected to go into effect on November 1, 2016 that will allow a supplier to cost-justify to the Commission fixed costs that exceed the CPM soft offer cap).

[131] *See* new tariff section 30.12.1. New tariff sections 30.12.2 through 30.12.4 set forth provisions regarding notice and process, documentation requirements, and payment and allocation of costs recovered pursuant to a Commission order that are very similar to provisions in new tariff section 30.11 as approved in the proceeding on the May 9 Tariff Amendment.

G. Discontinue the CAISO's Expanded Authority to Reserve Internal Transfer Capability by Adjusting Transmission Constraints and to Adjust the Release of CRRs

The CAISO proposes to discontinue the tariff provisions accepted in the June 1 Order that expanded the CAISO's authority to reserve internal transfer capability by adjusting transmission constraints.[132] The tariff provisions are no longer needed to manage reliability, which was the basis for their acceptance in the June 1 Order.[133]

In tandem with discontinuing the tariff provisions described above, the CAISO also proposes to discontinue the tariff provisions accepted in the June 1 Order that permit the CAISO 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.[134] Because the CAISO no longer needs to adjust transmission constraints pursuant to the tariff provisions described above, it also no longer requires the tariff provisions for adjusting CRRs.

III. Stakeholder Issues

As explained above, stakeholders and DMM either supported or did not oppose extending the measures proposed in this filing for another 12 months. They also raised several issues as discussed below.

A number of stakeholders requested that the CAISO provide additional documentation and procedures to increase the information it releases to the market related to these measures and its enhanced gas-electric coordination. The CAISO is already in the process of doing this where appropriate.

DMM and a stakeholder stated that the CAISO should pursue tariff revisions for price mitigation of incremental exceptional dispatches due to natural gas limitations. They also urged the CAISO to develop a methodology to mitigate decremental exceptional dispatches. The CAISO plans to examine this as part of an upcoming stakeholder process and could accelerate this if bidding practices appear to necessitate more expedient action.

Some stakeholders supported the CAISO pursuing long-term market enhancements to its commitment cost and default energy bid designs. The

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132 Deleted tariff section 27.5.6(f).

133 *See* June 1 Order at P 63.

134 Revised tariff section 36.4.

CAISO plans to examine long-term market enhancements in an upcoming stakeholder process.

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

The CAISO respectfully requests that the Commission accept the proposed tariff revisions on an expedited basis. Maintaining the previously approved provisions with the few modifications proposed herein will ensure that the CAISO has the necessary procedures and flexibility in place to timely address the risks posed by the limited operability of Aliso Canyon during this winter. Therefore, the CAISO requests that the Commission issue an order accepting this filing by November 28, 2016.

The CAISO also requests that the Commission grant waiver of its notice requirements to permit the tariff revisions to go into effect as of November 30, 2016.[135] Good cause exists to grant this waiver in order to prevent any gap in time from occurring between (i) when the tariff revisions accepted in the June 1 Order will automatically be superseded by the tariff as it existed prior to the effectiveness of the May 9 Tariff Amendment and (ii) when the tariff revisions contained in the instant filing go into effect. Therefore, the Commission should grant the requested waiver.

V. Interim Effectiveness of the Tariff Revisions Until November 30, 2017 to the Extent the Commission Does Not Permit Them to Remain in Effect Beyond that Date Pursuant to a Subsequent CAISO Filing

The CAISO expects that Aliso Canyon will not be operational during the bulk of 2017. Based on the study for the summer of 2016, the CAISO anticipates that if the Aliso Canyon does not become fully operational by next spring and summer, the same risks identified in that study will be present. The CAISO anticipates, however, that some or all of the tariff revisions proposed in this filing may not be needed after November 30, 2017, when 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.

For these reasons, the CAISO requests that the Commission permit the interim tariff provisions proposed in this filing to be in place for an additional 12 months, *i.e.*, until November 30, 2017. Further, the Commission and market

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[135] Pursuant to section 35.11 of the Commission's regulations, 18 C.F.R. § 35.11, the CAISO respectfully 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 November 30 effective date.

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.[136]

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 November 30, 2016 effective date 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, 2017.[137] 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, 2017, 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 (and before the May 9 Tariff Amendment went into effect).

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, 2017. 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, 2017 as described above; (2) be permitted to remain in effect after November 30, 2017 with no modifications; or (3) be permitted to remain in effect after November 30, 2017 with modifications.[138]

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

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

[138] The FPA 205 filing or filings submitted will include a request that the Commission issue an order accepting them on or before November 29, 2017.

VI. Communications

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

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VII. 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.

VIII. 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 Information Regarding Aliso Canyon and CAISO Stakeholder Process
Attachment D	Draft Final Proposal
Attachment E	DMM Comments
Attachment F	Board Memorandum

IX. Conclusion

For the reasons set forth in this filing, the CAISO respectfully requests that the Commission issue an order by November 28, 2016 that accepts the tariff revisions contained in this filing effective November 30, 2016.

Respectfully submitted,

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Attachment A – Clean Tariff Records

Filing to Maintain in Effect for One Year Certain Tariff Provisions Previously Accepted on an Interim Basis to Address Limited Operability of Aliso Canyon Facility

California Independent System Operator Corporation

6.2.1.3 Individually Assigned Login Accounts

The CAISO will provide an interface for data exchange between the CAISO and Scheduling Coordinators who shall each have individually assigned login accounts via digital certificates. Through the use of the security provisions of CAISO's secure communication system, data will be provided by the CAISO to Scheduling Coordinators on a confidential basis (such as Day-Ahead Schedules and resource-specific pricing data resulting from the enforcement of a natural gas constraint as specified in Section 27.11 for individual Scheduling Coordinators). Other CAISO data that is not confidential (such as CAISO Demand Forecasts) will be published on the public access reporting system of the CAISO Website and be available to anyone.

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6.5.2 Communications Prior To The Day-Ahead Market

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6.5.2.2.3 Advisory Day-Ahead Market Results

The CAISO may provide to the responsible Scheduling Coordinator its 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.

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6.5.2.3.4 Greenhouse Gas Price Indices

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

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6.5.4 RTM Communications Before The Trading Hour

6.5.4.2.3 The CAISO will publish the natural gas price indices 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 if 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 related to enforcement of natural gas constraint pursuant to Section 27.11.

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27.10 [NOT USED]

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27.11 Natural Gas Constraint

The CAISO may enforce constraints that limit the maximum amount of natural gas that can be burned by natural gas-fired resources in the Southern California Gas Company and San Diego Gas & Electric Company gas regions, 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 be reflected in the Marginal Cost of Congestion component of the Locational Marginal Prices of only 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. The CAISO will provide, through the procedures set forth in Section 6.5.10.1.1, information on whether the CAISO plans to enforce a natural gas constraint in the Day-Ahead Market, and after the Day-Ahead Market is executed, whether it enforced a natural gas constraint in the Day-Ahead Market. In addition, to the extent feasible in advance of the deadline for submitting Bids for the Day-Ahead or Real-Time Market, as applicable, the CAISO will issue a notice through its market notification system indicating its intent to enforce a natural gas constraint along with the affected areas and the magnitude and expected duration of the natural gas constraint.

* * * *

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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30.12 Eligibility to Submit Filings to Recover Marginal Fuel-Related Costs

30.12.1 Applicability

A Scheduling Coordinator or EIM Participating Resource Scheduling Coordinator may seek to recover through a FERC filing pursuant to Section 205 of the Federal Power Act any actual margin fuel procurement costs that cannot be recovered through CAISO market revenues under the following conditions:

(i) A Scheduling Coordinator or EIM Participating Resource Scheduling Coordinator is mitigated to its Default Energy Bid that is calculated pursuant to any of the options set forth in Section 39.7.1, or the competitive LMP through the Local Market Power Mitigation as specified in Sections 31.2 and 34.1.5;

(ii) A Scheduling Coordinator whose Exceptional Dispatch is mitigated pursuant to Section 39.10 for any of the options set forth in Section 39.7.1, or submits no Bid, and the Exceptional Dispatch is settled at the greater of the applicable Default Energy Bid or resource-specific LMP;

(iii) A Scheduling Coordinator or EIM Participating Resource Scheduling Coordinator that is required by FERC order to submit Bids no greater than its Default Energy Bid calculated pursuant to any of the options set forth in Section 39.7.1, and submit Bids at the Default Energy Bid; or

(iv) A Scheduling Coordinator that is subject to a Generated Bid as set forth in Sections 30.7.3.4, 39.7.1.1.1, and 40.6.8.

30.12.2 Notice and Process

The Scheduling Coordinator or EIM Participating Resource 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 Operating Day. Within sixty (60) Business Days after the Operating Day for which the Scheduling Coordinator or EIM Participating Resource Scheduling Coordinator provides notice to the CAISO per this Section, the CAISO will provide the Scheduling Coordinator or EIM Participating Resource 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.

30.12.3 Documentation Required for FERC Filing

Each filing the Scheduling Coordinator or EIM Participating Resource Scheduling Coordinator submits to FERC must include:

(1) Data supporting the Scheduling Coordinator's or EIM Participating Resource Scheduling

Coordinator claim to the unrecovered costs it seeks, including invoices related to 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 or EIM Participating Resource Scheduling Coordinator described above in this Section.

30.12.4 Payment and Allocation of Costs Recovered Pursuant to a FERC Order

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

* * * *

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.

* * * *

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 recent 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 based on natural gas prices reported by the Intercontinental Exchange one (1) day prior to the applicable Trading Day between 8:00 and 9:00 a.m. Pacific Time for natural gas deliveries on the Trading Day, which is a volume-weighted average price calculated by the Intercontinental Exchange based on trades transacted that day 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 for natural gas deliveries on the Trading Dya, 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/therm 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 change in the gas price is necessary after the initial increase, the CAISO will issue a Market Notice specifying the amount of the increase.

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39.7.1.7 Filings with FERC to Recover Actual Marginal Fuel Procurement Costs

A Scheduling Coordinator for a resource subject to any of the Default Energy Bid Options in Section 39.7.1 may seek to recover actual marginal fuel procurement costs pursuant to a filing with FERC in accordance with Section 30.12.

* * * *

39.7.2 Competitive Path Designation

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.

(b) Transmission Constraints for the RTM - As part of the MPM processes associated with the RTM, the CAISO will designate a Transmission Constraint for the RTM as non-competitive when the sum of the supply of counter-flow from all portfolios of potentially pivotal suppliers to the Transmission Constraint and 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(b):

(i) Counter-flow to the Transmission Constraint has the meaning set forth in Section 39.7.2.2(a)(i).

(ii) Supply of counter-flow from all portfolios of potentially pivotal suppliers to the Transmission Constraint means the minimum available capacity from internal resources controlled by the identified potentially pivotal suppliers that provide counter-flow to the Transmission Constraint. The minimum available capacity for the current market interval will reflect the greatest amount of capacity that can be physically withheld. The minimum available capacity is the lowest output level the resource could achieve in the current market interval given its dispatch in the last market interval and limiting factors including Minimum Load, Ramp Rate, Self-Provided Ancillary Services, Ancillary Service Awards (in the Real-Time Market only), and derates.

(iii) Potentially pivotal suppliers mean the three (3) portfolios of net sellers that control the largest quantity of counter-flow supply to the Transmission Constraint that can be withheld. Counter-flow supply to the Transmission Constraint that can be withheld reflects the difference between the highest capacity and the lowest capacity of a resource's Energy Bid (not taking into account the Ramp Rate of the resource), measured from the Dispatch Operating Point for the resource in the immediately preceding fifteen (15) minute FMM interval (taking

into account the Ramp Rate of the resource), adjusted for Self-Provided Ancillary Services and derates in determining whether to designate a Transmission Constraint as non-competitive for the RTM, or adjusted for Ancillary Service Awards and derates in determining whether to designate a Transmission Constraint as non-competitive for the RTM. In determining whether to designate a Transmission Constraint as non-competitive for the RTM, counter-flow supply to the Transmission Constraint that can be withheld also reflects the PMin of each Short Start Unit with a Start-Up Time of sixty (60) minutes or less that was off-line in the immediately preceding fifteen (15) minute interval of the FMM. In determining whether to designate a Transmission Constraint as non-competitive for the RTM, counter-flow supply to the Transmission Constraint that can be withheld also reflects the PMin of each Short Start Unit with a Start-Up Time of fifteen (15) minutes or less that was off-line in the immediately preceding fifteen (15) minute interval.

(iv) Portfolio means the effective available internal generation capacity under the control of the Scheduling Coordinator and/or Affiliate determined pursuant to Sections 4.5.1.1.12 and 39.7.2.2(a)(vii). Effectiveness in supplying counter-flow is determined by scaling generation capacity by the shift factor from that location to the Transmission Constraint being tested.

(v) A portfolio of a net seller has the meaning set forth in Section 39.7.2.2(a)(vi).

(vi) Fringe supply of counter-flow to the Transmission Constraint means all available capacity from internal resources 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 (not taking into account the Ramp Rate of the resource), measured from the Dispatch Operating Point for the resource in the immediately preceding fifteen (15) minute interval of the FMM (taking into account the Ramp Rate of the resource), adjusted for Self-Provided Ancillary Services and derates in determining whether to designate a

Transmission Constraint as non-competitive for the RTM, or adjusted for Ancillary Service Awards and derates in determining whether to designate a Transmission Constraint as non-competitive for the RTM.

(vii) Demand for counter-flow to the Transmission Constraint means all internal dispatched Supply that provides counter-flow to the Transmission Constraint.

* * * *

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 30.12.

* * * *

Attachment B – Marked Tariff Records

Filing to Maintain in Effect for One Year Certain Tariff Provisions Previously Accepted on an Interim Basis to Address Limited Operability of Aliso Canyon Facility

California Independent System Operator Corporation

6.2.1.3 Individually Assigned Login Accounts

The CAISO will provide an interface for data exchange between the CAISO and Scheduling Coordinators who shall each have individually assigned login accounts via digital certificates. Through the use of the security provisions of CAISO's secure communication system, data will be provided by the CAISO to Scheduling Coordinators on a confidential basis (such as Day-Ahead Schedules and resource-specific pricing data resulting from the enforcement of a natural gas constraint as specified in Section 27.11 for individual Scheduling Coordinators). Other CAISO data that is not confidential (such as CAISO Demand Forecasts) will be published on the public access reporting system of the CAISO Website and be available to anyone.

* * * *

6.5.2 Communications Prior To The Day-Ahead Market

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6.5.2.2.3 Advisory Day-Ahead Market Results

The CAISO may provide to the responsible Scheduling Coordinator its 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.

* * * *

6.5.2.3.4 Greenhouse Gas Price Indices

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

* * * *

6.5.4 RTM Communications Before The Trading Hour

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

* * * *

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 if 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 related to enforcement of natural gas constraint pursuant to Section 27.11.

