Western Interconnection Gas – Electric Interface Study

Public Report

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1. Introduction

Executive Summary

The Western Interconnection is currently undergoing a fundamental transformation with the retirements of baseload resources and large additions of solar and wind generation. Up until 2015, Aliso Canyon’s 86 bcf of market-area gas storage and 1.8 bcf of withdrawal capacity were historically sufficient to balance system variability in the Southern California region. However, the operational limitations imposed on Aliso Canyon are now highlighting several issues that were previously masked; we are now effectively in an N-1\(^2\) scenario with any major disruptions in the gas transmission system or the Bulk Power System (BPS) pushing the system to the limit.

We expect two major factors to transform the role of natural gas generation in the electric power system of the Western Interconnection as we move forward:

- System reserve margins are expected to become increasingly tight through 2026, driven by baseload coal and nuclear retirements as well as steady increases in power demand; as a result, Wood Mackenzie and E3 forecast natural gas demand for power generation across the Western Interconnection to increase by 30% by 2026.
- Expansion of low-cost renewable generation capacity driven largely by state renewable policy goals will limit the overall need for utilization and dispatch of natural gas generation but will not fully replace the need for dependable electric generation capacity to meet peak demands and ensure the reliability of the bulk power system (BPS); while some of the capacity needs may be met by energy storage added in conjunction with increasing renewable penetration, the need for firm generation will not be eliminated.

To explore the nature of the vulnerability of electric reliability to major gas infrastructure disruptions, we examine multiple disruption scenarios representing pipeline ruptures, compressor station failures, and supply freeze-offs. Modelling and analysis of multiple disruption scenarios yields a number of key findings:

- The configuration of the gas-electric system combined with the retirement of Aliso Canyon creates region-wide reliability issues, resulting in widespread loss of electric load; the Southwest and Southern California regions appear to be most vulnerable to major disruption events due to 1) heavy reliance on gas generation to meet peak demands, and 2) limited gas storage capability.
- Other regions in the Western Interconnection are more resilient to major gas system disruptions, largely owing to increased compensation capabilities stemming from market-area gas storage and alternative energy sources including reliance on the region's robust interstate transmission system.
- The existing strain on the system indicates that even modest changes to working assumptions such as fossil fuel plant closures or natural gas storage limits could exacerbate existing challenges; natural gas support will continue to be necessary to ensure system reliability while achieving policy goals.

Consequently, the development of a balanced portfolio of mitigation options is critical to assure system reliability in a changing power landscape. Maintenance of and new investments in gas and electric infrastructure are necessary to preserve reliability of the BPS:

- Maintaining and investing in natural gas infrastructure — including supply, delivery, storage, and generation—is necessary to meet the near-term and long-term reliability needs of the Western Interconnection even as the BPS transitions towards higher penetrations of renewable and energy storage resources.
- At the same time, pursuing a balanced portfolio of alternative mitigation strategies can help insulate the BPS from reliability risks at the gas-electric interface; these include investments in renewable generation and energy storage, demand response programs, and dual-fueled generation capability.

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1 Working capacity reduced to 24 bcf
2 Refers to a contingency involving the unexpected failure or outage of a system component. N-1 refers to the failure of one large system component, N-2 refers to the combination of two such failures, etc.
• Improved coordination of gas and electric industries' operating practices will be critical for maximizing compensation capability and ability to respond to both business-as-usual and sustained disruption scenarios. The project team has identified five distinct areas for potential change:
  o **Improved Regional Coordination**: Implementation of regional contingency planning exercises led by WECC to facilitate coordination and compensation responses
  o **Resource Adequacy Assessment**: Greater transparency of firm gas supply contracting and linkage to power plants served in planning reserve margin reports to allow for more robust planning processes
  o **Curtailment Priorities**: 1) Designation of specific plants as critical to grid reliability as core end-use to allow for additional flexibility for compensation via transmission, 2) Additional clarity around interstate pipeline curtailment protocol (e.g. transparency around single-sourced customers and other possible exceptions to written protocols)
  o **Forecasting & Execution**: Revisit LDC balancing procedures for core customers (e.g. previous-day nominations versus actual usage) to alleviate operating pressures on generation customers
  o **Gas-Electric Day Mismatch**: Split of the existing weekend nomination period into daily blocks, resulting in a 7-day nomination cycle to minimize response times over the weekend period

• Moving these changes forward will require buy-in at all levels (e.g. gas pipeline operators, utilities, generators, PUCs, NERC, NAESB, FERC) in order to effectively improve existing protocols and procedures

**Background**

In September 2017, the Western Electricity Coordinating Council ("WECC") commissioned Wood Mackenzie ("Woodmac"), Energy + Environmental Economics ("E3"), and Argonne National Laboratory ("Argonne") to conduct a study of the gas-electric interface in the Western Interconnection to identify potential threats to grid reliability at present and in the future. The Western bulk power system ("BPS"), which includes a regionally and technologically diverse portfolio of generation resources, is currently undergoing two simultaneous major transitions that will impact its future operations and the role of natural gas generation:

• Baseload coal and nuclear plants are expected to retire in significant quantities in the coming decade
• Cost reductions and regional policies will result in significant deployment of low-cost variable resources such as wind and solar PV

Each of these changes will impact the role of natural gas generation in the power system, though their impacts will be different (and in some instances, countervailing). Retirement of existing baseload resources will most likely result in increased commitment and dispatch of existing natural gas generation and may require additions of new firm gas generation capacity to ensure system reliability. The addition of renewable generation, on the other hand, will tend to reduce dispatch of gas generators for supplying energy, but will not fully displace the need for dispatchable resources to ensure system reliability due to the variability and intermittency of solar and wind resources. While the net impact of these two transitions on the overall level of gas throughput will depend on the pace of each transition, a large base of installed natural gas capacity will undoubtedly continue to play a crucial long-term role in meeting the reliability needs of the Western Interconnection, providing key flexibility and peaking services to the BPS.

