Aliso Canyon Gas-Electric Coordination

Straw Proposal

April 15, 2016

Table of Contents

1. Executive Summary

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

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

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

(1) Evaluate reliability risks emerging from abrupt change in gas storage capacity at the Aliso Canyon storage facility,
(2) Evaluate how gas balancing rules regardless of the penalty structure adopted by SoCalGas and SDG&E might affect resources' ability to manage their generation assets,
(3) Identify and develop market mechanisms or tools to support reliability and ensure markets are not adversely affected.

A balancing requirement over a day will require resources to manage their gas procurement and subsequent pipeline nomination so the amount of nominated gas is within a tolerance band (expressed in percentage) of its actual gas burn. These strict gas balancing requirements support gas system reliability by signaling to gas customers when their gas deviations over the day are outside the tolerance band and imposing a charge associated with such deviations. The penalties associated with the violating either a daily balancing requirement or an operational flow order introduces a new risk to gas customers including electricity generators in the ISO markets that may affect traded prices of natural gas.

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

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

- Coordinate ISO market instructions or exceptional dispatches with daily balancing requirements.
- Include mechanisms to reflect intraday prices reflecting strained gas condition in commitment cost and mitigated incremental energy bids.

In Section 4 of this Straw Proposal, the ISO discusses its evaluation of the issues affecting gas and electric service under the constrained conditions due to limited operability of Aliso Canyon. In this Straw Proposal, the ISO identifies and proposes measures to mitigate the inter-agency task forces identified risks, which include:

- In Section 5, the ISO discusses measures to mitigate the risk where planned and unplanned outages on gas system often limit pipeline and other storage availability that impact gas availability.
- In Section 6, the ISO discusses measures to mitigate the risk where daily imbalances exceeding 150 million cubic feet (MMcf) affecting operating pressures that undermine pipeline integrity.
- In Sections 5.2, 7 and 8, the ISO discusses measures to address the risk that the electric system could be adversely impacted when its rapid ramping can exceed dynamic capability of gas system i.e. contingency recovery, renewable generation following, or significant changes in load.

Besides addressing the risks raised by the task force, the ISO identified need to propose changes to its day-ahead gas price index used to determine its cost estimates. There has been a change to the timing when Intercontinental Exchange (ICE) is releasing the next day index used for the manual price spike procedure which would require moving day-ahead market timeline to continue the procedure. Given the increased need to include accurate gas price information in both day-ahead and real-time under these constrained conditions, the ISO is addressing long term enhancements to replace the manual gas price spike procedure in Section 9.

2. Plan for Stakeholder Engagement

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

Milestone	Date
Issue Paper Posted	3/17/16
Stakeholder Call	3/23/2016
Stakeholder Written Comments Due	3/30/2016
Working Group Stakeholder Meeting	4/06/2016
Straw Proposal Posted	4/15/2016
Market Surveillance Meeting discussion item	4/19/2016
Stakeholder Written Comments Due	4/21/2016
Draft Final Proposal and Draft Tariff Language Posted	4/25/2016
Stakeholder Call	4/27/2016
Stakeholder Written Comments Due	4/27/2016

3. Background

3.1. Aliso Canyon Impact

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

- The Division of Oil, Gas and Geothermal Resources is to continue its prohibition on injecting gas into the storage facility until a comprehensive review of the storage and wells and air quality in the area is complete; and
- The CPUC and CEC are to coordinate with the ISO to "take all actions necessary to ensure the continued reliability of natural gas and electricity supplies… during the moratorium on injections…"

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

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

1. Daily imbalances exceeding 150 million cubic feet (MMcf) affecting operating pressures that undermine pipeline integrity
2. Planned and unplanned outages on gas system often limit pipeline and other storage availability
3. Rapid ramping of electric generation can exceed dynamic capability of gas system i.e. contingency recovery, renewable generation following
4. Cold weather to east can reduce gas supplies for California

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

To mitigate the risk of gas curtailments and impacts to electric reliability because of Aliso Canyon, SoCalGas and SDG&E filed the motion for Interim Order Establishing Temporary Daily Balancing Requirements at the CPUC.[5] The motion proposed to impose an interim daily gas balancing penalty of 150% of daily gas indices for daily gas deviations where the difference between nominated gas flows and actual gas demand (burned gas) falls outside a 5% tolerance band, which if approved by CPUC will be effective May 1, 2016.

Since filing the joint motion for daily balancing, SoCalGas and its customers have entered into settlement discussions. Given the uncertainty around what penalty structure SoCalGas will effect this summer, any discussion of daily balancing or balancing over a day should be understood to refer to any situation where a daily balancing requirement is in effect. Even under an operational flow order (OFO) structure, if issued SoCalGas's customers will for the day

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

[5] Application 15-06-020.

issued be required to balance their nominated flows within a tolerance band of their actual gas burn.