* * * *

27.10 [NOT USED] ~~Flexible Ramping Constraint~~

~~The CAISO may enforce a Flexible Ramping Constraint in the RTM. Any flexible Dispatch capacity constrained to be available as a result of the Flexible Ramping Constraint in RTM will come from capacity that is not designated to provide Regulation or Operating Reserves, and will not offset the required procurement of Regulation or Operating Reserves in RTUC. To the extent a resource incurs an opportunity cost for not providing Energy or Ancillary Services in the FMM or RTD interval as a result of a binding Flexible Ramping Constraint, all resources resolving that Flexible Ramping Constraint will be compensated pursuant to Section 11.25. In the FMM or RTD the resources identified as resolving the Flexible Ramping Constraint in the corresponding RTUC run will be the only resources used to resolve the Flexible Ramping Constraint enforced in FMM or RTD. The Flexible Ramping Constraint can be satisfied only by committed online dispatchable Generating Units, Participating Load, and Proxy Demand Response resources with ramping capability for which a Scheduling Coordinator has submitted Economic Bids for Energy for the applicable Trading Hour, and Dynamic System resources as specified below. This constraint cannot be satisfied by System Resources that are not Dynamic System Resources. Dynamic System Resources can become eligible to participate in relieving the Flexible Ramping Constraint if the Scheduling Coordinator scheduling that Resource can demonstrate that it has firm transmission service to the CAISO Balancing Authority Area intertie that allows the resource to deliver additional Energy in Real-Time, consistent with the requirements of Section 1.5 of the Dynamic Scheduling Protocol in Appendix M. This Dynamic System Resource must demonstrate that the Dynamic System Resource has acquired sufficient firm transmission to support the total quantity of Energy and Ancillary Services offered in the Real-Time Market by submitting an E-Tag with a transmission profile that reflects the necessary transmission reservation(s) outside the CAISO Balancing Authority Area.~~

~~Procurement of Flexible Ramping Constraint capacity from Dynamic System Resources is limited by the available capacity in Real-Time for the applicable interval on the applicable intertie transmission constraint with which the Dynamic System Resource is associated. The quantity of the flexible ramping capacity for each applicable CAISO Market run will be determined by CAISO operators using tools that estimate the: 1) expected level of imbalance variability; 2) uncertainty due to forecast error; and 3) differences between the hourly, fifteen (15) minute average and historical five (5) minute Demand levels. The Flexible~~

~~Ramping Constraint relaxation parameter is $60.~~

* * * *

27.11 Natural Gas Constraint

The CAISO may enforce constraints that limit the maximum amount of natural gas that can be burned by natural gas-fired resources in the Southern California Gas Company and San Diego Gas & Electric Company gas regions, 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 be reflected in the Marginal Cost of Congestion component of the Locational Marginal Prices of only 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. The CAISO will provide, through the procedures set forth in Section 6.5.10.1.1, information on whether the CAISO plans to enforce a natural gas constraint in the Day-Ahead Market, and after the Day-Ahead Market is executed, whether it enforced a natural gas constraint in the Day-Ahead Market. In addition, to the extent feasible in advance of the deadline for submitting Bids for the Day-Ahead or Real-Time Market, as applicable, the CAISO will issue a notice through its market notification system indicating its intent to enforce a natural gas constraint along with the affected areas and the magnitude and expected duration of the natural gas constraint.

* * * *

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.~~

* * * *

30.12 Eligibility to Submit Filings to Recover Marginal Fuel-Related Costs

30.12.1 Applicability

A Scheduling Coordinator or EIM Participating Resource Scheduling Coordinator may seek to recover through a FERC filing pursuant to Section 205 of the Federal Power Act any actual margin fuel procurement costs that cannot be recovered through CAISO market revenues under the following conditions:

(i) A Scheduling Coordinator or EIM Participating Resource Scheduling Coordinator ~~that~~ is mitigated to its Default Energy Bid that is calculated pursuant to any of the options set forth in Section 39.7.1, or the competitive LMP through the Local Market Power Mitigation as specified in Sections 31.2 and 34.1.5;

~~(i)~~(ii) A Scheduling Coordinator whose Exceptional Dispatch is mitigated pursuant to Section 39.10 for any of the options set forth in Section 39.7.1, or submits no Bid, and the Exceptional Dispatch is settled at the greater of the applicable Default Energy Bid or resource-specific LMP;

(iii) A Scheduling Coordinator or EIM Participating Resource Scheduling Coordinator that is required by FERC order to submit Bids no greater than its Default Energy Bid calculated pursuant to any of the options set forth in Section 39.7.1, and submit Bids at the Default Energy Bid; or

(iv) A Scheduling Coordinator that is subject to a Generated Bid as set forth in Sections 30.7.3.4, 39.7.1.1.1, and 40.6.8.

30.12.2 Notice and Process

The Scheduling Coordinator or EIM Participating Resource 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 Operating Day. Within sixty (60) Business Days after the Operating Day for which the Scheduling Coordinator or EIM Participating Resource Scheduling Coordinator provides notice to the CAISO per this Section, the CAISO will provide the Scheduling Coordinator or EIM Participating Resource 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.

30.12.3 Documentation Required for FERC Filing

Each filing the Scheduling Coordinator or EIM Participating Resource Scheduling Coordinator submits to FERC must include:

(1) Data supporting the Scheduling Coordinator's or EIM Participating Resource Scheduling Coordinator claim to the unrecovered costs it seeks, including invoices related to 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 or EIM Participating Resource Scheduling Coordinator described above in this Section.

30.12.4 Payment and Allocation of Costs Recovered Pursuant to a FERC Order

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

* * * *

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.~~

* * * *

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 recent 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 based on natural gas prices reported by the Intercontinental Exchange one (1) day prior to the applicable Trading Day between 8:00 and 9:00 a.m. Pacific Time for natural gas deliveries on the Trading Day, which is a volume-weighted average price calculated by the Intercontinental Exchange based on trades transacted that day 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 for natural gas deliveries on the Trading Dya, 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/therm 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 change 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.~~

* * * *

39.7.1.7 Filings with FERC to Recover Actual Marginal Fuel Procurement Costs

A Scheduling Coordinator for a resource subject to any of the Default Energy Bid Options in Section 39.7.1 may seek to recover actual marginal fuel procurement costs pursuant to a filing with FERC in accordance with Section 30.12.

* * * *

39.7.2 Competitive Path Designation

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.

(b) Transmission Constraints for the RTM - As part of the MPM processes associated with the RTM, the CAISO will designate a Transmission Constraint for the RTM as non-competitive when the sum of the supply of counter-flow from all portfolios of potentially pivotal suppliers to the Transmission Constraint and 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(b):

(i) Counter-flow to the Transmission Constraint has the meaning set forth in Section 39.7.2.2(a)(i).

(ii) Supply of counter-flow from all portfolios of potentially pivotal suppliers to the Transmission Constraint means the minimum available capacity from internal resources controlled by the identified potentially pivotal suppliers that provide counter-flow to the Transmission Constraint. The minimum available capacity for the current market interval will reflect the greatest amount of capacity that can be physically withheld. The minimum available capacity is the lowest output level the resource could achieve in the current market interval given its dispatch in the last market interval and limiting factors including Minimum Load, Ramp Rate, Self-Provided Ancillary Services, Ancillary Service Awards (in the Real-Time Market only), and derates.

(iii) Potentially pivotal suppliers mean the three (3) portfolios of net sellers that control the largest quantity of counter-flow supply to the Transmission Constraint that can be withheld. Counter-flow supply to the Transmission Constraint that can be withheld reflects the difference between the highest capacity and the lowest capacity of a resource's Energy Bid (not taking into account the Ramp Rate of the resource), measured from the Dispatch Operating Point for the resource in the immediately preceding fifteen (15) minute FMM interval (taking

into account the Ramp Rate of the resource), adjusted for Self-Provided Ancillary Services and derates in determining whether to designate a Transmission Constraint as non-competitive for the RTM, or adjusted for Ancillary Service Awards and derates in determining whether to designate a Transmission Constraint as non-competitive for the RTM. In determining whether to designate a Transmission Constraint as non-competitive for the RTM, counter-flow supply to the Transmission Constraint that can be withheld also reflects the PMin of each Short Start Unit with a Start-Up Time of sixty (60) minutes or less that was off-line in the immediately preceding fifteen (15) minute interval of the FMM. In determining whether to designate a Transmission Constraint as non-competitive for the RTM, counter-flow supply to the Transmission Constraint that can be withheld also reflects the PMin of each Short Start Unit with a Start-Up Time of fifteen (15) minutes or less that was off-line in the immediately preceding fifteen (15) minute interval.

(iv) Portfolio means the effective available internal generation capacity under the control of the Scheduling Coordinator and/or Affiliate determined pursuant to Sections 4.5.1.1.12 and 39.7.2.2(a)(vii). Effectiveness in supplying counter-flow is determined by scaling generation capacity by the shift factor from that location to the Transmission Constraint being tested.

(v) A portfolio of a net seller has the meaning set forth in Section 39.7.2.2(a)(vi).

(vi) Fringe supply of counter-flow to the Transmission Constraint means all available capacity from internal resources 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 (not taking into account the Ramp Rate of the resource), measured from the Dispatch Operating Point for the resource in the immediately preceding fifteen (15) minute interval of the FMM (taking into account the Ramp Rate of the resource), adjusted for Self-Provided Ancillary Services and derates in determining whether to designate a

Transmission Constraint as non-competitive for the RTM, or adjusted for Ancillary Service Awards and derates in determining whether to designate a Transmission Constraint as non-competitive for the RTM.

(vii) Demand for counter-flow to the Transmission Constraint means all internal dispatched Supply that provides counter-flow to the Transmission Constraint.

* * * *

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 30.12.

* * * *

Attachment C – Aliso Canyon Background Information

Filing to Maintain in Effect for One Year Certain Tariff Provisions Previously Accepted on an Interim Basis to Address Limited Operability of Aliso Canyon Facility

California Independent System Operator Corporation

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. For winter operations, Aliso Canyon provides needed winter supply and withdrawal services and allows preparation for the following summer.[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.[4]

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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 the submittal of the May 9 Tariff Amendment and of 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.

[4] *Id.* at 10.

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 (Bcf) are being stored 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 California Public Utilities Commission (CPUC) and the California Energy Commission (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, as well as other materials discussed below, 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 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

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[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 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.

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 caused gas-balancing conditions in southern California to become more strained, over both the SoCalGas and SDG&E gas systems, and these conditions were expected to worsen during the summer of 2016. As detailed in the Risk Assessment Report and the Reliability Action Plan, the Inter-Agency Task Force performed analyses that identified the risks to the SoCalGas operating region starting that summer. To address the risks, the Inter-Agency Task Force proposed a total of 18 mitigation measures, including changes to the CAISO market to improve gas-electric coordination.[8]

The CAISO and other entities in California took a number of actions to address the risks presented by the limited operability of Aliso Canyon. In the May 9 Tariff Amendment, the CAISO explained that while it expected these actions to prove instrumental in mitigating the challenges posed, significant electric grid reliability concerns remained that stemmed from the interaction between gas balancing requirements and the reliance on gas-fired resources to serve load in southern California. The CAISO stated that it proposed the tariff revisions set forth in the May 9 Tariff Amendment both to address these reliability concerns and to avoid exacerbating issues caused by an already constrained gas system.[9] Most of those tariff revisions went into effect on June 2, 2016, with more of the tariff revisions going into effect on July 6, 2016.

The CAISO also established an ongoing practice of holding biweekly calls with the gas companies regarding outage planning. In addition, during normal operations, the CAISO provides two-day-ahead and one-day-ahead gas burn schedules to the gas companies, holds daily calls with them regarding the gas burn schedules, and notifies the gas companies if real-time gas burns are higher than the gas burn schedules. When peak operations are necessary during a day, the CAISO issues flex alerts or imposes restricted maintenance operations, holds peak-day reliability calls that include the gas companies, the Peak

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[8] Additional information regarding the identified risks and mitigation measures is provided in attachment C to the May 9 Tariff Amendment.

[9] Transmittal letter for May 9 Tariff Amendment at 2-5; attachment C to May 9 Tariff Amendment.

Reliability Coordinator (Peak RC),[10] participating transmission owners, and neighboring balancing authorities, and holds peak-day market calls with all market participants.

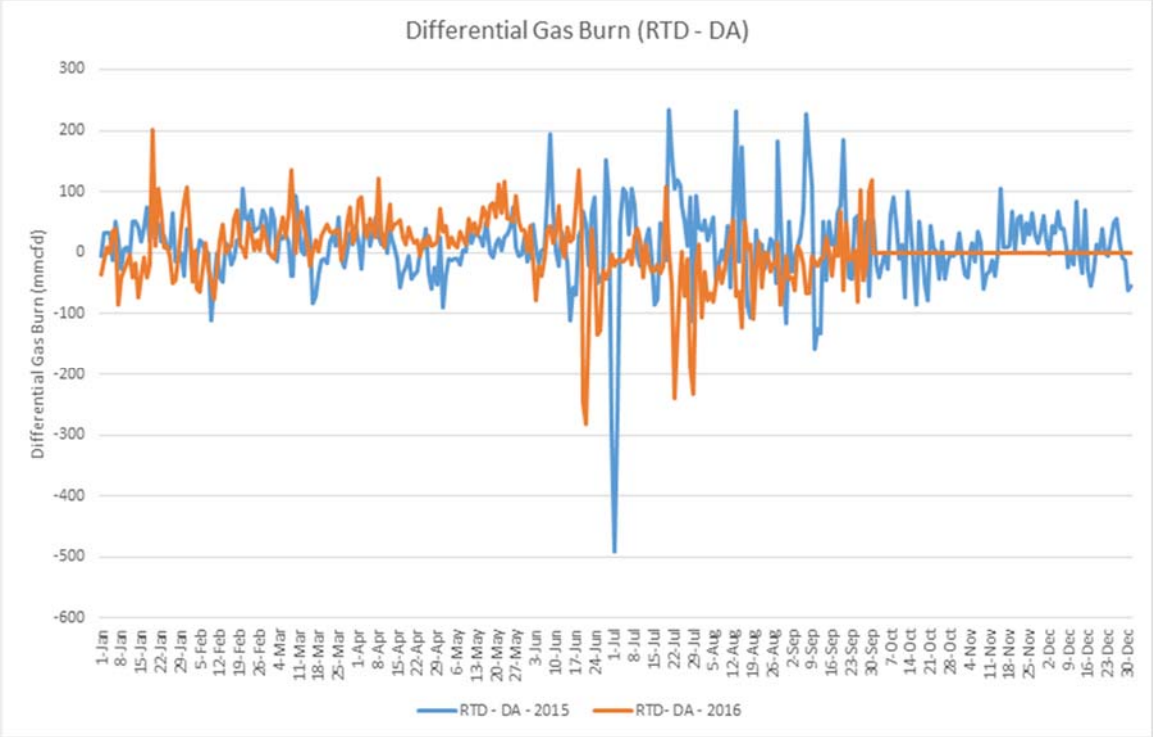
When gas limitation conditions occur in the SoCalGas service territory, CAISO personnel follow a CAISO procedure addressing gas-electric operations coordination under such conditions.[11] Pursuant to the procedure, if SoCalGas notifies the CAISO of a gas curtailment watch, the CAISO can manage the electric system by using gas constraints, adjusting internal transfer capability, or issuing exceptional dispatch instructions to resources. In the event that SoCalGas notifies the CAISO of a pro rata gas curtailment, the CAISO can manage the electric system using gas constraints or issuing exceptional dispatch instructions. The CAISO issues market notifications when it takes such action.

The various actions that the CAISO and other entities took were effective in addressing the risks presented by the limited operability of Aliso Canyon during the summer. With regard to the markets operated by the CAISO, the market results for June through August of 2016 indicate that suppliers scheduled in a more conservative manner than they had for those months in 2015 to bring sufficient gas on-line, and did not drive real-time imbalances causing more gas to be demanded in real-time than day-ahead. These market results are shown in Figure A below. In Figure A, the orange lines represent the difference (*i.e.*, imbalance) between the gas burn amounts on the SoCalGas system between the CAISO's five-minute real-time dispatch and residual unit commitment process schedules. When the orange line falls below zero for a given day, that day had a negative imbalance. A negative imbalance means that the CAISO scheduled greater amounts of power in the day-ahead market and that suppliers either (i) scheduled gas accordingly or (ii) were not able to schedule gas but did bid effectively to reduce their output consistent with their scheduled gas.