As the BPS undergoes major changes in the composition of its resource base, the ability of the gas delivery network of the Western Interconnection to keep up with increasing peak demand becomes a key question. The challenges faced in the Los Angeles Basin because of the Aliso Canyon gas storage field situation in 2015 have focused attention on the reliability and adequacy of the existing natural gas delivery system to support electric generation in the West now and into the future.

The project team of Woodmac, E3, and Argonne was selected for their combined ability to bring a detailed and comprehensive view of both the gas and electric industries as well as their ability to provide granular modeling capabilities, which was critical to the success of this study:

• Wood Mackenzie is a commercial research and consulting firm whose expertise spans the entire energy value chain. Within the natural gas industry, Woodmac leverages its world-class research capabilities and expertise to form a comprehensive view of gas markets, supported by its detailed upstream and production data, demand forecasts, and midstream flow/price modeling capabilities
• E3 is one of the premier power consulting firms in the West and possesses extensive experience in all sectors of the electricity industry. E3 provides unparalleled expertise of power markets, planning, policy, regulation,
Argonne National Laboratory is a US Department of Energy (USDOE) multidisciplinary science and engineering research laboratory with significant experience in disaster impact analysis and pipeline hydraulic modeling. Argonne has substantial experience in similar reliability studies and consequently can leverage its comprehensive datasets on power plants, gas pipelines, and gas contracting.

To this end, the project team engaged in an extensive eight-month effort with input from key gas and electric stakeholders to 1) conduct an assessment of market dynamics through 2026; 2) define and model 10 natural gas disruption scenarios and evaluate the resulting impacts to the BPS and 3) analyze the capabilities and cost of potential mitigation options and identify actionable recommendations for improving existing operations, procedures, and protocols. Ultimately, the goal in the study was to identify where and under what conditions fuel supply risks exist and to identify possible mitigation options for utilities to ensure that the gas generation fleet has a reliable supply of fuel that can allow for the flexible generation profiles we expect to become increasingly prevalent in the future.

This Public Report details the key findings and results from our study, which utilizes the 2026 WECC Common Case\(^3\) as its base forecast. While this study incorporates and utilizes significant input provided by key utilities and gas pipeline operators in the West, the statements and opinions expressed in this document reflect the views held by the project team of Woodmac, E3, and Argonne. This document is intended for public circulation and consequently does not include all supporting details and information from the study due to confidentiality reasons.

## 2. Western Interconnection Market Dynamics

The BPS of the Western Interconnection has historically been powered by a diverse mix of energy supply resources and associated delivery infrastructure:

- Baseload coal and nuclear generation,
- Baseload, intermediate, and peaking natural gas generation, supplied by long-haul gas pipelines and market-area storage,
- Large-scale hydroelectric generation, and
- Variable and baseload renewables generation (e.g. solar, wind, and geothermal)

Historically, the existing network of interstate and intrastate gas pipelines and storage facilities have been sufficient to meet the operating needs of gas generators in the BPS. However, the gas-electric system has already experienced a number of events symptomatic of a system operating at or near its physical limits:

- Unplanned SoCalGas pipeline outages in fall 2017 resulted in gas price spikes of >$12/mmbtu,
- Freeze-offs in winter 2018 brought the interstate gas system to the brink of firm gas curtailments, and
- In March 2018, the CPUC ordered SoCalGas to inject gas after storage inventories reached “critically low” level

The gas-electric interface of the Western Interconnection faces increasing volumetric and flexibility constraints that could translate to reliability challenges. Coal and nuclear retirements create a deficit of baseload generation capacity in the bulk power system, increasing the dependence on gas. Large additions of renewables help mitigate the loss of coal- and nuclear-generated power but do not replace the increased need for the firm, dependable capacity provided by natural gas generation.

\(^3\) 2026 WECC Common Case version 1.5
This study uses the WECC 2026 Common Case\(^4\) as the basis of the analysis conducted. The Common Case, using assumptions developed from current utility plans and state energy policy, assumes the following key changes to the loads and resources of the Western Interconnection:

- Retirements of ~9 GW of coal and ~2 GW of nuclear by 2026 across the region, including major baseload plants in California, the Pacific Northwest, and the Desert Southwest
- Wind capacity increases by 9 GW to reach 29 GW of capacity, with most additions in the Pacific Northwest
- Solar capacity doubles to 36 GW of capacity by 2026, with 18 GW of additions solely in California
- Total Western Interconnection load increases by ~7% from 2018 to 2026

The changing composition of the generation fleet in the Western Interconnection has several implications for the role of natural gas within the electricity sector.

