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Aliso Canyon Winter Risk Assessment Technical Report

Prepared by the Staff of the California Public Utilities Commission, California Energy Commission, the California Independent System Operator, the Los Angeles Department of Water and Power, and Southern California Gas Company

August 22, 2016

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EXECUTIVE SUMMARY

This technical report assesses the risks to energy reliability in the Greater Los Angeles and Southern California area during the coming winter months without the use of the Aliso Canyon natural gas storage facility. This assessment was developed by the Aliso Canyon Technical Assessment Group, which consists of technical experts from the California Public Utilities Commission (CPUC), California Energy Commission (Energy Commission), the California Independent System Operator (California ISO), the Los Angeles Department of Water and Power (LADWP), and the Southern California Gas Company (SoCalGas).

This technical assessment is based on the 1-in-10-year cold winter day design standard that the CPUC established for the SoCalGas/San Diego Gas & Electric (SDG&E) service territories to meet the gas requirements of core and noncore customers on the coldest day with a 10-year recurrence interval. The assessment finds that this standard cannot be met without withdrawing supply from Aliso Canyon during the coming winter months. For the gas system to maintain system reliability under current conditions, without Aliso Canyon, supportable gas demand is estimated to be 4.7 billion cubic feet per day (Bcfd) which is lower than the 5.2 Bcfd demand forecast established by the 1-in-10 cold day design standard. To the extent that the core and noncore gas demand totals reach or exceed the supportable demand, SoCalGas has the authority to curtail noncore customers to maintain gas system reliability. Several factors contribute to the volume of curtailment including actual daily gas demand, planned and unplanned outages to non-Aliso Canyon storage that reduce supply, and planned and unplanned pipeline outages that reduce delivery capacity. Furthermore, prolonged periods of high gas usage increase the risk of gas curtailments and potential electric service interruption such as during extreme cold weather when core customer natural gas usage is high and supplies external to the SoCalGas/SDG&E service territories are limited, thus reducing the amount of continuous gas available to core and noncore customers.

Because of the effectiveness of the Aliso Canyon Summer Action Plan, as of the time of this report, no gas has been withdrawn from Aliso Canyon to maintain electric reliability. The current supply remains at roughly 15 billion cubic feet (Bcf) of working gas in storage.

The report addresses only the winter of 2016-2017. The hydraulic analyses found that:

- The SoCalGas/SDG&E 2016-2017 1-in-10-year cold day design standard of 5.2 Bcfd **cannot** be supported without Aliso Canyon supplies.
- The maximum sendout that can be supported without Aliso Canyon supply is 4.7 Bcfd, which assumes no other transmission or storage facility outages and 100 percent utilization of receipt point and storage withdrawal capacity.

- Limiting storage withdrawal to tubing flow only[1] operation in conjunction with a line 3000 outage reduces the maximum sendout capability to 4.5 Bcfd.
- Any loss of flowing supply below 100 percent utilization[2] will further reduce sendout capacity on a one-to-one basis.
- The SoCalGas/SDG&E system has sufficient capacity to meet the 1-in-35-year peak day design standard of 3.5 Bcfd for core service without supply from Aliso Canyon and without assuming 100 percent receipt point utilization.
    - However, there is increased risk of localized core outages without the availability of Aliso Canyon supply that results from interstate pipeline supply shortfalls or storage/transmission facility outages.
- Per SoCalGas Rule No. 23 and SDG&E Gas Rule No. 14, should the level of gas curtailment required exceed the electric generation use not necessary to maintain electric grid reliability, other noncore customers are to be curtailed before more electric generation load is shed. These other noncore customers include businesses such as refineries, hospitals, and airports, and these customers may not be able to comply fully or quickly with a curtailment order. If this is the case, additional electric generation gas demand may be curtailed, increasing the risk of electric load shed.
- While the SoCalGas and SDG&E system has sufficient capacity to meet the 1-in-35-year peak day design standard without supply from Aliso Canyon, core customers (residential and small commercial/industrial businesses) may still be susceptible to localized losses of service during periods of widespread cold weather conditions across the United States, noncompliance of curtailment orders from noncore customers, and/or supply disruptions upstream of the SoCalGas/SDG&E system on the interstate pipelines.

The electric analysis found that:

- The LADWP/California ISO joint power-flow study found that electric reliability can be satisfied for a 1-in-100-year winter peak electric load conditions with a minimum gas burn of 96 million cubic feet per (MMcfd) by electric generation in the SoCalGas/SDG&E service territories in response to post N-1[3] contingency conditions and as low as a gas burn of 22 MMcfd (with

[1] Natural gas storage wells consist of two layers of cement bonded to steel casing. The surface casing supports the well while the permanent well production casing runs from the surface down to the natural gas storage reservoir. Steel "tubing" sits inside the well production casing from the surface to the liner, which is the transition into the natural gas storage reservoir. At the bottom of the casing, a "packer" seals the well and helps preserve pressure. Once the well is sealed, the tubing is used to inject or withdraw natural gas.

[2] Percent utilization refers to the percentage of the available receipt point capacity that is being used by market participants on the SoCalGas system.

[3] N-1 is the loss of any generator, transmission line, and transformer, shunt device without a fault or single pole block on a high-voltage direct current (HVDC) transmission line.

somewhat higher risk) under normal pre-contingency conditions and the ability to import generation into the Los Angeles Basin.

- Gas curtailment of electric generation may be necessary when the SoCalGas/SDG&E total core and noncore gas demand exceeds 4.5 Bcfd which assumes 100 percent gas receipt point utilization or 4.2 Bcfd assuming 85 percent gas point utilization.
- The electric system is expected to be able to maintain electric reliability for the winter of 2016-2017 without interruption to electric service so long as the total SoCalGas supportable gas delivery and supply is greater than 4.1 Bcfd under normal pre-contingency conditions and 4.2 Bcfd to support N-1 contingency conditions on the electric system.
    - Under normal pre-contingency conditions, sufficient electric transmission and electric supply from resource outside of the SoCalGas/SDG&E service territories are expected to be available to replace the magnitude of gas curtailments that may occur during the winter of 2016-2017. Depending on the magnitude and timing of gas curtailments, however, access to replacement energy may require emergency assistance from neighboring balancing authorities.
- If supportable SoCalGas gas delivered supply falls below 4.1 Bcfd during peak winter gas demand conditions, it may be necessary to withdraw from Aliso Canyon to avoid electric load interruption.
- Although the electric system can operate with extremely low gas consumption during the winter months, doing so would result in increased dispatch costs.

A separate *Aliso Canyon Gas and Electric Reliability Winter Action Plan* discusses mitigation measures for electric reliability.

INTRODUCTION

This technical report is the work of the Aliso Canyon Technical Assessment Group, which used the report to develop the Winter Action Plan. The Winter Action Plan addresses natural gas and associated electricity reliability impacts due to the SS-25 well leak and subsequent operating status of the Aliso Canyon underground natural gas storage field.

The Technical Assessment Group analyzed reliability for winter 2016-2017. It looked at the SoCalGas/SDG&E service territories to understand the operational and capacity constraints that might exist. Given the uncertainty about operations at the field and recognizing the January 2016 order of the CPUC[4] to hold inventory at 15 Bcf to protect energy reliability, the analysis looked at operations

[4] On January 21, 2016 CPUC Executive Director Timothy Sullivan directed SoCalGas to withdraw natural gas from Aliso Canyon down to an actual working gas inventory of 15 Bcf. Sullivan further directed SoCalGas to hold the gas inventory at this level to meet energy reliability requirements. The directive can be found at: http://ow.ly/kfbm303pLUJ.

assuming no injection and no withdrawal from Aliso Canyon. The analysis was conducted to evaluate how critical Aliso Canyon is to the integrated operations of gas and electric system. It identifies the ability for the gas system to meet the 1-in-10-year cold day reliability planning criteria, the ability for the electric system to meet minimum operating criteria, and the ability of the electric system to replace lost energy due to gas curtailments from outside the SoCalGas/SDG&E service territories.

The report provides background on SoCalGas' system operations, including existing tools to manage its system and the inter-relationship with the SDG&E gas system that SoCalGas supplies and operates. It discusses electric and gas coordination and reliability and provides background on the electric generation and transmission of the LADWP and California ISO balancing authority areas.

The report details the gas operations simulations conducted by SoCalGas, with oversight by the Technical Assessment Group. The group assessed 1-in-10-year cold day design criteria and found the criteria could not be met, leading to gas reduced system demand capacity. These operational findings lead to some of the mitigation measures documented in the Winter Action Plan.

The gas analysis in this report was reviewed and findings documented in a separate report by an independent review team made up of experts from Los Alamos National Laboratory and Walker & Associates.

Having assessed the conditions that could cause natural gas curtailments, the Technical Assessment Group translated those into impacts to electricity generation for the combined LADWP and California ISO balancing authority areas relative to operational constraints and reliability criteria.

BACKGROUND

The technical assessment focuses on the impacts to the gas and electric system without using Aliso Canyon. It is not an update to the Summer Assessment published April 2016, which is posted on the CPUC website.[5]

Winter gas demand is significantly higher than summer demand and driven by cold weather. In the winter, 60 percent of the total gas demand comes from the residential heating load. The reliability challenge can occur across the entire SoCalGas/SDG&E service territories. Gas storage in conjunction with pipeline capacity has been designed to meet the day-to-day needs of higher winter demand. In

[5] The Summer Action Plan is at: http://www.energy.ca.gov/2016_energypolicy/documents/2016-04-08_joint_agency_workshop/Aliso_Canyon_Action_Plan_to_Preserve_Gas_and_Electric_Reliability_for_the_Los_Angeles_Basin.pdf. The associated Technical Assessment is at: http://www.energy.ca.gov/2016_energypolicy/documents/2016-04-08_joint_agency_workshop/Aliso_Canyon_Risk_Assessment_Technical_Report.pdf. The May update to the Action Plan is at: http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-02/TN211671_20160527T164305_Aliso_Canyon_Update.pdf .

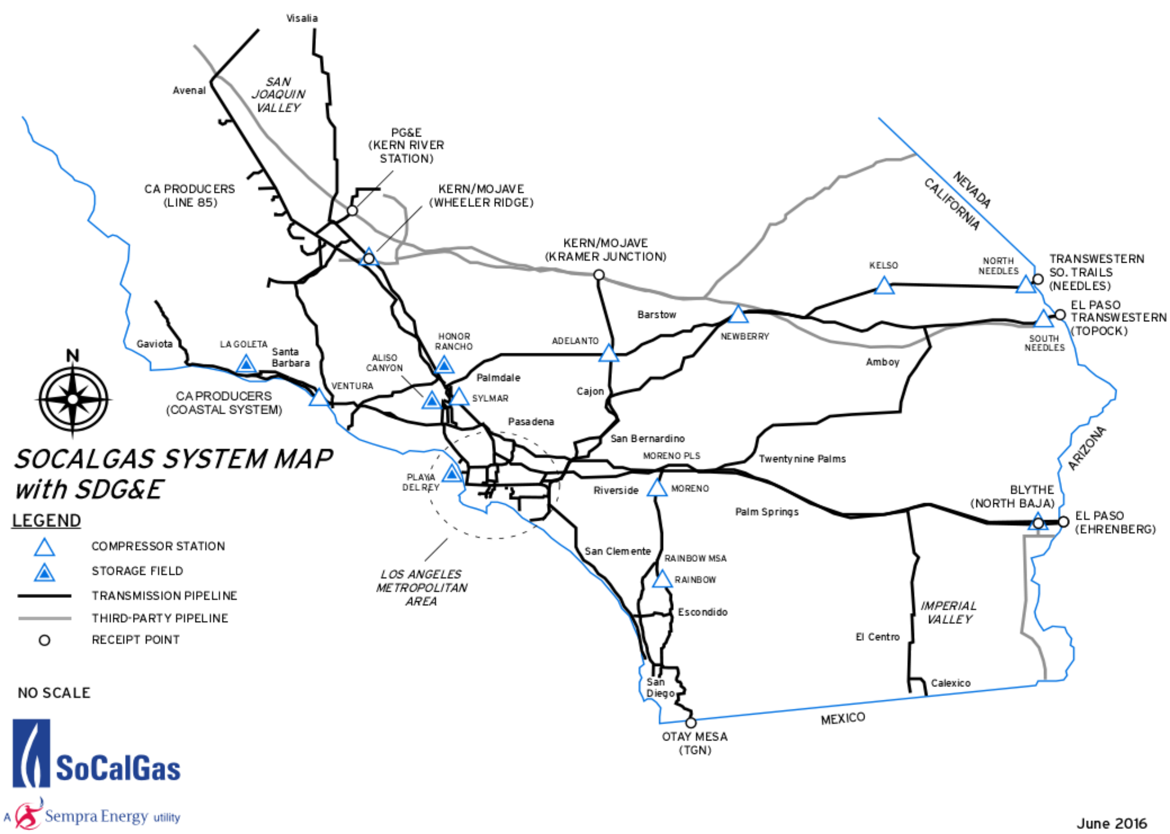
addition, storage is a critical source of winter supply used to meet demand during multi-day cold periods and managing peak hour demand throughout the day.

The analysis addresses the variables and circumstances specifically related to winter.

The following section discusses the background of gas operations and t electric operations.

SoCalGas and SDG&E own and operate an integrated gas transmission system consisting of pipeline and storage facilities. With their network of transmission pipelines and four interconnected storage fields, SoCalGas and SDG&E deliver natural gas to more than five million residential and business customers. A map of the SoCalGas transmission system is on Figure 1.

Figure 1: SoCalGas' Gas Transmission System



The gas transmission system supports 21 million residents in Southern California. The system extends from the Colorado River to the east of SoCalGas' roughly 20,000 square-mile service territory, to the Pacific Coast on the west, from Tulare County in the north, and to the U.S./Mexico border in the south (excluding parts of Orange and San Diego Counties).

