Aliso Canyon Gas-Electric Coordination

Revised Draft Final Proposal

May 04, 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. On March 1, 2016 SoCalGas and San Diego Gas & Electric (SDG&E) submitted a joint motion (motion) at CPUC proposing daily balancing requirements[1] in response to the abrupt change in its gas storage capacity at its Aliso Canyon storage facility. On April 2016, the inter-agency task force published its Technical Assessment Report which identified four major risks to the SoCalGas operating region beginning summer 2016.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

2. Plan for Stakeholder Engagement

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

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

3. Changes to the Proposal

Changes from the Draft Final Proposal are as follows:

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

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

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

4. Background

4.1. Aliso Canyon Impact

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

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

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

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

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

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

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

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

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

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

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

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[4] *See* California Department of Conservation, Division of Oil, Gas, and Geothermal Resources, Requirements of Comprehensive Safety Review of the Aliso Canyon Natural Gas Storage Facility http://www.conservation.ca.gov/index/Documents/Comprehensive%20Safety%20Review%20Aliso%20Canyon.pdf
[5] Application 15-06-020.

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

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

(1) implements its daily balancing proposal,

(2) uses its existing OFO authority, or,

(3) implements an alternative balancing mechanism.

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

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

4.2. FERC Order 809

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

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

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

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

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

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

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

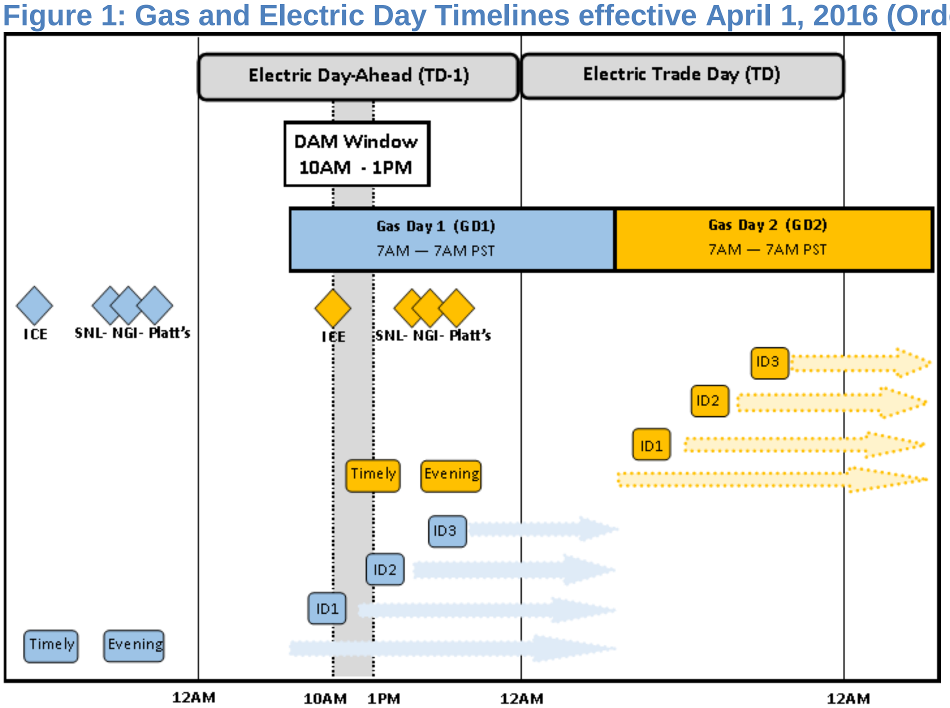
publication of market results forward.[9] FERC accepted the ISO's proposal to not change the day-ahead market window.

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

4.3. Alignment of natural gas and electric markets

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

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



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

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

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

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

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

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

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

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

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

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

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

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

5. Identified Issues

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

6. Proposals for operational tools

6.1. Introduce gas constraints

6.1.1. Problem statement

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

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

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

<u>Discussion on (1) capacity reduction limitations</u>

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

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

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

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

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

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

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

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

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

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

6.1.2. Constraint details

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

Defining affected generators under gas constraint(s)

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

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

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

General constraint formulation

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

Equation 1: Gas Constraint(s)