First, at the levels of baseload retirements and renewable additions considered in this study, overall reliance on natural gas for electricity generation will increase in the coming decade. The amount of renewable generation needed to meet current state policy goals is not sufficient to entirely offset the loss of roughly 12,000 MW of baseload generation retirements. Figure 2.2 shows the trend in natural gas demand and utilization of combined cycle gas turbines between 2018 and 2026; across the full Western Interconnection both trend upward, linked directly to the scheduled retirements of baseload generators shown in Figure 2.1. Specific trends vary by region; for instance:

- In California, where addition of renewables to meet a 50% RPS policy goal is expected to drive large and steady investment in renewables, gas utilization declines slowly until 2024, when the retirement of the 2,000 MW Diablo Canyon Nuclear Power Plant causes a notable upward swing in gas dispatch.
- In the Southwest and Northwest regions, coal plant retirements planned for the coming years are expected to result in a near-term increase in demand for natural gas generation; if additional coal plants are shut down this upward trend could be exacerbated. Our market analysis has been supported by additional discussions with key pipeline operators in the region, who have all expressed concerns around tightening constraints and less available capacity in the same timeframe.

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\(^4\) WECC 2026 Common Case version 1.5
Second, natural gas generation will play an increasingly important role in meeting system reliability needs during peak periods. Because of their timing of production and intermittency, wind and solar PV resources have a limited contribution to meeting regional peak demands compared to firm, dispatchable resources like coal or natural gas. While energy storage appears poised for a major cost breakthrough, its capability to displace the need for firm generation resources is currently unknown but likely limited; the need for energy storage resources to maintain a state of charge to dispatch on demand and their reliance on other generation resources to provide that state of charge limits their potential contributions to system reliability. As a result, natural gas resources will continue to play a growing role in meeting regional capacity needs, and with the retirement of significant quantities of firm baseload generation, additional investment in gas generation is likely needed within the region to meet reliability needs.

Third, the changes in the resource mix of the Western Interconnection will change the timing and nature of how gas generation resources are dispatched and, by extension, the patterns of demand for natural gas. Increasing penetrations of intermittent renewable generation—specifically, wind and solar PV—will lead to increasingly variable and uncertain "net load"—electricity demand less the output from renewable resources. This phenomenon is illustrated in Figure 2.3, which shows the change in California net load between 2017 and 2026 on a typical summer day. The anticipated expansion of solar PV in California creates a need for significant upward ramping capability over a relatively short times scale (approximately three hours); much of this upward ramping capability will be met by flexible natural gas generation. In an industry whose business practices and conventions are largely designed around the concept of a ratable gas day, the increasingly variable and uncertain nature of natural gas demand may create strains between pipelines and generators.
Of course, the impacts described above are an outcome resulting from the specific assumptions made in the study with respect to baseload retirements and renewable additions. Events that have occurred since the time of the development of the 2026 Common Case appear likely to accelerate the trends discussed above; utilities have announced plans to shut down additional coal units, and advancing policy discussions in many states and demand for clean energy resources increasingly driven by customer demands may also lead to increased renewables and energy storage over the same time. These uncertainties make the outlook on natural gas demand in the power sector itself uncertain in the future; however, regardless of the level of natural gas demand in electricity, natural gas generation will continue to play a crucial role in meeting the region’s reliability needs, and maintenance (or even expansion) of infrastructure needed to ensure its availability cannot be neglected.
The Western Interconnection enjoys access to diverse, abundant, and economic natural gas supply sources between the Western Canada (WCSB), Permian, Rockies and San Juan basins. The combined reserves represent 350 tcf available at break-evens of less than $4/mmbtu for dry gas and $50/bbl for associated gas. However, this wealth of resources is dependent on a limited number of long-haul pipelines to deliver natural gas from supply areas to large demand centers in the Pacific Northwest, California and the Desert Southwest:

- DSW markets (e.g. Phoenix) are essentially dependent on the El Paso and Transwestern pipelines
- PNW markets rely upon Northwest and GTN pipelines for their natural gas as well as gas storage
- Northern California markets are supplied by GTN and, to a lesser extent, Ruby pipelines as well as gas storage
- Southern California markets are reliant on El Paso, Transwestern and Kern River pipelines as well as gas storage

This widespread reliance on long-haul pipelines results in reliability risk due to the potential for disruptions in delivery capability; a major gas disruption at a single point can have additional effects in several different markets.

As shown in Figure 2.4, most major interstate pipelines in the West are expected to be highly utilized (80% - 95% on peak month basis, of which about half of the demand comes from power generation). Natural gas supply to the Desert Southwest will become increasingly supplied from the Permian basin, as San Juan production is expected to slowly decline over time. This switch will create a greater reliance on Permian and West Canadian gas for the West region, with potential reliability risks in Desert Southwest and Southern California, as well as the Pacific Northwest that are studied in the next section.
Another critical assumption to this study is the decommissioning of the Aliso Canyon underground natural gas storage. This assumption was made to examine the full impact of disruptions of the gas infrastructure without the presence of any major gas storage in Southern California. The study considered sensitivities to this scenario, which are presented in the following sections: a scenario with Aliso Canyon remaining online at the reduced operational capacity and a scenario with an underground gas storage facility in Arizona, to assess the impact of these facilities on the disruptions modeled.