3.2. FERC Order 809

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

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

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

The ISO provided an update to stakeholders on the impacts of FERC No. 809 on June 19, 2015.[7] The ISO did not discover sufficient benefits to gas-fired generators to justify the costs of moving the day-ahead market run time window to earlier in the day. In a stakeholder process, the ISO considered three alternatives and found Alternative 2, to not move the day-ahead market window,

---

[6] Federal Energy Regulatory Commission, Docket No. RM14-2-000; Order No. 809, April 16, 2015.
[7] See Proposal – FERC Order No. 809 available at: http://www.caiso.com/Documents/Proposal_FERCOrderNo809.pdf.

to be the most effective design.[8] This was because at the time obtaining gas nominations on the pipelines serving California generators was not a problem. There was sufficient access to storage and stakeholders stated there was enough notice for procurement during evening nomination cycle for gas flows beginning 7AM PST on the electric operating day.

Besides the order, FERC issued a companion section 206 proceeding requiring ISOs and RTOs to propose changes to their electric market nominating timelines, or to demonstrate why changes are unnecessary after adoption of the final rule in RM14-2. The filing was due 90 days after April 16, 2015. The ISO filed its response to FERC's 206 proceeding in EL14-22 asking the Commission to find the ISO did not need to move the timing of its current day-ahead close and publication of market results forward.[9] FERC accepted the ISO's proposal to not change the day-ahead market window.

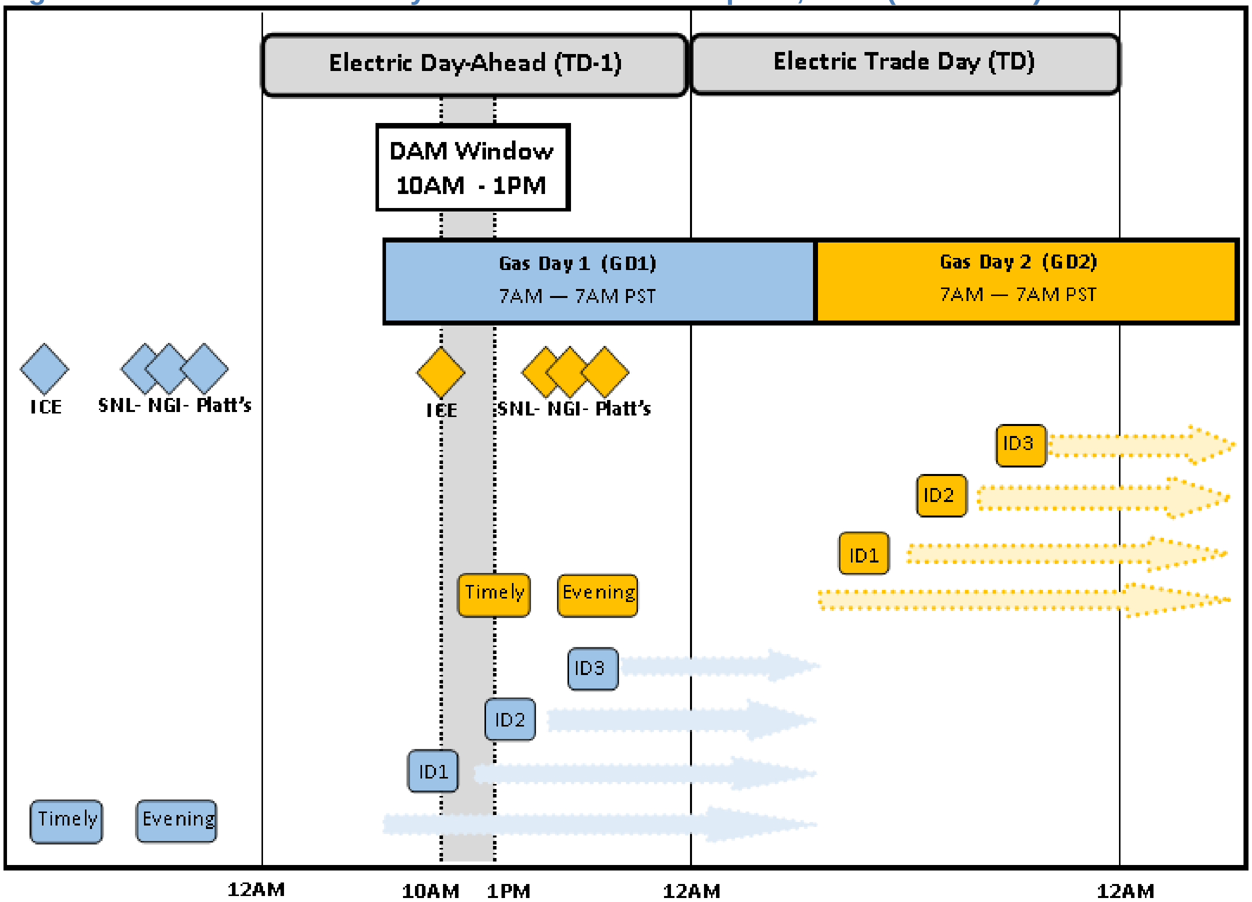
In light of reduced access to storage due to limited operations of Aliso Canyon, the most effective day-ahead market timeline design might require reevaluation.