The SoCalGas transmission system was designed to receive and redeliver gas from the eastern regions, to the load centers in the Los Angeles Basin, Imperial Valley, San Joaquin Valley, north coastal areas, and San Diego County. As SoCalGas' and SDG&E's customers accessed new supply sources in Canada and the Rocky Mountain region, the system was modified to concurrently accept deliveries from the north. The system today has the potential capacity to accept up to 3,875 MMcfd of interstate and local California supplies. These flowing supplies, however, do not exceed 3,000 MMcfd.[6]

SoCalGas and SDG&E's primary supply sources are the southwestern United States, the Rocky Mountain region, Canada, and California's on and off-shore production. The interstate pipelines that supply the SoCalGas transmission system are El Paso Natural Gas Company (El Paso), North Baja Pipeline (North Baja), Transwestern Pipeline Company (Transwestern), Kern River Gas Transmission Company (Kern River), Mojave Pipeline Company (Mojave), Questar Southern Trails Pipeline Company (Southern Trails), and Gas Transmission Northwest (GTN), via the intrastate system of Pacific Gas and Electric Company (PG&E). The SoCalGas transmission system interconnects with El Paso at the Colorado River near Needles and Blythe, with North Baja near Blythe, and with Transwestern and Southern Trails near Needles. SoCalGas also interconnects with the common Kern/Mojave pipeline at the Wheeler Ridge Compressor Station in the San Joaquin Valley and at Kramer Junction in the high desert. At Kern River Station in the San Joaquin Valley, SoCalGas maintains a major pipeline interconnection with the PG&E intrastate pipeline system and receives PG&E/GTN natural gas deliveries at that location.

SoCalGas operates four storage fields that interconnect with its transmission system. These storage fields – Aliso Canyon, Honor Rancho, La Goleta, and Playa del Rey – are near the primary load centers of the SoCalGas system. They have a combined inventory capacity of 135.6 Bcf, a combined firm injection capacity of 850 MMcfd, and a combined firm withdrawal capacity of 3,680 MMcfd. Some systems, such as the PG&E gas transmission system, have significant linear pipelines and rely heavily on linepack (storing gas in the pipeline as opposed to within a storage facility) for storage. SoCalGas' system does not have as much sufficient linepack as others. It operates using storage and pipeline supplies to meet its customer demand. The SoCalGas system cannot function with only pipeline supply or with only storage supply. Storage fields are critical to the SoCalGas system.

In contrast, SDG&E has no storage fields in its service territory. Almost all of the gas into the SDG&E system comes from SoCalGas via its Southern System through the Moreno Compressor Station. While discussed as a separate system, SDG&E's gas transmission system integrates with the SoCalGas system and falls under the responsibility of the SoCalGas system operator.

Because electric generators are SoCalGas noncore customers, neither the LADWP nor generation owners under the California ISO purchase gas supply directly from SoCalGas. SoCalGas only provides the pipeline transmission services required to transport the gas to the generation fleet.

[6] www.socalgas-envoy.com; ENVOY is SoCalGas' electronic bulletin board which enables end-use customers, shippers, and energy marketers to schedule gas for delivery into Southern California.

Operational Role of Aliso Canyon

Aliso Canyon is the largest of SoCalGas' four storage fields in all regards: largest inventory capacity at 86.2 Bcf, largest withdrawal capacity at 1,860 MMcfd, and largest firm injection capacity at 413 MMcfd. For summer operations (April through October), the SoCalGas Gas Control department strives to fill the storage field completely to provide firm injection services to their customers and to prepare for the upcoming winter. The withdrawal capacities of Aliso Canyon are also used during the summer to provide supply during the hourly peak electric generation demands that occur throughout the day. These generation demands cannot be met with flowing supplies because of the speed and magnitude that these peaks occur.

These peak demands are supplied using the limited local linepack, which needs to be replenished in order for the gas transmission system to remain above operational pressure limits. Because gas travels through the pipeline network at relatively slow speed, gas supplies from storage are better suited to replenish this linepack because of the closer proximity of the storage fields to the area of the peak demand compared to supplies from the interstate pipelines.

For winter operations (November through March), gas control uses Aliso Canyon to provide needed winter supply and withdrawal services. The large supply of gas that Aliso Canyon provides in the winter to the Los Angeles Basin also allows SoCalGas to maintain service to its customers outside the basin. Interstate pipeline gas supplies become more expensive and less available during the winter due to competition with other market areas and weather-related events such as well freeze-offs. During this time, customers often elect to deliver as little as possible to the SoCalGas system or supplies are not available for purchase. Without Aliso Canyon providing supply to the Los Angeles Basin, SoCalGas will have to choose whether to send supplies to the Los Angeles Basin or to other Southern California communities.

Without Aliso Canyon, SoCalGas' storage capacity falls to 49.4 Bcf (a 64 percent loss), 437 MMcfd of firm injection (a 49 percent loss), and 1,820 MMcfd of firm withdrawal (a 51 percent loss). Only SoCalGas' Honor Rancho storage field can provide for some of the lost capability to support demand in the Los Angeles Basin. The Playa del Rey storage field is too small to provide that level of support, while the La Goleta storage field is too far away and lacks the ability to effectively move gas to the Los Angeles Basin. The Honor Rancho storage field has significantly less inventory capacity than Aliso Canyon. It frequently supports demand centers in the San Joaquin Valley, the Northern System, and the Coastal System, limiting its effectiveness to support the Los Angeles Basin.

Existing Tools to Manage the SoCalGas and SDG&E System

Customers are responsible for scheduling and delivering gas supplies to the SoCalGas and SDG&E system to meet their usage. SoCalGas has few tools besides its storage fields to manage the mismatch between what customers bring onto the system in supplies and their usage. This mismatch can occur for a variety of reasons, including SoCalGas' and SDG&E's current monthly balancing rules, unexpected changes in weather, price arbitrage opportunities, well freeze-offs in the supply basins, and customer operational changes. With Aliso Canyon temporarily unavailable as a physical tool for the SoCalGas system operator, SoCalGas must rely on regulatory tools to manage the reliability, integrity, and safety of the system.

These tools include the low operational flow order ("low OFO"), the high operational flow order ("high OFO"), the emergency flow order ("EFO"), and SoCalGas Rule 23/SDG&E Gas Rule 14 curtailment procedures. The OFO procedures are orders initiated by SoCalGas under specified circumstances to encourage tighter balancing on the system: more gas onto the system ("low OFO") or less gas on the system ("high OFO"). Tools for more extreme balancing needs are the EFO and if required, actual curtailment of gas to customer facilities using the curtailment rules. System reliability and integrity may be compromised if customers do not respond to the financial signals provided by these tools.

The low OFO and EFO procedures help minimize supply-related curtailment threats by ensuring that transportation customers do not use any more storage withdrawal than has been physically allocated for balancing. It also provides an incentive for customers to bring more pipeline supply into the system. The overuse of withdrawal for transportation balancing can jeopardize system reliability by exhausting SoCalGas' total withdrawal capability. The more closely customers align their supplies with their usage, the less likely that operational issues develop that will necessitate the utility curtailing end-use demand because of inadequate supply.

Electric and Gas Operations Coordination and Reliability

The Aliso Canyon Gas storage facility is integral to the reliable operation of the electric grid and infrastructure. Gas storage acts like a shock absorber for the real-time dynamic variations in electric demand. These facilities also provide additional gas delivery capacity when gas demand exceeds the amount of flowing supply and provides a place to inject unused gas when electric demand is less than expected. In the winter, gas storage supports gas system and electric reliability when there is lower receipt point utilization throughout the SoCalGas/SDG&E service territories and there is less flowing gas supply through the pipelines to meet actual gas demand. Such differences are due to unplanned outages unexpected changes between the amount of gas scheduled the day before and the actual gas demand occurring in real time or gas procurement practices that can result in low-flowing supply.

The LADWP and California ISO balancing authorities are responsible for reliable electric service in their territories. SoCalGas has long used Aliso Canyon as a critical component of the transmission and distribution system. It provides natural gas service to the residential customers in the Los Angeles Basin, 17 natural gas-fired power plants, hospitals, oil refineries, and other key parts of California's economy. Although Aliso Canyon directly impacts 17 electric generating plants, reducing total gas capacity could impact 48 plants consisting of 148 units totaling 20,120 MW capacity of gas-fired resources throughout the SoCalGas/SDG&E service territories.

Under the North American Electric Reliability Corporation (NERC) definition, a balancing authority and transmission operator is responsible to maintain reliability by continuously balancing supply and demand and ensuring that the transmission is operated in a stable manner that prevents cascading outages from affecting the interconnection.[7] The LADWP and California ISO are responsible for bulk

[7] The LADWP and California ISO are both a balancing authority and transmission operator and are 2 of the 38 balancing authority areas in the Western Electric Coordination Council (WECC) interconnection. WECC promotes bulk electric system reliability in the Western Connection.

electric system reliability and operational control of the electric generating resources served by the SoCalGas/SDG&E service territories.

Under the NERC requirements, the balancing authorities need to stand ready to respond to a sudden real-time loss of a transmission or generation element. Electric capacity reserved on gas-fired generating resources is used to compensate for these sudden losses by instantaneously responding and recovering from the loss within minutes. Availability of gas-fired resources is key to maintaining local reliability during contingency events as required by NERC transmission operations standards. During the winter, if these generation resources are limited or curtailed due to gas limitations and replacement energy is not available outside of the SoCalGas/SDGE service territories, it may be necessary to interrupt electric load to maintain electric reliability as required by NERC reliability standards.

The ability for LADWP and California ISO to shift electric supply from the resources affected by Aliso Canyon to other resources in Southern California or outside of the SoCalGas/SDG&E service territories is limited based on timing and system conditions. The first limitation arises due to the need to maintain a minimum amount of local generation to ensure local reliability. The second limitation is due to limited ability to import energy into the area because of transmission constraints or supply availability. The ability to shift supply in the day-ahead market is greater and significantly decreases as real-time approaches.

California ISO

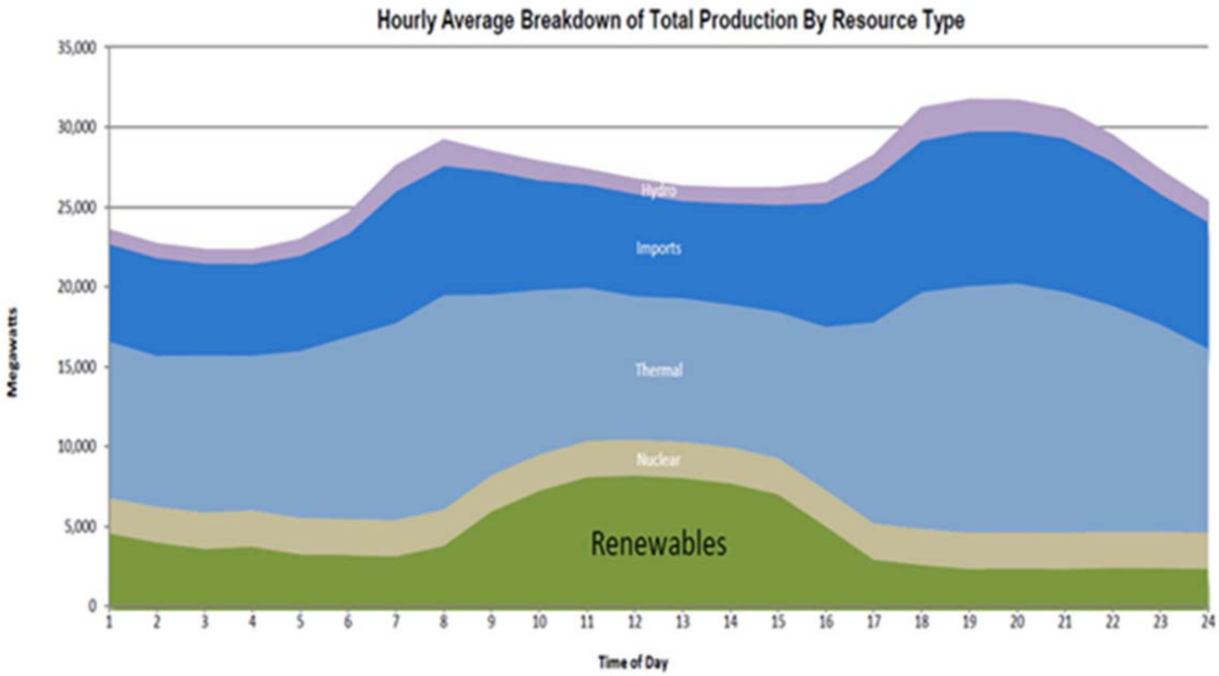
The California ISO is the bulk electric system operator for 30 million customers in Northern and Southern California and a small part of Nevada. As a system operator, the California ISO ensures bulk electric system stability and electric supply necessary to meet customer demand on a minute-by-minute basis 24 hours a day. The California ISO's service area includes SCE's 14 million electric customers, most of whom are in the Los Angeles Basin (excluding LADWP customers), SDG&E's 1.4 million customers, and several municipal utilities in the region. The California ISO's portion of the Southern California load is served by a diverse mix of electric generation including wind, solar, combined heat and power, hydroelectricity (hydro), gas-fired resources, and imported generation provided over high-voltage transmission lines. All these resources are optimized based on location, availability, and effectiveness to maintain transmission grid stability, voltage support, and thermal loading on transmission lines, and provide the most efficient power solution to meet demand.

California's electric system has 26,000 of miles of bulk electric transmission lines ranging from 60 kilovolts (kV) to 500 kV and hundreds of electric generation sources that work in concert to continuously maintain system reliability and balance supply and demand.

Customer demand varies based on weather conditions and patterns. During the winter, electric demand is lower overall but increases sharply in the evening when lighting load increases and solar production decreases. Increased penetration of variable energy resources, such as wind and solar, have produced a higher degree of operational volatility. To balance supply and demand during the volatile periods, flexible gas-fired generation is used to fill the energy needs when variable resources are not fully used or are unavailable.

Figure 2, which shows the California ISO system generation needed for December 15, 2015, illustrates a typical winter load pattern. The graph shows resource types that make up the energy needed to serve the 24-hour customer demand. Gas-fired (thermal) generation is a necessary component.