From the market analysis, several critical factors become apparent:

- Gas burn is expected to increase significantly, driven by baseload coal and nuclear retirements as well as overall load growth in the region. While additional renewables capacity provides some mitigation, the study results presented in the next section show that it will not be enough to offset the 11 GW of retirements and will also introduce additional volatility and uncertainty into intra-day swings.
- Maintenance, and possibly expansion, of gas system infrastructure will likely be needed to meet reliability needs.
- The Western Interconnection has access to ample supply from several different supply basins, but its reliance on long-haul gas pipelines poses reliability risk due to the ability of a single disruption to impact multiple markets.

### 3. Modeling Scenario Analysis & Results

The modeling efforts in this study formed one of the key components for the entire project by providing a reasonable estimate of the potential impacts that could result from each of the disruption scenarios. Consequently, there were several aspects that had to be pulled together to accomplish this complex analysis:

- **Contracting Analysis**: An analysis of all gas contracting positions in the Western Interconnection was undertaken to further refine the inputs to the modeling setup, as this plays a key role in how plants are supplied and which power plants are ultimately affected during shortages and/or curtailments.
- **Modeling Setup**: Coordination among the three major models (AURORA, NGfast, GPCM®) was necessary to set up the Base Case using the 2026 WECC Common Case and establish a robust process for modeling each of the disruption scenarios.
- **Modeling Results Validation**: Multiple iterations were conducted for each disruption scenario to validate the modeling results and ensure that gas-side and electric-side compensation (from line pack, storage, transmission, etc.) was accurately reflected.
- **Probabilistic & Economic Analysis Impact**: Translation of the unserved energy and unmet spinning reserves into "unrisked" and "risked" economic impact served to provide context for the magnitude of each disruption scenario.
Contracting Analysis

Figure 3.1: Contracting Analysis Methodology

A key component of the modeling efforts was the contracting analysis work stream, in which the project team analyzed the contracting positions for each utility and generator in the Western Interconnection to gain a better understanding of how much of their plant capacity was covered by firm transport (FT) contracts. As shown in Figure 3.1, the contracting analysis was conducted on three different bases:

- **Catastrophic**: a 24-hour max burn of baseload and peaking plants to simulate a sustained disruption stemming from a catastrophic event
- **Base Case**: a 7-hour peaking plant utilization to simulate business-as-usual conditions (as used in several IRP processes)
- **Peak Hour**: a 1-hour max burn to analyze peak-hour demand versus available peaking services offered by pipeline operators

The project team estimated the gas burn needed under all three bases by using the plant capacities, heat rates, and associated base vs. peaking functionality of each power plant. These figures and results were validated with the key utilities and generators throughout the Western Interconnection on a best-efforts basis.

The gas burn needs were compared against the firm contracting position for each utility and generator in the Western Interconnection. The project team reviewed online contracting info, pipeline indexes of customers, IRPs, marketing agreements, and validated results through contact and communication with the various utilities and generators to form an accurate picture. Combining these two analyses allowed the project team to form a view of how much generation capacity was uncovered by FT contracting in each of the three bases.

This contracting analysis was also instrumental in updating the proprietary dataset used in modelling disruption impacts to gas-fired power plants and formed a critical part of our modeling analysis by allowing for a more accurate simulation of curtailment procedures of firm versus interruptible gas supply.
Figure 3.2 shows a regional breakdown for the contracting analysis across the Western Interconnection, using the aforementioned three bases for calculation. Outside of California, approximately 10% – 20% of gas-fired generation is not covered by FT\(^5\) contracting; Pacific Northwest (PNW) and Rockies utilities have typically adopted a more conservative strategy with several companies having contracted for full coverage even on the 24-hour max burn basis. However, this is feasible due to the flexibility offered by gas storage, which allows the implementation of firm no-notice service for utilities and generators. Within the Desert Southwest (DSW) where storage options are nonexistent, utilities and generators were typically more reliant on IT\(^6\), especially for peaking generation; in this particular region peak demand for gas generation occurs during the summer which is off-season for overall peak gas demand, which has contributed to utilities historically feeling less need to contract for FT.

The situation in California is considerably different from the rest of the region:

- Virtually all generation on the local LDC system is effectively unsupported by FT due to existing curtailment protocols; consequently, ~80% of capacity is essentially relying on IT-type contracting for >23 GW of gas-fired generation.
- The California intrastate systems are designed to be capable of meeting all demand (both core and non-core) under a 1-in-10year cold weather event (though, with the reduced capability of Aliso Canyon, the current system may not meet these design criteria), but curtailment protocols classify electric generation as non-core end-use, meaning that utilities and generators would be the first to be impacted during curtailments.

The difficulties resulting from such a setup were previously avoided by the flexible capability of Aliso Canyon; the loss of this facility may now impede utilities’ ability to operate effectively on a day-to-day basis. Additionally, because generators are considered non-core customers, there is little value in holding FT further upstream on interstate pipelines feeding into California. As a result, generators have already released or expressed intentions to release firm capacity from several pipeline systems. This lack of alignment of commercial incentives also makes it more challenging for pipeline operators to

\(^5\) Firm Transportation contracts ensure pipeline capacity on a firm basis and is generally not subject to reduction or interruption

\(^6\) Interruptible Transportation contracts are subject to curtailment or interruption due to operating conditions or pipeline capacity constraints
secure enough interest during open seasons for new expansion projects on their systems. These disincentives create significant long-term reliability concerns as it ultimately reduces the ability of pipeline operators to invest in their system to increase reliability and deliverability for power generators.