3.3. Alignment of natural gas and electric markets

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

[8] See Straw Proposal at 15 available at:
http://www.caiso.com/Documents/StrawProposal_BiddingRulesEnhancements.pdf
[9] See EL14-22 Filing, July 23, 2015 at 15 available at:
http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13939292

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



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

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

The impact of using the GD1 price is that the gas price for purchases on the day the day-ahead market is run are not reflected in the ISO's variable cost option default energy bid or its commitment cost calculations resulting in commitment cost bid caps not fully reflective of expected market conditions. The gas price indices that reflect expected market conditions for

[10] ISO tariff section 30.4 and 39.7.1.1.1.3.

the majority of ISO's operating day are shown as orange diamonds in Figure 1. The corresponding gas day is also shown in orange.

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

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

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

The ISO's cost estimates use a next day gas price index, which is the volume weighted average of gas transactions during the timely procurement with a deadline for eligibility around 9:30AM PST (timely deadline)[12]. ISO's commitment cost estimates used in both day-ahead and real-time markets are based on next day gas price index for GD1. Under *Bidding Rules Enhancements - Generator Commitment Cost Improvements,* the ISO is proposing at its March board meeting to allow resources without day-ahead schedules to submit commitment costs in real-time based on next day gas price index for GD2. Default energy bids are currently determined for day-ahead using GD1 index and for real-time using GD2 index.

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

Because the market cannot consider the actual fuel costs generators would face, the ISO's solution (including prices) does not reflect the marginal cost of serving load. Generators would face the dilemma of either facing the daily imbalance charges or uninstructed imbalance energy costs if they do not deliver their energy commitment. This could lead to the need for out-of-

[11] Market Instruments BPM at 191.
[12] Cut off for eligibility varies by publisher but all are set to end with timely deadline.

market actions by the ISO to re-dispatch the system manually to account for their lack of performance to avoid causing a system reliability issue on the electric grid.

4. Identified Issues

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

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

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

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

The ISO understands from discussion with stakeholders and review of Issue Paper comments that the reliability risk is driven by uncertainty of incremental changes to day-ahead schedules in real-time. This risk would not be addressed by moving the day-ahead market timeline. The price risk associated with having to submit day-ahead bids prior to procurement when procurement would occur during less liquid trading would be alleviated by moving the day-ahead market window.

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

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

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

receive a binding start up instruction to start up by the real-time market. The ISO is concerned with the impacts on medium, short and fast start units of these daily gas balancing requirements.

Further, once a binding start-up instruction has been received by a resource, there is still a risk the ISO real-time processes could cause dispatch instructions that would cause a difference between nominated gas flows and actual gas burn. The ISO is concerned with the impacts to all committed resources of its issuing real-time dispatch instructions different than day-ahead schedules or earlier real-time market non-binding solutions.

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

Stakeholders have communicated to the ISO sometimes, gas cannot be procured because they might not be able to find a seller. Under this scenario, the ISO instruction could cause resources to incur balancing charges for operating outside the tolerance band to follow the instruction. The ISO wishes to better understand what scenarios could cause these instances and to explore whether any improvements are necessary to address this scenario.

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

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

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

Under strained gas conditions, intra-day gas procurement costs will likely increase due to the costs associated with the need for managing gas supply within a daily balancing tolerance band. ISO's cost estimates do not currently include information from the intra-day gas markets. Consequently, both commitment cost bid cap and mitigated energy bids might be restricted from reflecting observed prices. There is a risk fuel costs might exceed the commitment cost bid cap driving commitment costs to exceed the current day's bid cap that provides 25% headroom on ISO's commitment cost estimates. There is a higher risk due to the 10% margin of error used in calculating the default energy bid that resources mitigated to their variable cost option default energy bids would be mitigated to costs below its short-run marginal costs, reflective of deviation charges.

When intra-day gas prices are high enough relative to the next day gas index to not be able to be reflected in the default energy bid or commitment cost bid cap, the change in marginal costs are not modelled and the ISO's markets could experience less efficient commitments, dispatches, and insufficient cost recovery beginning summer 2016. These modelling concerns affect resources' commitment costs and any mitigated incremental energy offers[15]. The ISO is concerned by not sufficiently modelling or compensating resources for higher costs. This will cause resources without real-time must offer obligations to not participate in the ISO's real-time market resulting in less efficient market outcomes.

The ISO wishes to explore with its stakeholders if market mechanisms or other tools are necessary to address this issue and whether incentives are improved better through intra-market or after-the-fact solutions. Specifically at least these two questions will be discussed:

(1) Is there a need for adjustments to ISO's ability to model resources marginal costs and compensate resources for the additional short-run marginal costs associated with generator's managing their balancing requirements?
(2) Is there a need for other tools to ensure proper incentives are maintained in ISO's market such as an after-the-fact cost recovery of verifiable costs?