[10] Peak RC is the reliability authority for the CAISO balancing authority area.

[11] SoCalGas Service Area Limitations or Outages Procedure 4120C, available on the CAISO website at http://www.caiso.com/Documents/4120C.pdf.

Figure A



The CAISO believes that the exceptional gas-electric coordination and advanced electric planning, as well as the totality of the measures adopted by the CAISO pursuant to the June 1 Order, resulted in the limited number of days depicted in Figure A on which modest positive imbalances occurred from June through August. Overscheduling gas prior to real-time likely supported both gas and electric reliability risk, as the reliability risk was largely that there would be insufficient gas on the SoCalGas system when electric demand required gas to the fuel generating resources on that system.

The CAISO expects that Aliso Canyon will not be operational during the bulk of 2017.[12] The Inter-Agency Task Force has recently performed analyses that identify the risks presented by the limited operability of Aliso Canyon for this coming winter.[13] In particular, the CAISO and LADWP used gas curtailment

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[12] See http://www.argusmedia.com/pages/NewsBody.aspx?id=1324396&menu=yes.

[13] See the Aliso Canyon Winter 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 (Aug. 22, 2016) (Winter Risk Assessment Report) and the Aliso Canyon Gas and Electric Reliability Winter Action Plan 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 (Aug. 22, 2016) (Winter Action Plan), both available on the same CAISO website page as the other Inter-Agency Task Force materials discussed above.

estimates to determine how much of a gas curtailment the electric generators could absorb and whether electric service interruptions could occur. Their analysis concluded that, although the risk to electric reliability is expected to be less than it was this past summer, challenges for electric reliability will continue this winter due to the limited operability of Aliso Canyon.

Specifically, the analysis found that gas-fired electric generation could be susceptible to gas curtailments during the winter without Aliso Canyon under certain conditions. Although electric load is generally lower in the winter compared with the summer, the availability of electric generation supply may be reduced during the winter due to the commitment of fewer generators on-line and outages for scheduled maintenance. The analysis determined that any gas curtailments occurring this winter are not expected to result in electric load interruption, even with reduced availability of electric generation, so long as gas supply and receipt point utilization remains approximately 84 percent or higher (corresponding to a system capacity of 4.1 billion cubic feet per day (Bcfd) of gas) on peak gas demand days. At or above this 84-percent level, the CAISO and LADWP are expected to be able to secure sufficient generation outside of the SoCalGas and SDG&E service territories to avoid interrupting electric load. If, however, the gas supply and receipt point utilization falls below the 84-percent level, there is a risk that system capacity will not be sufficient to source gas to meet all customer needs. In that event, absent withdrawal of sufficient gas from Aliso Canyon to make up the shortfall, gas curtailment of electric generation may occur, potentially interrupting service to electric load.[14]

The CAISO and LADWP analyzed their ability to absorb a potential gas curtailment of 0.7 Bcf, which is the amount that would need to be curtailed if a 1-in-10-year winter peak demand event occurred based on SoCalGas's planning criteria for meeting gas demand of all customers (core and non-core). The analysis found that the CAISO and LADWP could absorb most but not all of a potential 0.7 Bcf gas curtailment, if: (1) electric transmission import capability remains unimpaired, (2) no gas-fired generation that is needed outside of the SoCalGas service area is out of service, and (3) every generating resource that the CAISO and LADWP seeks to use has natural gas to operate.[15]

The CAISO and LADWP would need a small amount of additional gas to support minimum generation requirements, such as those requirements needed to maintain transmission system reliability or respond to local contingencies. There also remains some risk of electric service interruption due to reliability rules that require balancing authorities such as the CAISO and LADWP to

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[14] Winter Risk Assessment Report at 30-40. This analysis assumes that multiple outages do not occur on the electric and gas system. *Id.* at 40. The Winter Risk Assessment Report also discusses the consequences of various scenarios with levels of system capacity different from the 4.1 Bcfd amount discussed above.

[15] Winter Action Plan at 4-5, 17-18.

maintain operating reserve margins. Gas-fired resources are normally used to maintain these operating reserves because they can respond rapidly to operating instructions. Even if the CAISO and LADWP can serve all electricity demand without using gas-fired resources, they need some gas to serve resources providing the operating reserves. If the CAISO and LADWP have no natural gas because of a gas curtailment, they could be required to shed load, thus resulting in the curtailment of electricity service to meet the operating reserve requirement.[16]

In addition to the mitigation measures for the summer referenced above, the Winter Action Plan "identifie[d] 10 new measures to help reduce, but not eliminate, the possibility of gas curtailments large enough to cause electricity service interruptions this winter":

- SoCalGas establishing a gas demand response program.
- Further efforts by SoCalGas to establish a gas conservation messaging campaign.
- Continuing a set of tighter gas balancing rules for non-core customers that was established pursuant to a settlement approved by the CPUC and that is currently scheduled to expire on November 30, 2016.
- Establishing gas balancing rules applicable to SoCalGas core customers.
- SoCalGas submitting reports to the CPUC describing rapid process in restoring pipeline service during maintenance outages.
- Exploring the feasibility of purchasing liquefied natural gas for delivery into the SDG&E system.
- Exploring what, if anything, natural gas producers can do to increase deliveries into the SoCalGas system.

[16] *Id.* at 5. The risks related to gas capacity limitations discussed above are a primary driver of the threat to electric reliability this winter. A lesser though still-present risk is that posed by gas imbalances from non-core customers for gas, which include gas-fired electric generators. The majority of demand for gas shifts in the winter from non-core customers to core customers (*i.e.*, residential and small commercial and industrial customers), with core customers using approximately 60 percent of gas supply. Also, demand for electricity is lower in the winter and there is more flexibility to shift responsibility to resources located outside of southern California for providing electricity into southern California, subject to transmission and generation outages. Non-core electric generators will, however, be the first to be curtailed if on-system gas is needed to meet core demand in the winter. *See* Winter Risk Assessment Report at 6-7, 14-16; Winter Action Plan at 10-12, 17-20.

- The CPUC updating a protocol that will apply if and when some of the gas stored currently being held at Aliso Canyon is withdrawn.

- The CEC monitoring refinery gas use and operations and California Attorney General monitoring gasoline prices for potential price manipulation.

- The CAISO using a maximum limit on electric generator gas burns in advance of very cold days.[17]

The CAISO believes that maintaining its existing, maximum natural gas constraint will allow the CAISO to use the constraint in advance of very cold days as recommended in the Winter Action Plan. The Winter Action Plan also recognized that efforts to make changes to the CAISO market to improve gas-electric coordination are ongoing.[18] The instant tariff filing includes such changes.

II. CAISO Stakeholder Process

On September 2, 2016, in the ongoing Aliso Canyon Gas-Electric Coordination stakeholder initiative, the CAISO established phase 2 of that initiative to evaluate on an expedited basis whether tariff provisions accepted in the June 1 Order to address the limited operability of Aliso Canyon should be maintained, modified, or discontinued after November 30, 2016.[19] The CAISO posted a phase 2 issue paper and straw proposal for stakeholder review on September 6, held a stakeholder conference call regarding the issue paper and straw proposal on September 9, and requested the submission of written stakeholder comments on the issue paper and straw proposal by September 14.

On September 16, Commission staff, the CAISO, and interested parties took part in the technical conference established pursuant to the June 1 Order. The participants at the technical conference discussed lessons learned regarding the efficacy of and the need to retain any of the tariff provisions accepted in the June 1 Order, as well as potential longer-term solutions to address ongoing limitations at Aliso Canyon.[20] On September 19, the CAISO's Market

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17 Winter Action Plan at 5, 20-25.

18 *Id.* at 24.

19 *See* http://www.caiso.com/informed/Pages/StakeholderProcesses/AlisoCanyonGasElectricCoordination.aspx. As discussed in the transmittal letter for this filing, the CAISO separately submitted the August 19 Tariff Amendment to maintain, on a permanent basis after November 30, the balance of the tariff provisions accepted in the June 1 Order.

20 *See* Supplemental Notice of Agenda and Discussion Topics for Staff Technical Conference, Docket No. ER16-1649-000 (Aug. 17, 2016).

Surveillance Committee (MSC) held a conference call that included discussion of the phase 2 initiative and the opportunity for stakeholders to provide verbal comments.

The CAISO issued a Draft Final Proposal in the phase 2 initiative on September 23, held a conference call with stakeholders to discuss the Draft Final Proposal on September 26, and requested the submission of written stakeholder comments on the Draft Final Proposal by September 28.[21] The CAISO posted draft tariff language to implement the Draft Final Proposal on September 29, requested written stakeholder comments on the draft tariff language by October 5, and held a conference call with stakeholders to discuss the draft tariff language on October 6.

Stakeholders generally supported continuation of the tariff provisions contained in this filing to mitigate the issues raised by the continued limited operability of Aliso Canyon. The CAISO addresses specific issues raised by stakeholders in the transmittal letter for this filing. In addition, the CAISO's Department of Market Monitoring (DMM) submitted written comments on the Draft Final Proposal explaining that DMM generally supports the key elements of the proposals finalized in the Draft Final Proposal.[22]

The CAISO Governing Board (Board) authorized the filing of this tariff amendment at a special session meeting held on October 3, 2016.[23]

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

[22] DMM comments on Draft Final Proposal at 1 (Sept. 28, 2016) (DMM Comments). The DMM Comments are provided in attachment E to this filing.

[23] 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 F to this filing.

Attachment D – Draft Final Proposal

Filing to Maintain in Effect for One Year Certain Tariff Provisions Previously Accepted on an Interim Basis to Address Limited Operability of Aliso Canyon Facility

California Independent System Operator Corporation

Aliso Canyon Gas-Electric Coordination

Phase 2

Draft Final Proposal

September 23, 2016

Table of Contents

Introduction

This document describes the California ISO's draft final proposal for the second phase of its Aliso Canyon Gas-Electric Coordination initiative. In early September 2016, the California ISO (ISO) launched the second phase of this initiative to address retaining temporary measures approved under Phase 1 still needed in light of winter risks beyond their November 30, 2016 sunset date.

The following table summarizes the ISO's proposal to either extend, retire, or extend with refinements each of the Phase 1 temporary measures.

Temporary Measures	**Proposal**	**Refinements**
Allow resources to rebid commitment costs in the real-time market for hours without day-ahead schedules or hours it received residual unit commitment start-up instruction. Scheduling Coordinator may not resubmit bid in real-time once committed for the trading hours that span its minimum run time.	Removed from scope and filed to extend permanently on August 19	No
No longer replicate bids in the short-term unit commitment run for resources that do not submit bids into the real-time market that are not scheduled in the day-ahead market and that do not have a real-time market must offer obligation.	Removed from scope and filed to extend permanently on August 19	No
Provide an after-the-fact cost recovery filing right at Federal Energy Regulatory Commission under Section 205 of the Federal Power Act when actual fuel procurement costs led to commitment costs that exceed its bid cap or energy costs that exceed the mitigated price.	Commitment Cost recovery removed from scope and filed to extend permanently on August 19; Energy cost recovery remains in scope and extended temporarily	Clarify eligibility for energy cost recovery is for any mitigated energy offer
Increase access to information prior to day-ahead by reporting scheduling coordinators' D+2 residual unit commitment results directly to the scheduling coordinator	Extend	Continue to pursue coordination enhancements
Increase ability of suppliers to reflect cost expectations in day-ahead bids by using an approximation of the next day gas index published	Extend	No

morning of the day-ahead market run to calculate reference levels		
Increase the gas commodity price index used to calculate default energy bids and commitment cost for resources in the Southern California Gas and SDG&E gas regions by introducing a commodity price scalar, for purposes of distinguishing resources affected by the gas limitations from the rest of the ISO market areas. The percent scalar is applied to the next day gas index published the morning of the day-ahead market run to calculate reference levels.	Extend	No
Ability to enforce gas constraints for either capacity or imbalance limitations and proposes to make refinements to the original constraints design	Extend	Yes
Allow the ISO to manually override the dynamic competitive path assessment to determine transmission paths should be deemed uncompetitive if the gas constraint is enforced based on a forward competitive path assessment	Extend	Clarify determination method and use by operators
Ability to suspend virtual bidding in the event the CAISO identifies market inefficiencies	Extend	No
Ability to adjust internal transfer capability to ensure 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	Retire	N/A
Ability to limit the amount of congestion revenue rights it releases in the monthly allocation and auction to be consistent with the reduced transfer capability	Retire	N/A

The discussion in this paper is organized into the following sections:

- Background: Background explanation for Phase 1 and Phase 2 of this initiative.
- Bidding Rules Enhancements Filing: Summary of temporary measures the ISO filed to extend permanently in its Tariff.

- Proposals to Improve Suppliers' Ability to Manage Gas Units: Discussion of ISO's proposal to extend these temporary measures.

- Proposals to Improve ISO's Ability to Manage Operations: Discussion of ISO's proposal to extend or retire temporary measures and description of refinements or clarifications.

- Plan for Stakeholder Engagement and Next Steps: Reviews ISO's plan for the stakeholder initiative targeting an October 3, 2016 board of governors meeting. This section also includes a request for stakeholder comments on the ISO's proposal.

Background

Under the *Aliso Canyon Gas Electric Coordination Measures* initiative Phase 1, the ISO launched an expedited process to address operational concerns raised due to reliability risks during summer raised in the inter-agency task force's technical report and action plan[1]. The ISO along with stakeholders designed 11 temporary measures which the ISO filed with the Federal Energy Regulatory Commission (FERC) for approval on May 9, 2016[2], to be effective through November 30, 2016. FERC subsequently approved this filing effective June 1, 2016 through November 30, 2016[3].

See the original Revised Draft Final Proposal for Aliso Canyon Gas-Electric Coordination for Phase 1 for background information and a description of each approved temporary measure[4]. For purposes of discussion, the ISO will refer to sections from the original Revised Draft Final Proposal throughout this draft final proposal for Phase 2.

The primary purpose of the second phase, Phase 2, is to evaluate a revised reliability assessment for winter 2016/2017 from the same inter-agency task force, the Winter Action Plan and Winter Risk Technical Report, and whether the revised assessment warrants continuing the ISO's authority to utilize the 11 temporary measures designed to address operational concerns due to reliability risks.

The ISO found the winter technical report showed continued reliability risks that merit extending its authority to use temporary measures. The winter assessment raised concerns that there might be capacity limitations on the gas system insufficient to meet gas demand given the magnitude of the demand during the gas winter peak. At this time, the ISO does not propose to

[1] All the inter-agency materials are accessible through the Aliso Canyon stakeholder page, http://www.caiso.com/informed/Pages/StakeholderProcesses/AlisoCanyonGasElectricCoordination.aspx.
[2] http://www.caiso.com/Documents/May9_2016_TariffAmendment_EnhanceGas-ElectricCoordination_LimitedOperation_AlisoCanyonNaturalGasStorageFacility_ER16-1649.pdf
[3] http://www.caiso.com/Documents/Jun1_2016_OrderAcceptingTariffRevisions_Establishing_TechnicalConference_AlisoCanyon_ER16-1649.pdf
[4] http://www.caiso.com/Documents/RevisedDraftFinalProposal_AlisoCanyonGas_ElectricCoordination.pdf

introduce new measures as the 11 measures previously approved are effective at managing capacity limitations in addition to imbalance limitations.[5]

Under Phase 2, the ISO evaluated whether reliability assessment warrants continued authority, which temporary measures are needed, and what refinements are needed. Further, the ISO considered where providing greater transparency would be appropriate.