The contracting analysis undertaken in the study yields a few key conclusions:

- Although behavior varies from company to company, a common contracting approach is to contract enough FT capacity to cover baseload needs and flex on IT capacity for peaking generation. While this practice is feasible for systems with ample spare capacity or dual-fuel generation, this will become more difficult as gas market dynamics tighten across the West.
- There is currently limited transparency and visibility into how gas-fired generation is supplied on a contracting basis; it is unclear how gas contracts are linked to the specific plant(s) they serve, which makes contingency planning difficult. Existing processes cover resource adequacy analysis but do not engage in contingency planning exercises.
- The issues resulting from existing LDC curtailment regulations in California are becoming more apparent with reduced Aliso Canyon operations, and multiple utilities and generators have indicated the increased operational difficulties stemming from these regulations. With no true FT-type contracting available for generation in California, utilities and generators are more susceptible to curtailments and also have less incentive to hold FT contracts on interstate pipelines leading into California, which is becoming increasingly unsustainable. While holding FT contracting will not enable generators to completely avoid curtailment (e.g. during high-impact, catastrophic disruptions), it does improve reliability for a number of other scenarios by virtue of moving generation further down the curtailment priority list (for interstate pipelines).

Modeling Setup

Figure 3.3: Detailed Modeling Methodology

The project team combined its modeling capabilities to create a robust methodology (Figure 3.3) for modeling each of the disruption scenarios. Three different and well-established models in the industry were used for this study:

- **GPCM®** is a model used in the industry to develop forecasts and scenarios for North American natural gas flows, price and basis. It includes forecasting of pipeline and storage utilization, deliveries and price at points throughout the North American gas market.
- **AURORA** by EPIS is a model used in the industry for electricity forecasting and analysis. It produces electric market price forecasts, and automated system optimization.
- **NGfast** by Argonne National Labs is a natural gas pipeline network modeling tool that enables the rapid assessment of impacts from disruptions and flow reductions in the nation’s natural gas network.
Syncing and coordination among three different modeling tools was critical for the study:

- The project team began by developing a base case reflective of the WECC 2026 Common Case using E3’s AURORA model on the power side and Wood Mackenzie’s GPCM® model on the gas side
- For each disruption scenario, Argonne’s NGfast tool was utilized to identify specific power plants impacted and/or suffering outages due to the specific disruption event, with gas compensation taken into account (e.g. gas storage, line pack, etc.)
- Using the list of impacted plants, E3’s AURORA model was used to simulate the operations of the electric power system during the disruption event, providing an estimate of the amount of unserved energy and unmet spinning reserves while accounting for the latent capability of the transmission and generation infrastructure to compensate for the disruption.

Scenario Modeling Results

**Figure 3.4: Table of Disruption Scenarios**

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Regional focus</th>
<th>Base (N-1) Case</th>
<th>N-2 case</th>
</tr>
</thead>
<tbody>
<tr>
<td>Disruption on a PNW pipeline</td>
<td>Pacific Northwest</td>
<td>Disruption at the US/Canada border (or upstream) receipt point on the system</td>
<td>Low hydro conditions</td>
</tr>
<tr>
<td>Seismic event disrupting Alberta supply</td>
<td>Pacific Northwest</td>
<td>M8+ earthquake in the Rocky Mountain House area, that disrupts natural gas production in Alberta</td>
<td>Low hydro conditions</td>
</tr>
<tr>
<td>Disruption on a Basin pipeline</td>
<td>Basin/ California</td>
<td>Disruption on the critical mainline section downstream of the supply basin and upstream of the demand centers</td>
<td>Low hydro conditions</td>
</tr>
<tr>
<td>Disruption on a DSW pipeline</td>
<td>Desert Southwest/ Southern CA</td>
<td>Disruption on critical Southern NM section of DSW pipeline</td>
<td>NA</td>
</tr>
<tr>
<td>Winter supply freeze-off in the Permian &amp; San Juan</td>
<td>Desert Southwest</td>
<td>Week-long winter supply freeze-off in the Permian and San Juan basins reducing supply by 1.5 bcf/d, higher residential gas demand. 15% of generation in AZ/NM unavailable due to freezing conditions</td>
<td>Low hydro conditions / Transmission outage from CA wildfire</td>
</tr>
</tbody>
</table>

Using the above modeling setup, the project team modelled ten different scenarios, as shown in Figure 3.4 above. These scenarios were defined using input from key players from both the gas and electric industries to include the most pressing

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7 Argonne’s NGfast model also takes into account dual-fuel capabilities, though compensation was limited due to procurement logistics as well as environmental regulations

8 In the operational simulation conducted herein, both unserved energy and the failure to meet spinning reserve needs are taken as an indication of a potential reliability event

9 As seen below in the results, the impacts for the N-1 DSW pipeline disruption scenario were quite significant; consequently, no N-2 scenario was run
concerns and agreed upon with the WECC Project Steering Committee to capture a representative spectrum of circumstances.

Figure 3.5: Outage Nameplate Capacity, Unserved Energy, and Unmet Spinning Reserves from Modeling Scenarios

As shown in Figure 3.5, the cases that exhibit the most impact are all centered around disruptions that affect the DSW and Southern California markets. However, it is important to note the distinction between the DSW pipeline rupture disruption scenario versus the freeze-off scenarios, as the former provokes a resource adequacy issue, while impacts in the latter result from transmission limitations.