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

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

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

Total gas burn limitation due to reduction in capacity or deliverability

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

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

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

Equation 2: Gas Capacity Reduction Limitation

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

$$RHS_t = \gamma_t\, R_h$$

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

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

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

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

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

Incremental gas burn limitation

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

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

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

Equation 3: Gas System Imbalance Limitation

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

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

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

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

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

The ISO would enforce this constraint for:

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

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

6.1.3. Pricing impacts

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

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

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

Table 3: Relative priority of relaxation of gas constraint

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

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

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

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

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

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

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

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

6.2. Reserve internal transfer capability

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

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

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

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

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

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

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

6.3. Reduce ancillary service procurement

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

6.4. Deem internal paths uncompetitive

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

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

6.5. Clarify authority to suspend virtual bidding

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

7. Proposals to improve market mechanisms

7.1. Increase access to information prior to day-ahead

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

- When a resource has not been committed in the day-ahead market for specific hours, the CAISO will propose that a resource may re-bid its commitment costs for those hours.

- Resources would not be able to re-bid commitment costs in the real-time market once operating and subject to a minimum run time constraint.

- ISO will implement in two phases where phase 1 will include tariff rule detailing the eligibility for rebidding commitment costs in real-time and phase 2 will fully automate validation rules that ensure within the market systems the commitment costs will not be accepted unless the criteria is met.

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

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

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

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

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

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

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

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

8. Next Steps

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

Appendix A: Gas Electric Coordination Process

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

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

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

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

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

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

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

Appendix B: Issue Paper Discussion Items

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

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

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

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

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

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

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

Appendix C: Nomogram Constraint

Introduction

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

An individual nomogram variable can be one of the following:

a) A transmission corridor MW flow value.

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

The following are examples of typical nomogram variable combinations:

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

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

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

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

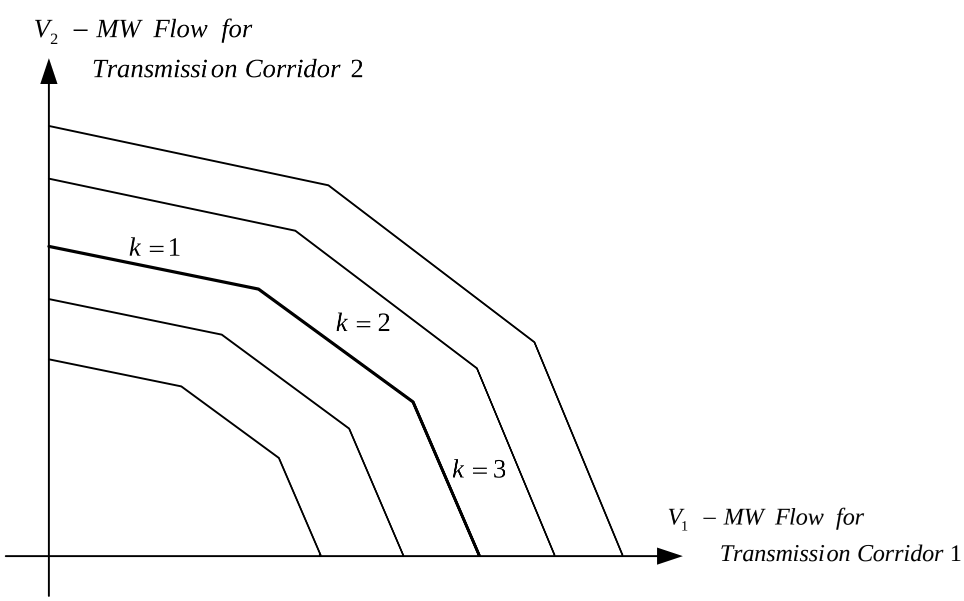


Figure 1. A Typical Nomogram Constraint

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

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

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

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

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

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

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

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

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

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

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

No other types of variables are supported.

