Aliso Canyon Gas-Electric Coordination

Issue Paper

March 17, 2016

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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. The ISO is initiating a stakeholder process to explore market mechanisms or other tools the ISO may consider, including the possible mitigation measures explored by the task force.

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. As a result of this motion, the ISO is initiating an expedited stakeholder process to evaluate what market mechanisms or other tools the ISO could provide to its resources to manage the risks associated with the proposed daily balancing requirement.

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 daily gas balancing requirements proposed by SoCalGas and SDG&E affect resources' ability to manage their generation assets,
(3) Identify and develop market mechanisms or tools necessary to support reliability and ensure markets are not adversely impacted.

The daily balancing requirement 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 daily gas balancing requirements support gas system reliability by signaling to gas customers when their daily gas deviations are outside the tolerance band and imposing a charge associated with such deviations. The penalties associated with the daily balancing, which 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 daily gas balancing is intended to mitigate risk to reliability on the gas system. Any measures designed to reduce reliability risk on the gas system will also reduce the risk of events that adversely impact electric reliability system. The ISO manages the dispatch of a number of generators that are 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 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.

The ISO believes it is necessary to evaluate whether current operations, if maintained, may lead to at least four adverse market impacts:

(1) Under current ISO market timing, the ISO day-ahead market timing does not inform gas procurement or pipeline nominations. The first cycle for day-ahead gas nomination (the timely nomination cycle) concludes at 9:30AM TD-1 (11:00AM TD-1 after April 1) prior to day-ahead market close increasing the risk of a mismatch between nominated gas flow and actual gas demand.
(2) ISO instructions could cause generators to incur balancing charges if they are unable to procure gas to follow ISO instruction while managing its deviations within daily balancing tolerance bands.
(3) Less efficient commitments and dispatches when intra-day prices reflect strained gas conditions so procurement costs for real-time purchases may differ significantly from ISO estimates.
(4) Resources may not sufficiently recover costs associated with meeting ISO instruction.

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.

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

Milestone	Date
Straw Proposal Posted	4/01/2016
Stakeholder Meeting	4/06/2016
Stakeholder Written Comments Due	4/13/2016
Draft Final Proposal Posted	4/15/2016
Stakeholder Call	4/22/2016
Stakeholder Written Comments Due	4/29/2016

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…"

Studies are underway involving the ISO, CPUC, CEC, SoCalGas Company, and the Los Angeles Department of Water and Power Balancing Authority to conduct assessments evaluating 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 work being done with the ISO, CEC and others to plan for reliable electric operations in light of Aliso Canyon limited operability. This study work will lead to an action plan addressing identified summer 2016 and/or winter 2016-2017 gas or electric reliability risks.

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 the completion of inspections by the Division of Oil, Gas, and Geothermal Resources of California's

Department of Conservation.[2] SoCalGas has limited ability to withdraw gas from the storage facility. Under these strained conditions, pipelines will generally 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.[3] 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.

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.[4] 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**

[2] *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

[3] Application 15-06-020.

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

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.[5] 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.[6] 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.[7] 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.