The DSW pipeline rupture scenario results in full disruption of gas service to 24 GW of gas generators, which translates into 428 GWh of unserved energy and 236 GWh of unmet spinning reserves. The impact can be traced back to the configuration of the pipeline system which yields two concentrated "islands" of power demand in Phoenix and Southern California; with the loss of a DSW mainline, there is simply not enough capacity remaining to provide the gas needed to compensate.

The various freeze-off scenarios result in conditions in which the electricity system is stretched to its limits and may face reliability challenges. In these scenarios, the failure of the balancing authorities in the Southwest and California to maintain sufficient spinning reserves could potentially translate directly to load shedding; this poses a real issue as even minor additional changes or impacts could yield unserved energy.

The other sub-regions (PNW, Basin, and Northern California) are more resilient to major gas system disruptions, largely owing to the combination of market area gas storage, presence of alternative energy source (e.g. hydro), transmission connectivity which allows for more electric-side compensation, and convention of contracting for firm fuel supplies for capacity resources. To stretch the electric system to its limits in these regions, it is necessary to assume extremely large-scale disruptions due to a catastrophic event knocking out significant supply from Canada. While not outside the realm of possibility, these events have a low probability of occurring.

Probability Analysis & Economic Impact

Figure 3.6: Unrisked & Risked Economic Impact for Modeling Scenarios

<table>
<thead>
<tr>
<th>$US bn</th>
<th>DSW Pipe Rupture</th>
<th>Freeze-Off + Low Hydro</th>
<th>Freeze-Off</th>
<th>Canada Disruption</th>
<th>Canada Disruption + Low Hydro</th>
<th>Other cases</th>
</tr>
</thead>
<tbody>
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</tbody>
</table>
The project team was able to translate the unserved energy and unmet spinning reserves into an estimated economic impact using previous studies and events to establish a correlation between interruption duration and cost per unit of unserved energy. This analysis was done by demand sector to provide a more granular assessment. Using the separate correlations by sector, the project team also utilized historical sales by state in order to estimate costs in different geographies.

Probability analysis was then conducted on the various scenarios in order to allow for a risked economic impact estimation. Pipeline disruption frequency was calculated using a 20-year US Department of Transportation (DOT) dataset as well as data from the Pipeline and Hazardous Materials Safety Administration (PHMSA), and taking into account three main factors: 1) annual frequency of occurrence of a pipeline break for each company, 2) percent of pipeline breaks with a shutdown period of one month or greater, and 3) probability that a single pipe break leads to a break in an adjoining pipe in the same corridor. Earthquake probabilities were calculated using interpolated seismic hazard values from the Canada National Building Code and associated statistical trends as well as historical records from Natural Resources Canada. Freeze-off probabilities were calculated using historical studies and records from NERC and FERC, while the low hydro conditions for the Pacific Northwest were based on the critical low hydrological conditions observed in 1937, which are commonly used in resource planning exercises in the region.

As shown in Figure 3.6, from a risked economic impact perspective our modeling efforts highlight the DSW pipeline rupture and the freeze-off as the highest-impact scenarios, though for differing reasons. The low probability of the DSW pipeline rupture reflects the strong overall safety record of the pipeline as well as the security from having four separate pipelines, but the high magnitude of the consequences of such a scenario raises the risked impact. Conversely, the freeze-off scenario shows a lower impact but is a high-probability 1-in-10 year event, which also yields a considerable risked economic impact.

The results of the modeling analysis serve to highlight several key points:

- The Southwest and Southern California's reliance on a few long-haul gas pipelines make them especially susceptible to gas system disruptions, especially in the absence of storage provided by Aliso Canyon. Should Aliso Canyon be shut down, this issue will become greatly exacerbated; it is likely that additional natural gas system infrastructure will be needed, even with increased renewables penetration.
- The compensation capability present in PNW illustrates the utility of market-area gas storage and transmission; the project team needed to assume a very low-probability, high impact disruption as shown in the Canada disruption cases in order to elicit any kind of unserved energy or unmet spinning reserves.
- The results clearly point towards two scenarios as the most concerning, though each has very different characteristics. The impact from a loss of a major DSW pipeline is astronomical in cost and consequently still yields a >$1 bn risked economic impact despite the low probability of occurring, illustrating the importance of resource adequacy. Conversely, the freeze-off scenario impact is much lower, but the regularity with which this event occurs yields a risked economic impact of ~$600 million, which highlights the consequences of having insufficient mitigation capabilities.

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10 Probabilities used in this study were calculated as described above, though conversations with pipeline operators indicate this probability could potentially be even lower due to the actual physical configuration and locations of the pipeline system.
It is important to note that the modeling efforts and scenario results assume perfect procurement, commitment, and dispatch, which is difficult to achieve in a real-world scenario; the impacts resulting from these contingencies are likely understated.

4. Mitigation Options & Recommendations

With multiple scenarios resulting in unserved energy and/or unmet spinning reserves, it is imperative that the key players in the Western Interconnection appropriately plan for such contingencies. Consequently, the project team has focused on two main avenues:

- Providing an array of options to cost-effectively mitigate the impact of various types of gas supply disruptions and durations. We strongly believe that meeting the future needs of the BPS in the Western Interconnection in a reliable manner will require a balanced portfolio of mitigation options, capable of handling both increasing intra-day, business-as-usual volatility as well as longer-term disruptions to the gas-electric system.
- Improving existing protocols and procedures to maximize the ability of the above portfolio mitigation options to compensate for losses and outages resulting from sustained disruptions. The results from our modeling scenarios assume perfect electric commitment and dispatch, gas procurement, and industry coordination; in a real-world scenario, having the proper processes in place is extremely important for impact mitigation.