Bidding Rules Enhancements Filing

This section includes a discussion of the temporary measures designed as a part of Phase 1 of *Aliso Canyon Gas-Electric Coordination* that the ISO has subsequently filed with FERC for consideration as permanent tariff amendments.

The ISO filed a tariff amendment on Friday, August 19, 2016[6] to extend the effectiveness of the three temporary measures included in the ISO's May 9, 2016[7] tariff amendment. These three measures were originally approved by the ISO Board on March 25, 2016 as part of the Board *Decision on Commitment Cost Bidding Improvements*[8] and were not intended to be temporary. The tariff amendment included the following measures:

- Allow resources to rebid commitment costs in the real-time market for hours without day-ahead schedules or hours it received residual unit commitment start-up instruction. Scheduling Coordinator may not resubmit bid in real-time once committed for the trading hours that span its minimum run time.

- No longer replicate bids in the short-term unit commitment run for resources that do not submit bids into the real-time market that are not scheduled in the day-ahead market and that do not have a real-time market must offer obligation.

- Provide an after-the-fact cost recovery filing right at Federal Energy Regulatory Commission under Section 205 of the Federal Power Act when actual fuel procurement costs led to commitment costs that exceed its bid cap and are unrecovered through market revenues.

Some stakeholder comments submitted on the ISO's Phase 2 straw proposal addressed these measures. Generally, the Environmental Defense Fund (EDF), Western Power Trading Forum (WPTF), Six Cities, SCE, PG&E NRG, and the Department of Market Monitoring (DMM) support the ISO's filing to permanently amend its tariff with these measures. However, DMM submitted

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[5] The Department of Market Monitoring has raised that there might be a need to mitigate exceptional dispatches related to the gas constraints under certain circumstances. The ISO and the Department of Market Monitoring continue to evaluate this issue and may later propose additional measures.

[6] http://www.caiso.com/Documents/Aug19_2016_TariffAmendment_BiddingRules_CommitmentCostsEnhancements_ER16-2445.pdf

[7] http://www.caiso.com/Documents/TariffAmendment-ExtendTariffMeasuresFiled-May9_2016-TemporaryMeasures.html

[8] Board of Governors Revised Motion, http://www.caiso.com/Documents/Decision_CommitmentCostBiddingImprovementsProposal-RevisedMotion-Mar2016.pdf

comments to FERC requesting that the ISO develop specific guidelines and details to the after-the-fact cost recovery provisions. As this is an open docket at FERC, the ISO will respond to these comments in its answer under the Bidding Rules and Commitment Cost Enhancements Previously Accepted on an Interim Basis filing (ER16-2445). Once filed, the ISO's answer will be available on the *Bidding Rules Enhancements* stakeholder initiative page.

Stakeholders commented to the ISO that these bidding flexibility improvements helped them manage their operational risk during summer 2016. As a result, in the event FERC does not issue a favorable order accepting the August 19 amendments in due time, the ISO will make necessary filings to extend these measures for the earlier of the term the Phase 2 measures are in place or until FERC accepts the measures on a permanent basis.

Stakeholder comments indicating that these measures have been helpful are supported by market results showing suppliers scheduling in a conservative manner to bring sufficient gas online and not driving real-time imbalances where more gas is demanded in real-time than day-ahead. The market results are shown in Figure 1 where the orange lines represent the difference between the gas burn amounts between the five-minute real-time dispatch and residual unit commitment process schedules (i.e. imbalance). When the orange line falls below zero that day had a negative imbalance. A negative imbalance means that the ISO scheduled greater amounts of power in the day-ahead market, suppliers scheduled gas accordingly, or if not able to schedule gas could bid effectively to reduce their output consistent with their scheduled gas.

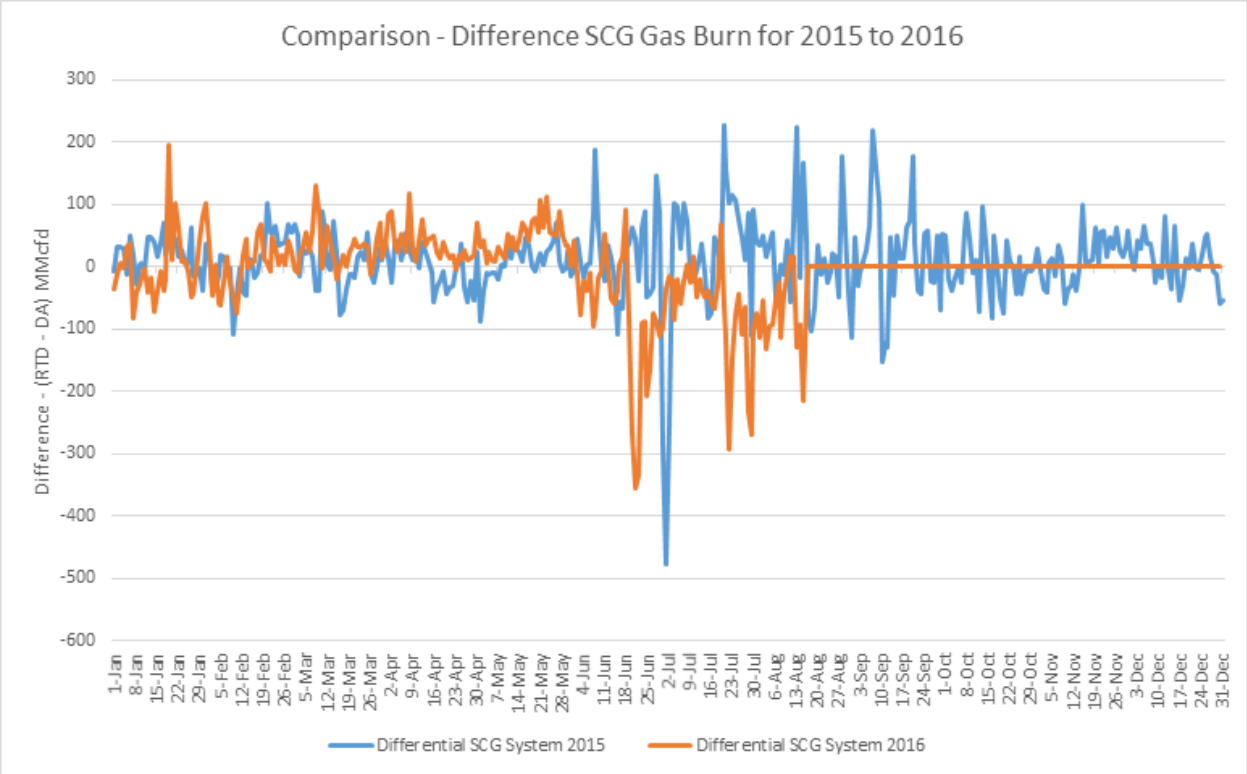


Figure 1: Comparison 2015 to 2016 - 5MM to DA RUC Gas Burn Amounts

In combination with good coordination and advanced electric planning, the more robust bidding flexibility is believed to have led to the limited days with modest positive imbalances and other days with negative imbalances during the summer months. Overscheduling gas prior to real-time likely supported both gas and electric reliability as the reliability risk was largely that there would be insufficient gas on Southern California Gas (SoCalGas) system when electric demand required gas to fuel their units.

ISO notes that the August 19, 2016 filing seeks permanent tariff amendments for an after-the-fact cost recovery filing right only for commitment costs in excess of the bid cap unrecovered through market revenues because this was the scope approved at the March Board of Governors session. To mitigate risks that energy costs could exceed an energy offers mitigated price, the ISO proposes to retain a temporary measure that provides an after-the-fact cost recovery filing right at FERC for incurred energy costs that exceed its mitigated price unrecovered through market revenues[9]. An energy offer is mitigated to its default energy bid price calculated differently depending on whether the scheduling coordinator selected the variable, negotiated or locational marginal price option (i.e. mitigated price). Regardless of the election, this filing right will be open to scheduling coordinators with energy costs that exceed the mitigated price unrecovered through the ISO's bid cost recovery mechanisms.

Proposals to Improve Suppliers' Ability to Manage Gas Units

The purpose of this section is to propose to extend, retire, or adjust the temporary measures to improve suppliers' ability to manage their gas-fired units beyond Phase 1's sunset date of November 30, 2016. The temporary measures in this section only apply to units in the SoCalGas system. The ISO identifies eligible units using a list that SoCalGas provided of electric generators within its system[10]. For additional details on the original design, see the original Revised Draft Final Proposal for Phase 1[11].

The ISO proposes to extend all three temporary measures improving suppliers' ability to manage their gas-fired units with only minor refinements to the first measure. The measures would remain effective beyond November 30th through Phase 2's sunset date.

The three temporary measures provided the ISO the authority to:

(1) Increase access to information prior to day-ahead by reporting scheduling coordinators' D+2 residual unit commitment results directly to the scheduling coordinator (Phase 1 Revised Draft Final Proposal, Section 7.1),

(2) Increase ability of suppliers to reflect cost expectations in day-ahead bids by using an approximation of the next day gas index published morning of the day-ahead market run

[9] This temporary measure would apply to units across the footprint for that market.
[10] The list of Electric Generators from SoCalGas, which defines the group of eligible resources, does not include combined heat and power (CHP) resources. CHP resources are not classified as Electric Generation under the SoCalGas tariff.
[11] http://www.caiso.com/Documents/RevisedDraftFinalProposal_AlisoCanyonGas_ElectricCoordination.pdf

to calculate reference levels (Phase 1 Revised Draft Final Proposal, Section 7.3),

(3) Increase ability of suppliers to reflect the impact of gas system constraints in the commitment costs and default energy bids of resources in the SoCalGas and SDG&E gas regions by adding a commodity price scalar in the form of a percent multiplier on the next day gas index published the morning of the day-ahead market run to calculate reference levels (Phase 1 Revised Draft Final Proposal, Section 7.2).

The following information will be discussed below:

- Minor refinements to increased access to information: Description of the ISO's proposal to continue to pursue enhancements to increase access to information to scheduling coordinators and the gas companies to support gas-electric coordination below.

- No revisions to the suppliers ability to reflect impact of gas constraints in affected areas in day-ahead or real-time commitment costs or default energy bids: Description of support for not proposing any refinements to the last two temporary measures improving suppliers' ability to reflect cost expectations in bid prices in either day-ahead or real-time.

Minor refinements to increased access to information

As the ISO discussed with stakeholders during the *Aliso Canyon Gas-Electric Coordination Phase 2* straw proposal stakeholder call and the September 19, 2016 Market Surveillance Committee meeting, the ISO will continue to look for on-going opportunities to enhance gas-electric coordination and increase access to information supporting those efforts between the ISO, gas companies, and scheduling coordinators.

NRG submitted comments in response to the Phase 2 Straw Proposal supporting providing scheduling coordinators their unit-specific gas burn data. Since this is a minor addition to the Phase 1 measure providing this data in MW, the ISO will propose to continue to pursue providing the residual unit commitment schedules in MMCFd to market participants in the same frequency as that provided to the gas companies.

While the ISO does not need to make tariff revisions to pursue its proposed coordination enhancements, it will pursue the following enhancements to provide:

- More than 24 hours of gas burn data so the gas company can see operating expectations across its operating day from 7AM-7AM Pacific,

- Real-time gas burn information, or

- Unit-level RUC gas burn amounts to both gas company and scheduling coordinators[12] for each gas burn amount reported to the gas company.

[12] Scheduling Coordinator would only receive its assets gas burn information.

No revisions to the suppliers ability to reflect cost expectations and gas system limitations in day-ahead or real-time bids

Under Phase 2, the ISO evaluated whether it should continue to pursue the use of the next day gas index published morning of its day-ahead market[13] and application of commodity price scalar on the same index for its real-time market. Given the broad support from stakeholders and the favorable gas burn imbalance trends shown in Figure 1 as well as the analysis below, the ISO finds that these improvements to its gas price index formulations in both day-ahead and real-time should be extended beyond the sunset date.

The advantages are:

- Day-ahead Gas Price Index: Formed using gas market price benchmarking the average price for the majority of the ISO's operating day and the fundamental factors driving those expectations rather than the gas market price benchmarking the majority of the prior day's market and that day's market fundamentals.

- Real-time Gas Price Index: Formed by applying a commodity price scalar to the next day gas index allows the commitment cost bid cap and default energy bids to include a premium acknowledging that intra-day, same-day, or custom deals will have prices that could be higher in real-time due to illiquidity and gas system limitations.

The discussion below first examines the potential for differences between gas costs the ISO uses in its calculations of commitment costs and default energy bids in the day-ahead market and actual gas costs. Next the ISO examines these differences in the real-time market.

Figure 2 below shows the benefits gained from these two measures by calculating the premium needed to reflect the highest traded price relative to the next day index used by that market. The green and yellow circles represent the potential for prices to exceed the next day average price in the day-ahead and real-time markets respectively:

- For the day-ahead market: The ISO calculated the percent difference between the highest traded prices traded on or reported by either the Intercontinental Exchange (ICE), SNL, or Natural Gas Index (NGI) to ICE's next day gas index published for the prior gas day (green circles).

- For the real-time market: the ISO calculated the percent difference between the highest prices traded on ICE to the ICE's next day gas index published morning of the day-ahead market (yellow circles).

[13] While the provision to use the next day gas index published the morning of its day-ahead market in its day-ahead market processes has not been implemented yet, once the ISO receives a FERC order to its request for clarification it will implement this measure directly.

