Aliso Canyon Gas-Electric Coordination

Draft Final Proposal

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1. Executive Summary

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Besides addressing the risks raised by the task force, the ISO identified the need to propose changes to its day-ahead gas price index used to determine its cost estimates. There has been a change to the timing when Intercontinental Exchange (ICE) is releasing the next day index used for the ISO’s manual price spike procedure, which would require re-opening the day-ahead market window around 11:30AM PST and likely publishing roughly by 3:45PM PST to continue the procedure. Given the increased need to include accurate gas price information in both day-ahead and real-time under these constrained conditions, the ISO is addressing long term enhancements to the price used in its cost estimates in Section 8.

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	4/26/2016
Stakeholder Call	4/27/2016
Stakeholder Written Comments Due	4/28/2016
Board of Governors Meeting	5/4/2016

3. Changes

Changes from the straw proposal are as follows:

- Gas Balancing Constraint: The ISO has removed its proposal to manage changes in generators' gas usage relative to day-ahead energy schedules (and presumably relative to gas nominations in the day-ahead timeframe) through a gas balancing constraint in the ISO real-time market. Since filing the joint motion for daily balancing, SoCalGas and SDG&E have noticed a settlement conference on April 28. Regardless of whether SoCalGas implements its daily balancing proposal, uses its existing OFO authority or, implements an alternative balancing mechanism, SoCalGas and SDG&E''s customers will need to balance their nominated flows within a tolerance band of their actual gas burn or face potential penalties. Consequently, this would have made the gas balancing constraint redundant with those mechanisms and potentially would have resulted in dispatches to individual generators that conflicted with those mechanisms. The ISO is changing its proposal to pursue improvements to its bidding rules discussed in Section 7.2 to better support the ability of generators to reflect the gas company's balancing mechanisms in ISO market bids.

- Generator Bidding: The ISO examined the following two options to better allow generators to reflect gas availability through bids submitted to the ISO market:
  :
  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

  There are policy issues related to these proposals that would benefit from further vetting and the ISO has determined it cannot implement these options in time to benefit the Aliso Canyon situation this summer. Instead, the ISO is proposing an alternative that will increase bidding flexibility for both commitment costs and incremental energy costs of generators affected by the Southern California Gas Company and SDG&E systems' constraints. The ISO proposes to increase the gas cost estimates used by the ISO market to establish commitment cost bid caps and default energy bids (DEBs) in the real-time market for generators affected by the Southern California Gas Company and SDG&E systems' constraints. This is described in Section 7.2.

4. Background

4.1. Aliso Canyon Impact

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

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

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

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

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

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

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

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

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

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

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

Since filing the joint motion for daily balancing, SoCalGas and SDG&E have noticed a settlement conference on April 28, 2016. SoCalGas and SDG&E''s customers will need to

[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.

balance their nominated flows within a tolerance band of their actual gas burn or face potential penalties regardless of whether SoCalGas:

(1) implements its daily balancing proposal,

(2) uses its existing OFO authority, or,

(3) implements an alternative balancing mechanism.

4.2. FERC Order 809

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

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

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**

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

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

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

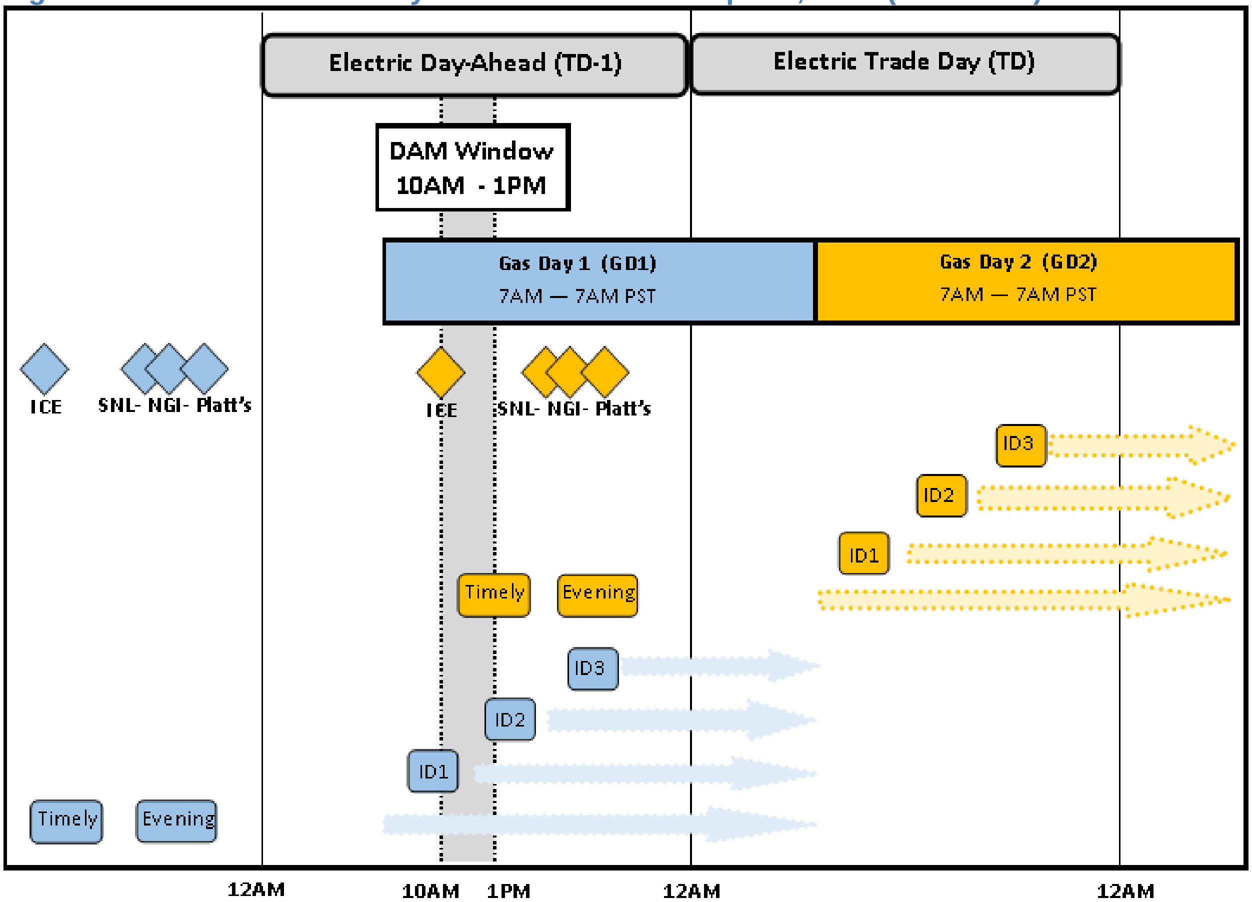
In light of reduced access to storage due to limited operations of Aliso Canyon, the most effective day-ahead market timeline design might require reevaluation.