Within the scope of this study, the project team examined a number of mitigation options through the lens of each of their capabilities as well as their capital cost. While this analysis did not delve into implementation, we believe that this is an area which merits further consideration and analysis, as having the proper market mechanisms and incentives in place will be critical for moving these options forward.

Mitigation Options Analysis

Figure 4.1: Mitigation Option Comparison

<table>
<thead>
<tr>
<th>Mitigation Option</th>
<th>Est. Incremental Capex</th>
<th>Barriers to Implementation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aliso Canyon</td>
<td>Limited</td>
<td>Political and regulatory opposition</td>
</tr>
<tr>
<td>AZ Gas Storage Project</td>
<td>$372 million</td>
<td>Open season interest</td>
</tr>
<tr>
<td>Gas Pipeline Capacity Expansion</td>
<td>$25 – 500 million (for 75 – 300 mmcf/d deliverability)</td>
<td>FERC process duration, open season interest</td>
</tr>
<tr>
<td>Dual-Fired Generation</td>
<td>Limited</td>
<td>Environmental and political regulations</td>
</tr>
<tr>
<td>Electric DR Initiatives</td>
<td>Limited</td>
<td>Limited</td>
</tr>
<tr>
<td>Battery Additions</td>
<td>$12 - $18 billion for 15 GW</td>
<td>Cost, recharging needs</td>
</tr>
<tr>
<td>Solar Capacity</td>
<td>Unable to compensate DSW pipeline rupture scenario</td>
<td>Daily profile limitations</td>
</tr>
</tbody>
</table>

Within the study, the project team examined seven potential mitigation options, each with their own unique advantages and disadvantages for cost, mitigation capability, and implementation.

Gas System Expansion

The project team has examined two potential options for gas system expansion: 1) investment into gas storage, and 2) investment into gas pipeline capacity.
Gas Storage Expansion

Figure 4.2: Potential Gas Storage Expansion Mitigation Options

<table>
<thead>
<tr>
<th>Case</th>
<th>Working capacity (mmcf)</th>
<th>Max withdrawal rate (mmcmcf)</th>
</tr>
</thead>
<tbody>
<tr>
<td>DSW base case</td>
<td>Aliso Canyon decommissioned</td>
<td></td>
</tr>
<tr>
<td>Aliso Canyon operational</td>
<td>24,000</td>
<td>800</td>
</tr>
<tr>
<td>AZ Gas Storage</td>
<td>4,000</td>
<td>400</td>
</tr>
</tbody>
</table>

The project team ran two additional sensitivities (Figure 4.2) with additional gas storage capacity added to the DSW pipeline rupture Base Case disruption scenario:

- A scenario with Aliso Canyon remaining online at the reduced operational capacity and maximum withdrawal rates as seen at present
- A scenario with an additional Phoenix-area gas storage facility coming online, based on Kinder Morgan's proposed Arizona Gas Storage project

Figure 4.3: Unserved Energy & Unmet Reserves (GWh)

Figure 4.3 shows the resulting impacts from the additional gas storage sensitivities and illustrates the compensation capability stemming from the presence of additional market-area storage. While the problem is not completely eliminated, the presence of an additional facility in the Phoenix area greatly reduces the amount of unserved energy, and the presence of Aliso Canyon eliminates all unserved energy and significantly helps with the unmet spinning reserves. However, this compensation capability comes at the cost of requiring a larger initial investment. Resuming operation of Aliso Canyon at
present levels would incur very little incremental capital expense, but the installation of the AZ gas storage facility would cost an estimated $372 million as currently envisioned.\(^{11}\)

**Gas Pipeline Capacity Expansion**

**Figure 4.4: Potential Areas for Pipeline Expansion**

The other potential option involves an expansion of the gas pipeline network itself. Through flow analysis and discussions with gas pipeline operators, the project team has identified a number of possibilities for capacity expansion:

- Expansion on El Paso Natural Gas (EPNG) or Transwestern (TW) systems in Phoenix area
- Expansion on Kern River Gas Transmission (KRGT) mainline
- Expansion on SoCalGas backbone system

Gas pipeline operators have indicated an incremental addition of 75 – 300 mmcmcf of deliverability could be achieved with an investment of ~$25 – 500 million depending on the configuration, and various other expansion designs around their respective systems could add an additional 100 mmcmcf – 1 bcf/d of deliverability into Southern California. While pipeline system expansions would provide additional flexibility to handle long-term sustained disruptions, they face a number of challenges:

- Projects are typically evaluated on 15 – 25 year timeframes, during which California climate policy will affect the gas throughput; this makes it challenging from both an operator evaluation and open season contracting standpoint to garner support
- Interstate expansions must be approved through the FERC regulatory process, which can take 36 months or longer
- Discussions with multiple pipeline operators have all indicated a key capacity constraint around SoCalGas’s system deliverability, which faces heavy political opposition to any form of expansion. If SoCalGas’s ability to receive volumes from interstate pipelines and deliver into Southern California’s market remains limited, any expansion upstream of those points will be ineffective