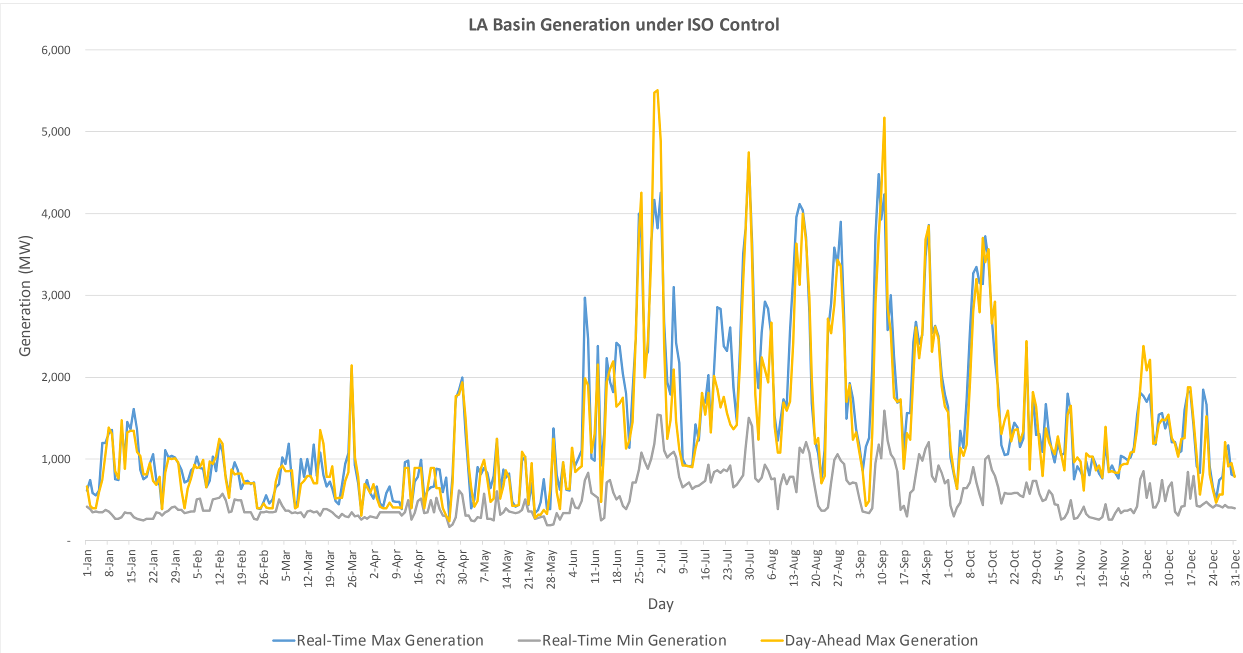
Figure 2: December 15, 2015 Electric Load Profile



This graph depicts the production of various generating resources across the day.

Figure 3 illustrates how the pattern of gas-fired generation use in the Los Angeles Basin under California ISO control changed over 2015. During the winter months, electric demand is lower than summer, and at times, is less than 1,000 megawatts (MW) per hour.

Figure 3: Los Angeles Basin Resource Utilization Under California ISO Control



LADWP

The LADWP, which provides reliable electricity to its 1.4 million customers, must maintain transmission line loading within limits, and provide voltage support for its system in accordance with mandatory reliability standards and prudent utility practices. If it cannot meet these reliability metrics, the LADWP is unable to import energy, which, along with local generation, is critical to maintaining reliable supply. Local gas-fired generation plays a key role in meeting these metrics with specific generation minimums required that vary based on the local power demand and system conditions. The higher the demand, the more basin gas-fired generation is required. The LADWP owns some 40 percent of the gas-fired generation capacity in the Los Angeles Basin. This local, in-basin generation represents about 47 percent of the LADWP's net dependable system capability to meet its load. It imports the rest of the electricity needed using electric transmission lines it owns.

The LADWP forecasts its daily gas-fired generation requirement to meet its load and reliability requirements and schedules the necessary gas to meet this generation requirement. This forecast is based on expected system demand, weather, and system conditions. Loss of a generation resource or transmission circuit, an unexpected reduction in variable generation (primarily wind and solar), and/or weather forecasting error may significantly increase the need for gas-fired generation. These events often happen with little warning.

During the 2016 summer peak, the LADWP's Mead-Victorville 287 kV line 1 was not available, reducing its import capability. This line is scheduled to return to service before the winter peak occurs. The LADWP's import capability during the winter peak will be much higher than in the 2016 summer peak, while the winter peak load will be much lower. The forecasted winter peak for the LADWP balancing authority is 4,309 MW. The expected reliable winter import capability is a combined 5,010 MW on the Victorville to Los Angeles Transmission Path, Pacific DC Intertie, and Sylmar AC Intertie. The LADWP will meet reliability requirements even with all gas-fired basin generation off, provided two synchronous condensers are available at Scattergood and two are available at Haynes for voltage regulation and support. This is true even after assuming all known planned outages scheduled during December when the winter peak may occur. Planned or unplanned transmission system outages may require in-basin gas-fired generation to meet the reliability criteria.

GAS OPERATIONAL ANALYSIS AND ASSESSMENT

Introduction

To quantify the potential system and customer impacts resulting from the limited ability to use Aliso Canyon during the winter, SoCalGas performed a series of hydraulic analyses to determine the system capacity under winter load conditions without Aliso Canyon. Conducting a mass balance review of the SoCalGas and SDG&E gas transmission system comparing supply and demand can provide an initial screening, but ultimately is insufficient. Such an analysis can provide only an indication of a problem if the difference between supply and demand is large. This comparison does not consider the way the system responds to intra-day changes in demand and the resulting impact on system operating pressures. Hydraulic analyses take these dynamic demand patterns into consideration and use industry standard flow equations to calculate the resulting pressure changes throughout the pipeline network.

SoCalGas performed hydraulic analyses of its system based on the CPUC-mandated 1-in-10-year cold day design standard. While SoCalGas expects to have some capability to use the Aliso Canyon supply at some point during the winter, there is still uncertainty about the inventory level that will be available and the performance of the wells, which will be subject to new operational restrictions. This assessment assumed no supply was available from Aliso Canyon. Additional simulations assumed tubing-only flow restrictions on withdrawal at the other storage fields and a pipeline outage on line 3000 in the Northern System.

Hydraulic Analyses Summary

The hydraulic analyses produced several findings:

- The SoCalGas/SDG&E 1-in-10-year cold day design standard of 5.2 Bcfd **cannot** be supported without Aliso Canyon supplies.
- The maximum sendout that can be supported without Aliso Canyon supply is 4.7 Bcfd, assuming no other transmission or storage facility outages and 100 percent utilization of receipt point and storage withdrawal capacity.
- A line 3000 outage reduces the maximum sendout to 4.5 Bcfd.

- Any loss of flowing supply from 100 percent utilization will further reduce sendout capacity on a one-to-one basis.
- The SoCalGas/SDG&E system has sufficient capacity to meet the 1-in-35-year peak day design standard of 3.5 Bcfd for core service without supply from Aliso Canyon and without assuming 100% receipt point utilization.
    - There is increased risk of localized core outages without the availability of Aliso Canyon supply that results from interstate pipeline supply shortfalls or facility outages.

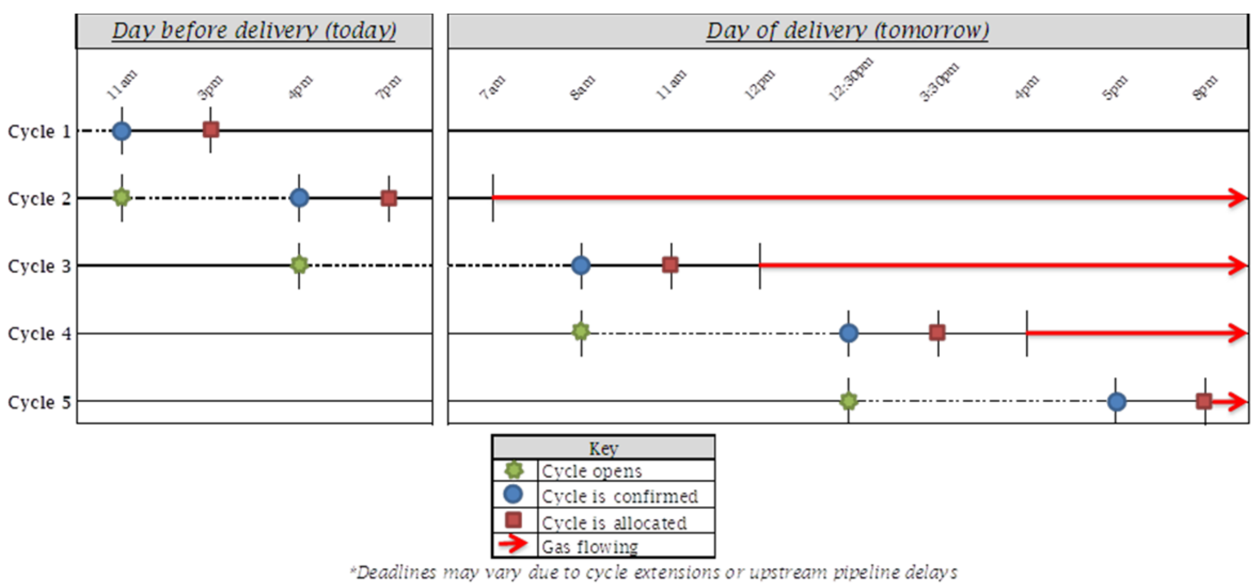
Scheduling of Interstate Gas Supply

Gas supplies do not enter the SoCalGas and SDG&E transmission system as customer demand changes throughout the day. It is scheduled at specific intervals throughout the day at a constant rate. This constant rate of supply is rarely in balance with demand. SoCalGas uses storage injection and withdrawal to make up this difference between flowing supplies and demand and to meet peak demand.

SoCalGas' Utility Procurement Department purchases and schedules gas supplies for the majority of core (residential and small commercial/industrial) customers. Noncore customers procure their own gas supplies for transportation on the SoCalGas and SDG&E system. The SoCalGas system operator is authorized to purchase supplies only to maintain reliability on SoCalGas' Southern System.

Gas is scheduled in six scheduling cycles throughout the day to allow customers multiple opportunities to adjust supply to demand. Two cycles occur prior to the gas day, three cycles are during the gas day, and one cycle occurs after the gas day to allow paper transactions to clear imbalances. Figure 4 illustrates the SoCalGas gas scheduling cycles when supplies are confirmed and when they actually start flowing.

Figure 4: SoCalGas Gas Scheduling Cycles



Curtailment Order of Noncore Gas Service to Maintain Core Service

SoCalGas/SDG&E's curtailment policies will change November 1, 2016, to reflect the CPUC's July 14, 2016, approval of the curtailment procedures settlement agreement. The SoCalGas/SDG&E system will be divided into 10 new geographic end-use transportation curtailment zones known as "local service zones." These local service zones will determine the boundaries of most localized curtailments. Curtailment priorities have been updated as follows:

- Step 1 – All non-operating dispatchable electric generators that are not running or are not forecasted to run shall remain off within the affected local service zone(s).
- Step 2 – Up to 60 percent pro rata of dispatched electric generation load in the winter months, up to 40 percent pro rata of dispatched electric generation load in summer months within the affected local service zone(s).
- Step 3 – Up to 100 percent pro rata cogeneration and noncore commercial and industrial customers within the affected local service zone(s). Refineries and ancillary refinery facilities may maintain an agreed-upon minimum usage as defined in their contract during this time.
- Step 4a – Remaining refinery load not curtailed in Step 3.
- Step 4b – Remaining dispatchable electric generation load not already curtailed in Steps 1 and 2.
- Step 5 – All core priority 2A load, pro rata.

Hydraulic Software & Modeling

SoCalGas has created a detailed proprietary model of its gas transmission network and has used it with DNV GL's Synergi Gas software application to perform hydraulic calculations for pipeline networks for more than 30 years. The model includes all transmission and storage assets (pipeline, compressor stations, valve stations, and storage fields) and all associated interconnections, locations for supply to be delivered to the system, and locations of demand on the system. Hourly demand profiles are applied to these points of customer demand, which can be a collection of customers (such as a point of supply from the transmission system to a distribution system) or a specific customer facility, such as an electric generating plant.

DNV GL has more than 44 years of industry-leading modeling software experience, and Synergi provides modeling of large, complex, integrated multi-pressure level systems with full control over gas constraints (gravity, heating value, and viscosity), equations of state, friction factor calculations, and heat transfer constants for both steady-state and transient analysis.

The model of the system is constructed from nonlinear mathematical equations based on the provided network information. These equations represent network interconnection based on Kirchhoff's first law, which states that the flow into or out of a node in a network must sum to zero for mass to be conserved.

The equation solutions predict pressures, flows, valve positions, pipe diameters, compressor powers and speeds, and storage field utilization factors.

The application solves all equations in terms of nodal pressure, and then computes the resultant facility flows, given that facility flows are expressed as functions of unique constants and upstream and downstream pressures. The iterative process ideally results in a solution where all unknown facilities, unknown pressures, and unknown flows are solved to within the set tolerances.In contrast to demand, supply is delivered steadily to the system. Supply and demand are rarely in balance. Anytime when supply is less than the demand on the system, the system is said to be "drafting." When supply is greater than demand, the system is said to be "packing," so long as the ability to increase pack still exists. Because natural gas is a compressible medium, a pipeline can be used to store gas supply by operating between its minimum and maximum operating pressures, "packing" gas supply when the demand is low (and operating nearer to the maximum operating pressure) and "drafting" gas supply when the demand increases (and operating towards the minimum operating pressure). The volume of gas that can be stored in a pipeline is often referred to as "linepack."

The SoCalGas and SDG&E system has very little pack and draft capability, or linepack, relative to other pipeline networks, such as PG&E's system. While SoCalGas and SDG&E use the limited pack and draft capabilities when they have to quickly meet localized changes in hourly demand, they depend upon their storage fields to replenish lost linepack through withdrawal (taking gas out of the storage field) during the day or to absorb excess gas supplies through injection (putting gas into the field). Flowing supply coming into the system is too far from the load center and comes in too slowly to perform this function. The system flexibility that their storage fields provide enables SoCalGas and SDG&E to maintain uninterrupted service to their customers.