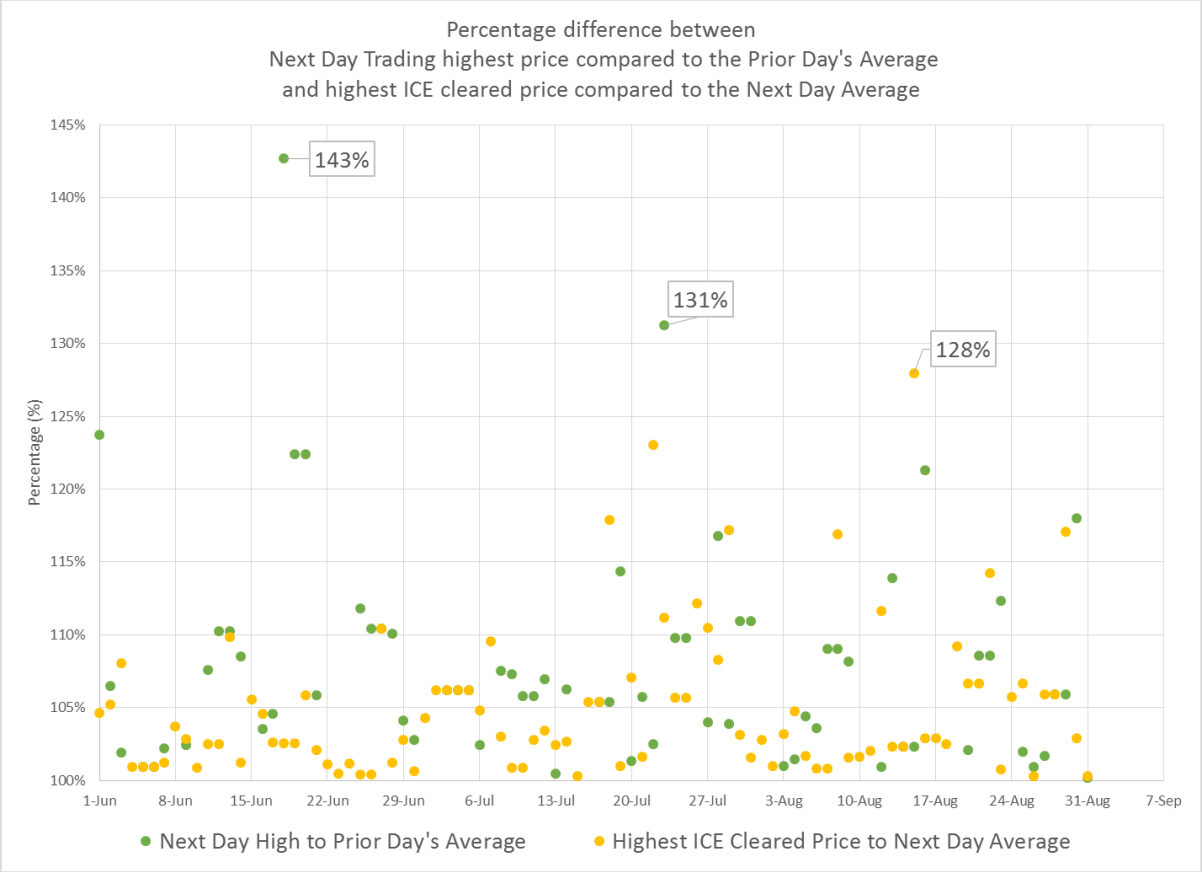


Figure 2: Compare high trades to next day gas indices

The day-ahead market

ISO believes Figure 2 shows significant benefits are provided by using the more timely gas market price in its day-ahead market, which is the next day gas index published morning of the ISO's day-ahead market. Of the 92 days from June through August 2016, the ISO saw 19 days where the highest traded price was over 110% higher than the next day gas index published the day prior to the ISO's day-ahead market. This would mean that default energy bids may not have accounted for costs on 20 percent of those days[14]. If the use of the more timely gas index had been in place during this period, the number of days where the highest traded price exceeded 110 percent of the next day gas index used would have dropped to 12 out of 92.

20 percent of days observed potentially not supporting cost recovery for mitigated energy offers is a substantial risk. The 7 percent reduction in days where mitigated energy prices might not account for costs if the enhancement where implemented is a significant benefit. Consequently, the ISO finds it appropriate to continue pursuing the use of the next day index published the morning of the ISO's day-ahead market run to narrow this likelihood.

[14] Day-ahead gas price index (DAM GPI) is the sum of the next day index published one day prior to the ISO day-ahead market run plus the geographically appropriate transportation rate.

The potential for the commitment cost bid cap to limit suppliers' ability to submit commitment cost bids consistent with their cost expectations due to the gas price the ISO currently uses is much lower. Out of 92 days reviewed, only 2 days[15] had trading where the highest traded price was more than 125% higher than the next day gas index used. If the relevant price index had been used, the two days' percent differences would have been 122 percent and 110 percent instead of 143 percent and 131 percent respectively.

In addition to this analysis, the ISO considered stakeholders' feedback[16], which generally supported the implementation of the temporary measure that would increase the ability of suppliers to reflect cost expectations in day-ahead bids by using an approximation of the next day gas index published morning of the day-ahead market run to calculate reference levels (Phase 1 Revised Draft Final Proposal, Section 7.3).

NRG supports this measure as a near-term measure but continues to encourage the ISO to investigate longer term solutions enabling market participants to reflect their own gas costs and risks in bid prices. DMM strongly supports this temporary feature. They recommend the ISO file to make this a permanent feature in its tariff rather than temporary.

Based on the ISO's support provided above and evaluation of stakeholders' comments, the ISO proposes to retain the authority to use this feature without any revisions to the Phase 1 approved language. For the purposes of this Phase 2 of the Aliso related measures, the ISO proposal to extend this provision will be on a temporary basis.

<u>The real-time market</u>

ISO believes Figure 2 shows significant benefits were provided by applying the commodity price scalar to the next day gas index published the morning of its day-ahead market to form the real-time gas price index (RTM GPI). The commodity price scalars are a measure that did help mitigate the risk that real-time market bid costs might not fully reflect costs when energy offers were mitigated. Regarding commitment costs, the ISO does not observe significant benefits from looking at systematic price differences alone by applying a scalar higher than 125 percent to the next day gas index. There are additional benefits provided by having this higher scalar in place beyond capturing systemic price differences as it allows resources to reflect gas system constraints so the supplier can manage their unit within gas rules.

The ISO finds that the commitment cost scalar at 175 percent is appropriate at this time. The ISO's analysis is strictly based on the experience over this past summer. The ISO and stakeholders do not know whether the current values will be appropriate over the months to come. Because of the uncertainty the ISO proposes to retain the current values and the authority it has to increase or decrease those amounts as appropriate.

Of the 92 days from June through August 2016, the ISO saw 12 days where the highest traded ICE price was over 110% higher than the next day gas index published the morning of its day-

[15] June 18 and July 23.
[16] NRG, WPTF, and DMM.

ahead market run. This would mean that default energy bids may not have accounted for costs on 13 percent of those days[17]. The temporary measure resulted in the number of days that may not have accounted for costs when mitigated dropping to 1 percent of those days.

The potential for the commitment cost bid cap to limit suppliers' ability to submit commitment cost bids consistent with their cost expectations due to the gas price the ISO currently uses is much lower. Out of 92 days reviewed, only 1 day[18] had trading where the highest traded price was more than 125 percent higher than the next day gas index published the morning of the ISO's day-ahead market. With the commodity price scalar of 175 percent applied to the next day gas index to set the commitment cost bid cap, the ISO did not see any ICE traded gas prices in real-time that approached those price levels.

Again the ISO weighed stakeholders' feedback on this measure. Stakeholders[19] generally supported the implementation of the temporary measure that would increase ability of suppliers to reflect cost expectations in day-ahead bids by using an approximation of the next day gas index published morning of the day-ahead market run to calculate reference levels (Phase 1 Revised Draft Final Proposal, Section 7.3).

While supportive, NRG and WPTF expressed concerns that the commodity price scalar levels may not be sufficiently high to reflect winter conditions. In response to the above described analysis, NRG comments, "NRG also agrees that, based on the experience from Summer 2016, the 75% scalar used in the real-time market for commitment cost caps and default energy bids has been sufficient. However, given that past performance does not always reliably capture the range of possible future results, the CAISO should be ready to adjust the scalar based on conditions observed at the time.[20]" WPTF echoed this concerns, stating: "It is unclear why the ISO believes that 125% will continue to be sufficient through the winter. If gas prices indicate 125% was about right most of the time in the summer when there were no significant gas events and the ISO didn't even have to use any of their sought measures from FERC, it seems like this would need to be increased given expected winter conditions. The analysis on slide 23 demonstrates the appropriateness of 125%, but if this is not increased, when the ISO redoes this analysis into the winter, WPTF would expect there to be a very different story told.[21]"

In response to these comments, the ISO would like to clarify that the analysis of summer conditions provides information at this time as to whether any changes to the filed tariff language need to be made through Phase 2. The tariff language as approved by FERC states that:

> 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

[17] Day-ahead gas price index (DAM GPI) is the sum of the next day index published one day prior to the ISO day-ahead market run plus the geographically appropriate transportation rate.
[18] August 15.
[19] NRG, WPTF, SCE, and DMM.
[20] NRG Comments, Page 4, available at http://www.caiso.com/Documents/NRGComments_AlisoCanyonGas-ElectricCoordinationPhase2StrawProposal.pdf.
[21] WPTF Comments, Page 2, available at: http://www.caiso.com/Documents/WPTFComments_AlisoCanyonGas-ElectricCoordinationPhase2StrawProposal.pdf.

> 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. [emphasis added]

The ISO proposes to retain the authority to increase the current values as appropriate. The ISO's Phase 2 proposal is to retain the scalars at their initial levels with the authority to increase or decrease if winter conditions arise that warrant the adjustments.

The ISO continues to commit to consider adjustments if the scalars are not representing the increased Bid amount that fulfills the following 3 criteria: (1) improves the dispatch of these resources so that they more likely to be dispatched to address local needs and not system needs; (2) better accounts for systematic differences between day-ahead and same-day natural gas prices that materialize; and (3) improves ability to manage the generators gas usage within applicable gas balancing rules.

Based on the ISO's analysis provided above, and its consideration of stakeholder and DMM input, the ISO proposes to retain the authority to use this feature without any revisions to the Phase 1 approved language.

Proposals to Improve ISO's Ability to Manage Operations

This section describes the ISO's proposal to extend, retire, or refine the temporary measures[22], implemented as part of the Phase 1 of the A*liso Canyon Gas Electric Coordination* initiative, that were put into place to improve the ISO's ability to reliably manage electric operations in light of concerns of limitations on the gas system and to mitigate potential adverse market outcomes associated with implementing these measures.

The ISO implemented five temporary measures to improve its ability to manage electric operations in light of gas concerns and mitigate against potential adverse market outcomes, the measures were:

(1) Ability to enforce gas constraints for either capacity or imbalance limitations (Phase 1 Revised Draft Final Proposal, Section 6.1) and proposes to make refinements to the original constraints design,

(2) Allow the ISO to manually override the dynamic competitive path assessment to determine transmission paths should be deemed uncompetitive if the gas constraint is

[22] The temporary measures[22] in this section only apply to units in the Southern California Gas system. The ISO identifies eligible units using a list SoCalGas provided of electric generators within its system. The measures would remain effective beyond November 30th through Phase 2's new sunset date.

enforced based on a forward competitive path assessment (Phase 1 Revised Draft Final Proposal, Section 6.4),

(3) Ability to suspend virtual bidding in the event the CAISO identifies market inefficiencies when the gas constraint is enforced or internal paths are adjusted (Phase 1 Revised Draft Final Proposal, Section 6.5),

(4) Ability to adjust internal transfer capability to ensure 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 (Phase 1 Revised Draft Final Proposal, Section 6.2), and

(5) Ability to limit the amount of congestion revenue rights it releases in the monthly allocation and auction to be consistent with the reduced transfer capability (Phase 1 Revised Draft Final Proposal, Section 6.2).

For details on the original design, see the original Revised Draft Final Proposal for Phase 1 in Phase 1 Revised Draft Final Proposal, Section 6.

The ISO proposes to extend three of the five temporary measures improving ISO's ability to reliably manage electric operations in light of concerns of limitations on the gas system combined with mitigation measures. The ISO proposes to extend the authority to enforce gas constraints with refinements.

Proposed Extensions and Refinements

The purpose of this section is to discuss the temporary measures the ISO proposes to extend, propose refinements to the gas constraints design, and to provide guidance as to what additional detail it will provide in the implementation phase.

The three temporary measures proposed to extend under Phase 2 are:

(6) Ability to enforce gas constraints for either capacity or imbalance limitations (Phase 1 Revised Draft Final Proposal, Section 6.1) and proposes to make refinements to the original constraints design,

(7) Allow the ISO to manually override the dynamic competitive path assessment to determine transmission paths should be deemed uncompetitive if the gas constraint is enforced based on a forward competitive path assessment (Phase 1 Revised Draft Final Proposal, Section 6.4),

(8) Ability to suspend virtual bidding in the event the CAISO identifies market inefficiencies when the gas constraint is enforced (Phase 1 Revised Draft Final Proposal, Section 6.5).

The ISO proposes to maintain the ability to enforce gas constraints in the day-ahead or real-time market to address either gas capacity or imbalance limitations. However, some modest adjustments to the gas constraint designs are appropriate.

Stakeholders[23] generally supported extending the authority to enforce the gas constraints to manage gas-electric reliability. While supportive, WPTF and NRG both requested the ISO provide additional information as to when the constraint would be applied versus exceptional dispatches. The ISO directs these stakeholders to its relevant operating procedure. Operating Procedure 4120c[24] provides the defined procedures Operators follow during SoCalGas and SDG&E service area actual or anticipated limitations or outages. The Operating Procedure will be updated as necessary.

After considering both internal and stakeholder feedback on the gas constraints design, the ISO determined minor adjustments would be appropriate. Generally, the ISO is proposing to automate the gas constraint[25] and refine the gas constraint formulation for either a capacity or imbalance limitation, the capacity limitation formulation and its appropriate use, the imbalance limitation and its appropriate use, and changes to the transformation of a daily limit to an hourly limit. Specifically, the ISO proposes four refinements to:

- Revise constraint to only limit maximum operating levels (This requires a tariff change)[26]

- Clarify documentation that capacity limitation is based on ISO assessment of its system needs in light of gas supply concerns (This will not require a tariff change. It will be implemented through BPM and or operating procedure changes)

- Clarify documentation imbalance limitation's constraint implementation to include managing electric system in response to gas company issuing a curtailment watch (This will not require a tariff change. It will be implemented through BPM and/or operating procedure change)

- Revise the gas constraint implementation to automate the ability to distribute either a capacity or imbalance limitation across hours as deemed appropriate (This will not require a tariff change. It will be implemented through BPM and/or operating procedure change)

The rest of this section will describe the proposed refinements, clarifications or plans to provide additional detail during the implementation phase.

[23] WPTF, NRG, SCE, and DMM.
[24] 4120C – SoCalGas Service Area Limitations or Outages, http://www.caiso.com/Documents/4120C.pdf.
[25] Until automated, the ISO will continue to have the functionality to manually calculate and enforce the constraint.
[26] ISO considers this sufficient clarification in response to DMM's request for clarification that the ISO was retiring the authority to impose a minimum gas burn constraint in its comments on Page 6.

Item 1 - revise constraint to only limit maximum operating levels

The ISO proposes to maintain the ability to enforce gas constraints in the day-ahead or real-time market to address either gas capacity or imbalance limitations. However, some modest adjustments to the gas constraint designs are appropriate.

As shown in Equation 1, the original gas constraints formulation showed that the affected areas' gas burn could be constrained to either be higher than or lower than an imposed limit.

Equation 1: Original 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 (only allowed for imbalance limitations).
RHS_t	Right hand side limit enforcing upper bound constraint (different limit formulation for capacity versus imbalance limitations)

Additionally, the imbalance limitation formulation specifically included a calculation for determining the LHS_t, shown in Equation 2.

Equation 2: 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 proposes to retire the authority to enforce the left hand side of the gas constraint. The left hand side would have limited market output to levels higher than that limit. Through further review the ISO believes that resources have the ability to meet imbalance limitations in which they need to burn a minimum amount of gas. They can be more assured of operating at a certain minimum output by lowering their bid price or self-scheduling.

On the other hand, the ISO believes it is still appropriate to maintain a gas constraint that limits the maximum burn. Resources ability to manage their unit to be assured of operating at a certain maximum output by increasing their bid price could be limited by its commitment cost cap or its default energy bid.

The proposed revised formulations are shown below in Equation 3 and

Equation 3: Revised Gas Constraint(s)

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

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)
RHS_t	Right hand side limit enforcing upper bound constraint (different limit formulation for capacity versus imbalance limitations)

Equation 4: Revised Gas System Imbalance Limitation

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

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

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

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_h	Daily upper bound deviation allowance relative to day-ahead market schedule, **this value can only be greater than or equal to 0[27].**
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

<u>Item 2: ISO will use the constraint based on its assessment of its system needs in light of concerns with gas supply</u>

ISO proposes to increase the flexibility to enforce the gas constraint with a capacity limitation. The ISO policy for deciding to enforce a gas constraint with a capacity limitation is that the maximum operating limit, or right hand side of the gas constraint, for capacity limitations is

[27] Adding clarity that the incremental constraint is incremental to day-ahead residual unit commitment schedules so must be greater than or equal to zero.

established by an input (R_h) that is determined by the ISO based on a generation amount in the area that the ISO determines is needed for electrical reliability.