ISO understands from discussion with stakeholders and review of Issue Paper comments there is broad agreement there exists a market design gap in which the ISO's commitment cost bid cap and mitigated energy offers do not allow generators to fully reflect costs. The concern surrounding this gap is exacerbated due to Aliso Canyon as this gap affects all generators across the footprint including Energy Imbalance Market participating generators. To ensure the ISO's dispatch in real-time is efficient and reliable, these cost estimates will be evaluated consistent with the change to the gas market structure.

5. Proposals for addressing risk of maximum gas burn limitations due to supply or deliverability capability

5.1. Introduce gas availability constraint

Based on the inter-agency technical assessment to which the ISO contributed, the ISO understands a primary factor that can adversely impact the gas system reliability, and consequently electric system reliability, is storage or pipeline outages or curtailments. Whether

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

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

The ISO supports exploring measures that can ensure these gas burn limitations are reflected in its markets both day-ahead and real-time as soon as possible. The ISO policy for outages and curtailments is:

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

ISO current policy places the responsibility on the generator to ensure it submits an outage card to the ISO's outage management system reflecting a limitation it might expect unless timing precludes the outage card from being reflected in the market. While an outage may be public, it may be unclear to generators exactly what their plant level limitation will be until the curtailment or their inability to procure gas occurs. Generators prefer to wait until receiving limitations from the gas company or are they cannot procure gas before they impose a plant level limitation through an outage card. Further once a notification is issued for curtailments, the ISO is evaluating whether operations could be improved through using the gas availability constraint to reflect curtailments instead of issuing exceptional dispatches when timing does not allow outage cards to be reflected in the current market run.

ISO proposes to implement a constraint in its real-time market that would limit the affected area gas burn to a maximum gas burn limitation communicated to the ISO from the gas company. The affected area, or the set of generators included in the constraint, will be the gas fired generation within the SoCalGas and SDG&E gas operating zone(s) identified by SoCalGas or SDG&E as under the maximum gas burn limitation. The constraint would limit the maximum allowable gas burn over the day. If the constraint was violated, the price of the constraint would be reflected in market prices.

ISO proposes to request authority to enforce the gas availability constraint[16] in its markets depending on when the outage or curtailment occurs. For example, if the gas company notifies the ISO it will have an outage on its pipelines reducing the availability of fuel in a defined zone to an expected maximum amount prior to the day-ahead market close, the constraint would be enforced in both day-ahead and real-time. If an unplanned outage occurs after day-ahead or curtailment is issued during real-time, the constraint could be enforced in real-time market run.

Equation 2 below reflects the proposed gas availability constraint where the market dispatch solution is constrained to less than a maximum allowable gas burn. The right hand side (RHS) limit defines the maximum allowable gas burn communicated to the ISO from the gas company. This maximum limit would be enforced and therefore if ISO operations determined additional generation from the affected generators is needed above this limit for electric reliability the additional generation could only be dispatched through exceptional dispatches once coordinated with the gas system operator.

To increase the affected generators ability to respond to electric service needs in the real-time when most needed by the system, the ISO proposes to allocate the daily maximum limitation across hours based on the expected load shape. The allowance distribution coefficient will generally reflect the percentage of forecasted demand for the affected area each hour represents within the day.

Equation 1: Gas Availability Constraint

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

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

$$RHS_t = R_h$$

S	Set of generators in affected area
P	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 which is an hourly value in MMcf provided by gas company
R_h	Daily upper bound deviation allowance relative to day-ahead market schedule

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

5.2. Reserve internal transfer capability

The ISO anticipates needing the flexibility to reduce available transfer capability (ATC) on Path 26 to ensure there is sufficient transfer capability to support reliable grid operations. ISO intends to derate the transfer capability in the day-ahead and real-time market and to manually release the transfer capability in real-time if the transfer capability is needed to deliver energy to Southern California.

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

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

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

The ISO is evaluating the impact reserving portion of transfer capability on Path 26 will have on congestion revenue right (CRR) revenue sufficiency. It will likely address this by limiting the amount of additional CRRs it releases in the monthly process.

6. Proposals for addressing imbalances between real-time and day-ahead that could adversely impact reliability

6.1. Increase access to information prior to day-ahead

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

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

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

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

6.2. Introduce gas balancing constraint in real-time

Based on the inter-agency technical assessment to which the ISO contributed, and the ISO's discussion with stakeholders in this stakeholder effort, the ISO understands a primary factor that can adversely impact the gas system reliability, and consequently electric system reliability, is a significant change in the dispatch of generators in the SoCalGas and SDG&E gas system between the real-time dispatch and day-ahead market schedules. For example, the technical assessment concluded that daily gas imbalances greater than 150 MMcf[17] significantly increase risk of gas curtailments that could result in electric service interruptions. Electric operations can affect gas reliability if electric market outcomes result in instructing affected generators to increase or decrease their gas imbalances to respond to ISO instructions. Therefore, the ISO

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

evaluated what measures might be appropriate to mitigate risk of imbalances of that magnitude and associated unintended consequences to gas and electric system reliability.