When SoCalGas' engineers model the gas transmission system, they perform the same actions on the model that SoCalGas' Gas Control Department uses operating the actual system. Because supplies are fixed and delivered at a relatively constant rate, the engineer will simulate bringing on or cutting back storage supplies, opening or closing valve stations, and firing or turning off compressor station units to meet the changing customer demand throughout the operating day, just as the gas control operators would. For a simulation to be successful, the engineer must perform the following:

- Operate the system safely between its minimum and maximum operating pressures at all times.
- Operate within the capacities of the transmission facilities.
- Fully recover system linepack at the end of each day.

Exceeding maximum operating pressures is against pipeline regulations and presents safety risks, while operating below minimum operating pressures jeopardizes continuous service to the distribution systems and customers, and fully recovering system linepack allows the simulated day to theoretically be repeated as often as necessary. Extreme demand conditions are rarely single-day events, and recovering the system linepack is required for the models to be successful. In reality, the system rarely recovers the pack completely in a day, and system stress is incrementally increased the day after a high-demand day.

Study Parameters and Assumptions

The winter assessment involved hydraulic simulations of the CPUC-mandated 1-in-10-year cold day design standard[8] without supplies from Aliso Canyon. Three scenarios below were reviewed:

1. No transmission or storage outages (only Aliso Canyon out of service)
2. Tubing-only flow restriction on withdrawal at other storage fields
3. Pipeline outage on transmission line 3000 in the Northern System

Each scenario was run iteratively to determine the capacity of the system, and the findings are summarized in Table 1. Hydraulic simulations were first performed for the 1-in-10-year cold day demand condition of 5.2 Bcfd to determine if the design standard could be met, and it could not. After determining that the design condition could not be met, the maximum system sendout that could be supported was found through an iterative process of reducing noncore demand until the criteria for a successful simulation were met.

Demand reduction was implemented as a pro-rata cut to electric generation demand in the Los Angeles Basin and in San Diego. This is consistent with the revised curtailment rules. Although the analysis only reduced electric generation demand, all noncore customers are potentially impacted during an actual curtailment event, including businesses such as refineries, hospitals, hotels, and airports.

SoCalGas' analysis utilized 100 percent of the available storage field (Honor Rancho, La Goleta, and Playa del Rey) and interstate pipeline supplies. This is not realistic, however the assumption is necessary to determine the maximum capacity to the gas transmission system. In reality, the actual capacity of the gas transmission system on a daily basis will be less than this amount, based upon the level of scheduled pipeline supplies, capabilities of the storage fields, and any other pipeline/equipment outages.

Receipt points are located in three zones on the transmission system: the Northern Zone with 1,590 MMcfd capacity, the Southern Zone with 1,210 MMcfd capacity, and the Wheeler Ridge Zone with 765 MMcfd capacity, for a total capacity of 3,565 MMcfd. Local California producers fall into two zones, the Coastal Zone and line 85 zone. Aging fields, declining production capability, and low oil prices have reduced recent production. SoCalGas used recent historical production levels for local California supplies for this analysis rather than the full capacity available to producers.

[8] D.02-11-073.

Table 1: Supply and Demand for the 1-in-10 Scenarios and Curtailment Requirements

Description	**Current System**		**Storage Tubing WD**	**Line 3000 Outage**
	1-in-10 Demand	Supported Demand	Supported Demand	Supported Demand
Demand *(MMcfd)*				
Core	-3304	-3304	-3304	-3304
Noncore Non-Electric Generation	-801	-801	-801	-801
Electric Generation	-1094	-564	-563	-462
TOTAL	**-5199**	**-4668**	**-4667**	**-4566**
Required Supplies *(MMcfd)*				
CA Producers	61	61	61	61
Honor Rancho	835*	403**	426**	541**
La Goleta	340	340	340	340
Playa Del Rey	300	300	300	300
Receipt Points (Flowing Supplies)	3565	3565	3565	3325
TOTAL	**5101**	**4669**	**4692**	**4567**
Imbalance *(MMcfd)*	**-98**	**1**	**25**	**1**

* 150 MMcfd stranded due to full utilization of the Wheeler Ridge Zone
**Fully utilized at peak times, figures represent daily volume needed to balance lower demand to manage operational pressures in the hydraulic analysis.

While a simple mass balance calculation of supply and demand does not take into effect the changing demand throughout the day, even this assessment shows that with no additional outages on the transmission or storage facilities and 100 percent receipt point utilization, there is still a 100 MMcfd deficit of supplies compared to the 1-in-10-year cold day design condition. There is not enough gas supply available to the SoCalGas/SDG&E system to support this level of sendout.

Although the mass balance shows that the maximum system receipt capacity without Aliso Canyon is 5.1 Bcfd, this level of demand cannot be served when the transient behavior of demand is taken into account. While demand profiles vary hourly throughout the day, flowing supplies are delivered on the SoCalGas/SDG&E system on a consistent hourly rate. Aliso Canyon, which is in the Los Angeles Basin, is able to directly serve the largest demand center on the system. With the loss of this significant level of supply, the remaining sources of supply are left to support the Los Angeles Basin demand center and the other demand centers on the system, such as those in San Diego, the San Joaquin Valley, and along the California coast in Santa Barbara and Ventura. To have a successful simulation, demand must be reduced from the 1-in-10-year cold day level to maintain minimum operating pressures and recover system linepack.

All simulations required high withdrawal rates from Honor Rancho, La Goleta, and Playa del Rey. High withdrawal rates require high levels of inventory as a driving force. As inventory diminishes throughout the winter, withdrawal rates will also diminish. SoCalGas has historically managed its inventory levels to provide sufficient withdrawal capacity to maintain service throughout the winter. This will be more difficult without the full use of Aliso Canyon and a tubing-only withdrawal restriction at all fields will have a compounding effect.

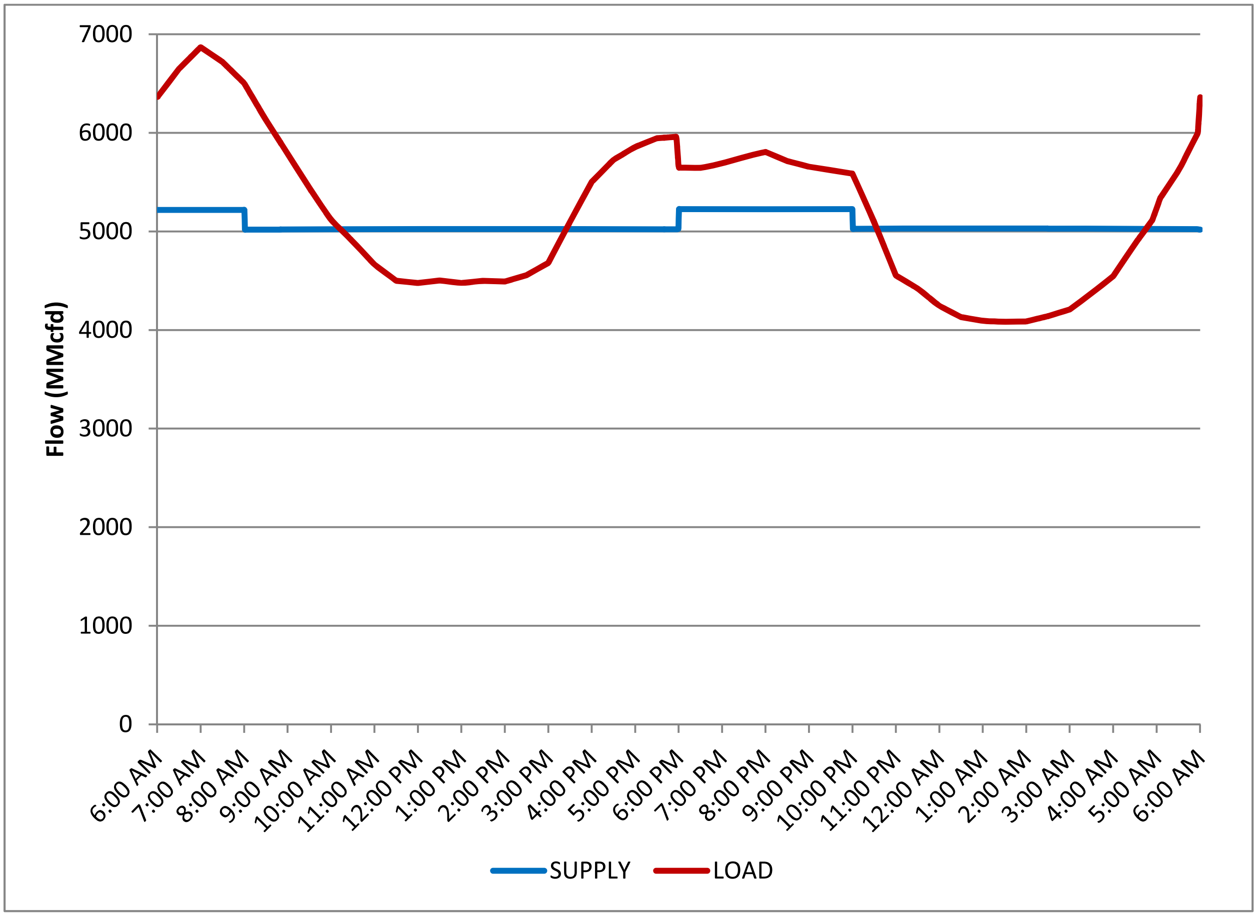
Results

Scenario 1: Maximum System Capacity, No Additional Transmission or Storage Constraints

This analysis began with the 1-in-10-year cold day demand condition. The hydraulic analysis for this 5.2 Bcfd demand scenario demonstrates that despite using all available supply to the system, except Aliso and 150 MMcfd of stranded gas at Honor Rancho, the operating pressures in the Los Angeles Basin transmission system fall to levels that cannot support core customers and fall to critical levels on the Southern System. This would lead to curtailments in the Los Angeles Basin and a curtailment of SDG&E is highly likely.

Figure 5 illustrates the supply and demand profile for the 5.2 Bcfd 1-in-10 design criteria. A winter natural gas demand profile has two peaks: one in the morning as people wake up and a second in the evening when people return home. Demand on the system exceeds supply during the morning and evening peak periods. All available supply is fully utilized during these periods. After the peak demand periods, Honor Rancho supplies must be reduced from full withdrawal rate to avoid an over-pressure condition, limiting the daily volume to 835 million cubic feet. Both Honor Rancho and the Wheeler Ridge Zone are on the same pipeline, forcing both supply points to compete for limited pipeline capacity. When the Wheeler Ridge Zone is operating at 100 percent utilization, Honor Rancho is limited to a maximum withdrawal of 835 MMcfd in the 5.2 Bcfd scenario.

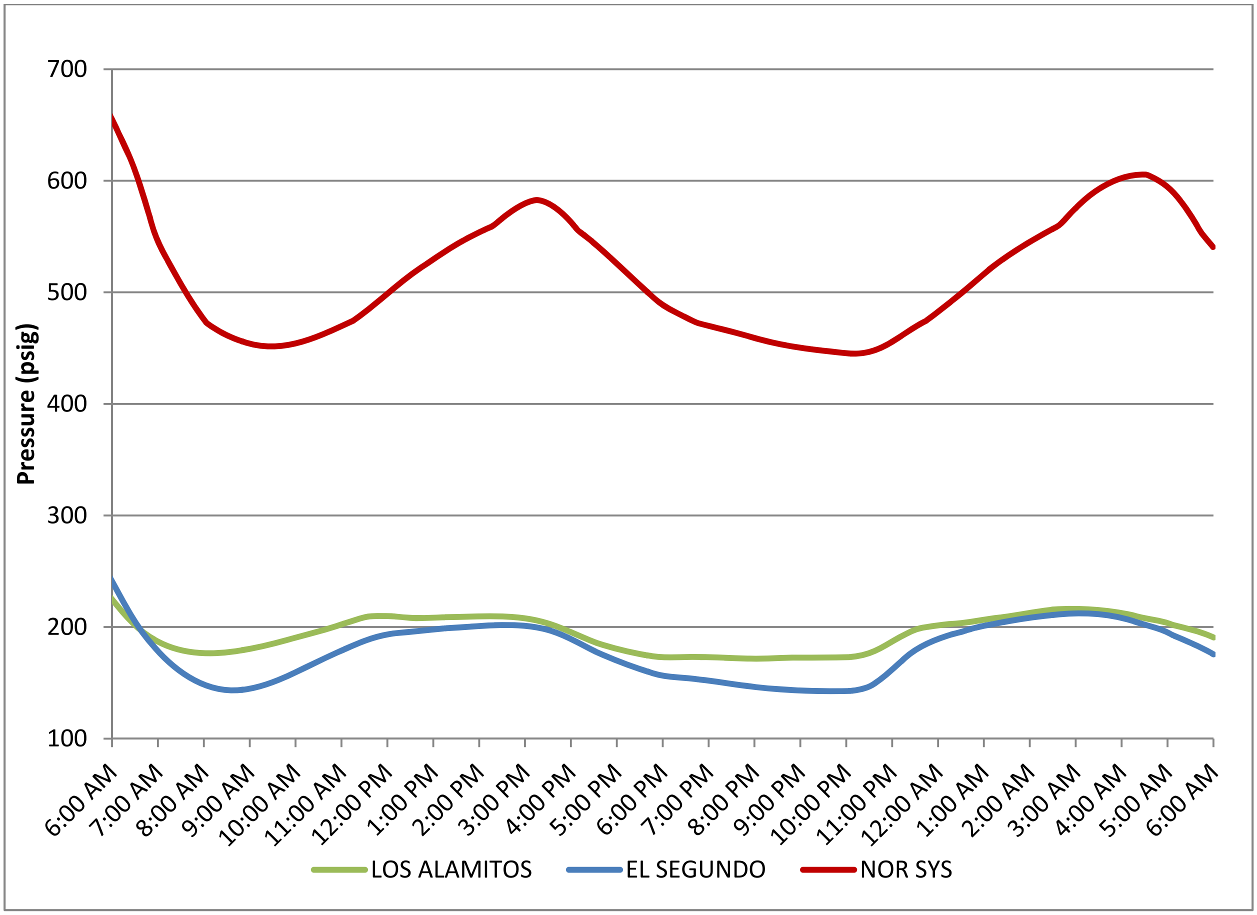
Figure 5: 5.2 Bcfd, No Additional Outages – Supply and Demand



SoCalGas' Northern System is a primary supply source to the Los Angeles Basin and provides limited support to the Southern System serving San Bernardino, Riverside, Imperial, and San Diego Counties. The Southern System currently lacks supply diversity. It depends primarily upon supply from a single interstate pipeline, with only a limited amount of support provided from one Northern System pipeline, line 6916. When supplies delivered on the Southern System are insufficient to support the related level of demand, SoCalGas can divert some Northern System supplies from the Los Angeles Basin to the Southern System, through existing crossover connections. Normally, SoCalGas would then supplement this loss of supply to the Los Angeles Basin with supply withdrawn from Aliso Canyon. In this scenario, that is not an option, and any Northern System gas supply delivered to the Southern System comes at the expense of the Los Angeles Basin.