4.3. Alignment of natural gas and electric markets

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

[7] See Proposal – FERC Order No. 809 available at: http://www.caiso.com/Documents/Proposal_FERCOrderNo809.pdf.
[8] See Straw Proposal at 15 available at: http://www.caiso.com/Documents/StrawProposal_BiddingRulesEnhancements.pdf
[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 may not be fully reflected in the ISO's variable cost option default energy bid or its commitment cost calculations resulting in commitment cost bid caps that may not be fully reflective of expected market conditions. The gas price indices that reflect expected market

[10] ISO tariff section 30.4 and 39.7.1.1.1.3.

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

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

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

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

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

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

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

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

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

5. Identified Issues

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

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

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

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

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

[13] Discussion assumes FERC Order 809 is effective so timing will be reflective of April 1, 2016.

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

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

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

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

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

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

ISO understands from discussion with stakeholders and review of comments that this risk is most severe for Scheduling Coordinators managing generators largely dispatched and relied on

[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).

as peaker units to respond to ISO's flexibility needs or mitigated resources that cannot manage gas limitations effectively through incremental energy offers.

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

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

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

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

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

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

The ISO understands from discussions with stakeholders and review of comments there is broad agreement there exists a market design gap in which the ISO's commitment cost bid cap and mitigated energy offers may not allow generators to fully reflect costs. The concern

[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.

surrounding this gap is exacerbated due to Aliso Canyon as this gap affects all generators across the footprint including Energy Imbalance Market participating generators. To ensure the ISO's dispatch in real-time is efficient and reliable, these cost estimates will be evaluated consistent with the change to the gas market structure. The ISO believes it is especially important for Southern California resources to be able to reflect real-time gas limitations in bids this summer so they are only dispatched for local needs and not system needs.

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

6.1. 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 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.

The ISO's current policy places the responsibility on the generator to ensure it submits an outage card to the ISO's outage management system reflecting a limitation it might expect unless timing precludes the outage card from being reflected in the market. While an outage may be public, it may be unclear to generators exactly what their plant level limitation will be until the curtailment or their inability to procure gas occurs. While it would improve electric market outcomes if generators submitted outage cards reflecting their share of the gas limitation as result of outage, generators might not be able to translate the outage information to a plant level limitation. Further once a notification is issued for curtailments, the ISO is evaluating whether operations could be improved through using the gas 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.

The 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 for the affected area in each market run based on an hourly limit provided to it by SoCalGas. For example, SoCalGas might notify the ISO of curtailment notification such that they would specify the gas operating zone(s) affected, the hours the curtailment will be in place (e.g. HE15 – HE18), and the maximum allowable burn for the hours which could vary across hours (e.g. 1 BCF for HE15, 1 BCF for HE16, 1 .5 BCF for HE17, and 1.5 BCF for HE18).

This constraint will be implemented using generation nomograms which, when binding, will result in dispatching generators not included in constraint so their LMP will be higher than LMP for generators subject to the constraint. In addition the load DLAP price will be higher than it would be without constraint. If the market cannot come to a feasible solution without violating the constraint, then the LMP for generators subject to the constraint will reflect the constraint penalty price. The ISO will establish this penalty price to function appropriately relative to the other penalty prices used by the market. The ISO is finalizing the implementation details to ensure the constraint will affect the resource specific price used to dispatch and settle affected generators but, to the greatest extent possible, not affect the LMP used for other purposes including congestion revenue right (CRR) settlement.