ISO proposes to implement a constraint in its real-time market that would limit the re-optimization of the affected electric generation in a manner designed to support pipeline operations[18]. The affected electric generation, or the set of generators included in the constraint, will be the gas fired generation within the SoCalGas and SDG&E gas operating zones. The constraint would limit the change in gas burn relative to day-ahead schedules' burn to within a balancing range (e.g. 150 MMcf) over the day. If the constraint was violated, the price of the constraint would be reflected in market prices.

Equation 2 below reflects the proposed gas balancing constraint where the gas burn for the real-time market dispatch is constrained to within a defined balancing range such as 150 million cubic feet (MMcf) around the gas burn for the day-ahead market schedules. The left hand side (LHS) and right hand side (RHS) limits define the balancing range within the real-time market processes will be able to re-optimize the set of generators within the affected area in real-time. This balancing range would be enforced and therefore if ISO operations determined additional generation from the affected generators is needed beyond this range for electric reliability the additional generation could only be dispatched through exceptional dispatches once coordinated with the gas system operator.

While the balancing range would be flexible enough to allow for changes to the value it would be limited to changes reducing the range not increasing the range greater than 150 MMcf. According to Technical Assessment Report, the constraint on the gas system is not a flexible constraint once certain conditions are present and in those instances the range should not exceed 150 MMcf. The ISO is evaluating whether using this constraint could be informed by other factors such as the SoCalGas's day-ahead demand forecast so the conditions where 150 MMcf is a reliability concern could trigger use of constraint.

If the gas reliability concern likely to impact electric service is anticipated to be a daily concern the constraint the ISO would default to enforcing this constraint in real-time until operability of Aliso Canyon is improved or other gas market structural changes are made to increase the ability of the gas system to support larger imbalances over a day. On the other hand, if the risk to reliability imposed by large imbalances is only present on days when certain fundamental factors are present the enforcement of this constraint would be triggered based on the fundamental factor(s).

To increase the affected generators ability to respond to electric service needs in the real-time when most needed by the system, the ISO proposes to allocate the daily range across hours based on the expected load shape. The allowance distribution coefficients will generally reflect

---

[18] The gas balancing constraint proposed would be a nomogram where the nomogram is defined in terms of generators and their interconnectivity to given transmission lines. Specifically, the nomogram will be defined in terms of gen-tie flows (with unity shift factors) after defining these gen-ties as nomogram flowgates. In this way, its shadow price will be included in the marginal cost of congestion (MCC). Each affected generator would be defined within the nomogram so that a SoCalGas and SDG&E system-wide gas balancing constraint could be reflected in the locational marginal prices (LMPs).

the percentage of forecasted demand for the gas operating zones each hour represents within the day. To further enhance the flexibility of this constraint, the ISO proposes to allow it to recapture portions of the allocated range unused for earlier intervals. For example, if balancing range allocated to the first 4 hours of the day was unused, the gas burn associated with that allocation would be recaptured and used to increase the allowable range for later periods consistent with expected load shape.

Equation 2: Gas Balancing Constraint

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

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

$$LHS_t = \beta_t\, R_l$$

$$RHS_t = \gamma_t\, R_h$$

$$\sum_1^N \beta_t = \sum_1^N \gamma_t = 1$$

S	Set of generators in affected area
G	Real-time market dispatch
$\bar{G}$	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)
LHS_t	Left hand side limit enforcing lower bound constraint
RHS_t	Right hand side limit enforcing upper bound constraint
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 lower bound limit over the intervals of a trading day
γ_t	Allowance distribution coefficients associated with upper bound limit over the intervals of a trading day

By introducing this constraint into the market, the ISO would be taking on the responsibility of managing the affected area's gas burn within a balancing band which can be supported by the gas system given the limited operability of the Aliso Canyon facility. The ISO plans to pursue whether SoCalGas will waive noncompliance charges to individual generators for following RTM instructions when the constraint is enforced.

The ISO views introducing this daily gas balancing constraint as assuming the responsibility for managing imbalances within a given balancing range. The management will be done across the entire SoCalGas and SDG&E operating zones and the costs of balancing gas burn changes within this constraint would be reflected in the locational marginal prices (LMPs) in the event the constraint was violated. Within the constraint, the ISO markets will more efficiently dispatch generators and it is better for load if the dispatch can be provided to the more economic generators which might cause them to violate their tolerance band even while the ISO constrains the affected area's imbalance to within the balancing range needed for reliability.