The winter assessment technical report identified as a primary risk that gas demand could exceed system capacity because gas system peaks in the winter. During winter months, core demand is about 60 percent of SoCalGas' system capacity and with the other non-core demand could exceed system capacity. The gas system capacity combined with its forecasted core demand drive the capacity limitation since the gas system must serve its core first. The winter assessment also found the ISO only needs to operate a limited amount of generation on the SoCalGas system to support reliable grid operations since electric load is lower in winter and sufficient energy could be delivered into the area to serve electric load.

To do so, the (R_h) input in Equation 5 is defined as shown in the variable descriptions below.

Equation 5: Revised Gas Capacity Reduction Limitation

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

$$RHS_t = \gamma_t R_h$$

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

$\boldsymbol{R_h}$	**Amount of generation expressed in MMCFd that the ISO determines is necessary to manage gas limitations and operate the electric system reliably**
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

Item 3: The ISO intends to continue to be able to use the constraint in response to gas company issuing a curtailment watch.

The ISO will ensure its operating procedure reflects that it may enforce the constraint when a gas company issues a curtailment watch.[28] The ISO also notes that in such circumstances depending on the totality of system conditions it observes it may use other tools such as exceptional dispatch to manage the gas limitations based on its coordination with the gas company.

The ISO's policy for enforcing a gas constraint with an imbalance limitation is the same as discussed above, the policy is: when deciding to enforce a gas constraint with an imbalance limitation the maximum operating limit, or right hand side of the gas constraint, for imbalance

[28] A notification that conditions are present that could result in curtailment

limitations is established by an input (R_h) that is determined by the ISO based on an incremental generation amount relative to the day-ahead residual unit commitment run in the area that the ISO determines is needed for electrical reliability.

Item 4: The ISO also plans on revising the gas constraint design to provide greater flexibility for ISO Operations to distribute either a capacity or imbalance limitation across hours as deemed appropriate.

The ISO proposes to maintain its original design for distributing the daily limitation across hours as the default method and would add a feature for Operators to override the default method. They would be able to override if there was a specific shape needed to better support electric operations.

NRG commented in response to the ISO's request for input on the best design for this transformation suggesting that the hourly shape be based on what drives the gas burn over the relevant time horizon. The ISO appreciates this suggestion and after further internal discussions found that the best design would allow a reasonable default, the original method, and give flexibility to choose to update the shape representative of the best information for burn drivers during the relevant time horizon.

The original design of the formulation for a capacity or imbalance limitation included allowance distribution coefficients that would transform a daily limit into an hourly value. This hourly value relates to 1 of the 24 hourly curves used to enforce the gas constraint in the market[29]. In the *Aliso Canyon Gas-Electric Coordination Phase 1* Revised Draft Final Proposal, Section 6.1.2 described how the ISO would perform this distribution. The ISO would distribute the daily limitation across hours based on a ratio of hourly load forecast to daily load forecast. This would support greater electric flexibility and be able to recapture portions of the allocated range unused for earlier intervals if necessary.

The ISO plans on enhancing the functionality for Operators to input allowance distribution coefficients that they believe would better support electric operations than the default method. For example if the gas constraint was enforced for all 24 hours but Operators felt that an equal distribution across the hours would better support gas-electric operations, the Operators could override the default through inputting ~4% as the distribution factor for each hour.

Item 5: Guidance as to what additional detail it will provide in the implementation phase

The ISO does not at this time believe that any refinements should be made to the mitigation measures proposed to extend. The ISO recognizes that WPTF and NRG reiterated their comments that bids should not be mitigated unless the potential to exercise market power or that the constraint is predictable and consistently binding can be demonstrated. Both stakeholders requested increased transparency on the two mitigation measures.

WPTF seeks additional information on the ISO ability to manually override the dynamic competitive path assessment to determine transmission paths should be deemed uncompetitive

[29] ISO uses existing nomogram functionality.

if the gas constraint is enforced based on a forward competitive path assessment (Revised Draft Final Proposal, Section 6.4):

- What would qualify as systemic binding to trigger overriding the dynamic competitive path assessment?
- How would the determination that systemic binding renders paths uncompetitive when gas constraint is enforced be communicated to market participants?
- How long would the determination remain in effect?

Under its implementation phase, the ISO plans on adding a description of its forward competitive path assessment methodology in its Market Operations BPM, Attachment B Competitive Path Assessment. Additionally, clarification will be added to how Operations will use this forward competitive path assessment when Operators make a judgement to enforce the gas constraint.

Any additional details on how the ISO might determine to suspend virtual bids in the event of adverse market impacts will not be provided at this time. NRG commented that the ISO must present a clear case backed up by evidence that it is necessary to suspend convergence bidding and identify criteria for restoration of convergence bidding. The ISO believes its commitment to issue a technical bulletin with justifications for a general suspension or limitation of Virtual Bids if suspended using this temporary authority should satisfy NRG's request.

Proposed Retirements

The purpose of this section is to discuss and provide support for the two temporary measures the ISO proposes to retire:

The two temporary measures proposed to be retired under Phase 2 are:

(1) Ability to adjust internal transfer capability to ensure 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 (Phase 1 Revised Draft Final Proposal, Section 6.2),

(2) Ability to limit the amount of congestion revenue rights it releases in the monthly allocation and auction to be consistent with the reduced transfer capability (Phase 1 Revised Draft Final Proposal, Section 6.2).

After Phase 1 of *Aliso Canyon Gas Electric Coordination* was completed, the Peak Reliability Coordinator (Peak RC) modified its system operating limit (SOL) methodology to allow a path's rated limit to exceed its rating under emergency conditions. As a result, the ability to limit is no longer needed to ensure sufficient transfers. The original policy goal is met through the new Peak RC policy.

To ensure it can serve load, ISO Operations can now utilize real-time contingency analysis to increase transfer capability while ensuring ISO grid reliability. The real-time contingency

analysis will show what level the system operating limit of each path should be to simultaneously serve load and maintain reliability. If the ISO's real-time contingency analysis shows that a reliability issue would not occur if load continues to be served above the path rating, Operations would not shed load pre-contingency. This would be due to the market or operators seeing a lower WECC Path Rating.

Stakeholders generally supported the ISO's proposal to retire this temporary measure as logical given its new ability to increase transfer capability. WPTF supported the retirement as the real-time contingency analysis allows the ISO to use up to date information to increase the transfer capability supporting reliability. NRG also supported the retirement as long as the alternative of not shedding load under emergency conditions up to the real-time system operating limit does not become a way in which ISO Operators take actions to "opaquely affect market results". The ISO would like to clarify that the revised system operating limit is not a limit that would go into the market. The ISO only has the authority to use the WECC path ratings for clearing bids and offers within its market.

The ISO found this alternative to be preferable because the revised limit would allow the ISO to avoid load shedding without having to employ a market intervention in day-ahead that could have significant impacts on the market solution and potentially introduce inefficiencies between the day-ahead and real-time market.

The ISO directs NRG and PG&E to Peak Reliability Coordinators' (Peak RC) information on their policy changes. Peak RC fact sheet states, "Peak has modified its System Operating Limits (SOL) Methodology to allow a Path SOL to exceed the Path rating under anticipated emergency conditions, requiring a significant amount of coordination in advance with Peak and other impacted TOPs and BAs.[30]" The mechanism that Operations would use to exceed the path rating is defined within NERC EOP-002-3.1[31]. Operations would declare an Energy Emergency Alert (EEA), which under Section 3.4 allows use to revisit SOL limits given RT information.

The second measure to adjust congestion revenue right amounts was a mitigation measure proposed to protect against potential adverse market outcomes if the ISO adjusted internal paths limits in the day-ahead market run systematically. If the adjustments were made systematically, congestion revenue right auction participants could have an incentive to procure congestion revenue rights on paths based on expectations that the limit used in the auction would be different than the limit used in the day-ahead market. The congestion revenue right holder could then profit off a difference in the definition of the path instead of congestion.

[30]Peak Reliability Coordinator Fact Sheet on Aliso Canyon, https://www.peakrc.com/aboutus/Facts/2016_05_23%20peak_reliability_fact_sheet_aliso_canyon_FINAL.pdf; Peak Reliability RC SOL methodology posted at https://www.peakrc.com/SOLDocs/Peak%20RC%20SOL%20Methodology%20for%20the%20Operations%20Horizon%20v7.1.pdf.

[31] http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-002-3.1&title=Capacity%20and%20Energy%20Emergencies&jurisdiction=United%20States

Since this measure was approved to be used as a result of using the ability to adjust the internal paths it is not needed without that measure. Consequently with the proposed retirement of the ability to adjust internal paths, the ISO will also retire the mitigation measure allowing an adjustment of the amount of congestion revenue rights available in the auction[32].

Summary of General Stakeholder Comments

In addition to specific stakeholder comments submitted on the ISO's proposal for Phase 2, several stakeholders submitted comments requesting long-term market enhancements or recommendations outside the scope of Phase 2.

The Environmental Defense Fund, NRG, and DMM all requested long-term market enhancements. The ISO understands that the strained conditions resulting from the limited operations of Aliso Canyon has exacerbated stakeholders' concerns that previously identified market design issues have not been addressed to their satisfaction. However, the measures pursued under the *Aliso Canyon Gas-Electric Coordination* initiative are primarily designed to address new concerns that arose not bridge the gap on long-term market design issues.

Any long-term market design enhancements should be pursued under a normal stakeholder process where the issue can be thoroughly explored and the best solution proposed after robust stakeholder participation.

The ISO will be evaluating its market design features impacting bidding flexibility balanced against market power protections and robustness of its mitigated prices under the *Commitment Cost and Default Energy Bid Enhancements* initiative. The ISO looks forward to continuing this discussion with its stakeholders under that effort.

DMM has recommended that the ISO consider mitigation for incremental or decremental exceptional dispatches. In addition several external stakeholders submitted comments supporting DMM's recommendations. The ISO believes considering this would benefit from additional time and stakeholder process. The ISO will continue to consider these recommendations.

Plan for Stakeholder Engagement and Next Steps

The current schedule for this initiative is shown below. Stakeholder comments will be due September 28, 2016. In comments, the ISO asks stakeholders to provide input on the ISO's draft final proposal. The ISO will present its proposal to its Board of Governors on October 3, 2016.

Milestone	Date
Issue and Straw Proposal Posted	9/7/2016
Stakeholder Call	9/9/2016

[32] WPTF submitted comments supporting the retirement of this provision.

Milestone	Date
Stakeholder Written Comments Due	9/14/2016
FERC Technical Conference	9/16/2016
Market Surveillance Meeting discussion item	9/19/2016
Draft Final Proposal and Draft Tariff Language Posted	9/21/2016
Stakeholder Call	9/26/2016
Stakeholder Written Comments Due	9/28/2016
Special Session Board Meeting	10/3/2016
Tariff Filing	10/14/2016

Attachment E – Department Market Monitoring Comments on Draft Final Proposal

Filing to Maintain in Effect for One Year Certain Tariff Provisions Previously Accepted on an Interim Basis to Address Limited Operability of Aliso Canyon Facility

California Independent System Operator Corporation

Comments on the Draft Final Proposal for Aliso Canyon Gas-Electric Coordination – Phase 2

Department of Market Monitoring
September 28, 2016

Overview

DMM generally supports the ISO's *Draft Final Proposal* to extend the temporary Aliso Canyon provisions. As noted in DMM's prior comments, DMM continues to provide two recomendations for enhancements to the ISO's proposal: [1]

- DMM recommends that the ISO file to permanently eliminate the current 1-day lag in gas prices used in the day-ahead market by updating gas prices used in the day-ahead market based on an average of next day gas trades reported on ICE between 8 a.m. and 9 a.m. prior to running the ISO's day-ahead market each day. The ISO has indicated that it may examine this issues as part of a bidding initiative it plans to initiate in the fourth quarter of 2016, which may result in modifications to be implemented in fall 2017. DMM believes that even if other changes to bidding rules are implemented in fall 2017, this measure represents a common sense element that should be included in the ISO market. This modification has universal support among stakeholders and that neither the ISO nor stakeholders have provided any reasons why this measure should not be implemented on a permanent basis.
- DMM also recommends that incremental and decremental exceptional dispatches related to the management of Aliso Canyon gas issues be considered non-competitive and subject to exceptional dispatch market power mitigation. The ISO notes that "several external stakeholders submitted comments supporting DMM's recommendations," but that "The ISO believes considering this would benefit from additional time and stakeholder process. The ISO will continue to consider these recommendations."[2]

DMM is supportive of the ISO's proposal to extend -- but not modify -- the current gas cost scalars used to increase commitment cost and default energy bid caps used in the real-time market at this time. DMM has not observed any significant detrimental impacts of the scalars in terms of market power and excessive or unnecessary market uplioft costs. However, DMM believes that analysis of market data indicate these scalars – particularly the 75 percent scalar for commitment cost bids – have not played a significant role in helping participants manage real-time gas usage. Thus, in the event DMM observes significant detrimental cost impacts

[1] Comments by Department of Market Monitoring on Aliso Canyon Gas-Electric Coordination Phase 2 – Straw Proposal, September 15, 2016: http://www.caiso.com/Documents/DMMComments_AlisoCanyonGas-ElectricCoordinationPhase2StrawProposal.pdf.
[2] *Draft Final Proposal*.

without any evidence that the scalars were providing significant benefits, DMM would recommend lowering the scalars.

Gas cost scalars

DMM is supportive of not modifying the current gas cost scalars for the time being since DMM has not observed any significant detrimental impacts of the scalars in terms of market power and excessive or unnecessary market uplift costs. However, DMM believes that analysis of market data indicate these scalars have not played a significant role to date in helping participants manage real-time gas usage. In the event DMM observes significant detrimental cost impact without any evidence that the scalars were providing significant benefits, DMM would recommend lowering the scalars.

The following sections provide a more detailed discussion of market data which DMM believes indicate that these scalars – particularly the 75 percent scalar for commitment cost bids – have not played significant role to date in helping participants manage real-time gas usage.

Impact of gas scalars on real-time gas usage

The *Draft Final Proposal* indicates that "in combination with good coordination and advanced electric planning, the more robust bidding flexibility is believed to have led to the limited days with modest positive imbalances and other days with negative imbalances during the summer months."[3] The ISO also notes that "some Stakeholders commented to the ISO that these bidding flexibility improvements helped them manage their operational risk during summer 2016."[4]

Figure 1 in the *Draft Final Proposal* is provided to show the combined impact of various factors that helped limit additional real-time gas usage following implementation of many special measures in early June. As shown in Figure 1, the difference between estimated real-time gas usage and gas needed to meet day-ahead schedules tended to be negative most days starting in June 2016 (indicating that real-time gas usage would be lower than scheduled supplies assuming generators scheduled gas to meet their day-ahead energy schedules).