Figure 6 depicts pressure on the Northern System and at points in the Los Angeles Basin near Los Alamitos on the east and near El Segundo on the west.

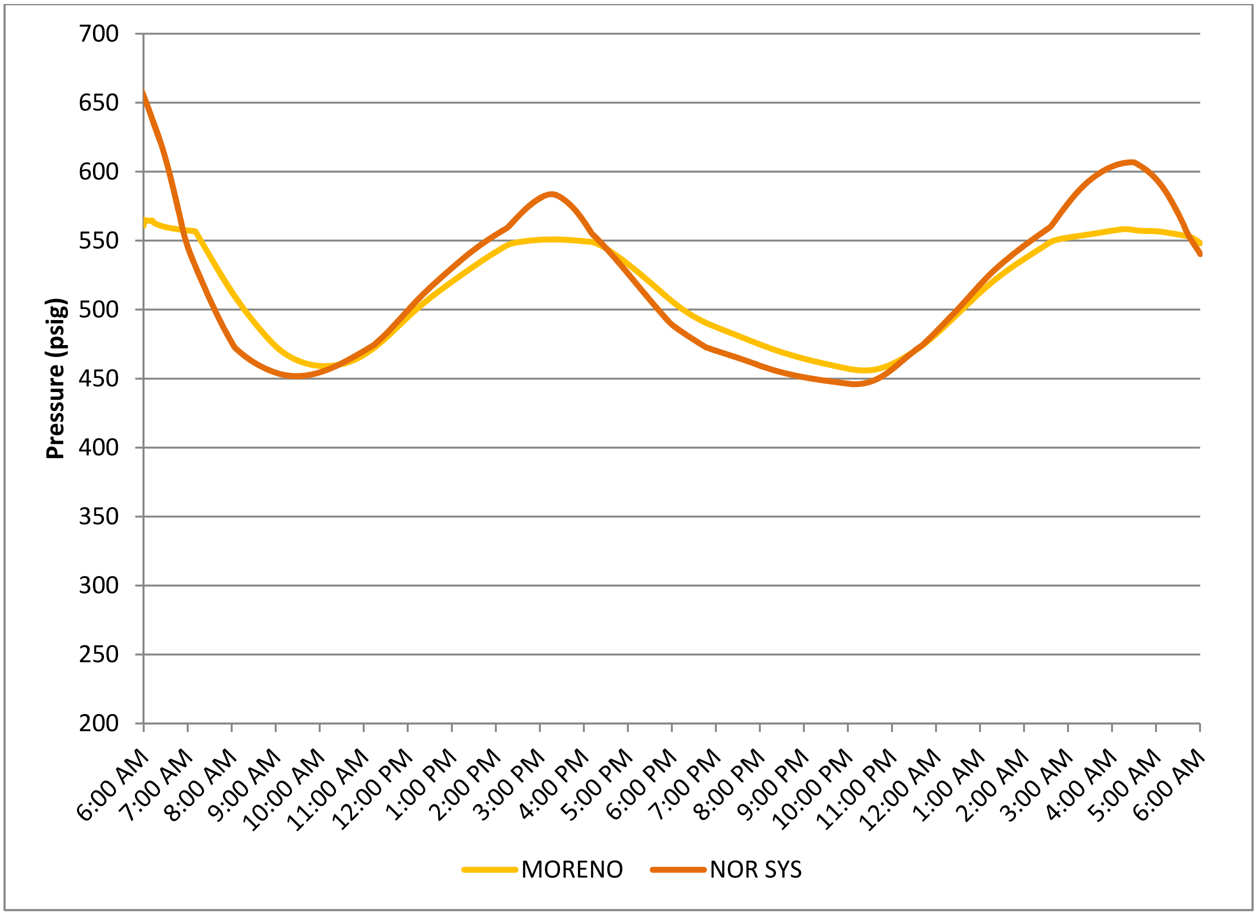
Figure 6: 5.2 Bcfd, No Additional Outages – Northern System and Los Angeles Basin Pressures



As shown in Figure 6, the Los Angeles Basin pressure begins the day at a low pressure, then declines to a point that cannot support core demand within an hour, and remains at this level for most of the day. In this case, a curtailment would have been issued long before the pressure declined to these levels to maintain service to core customers.

Figure 7 also shows the pressure on the Northern System, and the Southern System at the Moreno station. The Northern System supplies the Los Angeles Basin and part of the Southern System. Pressures declined significantly on the Northern System, hindering the ability to flow gas into the Southern System. The resulting pressure at the Moreno station reaches operating pressures that could result in compressor outages, likely leading to curtailment in SDG&E. The Moreno station is the primary supply to the SDG&E system.

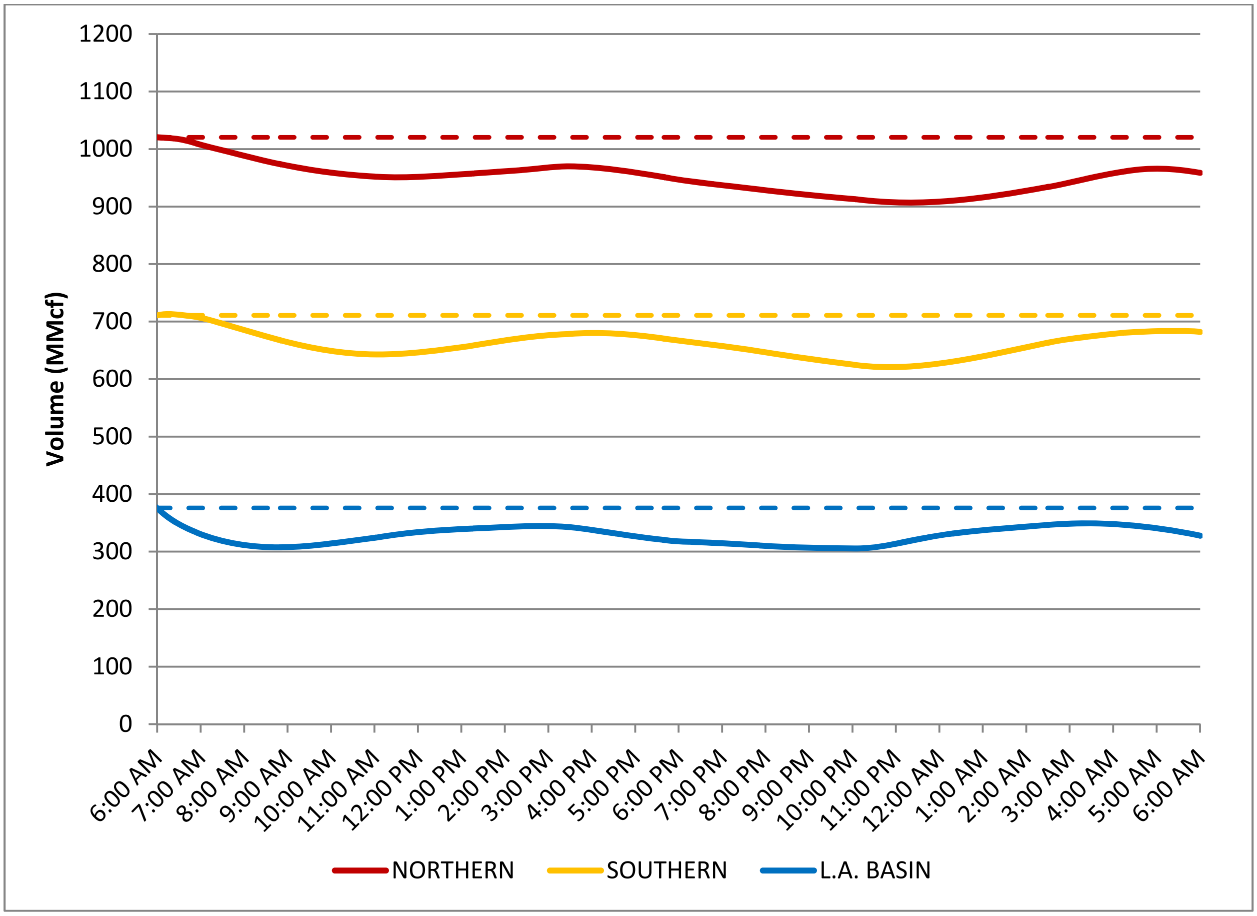
Figure 7: 5.2 Bcfd, No Additional Outages – Northern System and Moreno Pressures



With pressures at the Moreno station and the Northern System already at critically low levels, no additional supply from the Northern System could be sent to the Los Angeles Basin to prevent a curtailment.

Figure 8 shows the linepack in three subsystems, the Northern System, the Southern System, and the Los Angeles Basin. By recovering linepack by the end of the day, it is theoretically possible to serve this level of demand continually. For each subzone, the linepack was unable to recover by the end of the day.

Figure 8: 5.2 Bcfd, No Additional Outages – Subsystem Linepacks
(Initial levels Indicated as Dotted Line)



Despite the difference in supply and demand only being a deficit of 100 MMcfd, curtailment would have been required in the Los Angeles Basin and likely required on the SDG&E system as well.

To quantify the level of demand that could be supported without Aliso Canyon supplies, SoCalGas reduced the level of demand on the model and performed iterative hydraulic simulations until a successful simulation was completed. Electric generation demand was incrementally cut pro rata in the Los Angeles Basin and San Diego, until the simulation satisfied all the criteria to be considered successful. After the hydraulic simulations, SoCalGas determined the maximum sendout that could be supported is 4.7 Bcfd.

Figure 9 illustrates the supply and demand profiles for the 4.7 Bcfd simulation. Supply from all storage fields (without Aliso Canyon) is maximized during the morning peak, and then is reduced throughout the day to prevent an over-pressure situation. This process allows the system operator flexibility to meet the peak demand times on the system, which prevents minimum operating pressure situations. This is also why Honor Rancho supplies are listed at 403 MMcfd in Table 1, even though the field is capable of 1,000 MMcfd. While that maximum rate was available at the storage field and was used at times, more than 403 MMcf of supply was not required out of Honor Rancho over the course of the day to meet the reduced level of demand that could be supported. SoCalGas could also have chosen to reduce supply from Playa del Rey, La Goleta, the interstate pipelines, or any combination of these, but the results of the assessment would be unchanged.

Figure 9: 4.7 Bcfd, No Additional Outages – Supply and Demand

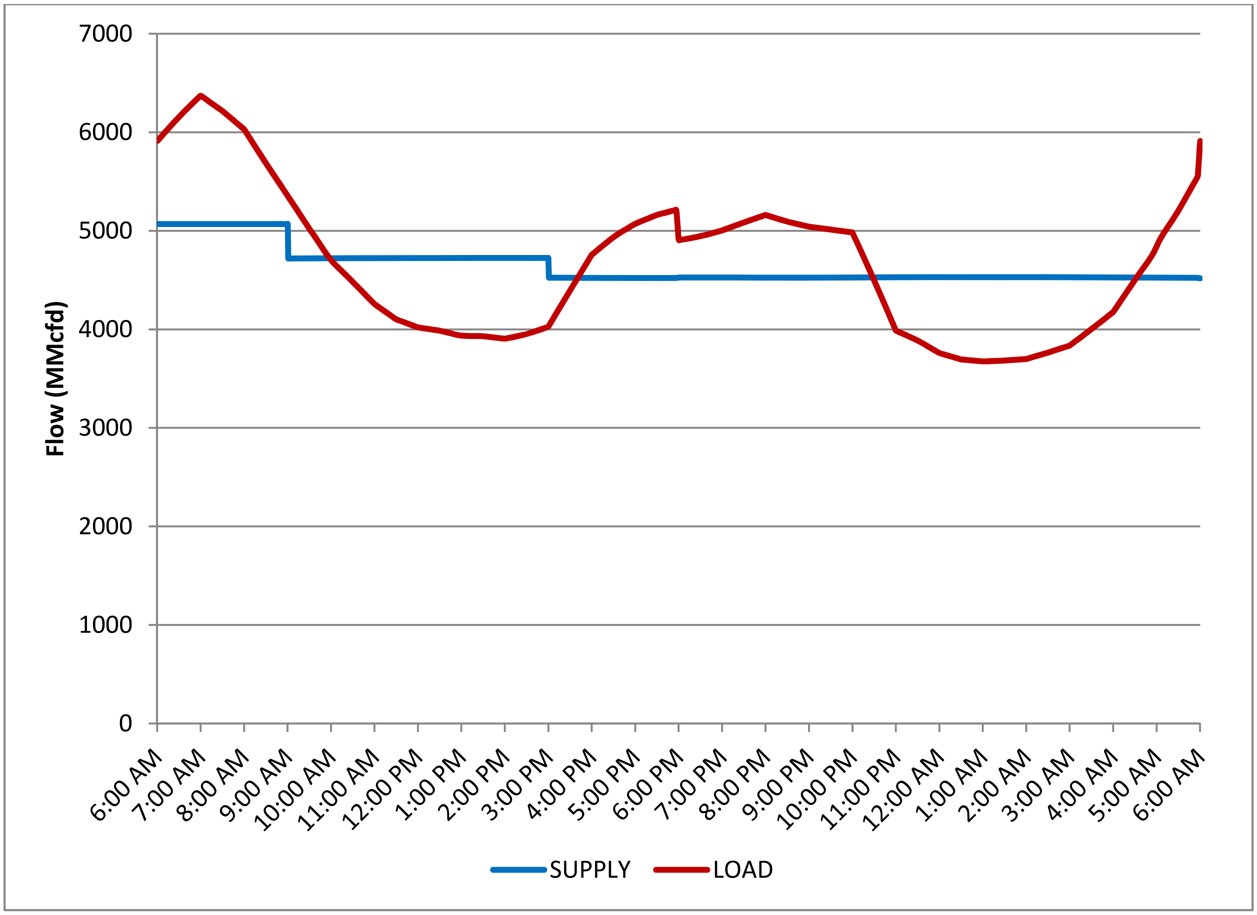


Figure 10 depicts the pressure on the Northern System and in the Los Angeles Basin near Los Alamitos and near El Segundo. Contrasting the 5.2 Bcfd simulation, pressures start much higher, stay above required pressures, and recover by the end of the day.