The ISO believes noncompliance charges when dispatched under this constraint provide no additional benefit since the market is constraining the affected area regardless of generator behavior. Noncompliance charges would also result in a less efficient dispatch of available gas supply. For example, a generator that would incur a noncompliance charge due to a real-time dispatch would be seen as less cost effective to the ISO real-time optimization than a less efficient generator not subject to a noncompliance charge. Had the gas system relied only on the proposed constraint, the ISO's optimization would have dispatched the more efficient generation and reduced the output of the less efficient generation. Further, the constraint will only dispatch generation outside of the balancing range if needed for local reliability through exceptional dispatches coordinated with the gas company. Consequently, there is no need to restrict generators to tolerance band as its redundant with the introduction of this constraint and any additional generation from affected area would be coordinated with the gas company.

7. Proposal for increased efficiency of real-time re-dispatch through use of real-time gas price information

With the implementation of a gas balancing constraint within the Southern California area, the balancing needs will largely need to be provided by generators outside of the affected area. In the real-time, the ISO re-optimizes its day-ahead market solution to continue to solve for the least cost, security constrained dispatch to serve load. Practically, the ISO markets will need to re-dispatch its system to respond to changes in load between day-ahead and real-time within this area as well as providing ramping needs for changes in renewable generation output.

Given the expected strictness of the proposed gas balancing constraint, it is paramount that generators across the ISO real-time footprint have the ability to submit commitment cost and incremental energy offers reflective of their marginal cost. Market prices that reflect the constrained conditions in Southern California will only be possible dependent on the accuracy of the bid prices submitted into the ISO market. This is important for generators to be able to manage their gas usage through their ISO market bids. For example, a short-start unit that did not receive a day-ahead schedule may not line up gas and should be able to reflect this unavailability through its bids.

The identified market design gap where real-time commitment cost bids do not fully reflect real-time gas price information impacts efficiency of commitments for medium, short or fast start units which do not receive binding commitments until real-time.

Since the commitment cost bid cap set at 125% of ISO's proxy cost calculation for start-up, transition or minimum load costs under the changed gas market conditions is expected to no longer capture real-time price volatility for majority of events. Further, all generators who have their incremental energy offers mitigated will have their ability to submit cost based offers into the market even more severely constrained since default energy bids only contain a 10% input for incidental costs other than the fuel proxy costs.

The ISO proposes to increase the accuracy of its cost estimates for commitment costs and incremental energy used in the real-time market to estimates based on a valuation of real-time gas prices. Two potential options for estimating commitment and incremental energy costs based on a valuation of real-time gas prices include:

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

The ISO will need to evaluate the implementation feasibility of the options to increase the accuracy of its commitment cost and default energy bid cost estimates. The ISO's objective is to select a design option that can be implemented by this summer. As an interim measure, the ISO is also considering simply increasing the real-time bid commitment cost bid cap and the adder[19] on default energy bids to values that reflect intraday gas price variations relative to the gas index price used to calculate these values. The commitment cost bid cap is currently 125 percent of calculated costs under the proxy cost option and the default energy bid adder is currently 10 percent. An open question is the change to these thresholds that would be appropriate to reflect the Aliso Canyon conditions.

7.1. Gas price quote submitted by generators

This option proposes introducing two new fields to the real-time market bid that would allow market participants to submit (1) a gas commodity price and (2) a gas transportation rate which together reflects marginal costs of procuring and shipping gas in real-time to meet an ISO dispatch.

This gas commodity price and gas transportation rate would be accepted from each generator and used to calculate the maximum allowable start-up cost, maximum allowable transition cost, maximum allowable minimum load cost, and the default energy bid. This sets the range up to 125% of the proxy cost estimates that generator can submit commitment cost offers as well as

[19] ISO notes that the 'adder' on default energy bids refers to the 10% multiplier used to estimate incidental costs in excess of fuel proxy costs.

sets the value at which mitigated energy offers would be reflected in the market. As a result, the bid cost recovery for each generator will be based on its bid-in gas commodity price and gas transportation rate ensuring sufficient cost recovery since the generator would be able to bid its expectation of costs.

This potential option would ensure that cost offers are reflected in the market so that the real-time market re-dispatch efficiently reflects the additional costs or savings to load from re-dispatch in real-time. This option mitigates the risk that the ISO's cost estimates are too restrictive for real-time bids since the estimates are currently based on next day indices which cannot capture real-time price differences when fundamentals dictate a change between day-ahead and real-time. While the 25% price cap on commitment costs currently provides some coverage for generators for their commitment costs, the 25% threshold cannot always cover the price volatility and while previously anticipated to be rarely exceeded the ISO anticipates an increase in instances where the 25% cannot reflect actual real-time costs given the severe loss of storage capability on the system.

The concern with implementing such an option is whether or not this opens the ISO market to a vulnerability whereby artificial gas price quotes are submitted and result in influencing the locational marginal prices across the system. The ISO would routinely monitor gas price quotes across Scheduling Coordinator and its known affiliates' portfolio of generators to flag behavioral patterns. This monitoring would result in referring Scheduling Coordinators gas price quote submission for further review through either (1) an audit process or (2) a referral to FERC's Office of Enforcement.