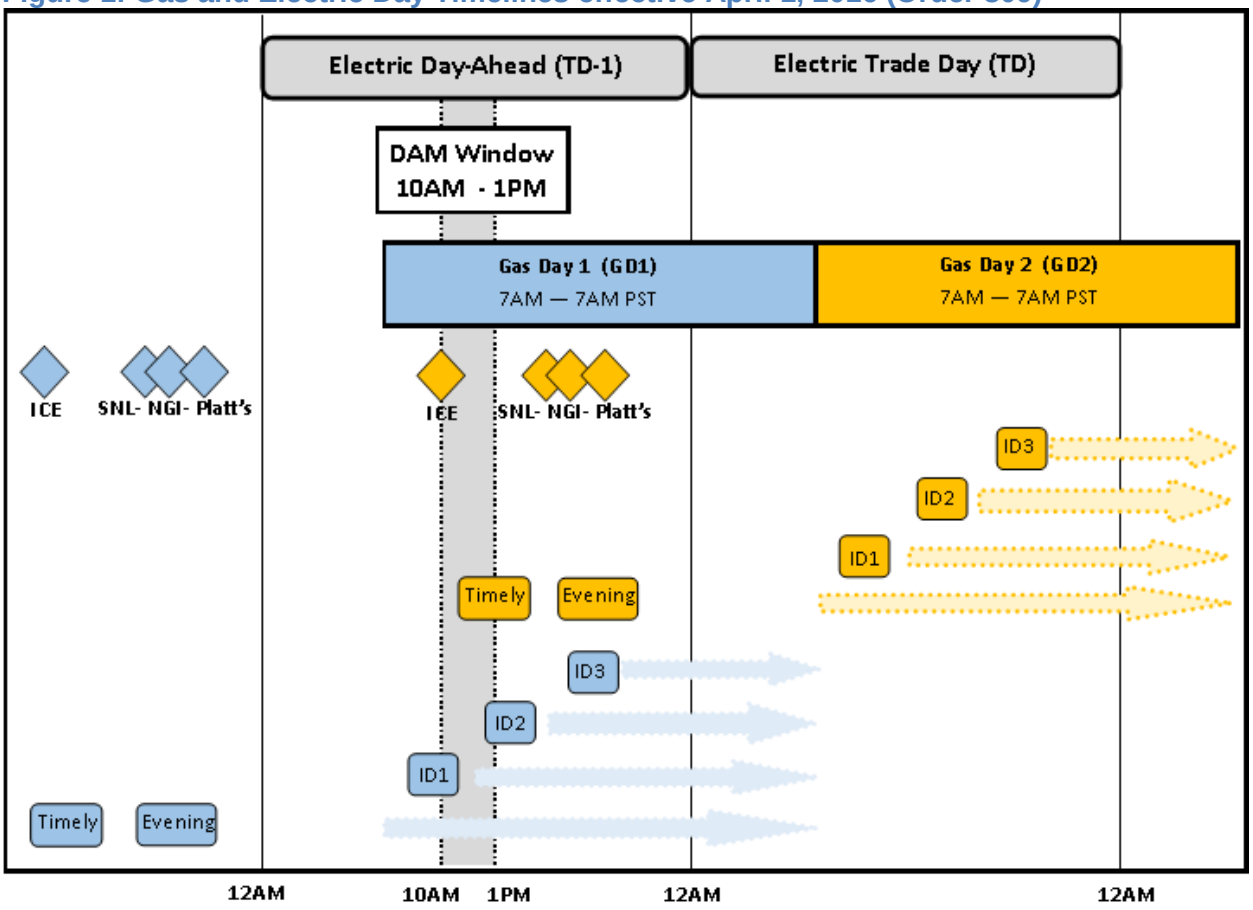
3.3. Alignment of natural gas and electric markets

The ISO acknowledges that the hours of the gas day and the electric day are not aligned. This impose 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

[5] See Proposal – FERC Order No. 809 available at: http://www.caiso.com/Documents/Proposal_FERCOrderNo809.pdf.
[6] See Straw Proposal at 15 available at: http://www.caiso.com/Documents/StrawProposal_BiddingRulesEnhancements.pdf
[7] See EL14-22 Filing, July 23, 2015 at 15 available at: http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13939292

Gas Day 2 (GD2) flows are represented by the colors gray, blue and orange respectively. The discussion in this section uses GD1 and GD2 as defined in Figure 1.

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



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[8], 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

[8] ISO tariff section 30.4 and 39.7.1.1.1.3.

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

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

Table 2: Natural gas day-ahead indices publication times[9]

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 generally around 9:30AM PST (timely deadline)[10]. 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 as well as insufficient cost recovery.

Because the market is not able to 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 be faced with 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

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

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

4. Identified Issues

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 in advance of 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.[11]

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.

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[12], 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 result in 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.

[11] Discussion assumes FERC Order 809 is effective so timing will be reflective of April 1, 2016.
[12] 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).

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 there are instances where 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, 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.

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 that 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[13]. The ISO is

[13] 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.

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?

5. 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?

6. Next Steps

The ISO will host a stakeholder call to discuss this issue on Wednesday, March 23, 2016. During this call, the ISO will engage stakeholders in a discussion of potential options to address the reliability, market efficiency and cost recovery concerns exacerbated due to the abrupt reduction of storage availability at the Aliso Canyon storage facility. Stakeholder comments will be due March 30, 2016. In comments, the ISO asks stakeholders to provide input on the questions raised by the ISO and seeks additional comments regarding issues not identified.