Figure 10: 4.7 Bcfd, No Additional Outages – Northern System and Los Angeles Basin Pressures

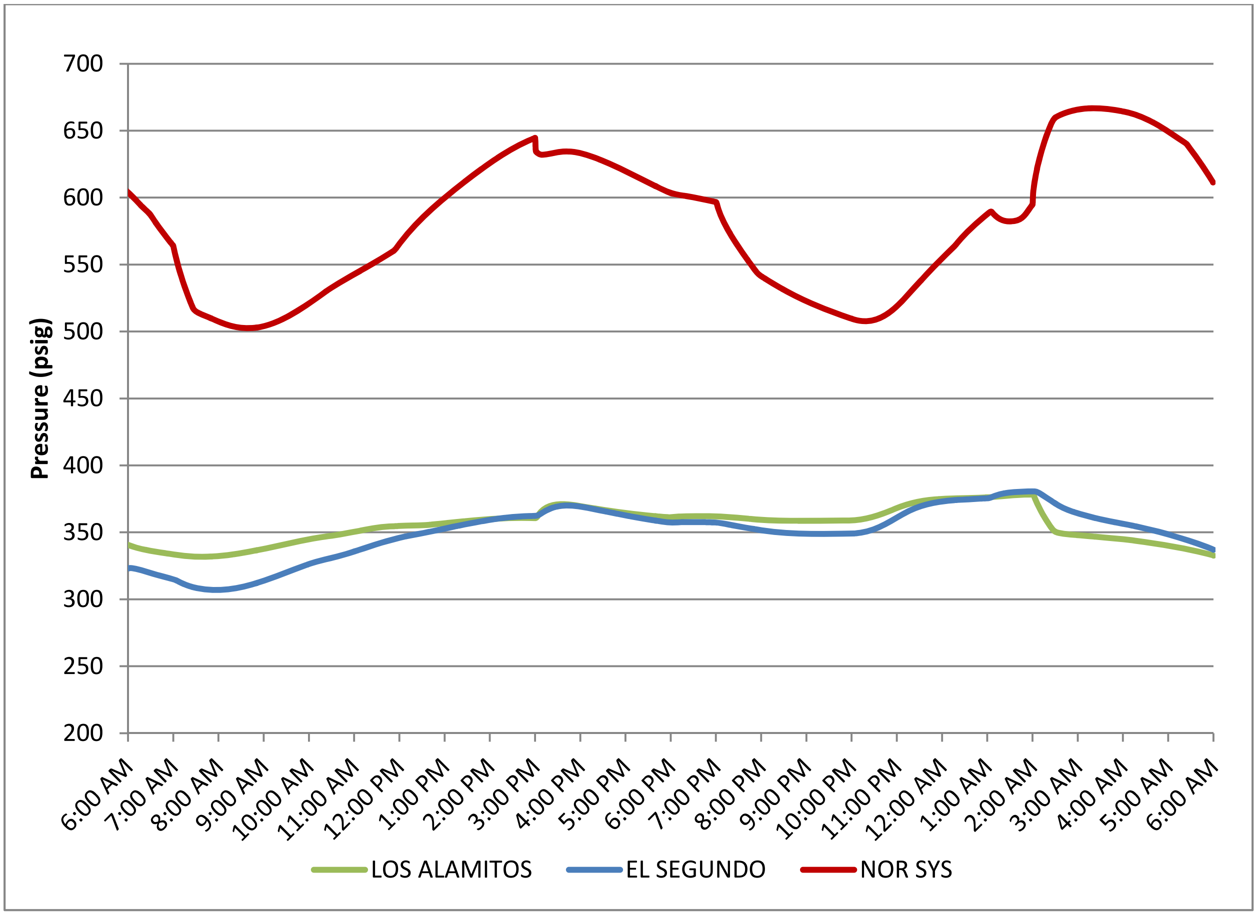


Figure 11 displays pressure on the Northern System and at Moreno station on the Southern System. Pressure at Moreno is kept above the operating pressure the system operator needs, and above the levels where curtailments may be issued. The Northern System pressure still declines rapidly in the morning hours, as linepack from the north is serving demand in the Los Angeles Basin and the Southern System. However, pressures are maintained and recover by the end of the day. The system operator may still call a curtailment given the rapid drop in pressures to ensure system reliability.

Figure 11: 4.7 Bcfd, No Additional Outages – Northern System and Moreno Pressures

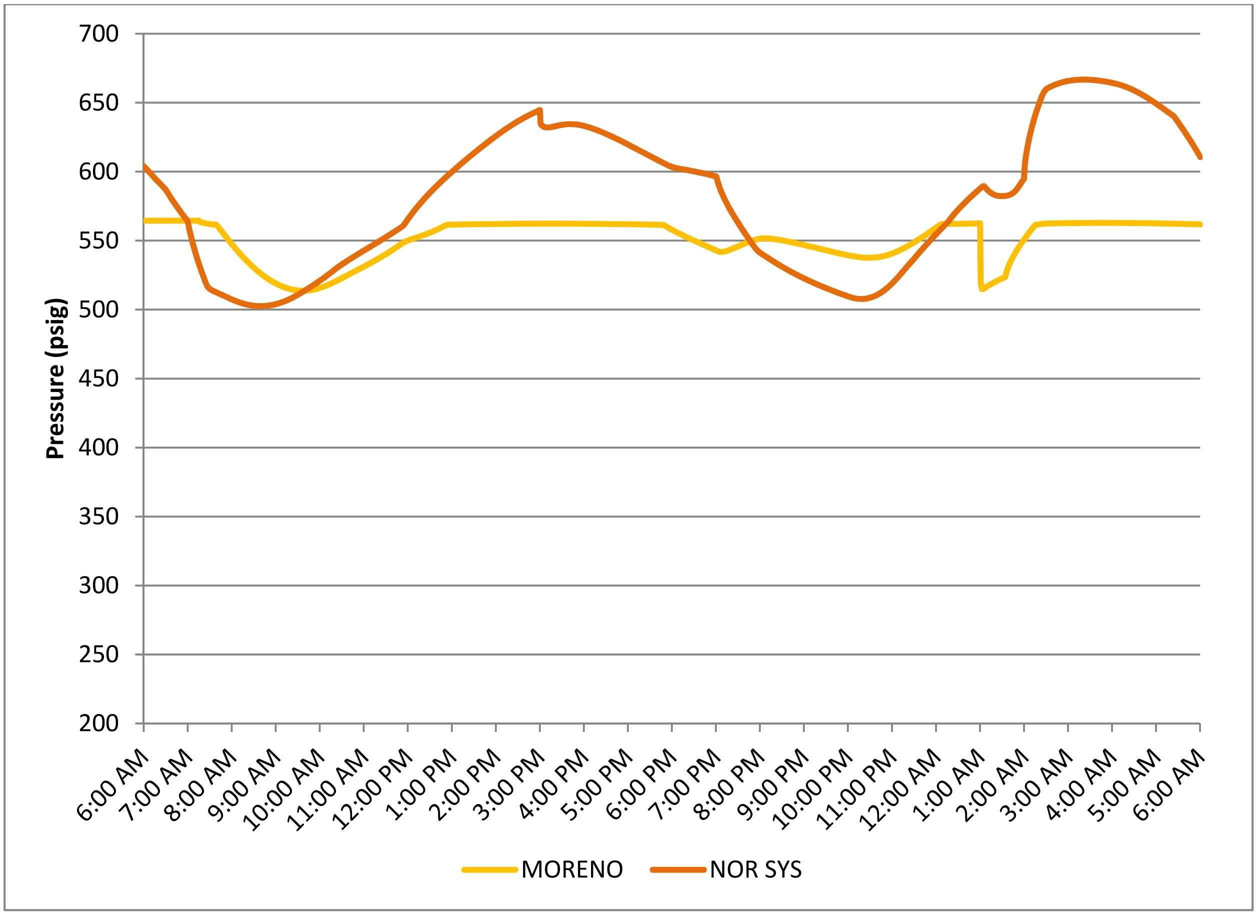
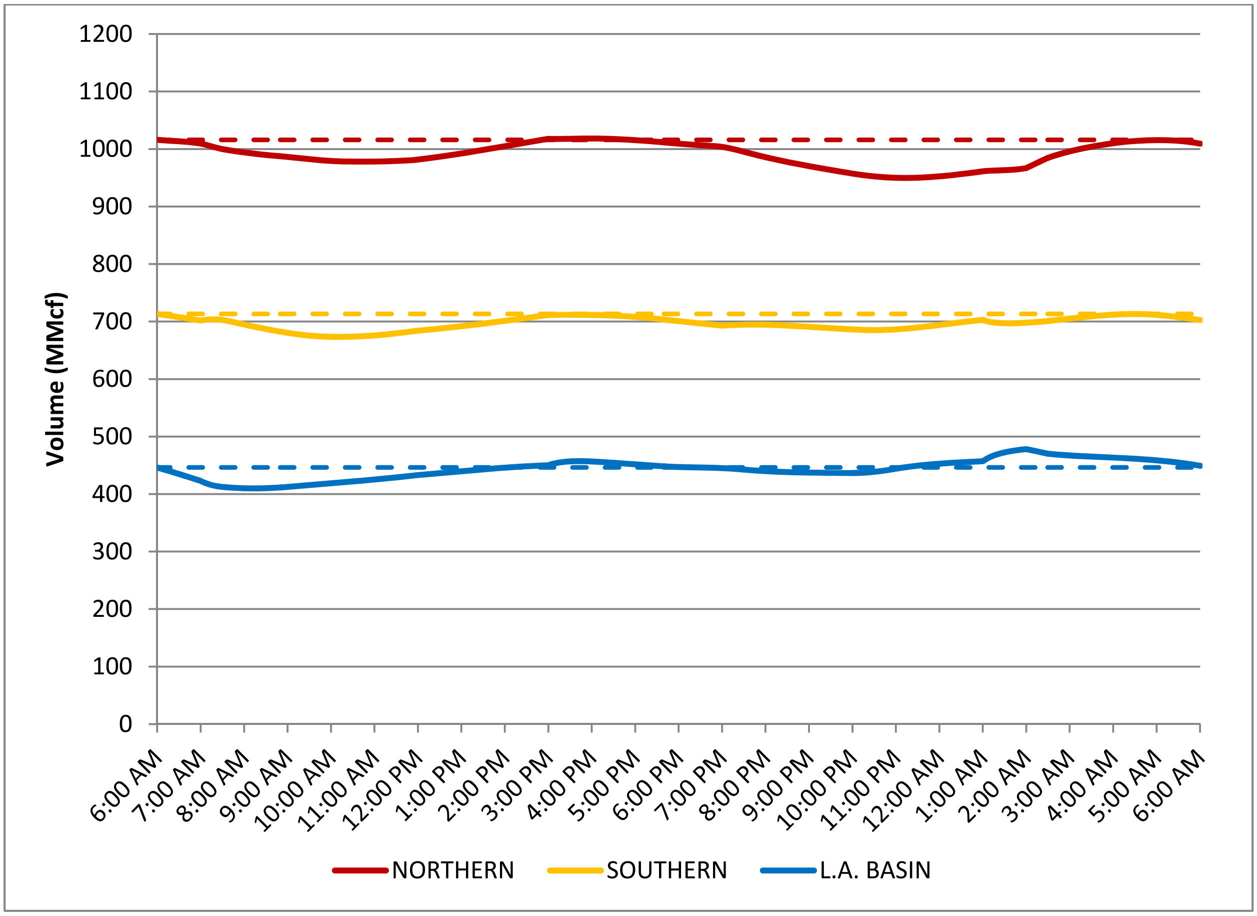


Figure 12 shows the linepack in three subsystems; the Northern System, the Southern System, and the Los Angeles Basin. By recovering linepack by the end of the day, it is theoretically possible to serve this level of demand continually. For each subzone, the linepack recovers to the morning levels.

Figure 12: 4.7 Bcfd, No Additional Outages – Subsystem Linepacks
(Initial Levels Indicated as Dotted Line)



The 4.7 Bcfd hydraulic analysis represents a successful simulation. All pressures are kept between minimum and maximum pressures, transmission capacities are not exceeded, and linepack is fully recovered by the end of the day.

Cold conditions frequently occur over consecutive days. The hydraulic analysis accounts for these consecutive days by requiring the linepack to fully return by the end of the day, allowing that day to be theoretically repeatable. Without Aliso and any other system outages, the maximum demand that can be supported is 4.7 Bcfd. Curtailment will be required for any day exceeding this demand, and additional curtailment will be required for insufficient supplies. This is true for each day during a cold period. For example, during a three-day cold period if insufficient supplies are received during the first day, curtailment will be required to maintain minimum system pressures and recover linepack in preparation for the second day.

Scenarios 2 & 3: Storage Tubing-Only Flow, Line 3000 Outage, and Receipt Point Utilization Assumptions

Tubing-only flow requires withdrawal wells at the storage fields to operate and withdraw gas from the reservoir through their respective inner tubing only, instead of also using the casing, which has a larger diameter than the tubing. The reduction in diameter limits the rate that the storage fields can withdraw and limits the demand able to be served. For Playa Del Rey and Goleta, withdrawal levels were kept to realistic daily withdrawal rates, which represent a tubing-only flow restriction. In the case of Honor Rancho, the stranded gas due to conflicts with the Wheeler Ridge Zone is equivalent to a tubing-only flow restriction at that field. Table 1 shows that the capacity to serve with and without the tubing-only flow constraint is both 4.7 Bcfd.