When initiating an audit process, the audit would require Scheduling Coordinators to provide support for their gas commodity price and gas transportation rate. The ISO would clarify what time period submitted information would be eligible for an audit so Scheduling Coordinators would know how long supporting documentation would need to be retained to respond to an audit. If information was found inaccurate, the ISO would resettle the Scheduling Coordinator's energy settlement and clawback of certain amount. For example, the ISO could clawback either 200% of bid cost recovery or 200% of market revenues.

The ISO would propose to request additional authority, if necessary, to initiate periodic and regular audits of Scheduling Coordinators based on their gas price quote submissions as well as commit to monitoring gas price quote submission behavior for anomalous behavioral patterns. These proposed safe guards are possible by creating this framework where the Scheduling Coordinator submits the price quote directly to the ISO providing the necessary visibility as well as transforming the behavior in question to that of whether false or misleading information was submitted to the ISO. Under this framework the ISO would have the authority to refer questionable behavior to FERC if it suspects the market participant intentionally submitted false or misleading information.

7.2. Volume weighted average price of exchange trades

The second option proposes the ISO upgrade its functionality to calculate a volume weighted average price (VWAP) using trades observed on ICE either transacted intraday or sameday.

The volume weighted average price would be calculated consistently with ICE's VWAP calculation[20].

This real-time gas price index would be used for hours prior to 5PM PST as this is the last time generators can transact gas and adjust their nominations to reflect this exchange of ownership. After 5PM PST, the price index would have to account for any gas noncompliance charges that could not be avoided due to the completion of the final nomination period. For example, for commitment or dispatches during hour ending 22 would be valued at VWAP expressed in $/MMBtu plus any noncompliance charge[21] expressed in $/MMBtu. While the generator does not actually purchase the gas on the pipeline it uses to meet the dispatch, the gas used does have a cost associated with it and would need to be replaced on the pipeline so the pipeline will continue to operate reliably which is why the ISO would propose to value based on real-time price information.

Depending on the timing needed to calculate default energy bid using real-time gas price index for a given trade hour(s), the ISO would define the time at which the calculation would be performed such as T-135 and would define the range of hours over which exchange trades would be captured for calculation in real-time VWAP for hour. The premise of this proposal is that transactions done in hours preceding a given real-time market interval will be more representative of the cost of generating to serve load than the day-ahead gas price index used for the day-ahead market.

Open questions under this option are: (1) what time should the real-time gas price index be calculated (e.g. T-135), (2) what is an appropriate window for valuing real-time gas price index for given interval (e.g. 6 hours, after midnight), and (3) does this real-time gas price index need to be updated hourly or would an update every 4 hours be sufficient to capture real-time price information in the real-time markets?

The advantage to this option is it does not change the framework over how the ISO markets calculate cost estimates. The cost estimates will still be based off of an average price. However, the current market design gap where the likelihood that generator-specific costs exceed the commitment cost bid caps or the default energy bid also remains.

Given its understanding that in the absence of a printed index for real-time trades there is extremely limited oversight of intraday or sameday transactions and the use of an average[22], the ISO finds that the market vulnerability risk from artificial prices influencing its market outcomes addressed under Section 7.1 is not mitigated under this option. Further auditing and monitoring measures such as those proposed in Section 7.1 would be very difficult as the ISO does not have visibility into market participant level data for these trades or the authority to monitor exchange traded gas transactions. Consequently, the ISO would not be able to change its

[20] Energy Information Administration description of ICE methodology is available at: http://www.eia.gov/electricity/wholesale/.

[21] The noncompliance charge is specific to a given gas tariff. Under SoCalGas' joint motion the proposed noncompliance charge was 150% of the next day gas price index.

[22] Using a median value would control for impact of large volume, high-priced trades whereas these transactions would still contribute to price formation under a VWAP metric.

review process to include an audit process or routine monitoring under this option since ISO has no authority over wholesale gas markets or visibility into who transacted in wholesale gas markets.

8. Proposal to accelerate implementation of select commitment cost bidding improvements enhancements

In March 2016, the ISO Board of Governors approved the Commitment Cost Bidding Improvements proposal[23] requesting a set of market enhancements that improve market participants' ability to more accurately reflect generators' commitment costs, better ensure recovery of actual costs, and better manage their use by the market. Of these approved enhancements, the ISO will ask FERC for expedited treatment of the following two board approved enhancement:

- Market participants will have the ability to re-bid commitment costs in the real-time market when a resource has not been committed in the day-ahead market.
- Market participants will have the opportunity to file with the Federal Energy Regulatory Commission to recover commitment costs that exceed the commitment cost bid cap and result in a net revenue shortfall over the day considering all market revenue.

The first enhancement was designed to address the ability of the real-time market to more efficiently commit generators through improving their ability to submit offers reflective of cost. As mentioned in Section 7, the ability for medium, short and fast start units to submit commitment cost offers reflective of costs is important to enable the real-time market processes to determine the efficient array of commitments needed to efficiently serve load so that the LMP sends accurate price signals to both generation and load. The ISO will implement real-time market commitment cost re-bidding, pending FERC approval, as soon as feasible.