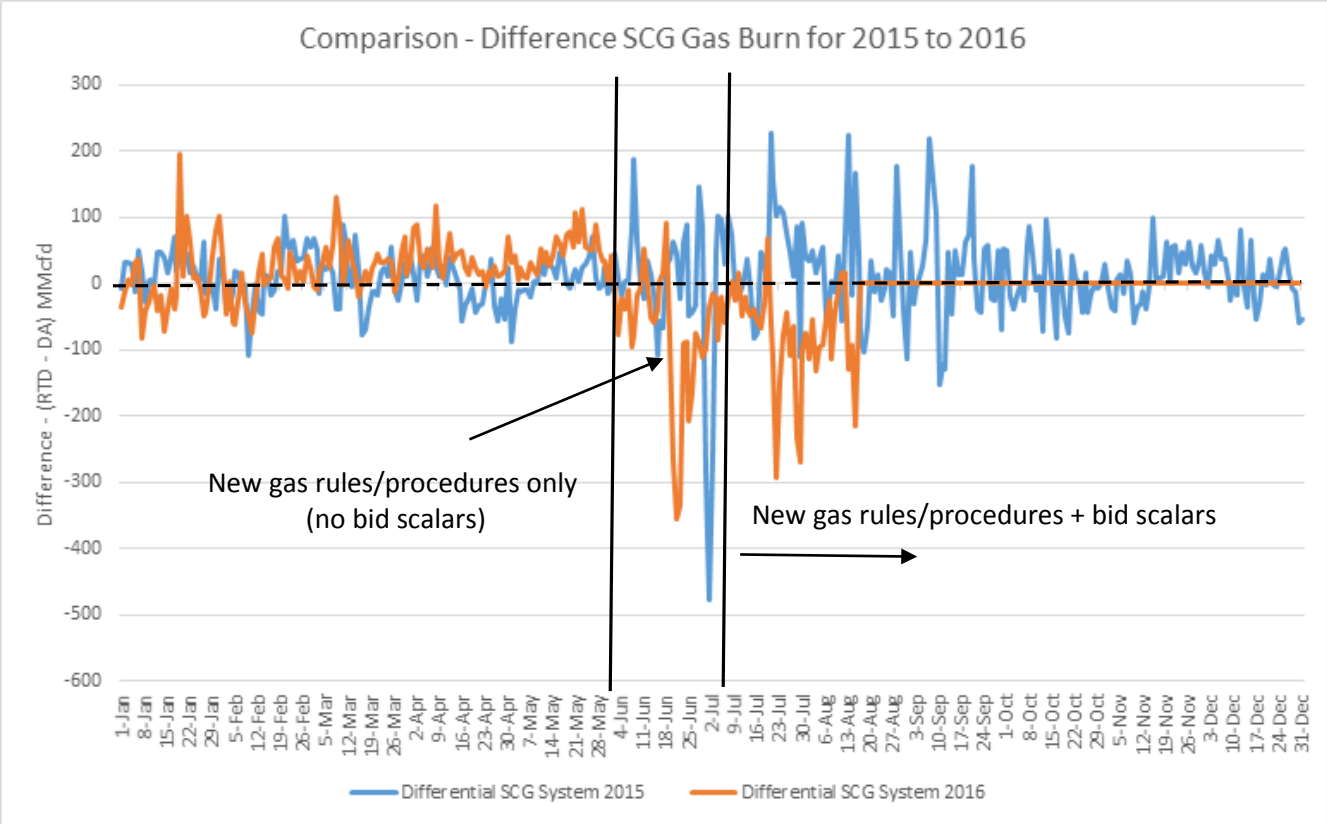
Figure 1 below shows the same Figure 1 from the *Draft Final Proposal*, but includes lines showing the date on which special gas provisions by SoCalGas and SDG&E were implemented (June 1, 2016) and the date on which the ISO implemented the gas cost scalars (July 6, 2016). Figure 1 below also includes a heavy dotted black line highlighting day when estimated real-time gas usage exceeded the ISO's calculation of gas needed to meet day-ahead schedules.

As shown in the annotated version of Figure 1 below, the trend of real-time gas usage below gas usage needed to meet day-ahead electric schedules began in June when special gas

[3] *Aliso Canyon Gas-Electric Coordination Phase 2 Draft Final Proposal*, September 23, 2016: http://www.caiso.com/Documents/DraftFinalProposal-AlisoCanyonGasElectricCoordinationPhase2.pdf.
[4] *Draft Final Proposal*.

provisions by the SoCalGas systems were implemented and continued for more than a month before the ISO implemented the gas cost scalars in July.

Figure 1. Gas usage before and after implementation of gas cost scalars



As shown in Figure 1 above, the days and magnitude of real-time gas usage in excess of gas needed for day-ahead schedules are approximately equal *before* and *after* implementation of the gas usage scalars. Before the gas scalars were in effect, positive differences in estimated gas usage occurred on 4 of the 34 days (or 12 percent of days) from June 2 to July 5. After gas scalars were in effect starting July 6, positive differences occurred on 6 of the following 41 days (or 15 percent of days).

Figure 2 and Figure 3 compare the same data on estimated gas deviations during the period before and after implementation of the gas cost scalars in terms of a duration curve of estimated daily gas deviations.

Based on these data – along with analysis of bidding data summarized below – DMM believes that the gas usage trend in Figure 1 is not due to the gas cost scalars and is instead likely due to other factors – such as good coordination and advanced planning and scheduling of substantial supplies of gas by participants prior to real-time.

Figure 2. Daily gas usage before and after implementation of gas cost scalars (all days)

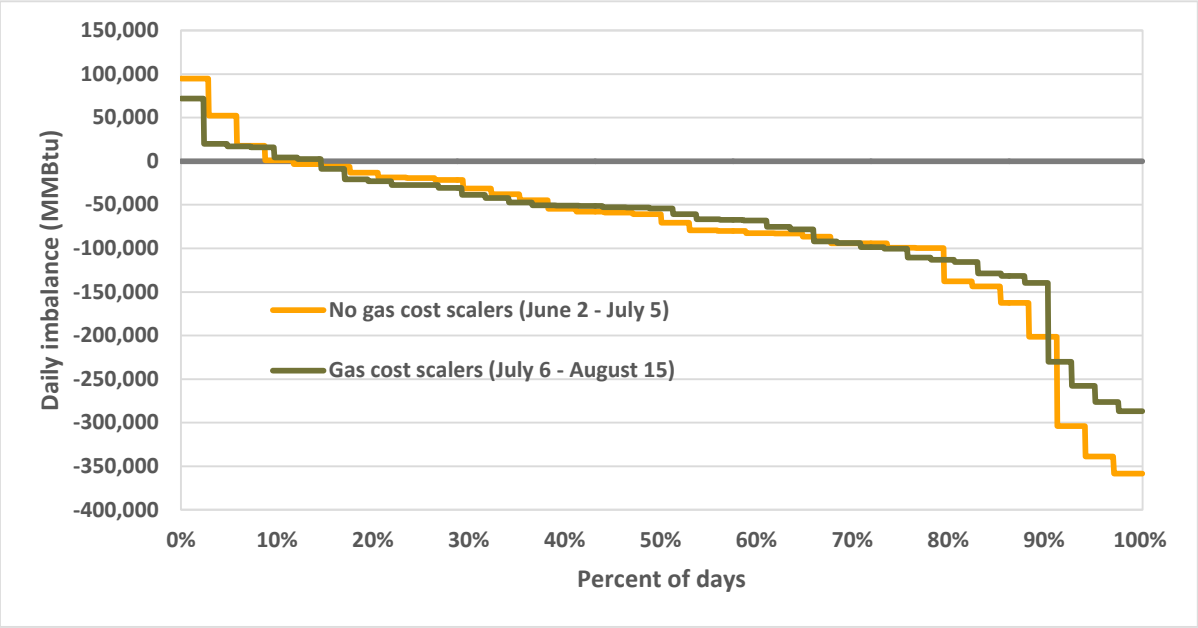
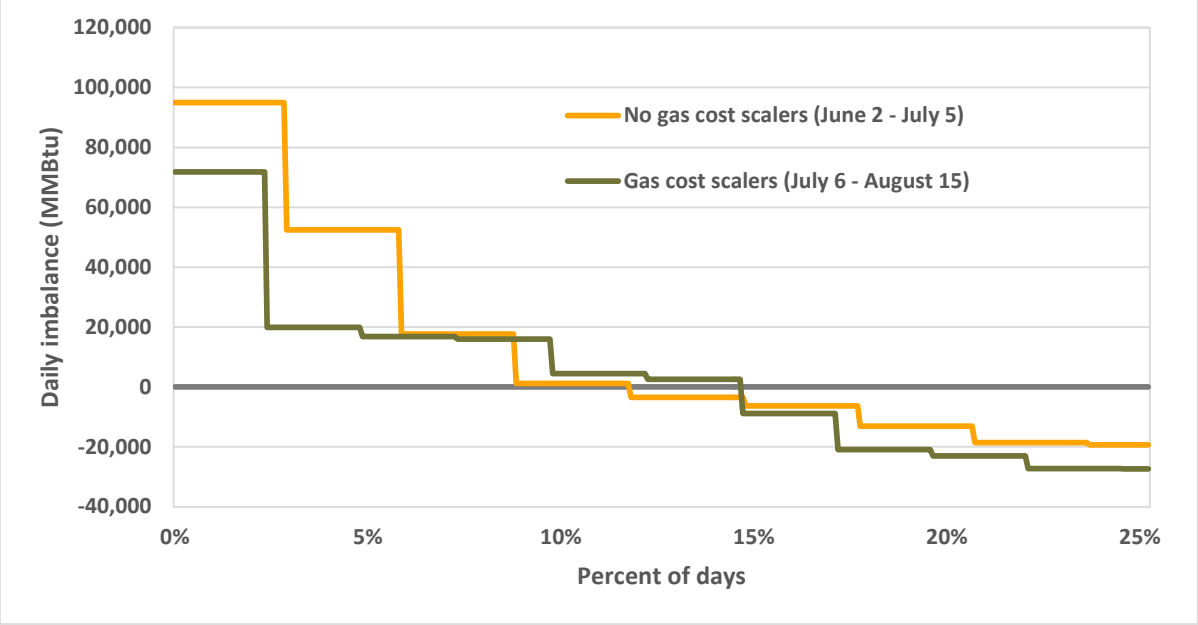


Figure 3. Daily gas usage before and after implementation of gas cost scalars (highest 25 percent of days)



In addition to the data in Figure 1 above, DMM believes that analysis of bidding patterns presented by DMM at the technical conference provides further indications that the upward bidding flexibility allowed due to the gas cost scalars is unlikely to have played a significant role in limiting additional real-time gas usage.

DMM's analysis presented at the technical conference shows that the additional headroom created by the 75 percent gas cost scalars for minimum load cost bids was used primarily by only one large participant. This one participant accounted for 99 percent of minimum load bids submitted at the bid cap after application of the 75 percent scalar and 85 percent of the minimum load bids submitted below the new bid cap and above the 25 percent headroom normally included in the bid cap for commitment costs.[5]

Other participants made some use of the additional headroom created by the 75 percent adder, while several participants made very limited use of this headroom.[6] The fact that only one supplier made significant use of the gas cost scalars – while several others made very limited use of the scalars – provides a further indication that the scalars are likely to have had limited impact on limiting real-time gas usage in excess of scheduled gas levels.

The ISO appears to concur with DMM's assessment that the commitment cost scalars have not provided significant benefits in terms of being needed to reflect actual gas prices in the real-time market. Specifically, the *Draft Final Proposal* states that "Regarding commitment costs, the ISO does not observe significant benefits from looking at systematic price differences alone by applying a scalar higher than 125 percent to the next day gas index."[7]

However, the *Draft Final Proposal* goes on to state that "there are additional benefits provided by having this higher scalar in place beyond capturing systematic price differences as it allows resources to reflect gas system constraints so the supplier can manager their unit within gas rules."[8] It is unclear it the ISO believes such additional benefits (i.e. helping suppliers manage resources within the gas rule) actually occurred during the summer months, or if the ISO believes these represent potential future benefits in the event gas and electric market conditions are different in the coming winter months.

As explained above, DMM believes that this analysis indicates that the 75 percent gas scalar for commitment costs did not end up having a signficant benefit in terms of helping to manage gas usage this summer. However, DMM agrees that the scalar may provide such benefits in the future in the event gas and electric market conditions are different in the coming winter months.

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[5] See *DMM Comments on Aliso Canyon market impacts*, September 16, 2016, p. 7: http://www.ferc.gov/CalendarFiles/20160915133258-DMMmarket-highlightsAliso.pdf.
[6] Ibid, p. 8.
[7] *Draft Final Proposal*.
[8] *Draft Final Proposal*.

DMM also notes that that following implementation of the 25 percent scalar used for default energy bids used in mitigation, we did not observe any systematic increase in energy bids in excess of the 10 percent headroom above estimated costs normally included in default energy bids and the approximately 35 percent level of headroom included after application of the 25 percent gas scalar. However, we did observe a few periods with higher demand where some participants may have increased their bids into the bid range afforded by the scalar. Though the impact on bids is difficult to assess directly as default energy bids are not directly correlated with incremental energy bids.

Thus, as explained in DMM's prior comments, while DMM believes the gas cost scalar – particularly the 75 percent scalar for commitment cost bids – have provided limited benefits, DMM is supportive of not modifying these for the time being since DMM has not observed any significant detrimental impacts of the scalars in terms of market power and excessive or unnecessary market uplift costs.

Same day gas costs

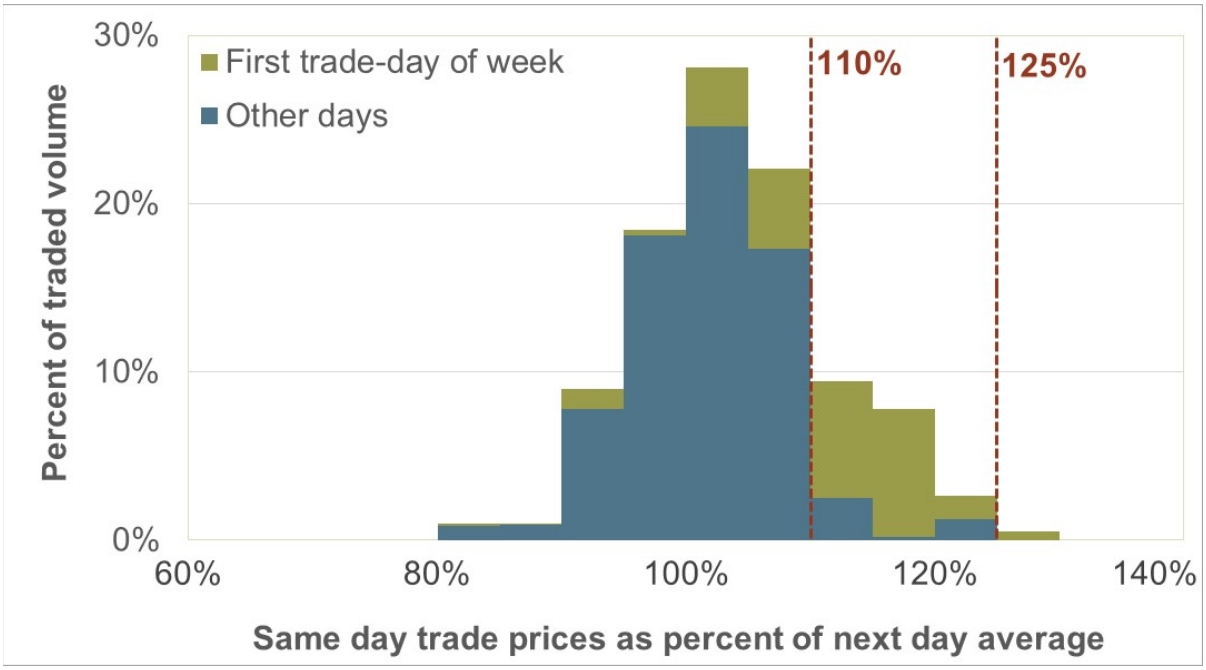
Under the ISO's proposal, the second criteria used by the ISO to determine if the gas cost scalars need to be adjusted is whether the scalar "better accounts for systematic differences between day-ahead and same-day natural gas prices that materialize."[9] Again, DMM's analysis indicates that the gas cost scalars have not been needed to account for any systematic differences in actual observed same-day natural gas prices and the next day gas costs used by the ISO to calculate commitment costs and default energy bids.