Line 3000 is a critical pipeline that receives supply from the Topock receipt point in the Northern System. With an outage on line 3000, 540 MMcfd from Topock cannot be received on the SoCalGas system. While 300 MMcfd of this supply loss can be received at the Kramer Junction receipt point, 240 MMcfd of supply would still be unavailable to the SoCalGas system. With line 3000 out of service, system capacity is further reduced to 4.5 Bcfd.

Any further loss in flowing supplies from the levels assumed in this assessment will result in a one-to-one ratio loss to sendout capacity. For example, an 85 percent receipt point utilization level results in a loss of about 530 MMcfd of pipeline supply (3565 – 0.85*3565), so the level of demand that could be supported falls to approximately 4.2 Bcfd (4700 – 535). Historically, winter supplies have mostly been within the range of 60 to 80 percent utilization. Before December 2015, SoCalGas winter balancing rules required customers to deliver 50 percent of supply to meet a five-day usage, and then balance on a monthly basis to within a 10 percent tolerance. SoCalGas and SDG&E now have the authority to compel customers to deliver higher levels of pipeline supplies during periods of system stress through the OFO and EFO mechanisms as specified in SoCalGas Rule No. 30 and SDG&E Gas Rule No. 30. While SoCalGas and SDG&E cannot forecast what level of supply may be delivered under the new balancing rules, it will likely be higher than what has been historically experienced, assuming that gas supplies are available for purchase and are not impacted by well freeze-offs or cold demand in other parts of the country competing for those supplies.

As the receipt point utilization drops below the assumed 100 percent level and/or other transmission or storage facilities are unavailable, service to noncore customers other than electric generation customers, including refineries, is at risk. Service to these other noncore customers is also at risk should the level of demand reduction required exceed the electric use at the time. Nothing in this assessment should be construed as limiting the risk to the electric generation market segment only.

Core Reliability, 1-in-35-Year Peak Day Design Standard

The 1-in-35-year peak day design standard is intended to protect core customers and includes demand only for core service. All other customers are assumed to be curtailed. Core demand[9] under this design standard is 3.5 Bcfd, which is within the system capacity to serve absent any supply from Aliso Canyon.

Although the system has sufficient capacity to serve the 1-in-35-year peak day demand, core customers may still be susceptible to a loss of service. Cold conditions are not typically limited to one region of the country, and other regions are all competing for limited gas supplies. Well freeze-offs further limit available gas supply, and noncore noncompliance to curtailment orders further jeopardizes core reliability.

SoCalGas normally uses storage supplies to address these situations. Without Aliso Canyon, storage withdrawal has been reduced by more than 50 percent. This limits SoCalGas' and SDG&E's options and flexibility to respond to these events.

In the case of noncore noncompliance to a curtailment order, SoCalGas and SDG&E may physically shut off noncompliant customers from the system that threaten core reliability. While this may lead to electric load shed or operational issues for customers such as refineries, those outcomes have faster recovery times than loss of core service and pilot light outages, and associated safety impacts. If that occurred, it would require several weeks to months before all pilot lights could be relit and core service re-established.

In the case of flowing supply shortages due to competition for limited pipeline supplies or well freeze-offs, there may be localized areas on the SoCalGas and SDG&E system where core service is lost. SoCalGas and SDG&E would take all operational actions to prevent such a situation, such as blocking open distribution regulators from the transmission system and curtailing service to nonresidential core customers. SoCalGas' operational options are limited without the significant level of storage supply that Aliso Canyon provided.

JOINT LADWP AND CALIFORNIA ISO IMPACT ANALYSIS AND RESULTS

Introduction

SoCalGas performed hydraulic simulation analysis for its 1-in-10-year cold day design standard representing a gas demand of roughly 5.2 Bcfd. SoCalGas determined that without supply from Aliso Canyon, critical operating gas pressures cannot be maintained in the Los Angeles Basin and Southern System to support the design standard. SoCalGas determined that a maximum winter gas demand of about 4.7 Bcfd could be supported without supply from Aliso Canyon as long as all transmission receipt points are utilized to 100 percent capacity. The maximum demand that can be supported on a 1-in-10-year cold day in conjunction with a line 3000 outage is further reduced to about 4.5 Bcfd. If receipt point utilization is less than 100 percent, there is a one-to-one reduction is supportable gas demand from the

[9] Retail and wholesale; the figures in Table 1 for core demand represent a 1-in-10-year temperature condition which is warmer than the 1-in-35-year condition.

4.7 Bcfd. Per SoCalGas' example at 85 percent utilization, the resulting supportable gas demand is about 4.1 Bcfd. Based on these findings, the LADWP and California ISO balancing authorities[10] jointly assessed impacts of the two different levels of supportable gas demand (4.7 and 4.5 Bcfd). In addition, two impact sensitivities were performed to determine the level of minimum gas capability necessary to support the electric system and avoid electric load interruption under normal and post-electric contingency events. These two sensitivities quantified for winter 2016-2017 1-in-10-year cold day show that about 4.1 and 4.2 Bcfd would be necessary to avoid load interruption under normal and post-contingency events, respectively.

Under CPUC rules,[11] electric generators are considered noncore service in the SoCalGas/SDG&E service territories and are the first gas customers called to reduce gas consumption. The more advance notice of such gas curtailments, the more time the electric system has to respond and reduce electric system impact. Short notice of gas curtailments reduces the options available to secure additional import energy to replace the energy lost by the gas curtailment. Because most replacement energy will have to be imported into the area, the ability of short notice gas curtailments will be limited by the electric transmission capacity and electric supply available outside the area at the time of the curtailment. Historically, during the winter season, Southern California and the Southwest have lower load level compared to summer. While the load may be lower, the availability of supply may be reduced due to fewer generators committed on-line and outages for scheduled maintenance.

As responsible balancing authority operators, the LADWP and the California ISO develop and implement daily resource plans to ensure adequate resources to meet their projected demand, including contingency and operating reserves required to meet the NERC reliability standard. These standards ensure sufficient resources are available to securely balance supply and demand under normal and contingency conditions.

This assessment focuses only on the electric reliability impact of gas constraints. There are also financial impacts of operating electric generation in non-economic ways to address supportable supply constraints on the SoCalGas/SDG&E service territories without Aliso Canyon. This assessment does not attempt to quantify those impacts.

Summary of Electric Findings

- The LADWP/California ISO joint power-flow study found that electric reliability can be satisfied for a 1-in-10-year winter peak electric load conditions with a minimum of gas burn of 96 MMcfd by electric generation in the SoCalGas/SDG&E service territories in response to post N-1 contingency conditions and as low as a gas burn of 22 million MMcfd (with somewhat higher risk) under normal pre contingency conditions and the ability to import generation into the LA Basin.

[10] The LADWP and California ISO balancing authorities include the municipal utilities of Anaheim, Riverside, Pasadena, Azusa, Banning, Colton, Burbank, and Glendale. The balancing authorities will be referred to as the LADWP and California ISO throughout the electric analysis section of this document.

[11] CPUC Decision 16-07-008 adopted a new curtailment procedures settlement agreement on July 14, 2016.

- Gas curtailment of electric generation may be necessary when the SoCalGas total core and non-core gas demand exceeds 4.5 Bcfd assuming 100 percent gas receipt point utilization or 4.2 Bcfd assuming 85 percent gas point utilization.
- The electric system is expected to be able to maintain electric reliability for the winter 2016-2017 without interruption to electric service so long as the total SoCalGas supportable gas delivery and supply is greater than 4.1 Bcfd under normal conditions and 4.2 Bcfd in case of N-1 contingency conditions on the electric system.
    - Under normal conditions, sufficient electric transmission and electric supply from resources outside the SoCalGas/SDG&E service territories are expected to be available to replace the magnitude of gas curtailments that may occur during the winter of 2016-2017. Depending on the magnitude and timing of gas curtailments, access to replacement energy may require emergency assistance from neighboring balancing authorities.
- If supportable SoCalGas gas delivered supply falls below 4.1 Bcfd during peak winter gas demand conditions, it may be necessary to withdrawal from Aliso Canyon to avoid electric load interruption.
- Although the electric system can operate with extremely low gas consumption during the winter months, doing so would result in increased energy dispatch costs.

Reliability assessments are conducted based on the expected electrical system conditions for the operating time period being analyzed. This focus in this report is the upcoming winter. These studies are performed using the applicable WECC seasonal base case, modified as needed to simulate the conditions expected for this season. This includes all planned transmission and generation outages. These conditions are modeled in an off-line power flow program that runs a battery of transmission and generation contingencies to determine minimum generation commitment and post contingency generation necessary to maintain NERC reliability requirements.[12]

The winter power flow case was modeled to study the minimum generation required in the LADWP and California ISO systems to maintain electric system reliability. The fleet of resources dependent on gas supplied by SoCalGas inside the Los Angeles Basin and the Southern System were kept at minimum while maintaining reliability of the electric system. Additional assumptions include maximizing the electric transmission capability for imports into the southern electric system while maintaining electric system reliability.

Multiple power flow case studies were developed for this assessment using the WECC - Operational Study Subcommittee's winter 2016-2017 1-in-10 winter power flow case. The winter peak analysis assumes the following electric demand levels:

[12] Minimum generation commitment and post-contingency generation are key drivers for gas usage and are necessary to avoid post-contingency load shed.

- SCE = 14,490 MW
- SDGE = 3,417 MW
- LADWP = 4,006 MW

The above load level roughly matches the peak demand on January 14, 2013 for SCE, SDG&E, and the LADWP, which was 21,828 MW,[13] and the system conditions assumptions in the SoCalGas 1-in-10-year cold day design standard. On January 14, 2013, the actual gas burn for the LADWP and California ISO was 885 MMcfd, which nearly 200 MMcfd less than the electric generation gas burn used in the SoCalGas 1-in-100-year cold day design condition.

As balancing authority and transmission operator, the LADWP and California ISO are required to meet NERC reliability standards requirements. These include the following:

- The requirement for the balancing authority to carry and maintain a minimum amount of contingency reserve.
- The requirement for the balancing authority and transmission operator to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 contingency planning) in accordance with NERC, regional reliability organization, sub-regional, and local reliability requirements.

The LADWP and California ISO performed a joint assessment to determine the minimum generation requirements based on the expected winter peak load. This assessment included the following:

- Power flow analysis to ensure acceptable electric system performance under pre- and post-contingency operations.
- Assumed normal transmission system configuration with all lines in service.
- The minimum generation levels to maintain local reliability, extrapolated to meet the load pattern.
- Maximized imports based on transmission and supply limitations required to meet customer demand not met by minimum generation levels within the SoCalGas service territory.

The winter reliability assessment focused on local transmission reliability including the contingency reserve requirement necessary to immediately meet the greater of the loss of the Most Sever Single Contingency (MSSC) or approximately 6 percent of the hourly peak load. The assessment also included replacement reserve capacity that will need to be sourced and procured after the first hour of a contingency.

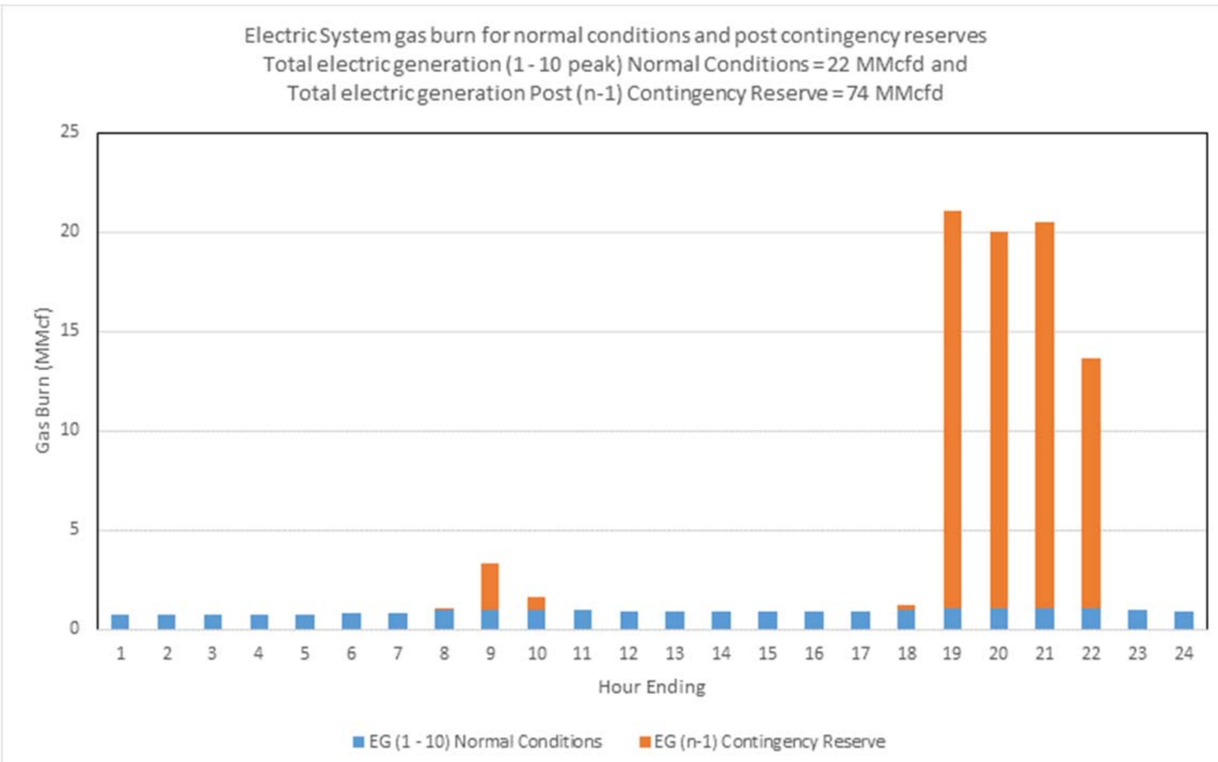
The quantity and location of the generation commitment may vary depending on load level, system topology, fuel costs, and economics each day. Historical experience and the winter 2016 seasonal assessment performed by the LADWP and California ISO show the need to have a minimum amount generation commitment inside the Los Angeles, Orange County and San Diego areas. The level of

[13] LADWP and California ISO winter peak loads occurred on January 14, 2013.

minimum generation commitment in the winter season is typically significantly lower than in the summer season.