The second enhancement was designed to address the infrequent and unlikely occurrence when the ISO's commitment cost bid cap does not allow generators to reflect incurred commitment costs under its cap based on an estimate of proxy fuel costs using a day-ahead gas price index.

Given the limited operability of Aliso Canyon changing the gas market structure, the ISO identifies a need to expand the opportunity to file for cost recovery ensuring both commitment costs and mitigated energy costs are eligible for review under FERC's just and reasonable standard. The ISO proposes to include the opportunity to file to recover incurred energy costs when mitigated and costs exceed the default energy bid and result in a net revenue shortfall over the day considering all market revenue.

The ISO's position that the use of cost recovery filings would be an exceptional occurrence was sound under the gas market conditions, with ample storage capability, at the time of policy development. To ensure this enhancement remains an avenue for cost recovery review for

---

[23] The board memo is available at: http://www.caiso.com/Documents/DecisionCommitmentCostBiddingImprovementsProposal-Memo-Mar2016.pdf.

exceptional occurrences, the ISO notes that the proposed improvements in Section 7 for ISO's estimates to be valued using real-time gas price information would be necessary so the anticipated price volatility in excess of the commitment cost cap and the default energy bid can be captured in the market and this cost recovery opportunity remains for extreme events the ISO cannot fully capture in its market.

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

As discussed in Section 3.3, there are two gas operating days overlapping the electric operating day where the second day or gas day 2 begins at 7AM PST. Currently, the ISO relies on its manual price spike procedure to allow it to reopen its DAM for generators to resubmit commitment cost offers under a bid cap using the GD2 next day index if the GD2 next day index is at least 25% higher than GD1 next day index. In this event, the ISO uses Intercontinental Exchange's published next day index for GD2.

The ISO recently learned that ICE has changed its publication time to 11:30 PST. This change in timing makes it infeasible to continue supporting the manual price spike procedure as holding back the DAM window that late would be moving the timeline back to a time that would adversely impact gas fired generators ability to prudently procure and nominate gas to meet ISO dispatch.

However, the cost of losing the benefit from using this price information as basis for ISO cost estimates in the day-ahead market is extremely high from an efficient dispatch as well as a cost recovery perspective.

The ISO proposes to implement a routine use of GD2 timely trading's price information as the basis for its cost estimates in the day-ahead. Similarly to Section 7, the ISO proposes two potential options for routinely including the timely trading information in its estimates:

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

For Option 1, the only change to that described in Section 7.1 needed to apply to day-ahead bids is that the new values would be included day-ahead bids as well as real-time bids.

For Option 2, the ISO would calculate the VWAP over the trade window consistent with ICE's methodology and in sufficient time to allow this day-ahead gas price index to be used to determine proxy costs and default energy bids. The ISO is evaluating whether it currently has access to live feed of exchange trades to produce this calculation and if it does not will initiate conversation with vendors as soon as possible to evaluate implementation timeline and costs.

10. Next Steps

The ISO will present the straw proposal on Tuesday, April 19, 2016. Stakeholder comments will be due April 21, 2016. In comments, the ISO asks stakeholders to provide input on the ISO's straw proposal.

Appendix A: Gas Electric Coordination Process

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

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

1. After receiving a curtailment notification, the ISO will perform assessment of curtailments impact on electric reliability and determine preferred allocation of curtailment across affected generators in a manner that supports reliability in both gas and electric systems.
2. At the time ISO provides pro rata curtailment amounts for each generator under its control to SoCalGas it will also provide a second set of curtailment amounts reflecting the preferred allocation of curtailment amounts across affected generators and request the gas company issue its curtailments based on these amounts instead of pro rata given electric reliability needs.
3. Explore how both SoCalGas and the ISO could formalize its joint procedure for various types of events so that affected generators would have one resource to consult to understand the procedure and the roles of each entity under this procedure.
4. Host a joint training prior to summer 2016 where both SoCalGas and ISO staff will ensure all generators have been fully briefed on the appropriate procedures for each event and can field questions at that time.

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

Appendix B: Issue Paper Discussion Items

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

(1) How, if at all, could the ISO provide additional information to generators prior to the intraday 3 for GD1 and the timely for GD2 gas nomination deadlines?
(2) What market changes or other tools, if any, could improve resources' ability to procure and nominate gas for GD1 and GD2 earlier to alleviate reliability and price risk?
(3) How do resources especially medium, short, or fast start units procure gas to meet ISO instructions in light of the risk of deviating from daily gas balancing requirements? Is there a difference in procurement practices depending on whether a binding start up instruction is issued versus if only advisory start up instructions have been issued?
(4) What market changes or tools, if any, would support gas system reliability while efficiently dispatching resources to support electric system reliability in the real-time?
(5) What market changes, if any, could improve ISO's ability to better model and compensate resources for the higher costs associated with committing or dispatching these resources identified in Section 4.3?
(6) How, if at all, the ISO should address or coordinate gas curtailments that effect ISO generation?