The ISO proposes to request authority to enforce the gas availability constraint[16] in its markets when SoCalGas notifies the ISO of a concern with its fuel supply or access to fuel based on its system conditions. This constraint would not be enforced daily but instead enforced in the market when the gas company notifies the ISO of the limitation and its details: (1) affected area, (2) affected hours, and (3) maximum allowable gas burn for each hour. For example, if the gas company notifies the ISO it will have an outage on its pipelines reducing the availability of fuel in a defined zone to an expected maximum amount prior to the day-ahead market close, the constraint would be enforced in both day-ahead and real-time. If an unplanned outage occurs after day-ahead or curtailment is issued during real-time, the constraint could be enforced in real-time market run.

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

Equation 1 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.

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

6.2. Reserve internal transfer capability

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

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

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

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

The 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. Likewise, the ISO will monitor the impacts virtual bidding has on its use of the mechanism. The ISOwill clarify its discretion in the tariff to suspend virtual bidding in the event adverse market or reliability impacts are identified.

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

7.1. Increase access to information prior to day-ahead

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

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

The second method discussed was providing advisory information to market participants on DAM results prior to the close of the timely nomination cycle. Currently the ISO runs a two day-ahead (2DA) 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 evaluated whether changes to this market run must be made to ensure there are sufficient bids used to clear the market in a manner that produces meaningful information for market participants. An open question was whether market participants support ISO using the most recent bids used for 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.

The ISO proposes to run the 2DA market consistent with current practice. ISO stresses to stakeholders that bids for the operating day must be submitted prior to 10AM 2 days before the operating day to include those bids in the 2DA market run. These bids can be resubmitted and updated up until 10AM day-ahead.

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

When generators are under a balancing requirement across a day, the penalty for violating the tolerance band allowed is intended to make the generators view the costs of gas differently. The ISO believes the change in economics introduced by the risk of noncompliance with a gas balancing requirement is intended to incentive certain behavior should be reflected in generators commitment cost and energy offers. In this way, the incentives designed by the gas markets can be reflected in the electric markets to change the incremental gas burn of generators in direction supporting gas reliability.

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

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

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

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

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

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

1. Gas price submitted by generators reflecting marginal cost of gas

2. Rolling volume weighted average price of exchange traded intraday and same day transactions for each commodity trading hub defined within a fuel region

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

While generators have the ability to increase or reduce incremental energy offers in the real-time as long as they are not mitigated, currently they do not have the ability to update commitment costs in real-time to reflect changes in expectation of marginal procurement costs and gas availability. The ISO proposes to:

1. Expand its board approved policy to allow resources to rebid their commitment costs in the real-time market to all resources regardless of whether it received a day-ahead schedule or received binding start-up instruction. The board approved policy did not allow generators to rebid their commitment costs if they had a day-ahead schedule or after the real-time market committed them. As a temporary measure, the ISO would not implement this restriction in recognition that the real-time market may commit generators outside of the hours committed in the day-ahead market or the hours subject to intra-temporal constraints. It is not feasible to implement limitations on rebidding that can recognize these situations by this summer

2. Increase the commitment cost bid cap used by the real-time market to allow commitment cost offers to reflect limitations on gas imbalances imposed on generators subject to the constraints due to the Aliso Canyon situation and better reflect intraday gas price variations relative to the gas price index. The commitment cost bid cap is currently 125 percent of calculated costs under the proxy cost option. The ISO proposes to increase the commitment cost bid cap by adjusting the gas price index used as an input into the commitment cost bid cap based on analysis that determines the maximum of two values: (1) the increased bid amount necessary to only dispatch generators affected by the Aliso Canyon situation for local needs and not system needs, and (2) any real-time price premium to account for systematic differences between day-ahead and same day gas prices that materialize. The ISO would initially set this value at the increased bid amount necessary to only dispatch generators affected by the Aliso Canyon situation for local needs and not dispatch them for system needs, which is anticipated to be about a 75% premium. The ISO will propose that the range at which it can adjust the gas price index be capped at the OFO price.

3. Increase the adder[17] on default energy bids to values that better reflect intraday gas price variations relative to the gas index price used to calculate these values and to reflect limitations on gas imbalances imposed on generators subject to the constraints due to the Aliso Canyon situation. The default energy bid adder is currently 10 percent.

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[17] 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.

The ISO proposes to adjust the gas price index used to calculate default energy bids in the same manner described in 2. above.

4. Expand its board approved policy providing the opportunity to seek after-the-fact commitment cost recovery to include a cost recovery filing opportunity for incurred marginal procurement costs associated with providing incremental energy, in addition to the previous board approved policy addressing commitment costs.

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

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

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

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

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

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

9. Next Steps

Stakeholder comments will be due April 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 on May 4, 2016.

Appendix A: Gas Electric Coordination Process

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

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

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

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

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

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

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

Appendix B: Issue Paper Discussion Items

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

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

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

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

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

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

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