Figure 13 shows the minimum generation needed in both LADWP and California ISO balancing authorities to meet normal conditions and to recover from a non-simultaneous contingency. The generation need is translated into a gas requirement 22 MMcfd and 96 MMcfd without the qualifying facilities (QF), respectively. A QF is a qualifying cogeneration facility or qualifying small power production facility, as defined in the Code of Federal Regulations, Title 18, Part 292 (18 C.F.R. § 292).

Figure 13: Minimum Generation, Gas Requirements in MMcfd



Impact Assessment

Minimum Energy Requirement

An analysis was conducted to determine the minimum energy and capacity requirements for the LADWP and California ISO system within the SoCalGas service area under normal 1-in-10-day winter operating conditions. Assuming all transmission lines are in service and non-QF generation is available, during winter peak conditions, the minimum output of generation served by the SoCalGas/SDG&E service territories to meet the studied reliability criteria was 108 MW for the combined LADWP and California ISO area. The combined minimum gas burn of 22 MMcfd was necessary to maintain electric reliability as shown in Figure 13.

A second analysis was conducted to determine the minimum energy and capacity requirements for LADWP and California ISO system within the SoCalGas service area under a post-contingency event during the 1-in-10-day winter operating conditions. To meet the requirement following the most severe single contingency, the minimum commitment of non-QF generation served by SoCalGas is 2,000 MW for the California ISO and is 585 MW for the LADWP. The energy commitment will be the greater of these two post-contingency needs as these contingencies are not assumed to be coincident events. These energy requirements were translated to a combined minimum gas burn of 96 MMcfd was necessary to maintain electric reliability after the worst case contingency event for the combined LADWP and California ISO area.

An analysis looked at the feasibility of procuring and delivering energy from outside the SoCalGas/SDG&E service territories into the Los Angeles Basin and the Southern System. The analysis evaluated the ability to replace the difference between the expected normal electric generation operating level of 885 MMcfd gas burn and the maximum supportable gas capability of 564 MMcfd or 462 MMcfd for noncore electric generation sector [14] determined by the SoCalGas assessment assuming 1) 100 percent receipt point utilization and no gas system outage and 2) 100 percent utilization, and tubing withdrawal only in conjunction with a line 3000 outage, respectively.

The minimum requirements discussed above also account for local transmission or distribution systems including local utilities that are embedded within the LADWP and California ISO balancing areas such as the cities of Riverside, Pasadena, Glendale, and Burbank.

The study also considered the NERC contingency reserve requirements that dictate that available unloaded generation is available to be called on and loaded to cover the loss of generation or transmission elements within the electric system. This reserve is required to be dispatched to cover the loss of MSSC and is typically within the 700 to 800-MW range for the LADWP for this level of imports. The reserve requirement for the California ISO supplied in the SoCalGas region is 400 to 800-MW. The reliability requirement is to cover this loss within 15 minutes and a second requirement to restore the contingency reserves within 60 minutes of activation. In many cases for the LADWP, this reserve energy must come from resources in the Los Angeles Basin.

Local Area Analysis

The local area impacts on electric generation, shown in Table 2, is based on the minimum generation under normal conditions resulting in a combined gas burn of 22 MMcfd for the LADWP and California ISO. Two supportable gas scenarios were assessed:

- The electric generation impact at a 4,668 MMcfd supportable gas demand at 100 percent receipt point utilization with no outages.
- The electric generation impact at a 4,566 MMcfd supportable gas demand with storage tubing withdrawal only and a gas line 3000 outage.

[14] Refer to Table 1.

Two additional sensitivity analyses were performed to determine the minimum supportable gas supply necessary to electric generation to avoid electric load interruption during a 1-in-10 winter load day under normal and post-contingency conditions.

The analysis began with the 5.2 Bcfd 1-in-10-year cold day design condition. It then credited the difference between the assumed gas burn for electric generation in the SoCalGas 1-in-10-year cold day demand forecast (1,094 MMcfd) and the highest historical combined winter gas burn for the LADWP and California ISO (885 MMcfd). An additional gas curtailment was taken to arrive at the gas demand in the scenarios above. The required gas curtailment was subtracted from the actual gas burn and compared to the minimum gas requirement. The ability for the gas supply to meet the electric generation minimum gas requirements is indicated in row 15 for the normal condition and row 16 for the post-contingency condition. A positive value indicates the amount of gas delivery that is capable of being supported is greater than the minimum gas requirement necessary to meet local reliability for the combined LADWP and California ISO balancing area. A positive value in rows 15 and 16 indicates that if a gas curtailment of electric generation load is called, the quantity of gas curtailment is not expected to impact the ability to meet electric demand. It would result in an increased cost in serving electric load. To the extent that the minimum gas requirements cannot be met, as indicated by a negative value, and all electric generation is curtailed as shown in column 3, the remaining curtailment will need to be mitigated by withdrawing gas supply from Aliso Canyon if available, coming from other noncore customers, or reducing electric load.

Table 2: Summary of Assessment of Electric Impact of Gas Curtailments for January 14, 2013 (Under Normal and Contingency Conditions)

Row	Description	Formula	Gas Curtailment Scenario - 100% Utilization - no outage	Gas Curtailment Scenario - 100% utilization, tubing WD only plus, line 3000 outage	Gas Curtailment Scenario - maximum curtailment that EG can handle under normal conditions - 84% Utilization
			January 14, 2013 - 1 in 10 Peak	January 14, 2013 - 1 in 10 Peak	January 14, 2013 - 1 in 10 Peak
1	SoCalGas 1-in-10 Gas Day Standard Requirement (MMcfd)		5,200	5,200	5,200
2	Gas burn credit for higher 1-10 EG forecast by SoCalGas as compared to January 14, 2013 actual EG burn (MMcfd)	1094 mmcfd - 885 mmcfd	209	209	209
3	Adjusted demand using the gas burn credit (MMcfd)		4,991	4,991	4,991
4	Additional gas curtailment for EG in order to maintain the supported gas demand (MMcfd)		323	425	863
5	Supported gas demand after the additional EG curtailment (MMcfd)		4,668	4,566	4,128
6	Actual ISO SoCalGas system gas burn on January 14, 2013 (MMcfd)		685	685	685
7	Actual LADWP balancing area gas burn on January 14, 2013 (MMcfd)		200	200	200
8	Combined actual ISO and LADWP gas burns (MMcfd)	Row 6 + Row 7	885	885	885
9	(ISO + LADWP) Actual Burns - Gas Curtailment (MMcfd)	Row 8 - Row 4	562	460	22
10	ISO SoCalGas system gas burn with minimum generation - with all transmission lines in service and no outages (MMcfd)		22	22	22
11	LADWP balancing area gas burn with minimum generation - with all transmission lines in service and no outages (MMcfd)		0	0	0
12	ISO SoCalGas system gas burn to cover n -1 contingency reserves (MMcfd)		74	74	74
13	LADWP balancing area gas burn to cover n -1 contingency reserves (MMcfd)		53	53	53
14	Combined ISO and LADWP minimum generation gas burn including the higher of the n-1 contingency reserves from LADWP and ISO (MMcfd)	Rows 10 + Row 11 + max(Row 12 , Row 13)	96	96	96
15	Amount of gas left for ISO + LADWP under normal conditions and with all transmission lines in service to maintain electric reliability (MMcfd)	Row 9 - Row 10	540	438	0
16	Amount of gas left for ISO + LADWP in order to cover n-1 contingency reserve to maintain electric reliability (MMcfd)	Row 9 - Row 14	466	364	-74
17	ISO LADWP MW Conversion of Gas Burn Short in Row 16 per hour (MW)	Row 16*103/24	2,000	1,562	-318

Ability to Re-supply Energy in the Event of Gas Curtailment

During a gas curtailment, a reduction in available gas will require replacing the electric generation within the SoCalGas/SDG&E service territories with electric generation from non-curtailed resources outside the service area. The LADWP and California ISO will attempt to re-dispatch to other energy sources but the options are limited to imports or other uncommitted gas resources. Other factors include transmission import capability and energy availability, and can take one to two hours to achieve.

Transmission availability into the Los Angeles Basin, Orange County and San Diego Areas

Transmission capacity for the winter is significantly greater than that of the summer. Increased transmission capacity combined with lower winter system loading, results in fewer direct impacts as a result of Aliso Canyon.

Import capability in Southern California from Northern California is limited by the north-to-south transmission path (Path 26) at a maximum of 4,000 MW total transfer capability when all lines are in service. If energy is already flowing before a gas curtailment, there will be limited capacity available to transport energy to absorb the curtailment. In addition, there is nearly 10,100 MW of east-to-west transmission capability between the California ISO and Nevada[14] and Arizona. In real-time, the ability to increase energy delivery from the Southwest is limited by the small amount of supply available.

Available generation outside the area served by SoCalGas

There are some gas-fired resources in Southern California that take gas service from pipelines other than those of SoCalGas/SDG&E such as the High Desert Power Plant. These resources can be used to help address gas curtailments to gas-fired resources on the SoCalGas/SDG&E service territories but may not serve to mitigate local transmission constrained areas in the Los Angeles Basin and the Southern System. In addition and depending on weather conditions, solar, wind, and hydro resources in Southern California can also be used to compensate for electric supply lost due to gas curtailment.

For the Los Angeles Basin, some energy may be shifted from gas-fired generation to the Castaic Power Plant in real time. But energy from Castaic is limited by reservoir elevation, and the plant cannot sustain maximum output for more than a few hours, particularly on successive days. Additionally, the scheduled maintenance plan has identified a six-week Castaic Federal Energy Regulatory Commission-mandated main plant and tunnel outage that will take place mid-November through mid-December 2016, making it unavailable. With Castaic unavailable, LADWP is forced to rely completely on external sources to address gas curtailments. This outage was considered in the power flow studies and the pre- and post-contingency reserve requirements. Once this maintenance is complete, LADWP gains greater flexibility to maintain reliability under gas curtailment scenarios.

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[14] In November 2015, NV Energy started participation in the Energy Imbalance Market (EIM). NV Energy's participation in the EIM there increases the real-time transfer capability between Nevada and Southern California and therefore increases the flexibility for the California ISO to respond to real-time gas curtailments.

Table 3 shows the volume of supply outside the SoCalGas region that would be necessary to replace electric generation in the event of gas curtailments. The analysis began with the gas curtailment that is translated in the amount of electric supply replacement required. The analysis sums up the expected available transmission capacity and non-gas-fired generation in the Southern California area and subtracts it from the replacement requirement in row 2. A positive number in row 9 indicates that the generation impacted by the gas curtailment can be replaced from outside generating resources. Replacement energy may require emergency assistance from neighboring balancing authorities. If the remaining energy is a negative number, and all re-supply options have been exhausted, additional gas will be required from other sources including Aliso Canyon or load shed may be required.

Table 3: Summary of Assessment of Electric Impact-Based Energy Replacement

Row	Description	Formula	Gas Curtailment Scenario - 100% Utilization - no outage	Gas Curtailment Scenario - 100% utilization, tubing WD only plus, line 3000 outage	Gas Curtailment Scenario - maximum curtailment that EG can handle under normal conditions - 84% Utilization
			January 14, 2013 - 1 in 10 Peak	January 14, 2013 - 1 in 10 Peak	January 14, 2013 - 1 in 10 Peak
1	Additional gas curtailment for EG in order to maintain the supported gas demand (MMcfd)		323	425	863
2	Supported Gas Demand after additional EG curtailment (MMcfd)		4,668	4,566	4,128
3	Energy Conversion of Curtailment for the hour (MW)	Row 1 *103/24	-1,386	-1,824	-3,704
4	Availability on Path 26 - Historical Average (MW)		1,047	1,047	1,047
5	Availability on Imports from East to West - Historical Average (MW)		2,805	2,805	2,805
6	Unloaded Capacity - SP26 (from Non-Gas Resources) (MW)		855	855	855
7	ISO available transmission capacity + available reserves from non-gas SP26 resources (MW)	Row 4 + Row 5 + Row 6	4,707	4,707	4,707
8	LADWP available transmission capacity + available reserves from non-gas resources (MW)		1,148	1,148	1,148
9	Total MW remaining after replacing the energy in case of curtailment for one hour	Row 3 + Row 7 + Row 8	4,469	4,031	2,151

The winter assessment was based on the establishment of the capacity available to meet gas demand absent supply from the Aliso Canyon storage field, based upon a 1-in-10-year cold day design standard, and the resulting impact on electric generation and reliability. The frequency of a curtailment event is indeterminate with this process, and would require information on daily usage unknown at this time. In lieu of estimating the number of days of risk of curtailment, a review of the historical five years of gas sendout on the SoCalGas system, as posted on ENVOY,[15] was conducted and shown on Table 4. This data is not an attempt to predict or infer the probability or number of days of risk going forward.

Table 4: Five Years of Historical Gas Sendout

MMCFD	Average Send out Days	Total send out days in 5 years
1 - 3000	108.20	541
3000 - 3500	36.20	181
3500 - 4000	19.40	97
4000 - 4500	5.00	25
4500 - 4700	0.20	1
ABOVE 4700	0.40	2

In conclusion, electric generation could be susceptible to gas curtailments during winter 2016-2017 without Aliso Canyon. Based on the electric analysis, these gas curtailments are not expected to result in electric load interruption as long as the gas supply and receipt point utilization remains above at least 84 percent (corresponding to a 4.1 Bcfd system capacity) on peak gas demand days. At an 84 percent receipt point utilization, the analysis indicates that the LADWP and California ISO are expected to be able to secure enough generation outside the SoCalGas/SDG&E service territories on an hourly basis to mitigate the need for electric load shedding. If the supportable gas delivery or supply falls below 4.1 Bcfd for local reliability or below 3.6 Bcfd for system reliability, it may be necessary to withdraw gas from Aliso Canyon to avoid electric load interruption during peak winter load conditions. This assumes that there are no multiple outages on the electric and gas system.

MITIGATION MEASURES

Mitigation measures are being reviewed and modified in the Winter Action Plan that attempts to reduce the risk identified in the technical assessment.

[15] www.socalgas-envoy.com; ENVOY is SoCalGas' electronic bulletin board which enables end-use customers, shippers, and energy marketers to schedule gas for delivery into Southern California.