Notation

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

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

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

Generation Group Nomogram Variable Equation

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

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

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

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

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

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

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

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

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

Nomogram Segment Equation

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Where as described in the previous section:

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

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

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

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

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

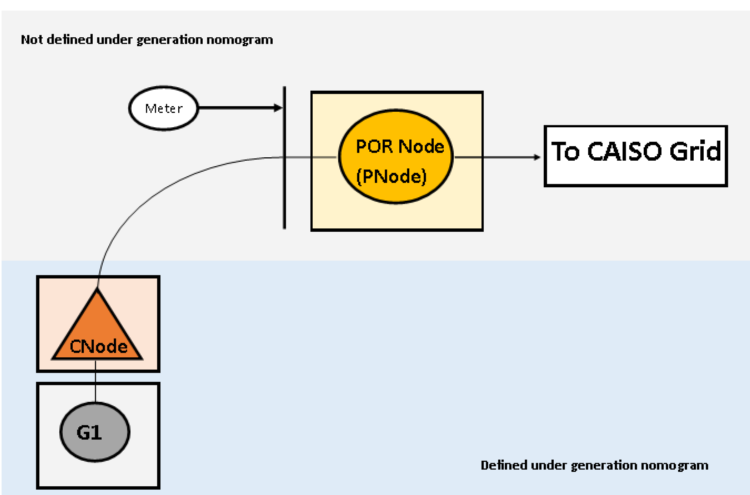
Impact on nodal prices

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

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

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

Figure 2: Simple generating unit with one CNode and Pnode



[20] Available on Page 11 at https://bpmcm.caiso.com/BPM%20Document%20Library/Managing%20Full%20Network%20Model/Managing%20Full%20Network%20Model%20BPM%20Version%208_clean.docx.
[21] The CAISO BPMs have adopted "Connectivity Node" or CNode as an alternative expression of "Node".

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

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

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

  System Resources (import/exports) will not participate in nomograms, but transmission corridors defined for inter-ties can be defined as nomogram variables.
- Values not permitted within a generation group
  - Only a subset of the units in an aggregate generation resource. Either the entire aggregate generation resource should be included within a generation group or none if it should be.

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

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

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

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

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

Nomogram Segment Equation

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Where as described in the previous section:

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

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

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

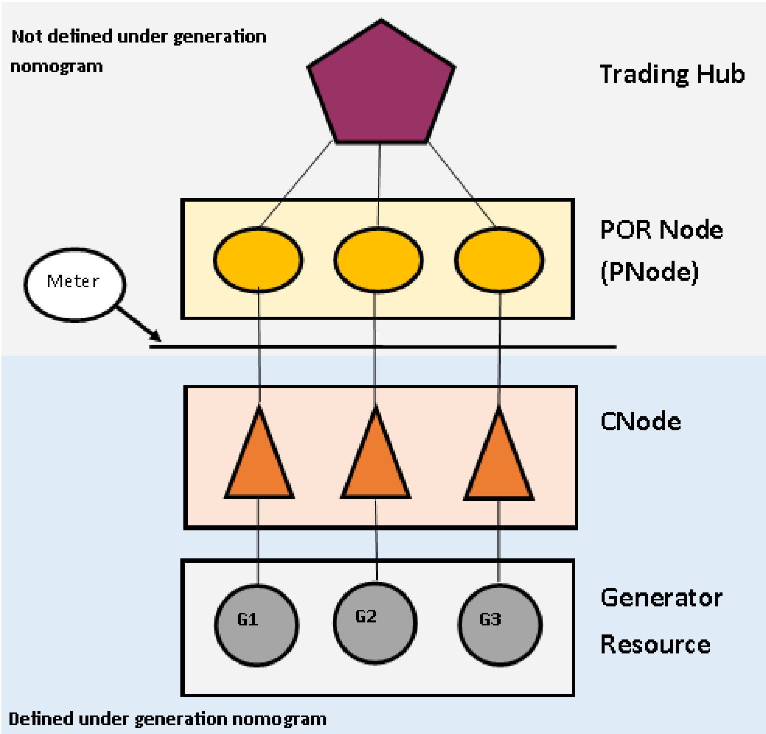
Where the node is the aggregate node (ANode) of the aggregate generating resource and the shift factor is the aggregate shift factor that corresponds to that aggregate node.

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

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

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

Figure 3: Relationship of nodes to aggregate pricing nodes



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

Appendix D: Gas Price Index Details

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

Equation 4: GPI Formulation

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

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

Where:

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

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

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

Equation 5: Proxy Start-Up Costs

Start-up Cost

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

Where:

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

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

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

Equation 6: Proxy Minimum Load Costs

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

Minimum Load Cost

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

Where:

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

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

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

Equation 7: Default Energy Bid Costs

Default Energy Bid Cost

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

Where:

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

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

$\text{Scalar} = 1.1$