Analysis presented by DMM at the technical conference show that only 0.5 percent of same day gas traded on ICE was more than 125 percent higher than the next day gas index normally used to calculate commitment cost bids, and that the price of these trades was only marginally higher than the 125 percent level (i.e. up to 128 percent). With regards to default energy bids, the increased flexibility may have been useful in a limited set of instances (above 110 percent) that typically occurred on the first trade-day of the week. This analysis is shown in Figure 4 below.

DMM recommends that the ISO initiave steps needed to implement a process for updating gas prices used in the real-time market based based on an average or same day trade prices on ICE each morning atbout 8 a.m. This process would be essentially the same as the process for updating next day gas prices used in the day-ahead market each morning. This would ensure that updated gas prices used in the real-time market were virtually always within the 10 percent and 25 percent headroom normally allowed for default energy bids and commitment cost bids.

[9] *Draft Final Proposal.*

Figure 4. SoCal Citygate same day gas trades compared to the next day index



While DMM's analysis is based on the volume of all trades on ICE, the ISO's analysis is based on the single maximum trade price on ICE each day. The ISO's analysis found that "out of 92 days reviewed, only 1 had trading where the highest traded price [for same day gas] was more than 125 percent higher than the next day gas index published the morning of the ISO's day-ahead market."[10] This one day represents about 1.1 percent of the 92 days examined by the ISO and had a maximum trade price of equal to about 128 percent of the next day prices used to calculate real-time bid caps.

While the ISO's analysis represents the number of days, our analysis shows that of the traded volume only 0.5 percent of same day trades exceeded the 125 percent threshold. We believe that focusing on the volume of trades rather than instances of days is a better metric and representation of trades exceeding the threshold.

Updated gas price for day-ahead market

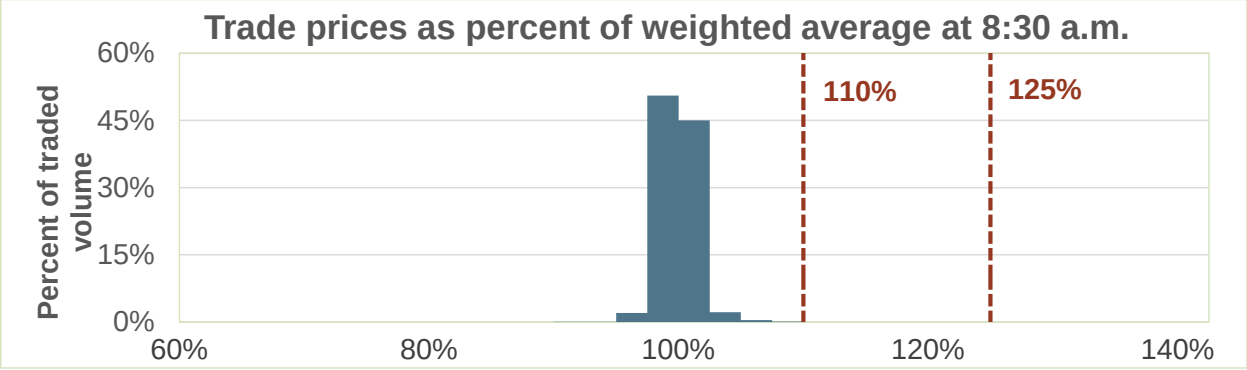
DMM recommends that the ISO file for permanent authority to eliminate the current 1-day lag in gas prices used in the day-ahead market by updating gas prices used in the day-ahead market based on an average of next day gas trades reported on ICE between 8 a.m. and 9 a.m. prior to

[10] *Draft Final Proposal*.

running the ISO's day-ahead market each day. This measure reflects a recommendation previously made by DMM in September 2015.[11]

Analysis by DMM presented at the technical conference shows that implementing this would ensure that gas prices used in the day-ahead market would have always been within the 25 percent and 10 percent levels of headroom already included in day-ahead commitment cost bid caps and default energy bids, respectively.[12] This analysis is provided in Figure 5 below.

Figure 5. Next day trade prices compared to proposed methodology



The ISO is only filing to extend this authority on a temporary basis. The ISO has indicated that it may examine this issues as part of a bidding initiative it plans to initiate in the fourth quarter of 2016, which may result in modifications to be implemented in fall 2017. DMM notes that this modification has universal support among stakeholders and that neither the ISO nor stakeholders have provided any reasons why this measure should not be implemented on a permanent basis.

DMM believes that even if other changes to bidding rules are implemented in fall 2017, this measure represents a common sense element that should be included in the ISO market. For example, even if bidding rules are modified to allow participants to request use of gas costs in excess of the cost used in the market software, this updated gas price represents the benchmark or default prices that would need to be used to assess such requests. In practice, DMM believes that data in Figure 5 shows that implementing this to eliminate the current 1-day lag in prices used in the day-ahead marker would provide the ISO and participants with a significantly more accurate representation of natural gas prices in the day-ahead market.

[11] *Report on natural gas price volatility,* Department of Market Monitoring, September 21, 2015, p.1: http://www.caiso.com/Documents/DMMReport-gas_price_analysis_september2015.pdf.

[12] *DMM Comments on Aliso Canyon market impacts*, p. 4.

Gas cost recovery

DMM recommended that the ISO clarify that the cost recovery provisions be expanded to include gas costs incurred as a result of energy dispatches only if these represented bids that were mitigated (i.e. *lowered*) through the ISO's automated bid mitigation procedures or mitigation rules for exceptional dispatches. The ISO's final proposal appears to do this.[13]

Exceptional dispatch

Since the ISO has indicated that exceptional dispatch will continue to be used as needed to manage Aliso Canyon gas limitations, DMM recommends that incremental and decremental exceptional dispatches related to the management of Aliso Canyon gas issues be considered non-competitive and subject to exceptional dispatch market power mitigation.

In response to requests from the ISO and stakeholders for DMM to provide some analysis supporting this recommendation, DMM provided analysis of structural market power in each of the gas sub-regions defined by the ISO. This analysis shows a high degree of structural market power in each of these gas regions.[14]

The ISO notes that that "several external stakeholders submitted comments supporting DMM's recommendations," but that "The ISO believes considering this would benefit from additional time and stakeholder process. The ISO will continue to consider these recommendations."[15]

[13] *Draft Final Proposal*.
[14] Comments by Department of Market Monitoring on Aliso Canyon Gas-Electric Coordination Phase 2 – Straw Proposal, p. 3.
[15] *Draft Final Proposal*.

Attachment F – Board of Governors Memo

Filing to Maintain in Effect for One Year Certain Tariff Provisions Previously Accepted on an Interim Basis to Address Limited Operability of Aliso Canyon Facility

California Independent System Operator Corporation

Memorandum

To: ISO Board of Governors

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

Date: September 29, 2016

Re: **Decision on Aliso Canyon gas-electric coordination phase 2 proposal**

This memorandum requires Board action.

EXECUTIVE SUMMARY

As detailed in Management's May 2, 2016 memorandum to the Board of Governors, 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 electrical generators in the area.

Management's May 2016 memorandum proposed a coordinated set of operational and market tools to address risks to electrical reliability posed by gas system conditions over the summer. The Board approved these measures that were later conditionally approved by FERC to be effective through November 30, 2016.

Based on an inter-agency task force study completed this summer, the limitations resulting from the loss of the Aliso Canyon storage facility are expected to continue to stress the gas system this winter.[1] In response, Management initiated a second expedited process to work with stakeholders to evaluate which market mechanisms and operational tools should be extended to address ongoing risks due to the continued unavailability of the Aliso Canyon facility.

As a result, Management is proposing to extend most of these measures beyond their current November 30, 2016 expiration date. Upon Board approval, Management will submit tariff revisions to FERC seeking expedited consideration of mitigation measures with an

[1] https://efiling.energy.ca.gov/getdocument.aspx?tn=212904

effective date beginning at the sunset date, December 1, 2016. Given the short timeframe to develop these provisions and the request for expedited consideration by the Commission, and the expectation that the Aliso Canyon facility will not be operational during the bulk of 2017, Management proposes that the provisions be temporary and expire on November 30, 2017.

Moved, that the ISO Board of Governors approves the Aliso Canyon gas electric coordination phase 2 proposal, as described in the memorandum dated September 29, 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 originally proposed a set of temporary operational and market tools to address reliability concerns resulting from the limited use of the Aliso Canyon natural gas storage facility. The measures were proposed as temporary to allow the ISO and stakeholders to review their effectiveness over the summer and to assess whether these measures, or other measures, would be necessary to address any continued reliability risks. Management conducted a new stakeholder process to review the effectiveness of the current measures and to assess whether they are needed to address the continued reliability risks outlined in the winter inter-agency task force study. As a result of this process, Management proposes to extend all but one of these measures to meet the following two policy objectives:

- 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, and

- Ensure ISO markets produce prices that reflect gas system limitations to mitigate the risk that ISO dispatch could adversely impact gas operators' efforts to manage their systems reliably.

Operational tools

One of the primary operational tools originally implemented as part of the Aliso Canyon mitigation measures was a gas burn constraint. The ISO coordinates with the gas company to the extent possible in setting gas burn limitations of the constraint. The constraint is enforced when gas system limitations exist or operators have a concern that electric system dispatches could compromise gas system conditions which in turn could compromise electric grid reliability. Depending on gas system limitations, operators have the ability to apply the constraint in either, or both, the day-ahead and real-time markets. Operators also have the ability to apply the constraint for individual or groups of zones defined by the gas

system. The constraint, when binding, limits the dispatch of generators subject to the constraint and affects resource-specific prices used for dispatch and settlement purposes. However, it does not impact the locational marginal price used for other purposes including load, congestion revenue rights, and virtual bids settlement. The ISO will enforce the gas constraint to manage gas constraint issues only in the Southern California Gas and San Diego Gas and Electric gas regions.

Management proposes to retain the constraint in the ISO market processes that limits the affected area generators' gas burn, with one modification. Management proposes to modify the constraint to no longer enforce that gas burn be kept to a minimum amount. Based on experience over the summer, resources have the ability to meet imbalance limitations in which they need to burn a minimum amount of gas. They can increase the likelihood of operating at a certain minimum output by lowering their bid price or self-scheduling.

As a result of the gas burn limitation constraint, Management also proposes to extend related measures. First, Management proposes to extend the authority to deem selected internal transmission paths competitive or uncompetitive when the gas burn constraint is enforced in the ISO market processes based on a determination that the actual electric supply conditions may be uncompetitive. Second, Management proposes to extend the authority to suspend virtual bidding if it observes virtual bidding causes market inefficiencies when the gas constraint is enforced.

The operational measures originally implemented also included a provision that allowed the ISO to reserve transfer capability on internal transmission paths. Management proposes not to extend this authority. The reliability authority for the ISO balancing area, *Peak Reliability Coordinator,* recently modified its system operating limit methodology to allow a path's rated limit to exceed its rating under emergency conditions. As a result, the ability to reserve internal transfer capability is no longer needed to ensure sufficient transfer capability is needed in real-time to meet unexpected southern California needs.

In conjunction with this, Management proposes not to extend the provisions in which the ISO would potentially limit the amount of congestion revenue rights it releases in the monthly allocation and auction to be consistent with any reduced transfer capability in the day-ahead market.

ISO market modifications

In addition to the operational tools described above, Management proposes to extend the ISO market modifications originally approved in phase 1. This will continue 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 was 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 SoCalGas/SDG&E systems. This modification allows generators' real-

time bid prices to better reflect gas system limitations and gas prices. This greater bidding flexibility increases 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 provides for the ISO 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 SoCalGas/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 was initially set to scale the gas commodity price to 175 percent of the gas index price. The ISO monitors whether this level is effective in meeting the three objectives listed above. The provisions provide the ISO with 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. To date, the ISO has not observed the need to adjust this scaler.

The measures also include provisions 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. The gas price used in the default energy bid calculation was initially scaled to 125 percent of the gas commodity price. Similar to the proxy cost calculation, the ISO has 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 is capped at 200 percent of the gas commodity price. The ISO has not observed the need to adjust this scaler.

The second market modification Management proposes to extend, applicable to all gas-fired generators, not just those in the affected area, is 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 draw from the Intercontinental Exchange an index published between 8:00 a.m. and 9:00 a.m. Pacific Time that represents the price of fuel based on trades made on the Intercontinental Exchange at that earlier time. The earlier index produced by the Intercontinental Exchange the ISO will use consists of a volume weighted average price using trades observed during the Intercontinental Exchange next day trading window prior to the time it is published.

The third market modification Management proposes to extend is to make two day-ahead advisory market results available to scheduling coordinators. Making this advisory information regarding estimates of resources' day-ahead market schedules available to market participants allows them to consider this information in purchasing gas in the next day gas trading that primarily occurs before ISO day-ahead market results are available. Finally, the proposal includes three market modifications that the Board approved earlier this year as part of the bidding rules and commitment cost enhancements initiative. Management included these modifications as part of the phase 1 Aliso Canyon so that they could implemented quickly to help address the Aliso Canyon reliability concerns. In August, the ISO filed these measures with FERC to be in effect on a permanent basis as previously approved by the Board in May. Because FERC has not yet issued an order approving these provisions, Management proposes to file with FERC to extend these provisions on a temporary basis until the later of the date on which FERC approves these provisions on a permanent basis, or November 30, 2017.

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 and are not restricted by a real-time commitment. This is important to allow them to reflect gas costs and limitations in the real-time market. The second of these 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. The third market modification is to permit market participants to file with FERC to have the opportunity to recover incurred costs that exceed commitment cost bid caps not recovered through market revenues as the result of high marginal fuel procurement costs not being fully reflected in the bid cap.

Finally, in addition to permitting market participants to file with FERC to recover costs incurred that exceed commitment cost bid caps, Management proposes to extend the temporary measure to allow for similar recovery of costs that exceed the mitigated energy bid.

POSITIONS OF THE PARTIES

Stakeholders strongly support the ISO's proposal to retain the operational tools and market mechanisms as temporary measures.

Department of Market Monitoring and Western Power Trading Forum both strongly support the ISO's continued ability to adjust the scalars applied to the gas commodity price. Department of Market Monitoring also strongly supports improving the gas price information used by the ISO day-ahead market.

A number of stakeholders request the ISO provide additional documentation and procedures to increase the information it releases to the market related to these measures and its enhanced gas-electric coordination. ISO is already in the process of doing this where appropriate.

Department of Market Monitoring and PG&E both believe the ISO should pursue tariff revisions for price mitigation of incremental exceptional dispatches due to natural gas limitations. They also urge the ISO to develop a methodology to mitigate decremental exceptional dispatches. Management plans to examine this as part of an upcoming stakeholder process and could accelerate this if bidding practices appear to necessitate more expedient action.

NV Energy and Environmental Defense Fund support the ISO pursuing long-term market enhancements to its commitment cost and default energy bid designs. Management plans to examine long-term market enhancements in an upcoming stakeholder process.

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.