Despite these challenges, gas pipeline operators are continuously evaluating potential expansion options and pushing forward with their projects. On May 10, 2018, El Paso Natural Gas applied to FERC to authorize its South Mainline Expansion Project, which would increase capacity on the company’s Line Nos. 1100 and 1103 in Hudspeth and El Paso counties in Texas. The project would expand the system with ~17 miles of a 30-inch loop line and two new compressors: a new 13,220 hp turbine-driven compressor station in Luna County, NM and a new 13,220 hp turbine-driven compressor station in Cochise County, AZ. Overall capacity of the South Mainline would be expanded by ~321,000 Dth/d at an

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\(^{11}\) As indicated by the public Open Season document (Notice ID #17005) issued by Kinder Morgan

\(^{12}\) Numbers and ranges provided by key gas pipeline operators in the West
incremental cost of $127.9 million, allowing for EPNG to meet demand in the Texas, New Mexico, Arizona, and California markets. The project has two major anchor shippers: Mexico’s state power company Comision Federal de Electricidad (CFE) and Salt River Project Agricultural Improvement and Power District (SRP).

Dual-Fired Generation

**Figure 4.5: Estimated Available Dual-Fired Generation Capacity (DSW Pipeline Rupture Disruption Scenario)**

![Dual-Fired Generation Diagram]

While dual-fired generation provides some additional mitigation capability, its effectiveness is limited by difficulties stemming from procurement logistics, economics, securing permits for burn and policy opposition. Utilities typically only keep enough fuel onsite for a few days of generation (if any at all) due to associated costs of storage, at which point access product pipelines, railroads, and terminals become key. As plants attempt to procure additional fuel, truck availability and pump capacity quickly become the limiting factors. Additionally, further limitations stem from environmental and policy regulations; for example, California permitting and environmental regulations mandate a maximum duration that dual-fired generation can run for, regardless of any consequences.

Consequently, dual-fired generation is a mitigation option that is better suited for shorter duration disruptions. In the DSW pipeline disruption scenario, we estimate that by keeping all existing dual-fired facilities online today, an additional 700 MW of compensation would be available.

**Electric Demand Response (DR) Initiatives**
Several utilities have implemented both formal and voluntary DR programs to manage peak demand at comparatively limited costs. Looking at both historical and present-day situations, DR programs and initiatives have been able to effectively reduce peak load by ~5% of total utility load on average, indicating that DR programs are best suited for peak shaving purposes and have limited effectiveness for long-term disruptions. Moving forward, continued implementation of electric DR programs and outreach will be a key tool for managing peak demand and limiting disruption impacts.

Natural gas DR programs do not have as robust a history as electric-sector programs. This is due, in no small part, to the fact that most natural gas customers that would be good candidates for DR programs are already taking interruptible natural gas service for cost-saving reasons. Nevertheless, it is possible that additional natural gas DR programs could be brought to bear to help address the issues identified here. These programs were not considered explicitly in this analysis because of lack of data about the availability and cost of gas customer DR.

Renewables & Battery Electric Storage
As states continuously push for more aggressive renewables targets and standards, utilization and implementation will continue to grow. The potential of renewables and energy storage investments to mitigate reliability risks on the gas system depends on the specific nature of the vulnerability identified. In the case of the DSW pipeline rupture, the primary reliability risk occurs in the 4-6 hour period in the late afternoon & early evening when the sun is setting but the outages of natural gas infrastructure are insufficient to meet the upward net load ramp. As shown in Figure 4.7, the effectiveness of electric generation investments to mitigate this risk varies by technology:

- New investments in solar resources provide relatively limited reliability benefit because most of the unserved energy occurs during periods of waning solar production. In fact, adding 30,000 MW of additional solar PV resources across the Southwest and Southern California is not sufficient to eliminate the unserved energy observed in this scenario.
- Battery storage provides a more effective mitigation investment to help meet load during the sundown period, but investments of a tremendous scale are needed to eliminate the unserved energy observed in this scenario: nearly 15,000 MW of 4-hour battery storage, likely requiring capital investments on the scale of $12 to $18 billion, would be needed.

While the scale of investments needed to fully mitigate this risk using battery storage or solar alone is prohibitive, this analysis suggests that consideration of reliability benefits associated with mitigation of gas system contingencies may be useful to incorporate in utility procurement decision-making processes.
The disruption scenario modeling described above assumes "perfect" response from electric generators in the Western Interconnection; that is, any electric generator that is not also disrupted by the assumed gas delivery challenge is assumed to respond instantaneously to prevent loss of load in the Western Interconnection, even if the load is located several states away. In order to approach perfect commitment and dispatch, and a perfect procurement level of compensation as seen in our modeling efforts, it is imperative that gas and electric industry protocols are properly aligned and coordinated. To this end, the project team has identified a number of actionable recommendations and improvements to existing processes:

1. **Improved Regional Coordination:** We recommend that WECC lead and conduct regional contingency planning exercises to prepare for a number of disruption scenarios. In a real-world event, achieving perfect dispatch and procurement is highly difficult; additionally, compensation for impacted plants often comes from different regions due to the interconnected nature of both the gas transmission pipelines and electric transmission lines. Consequently, regional coordination stemming from pre-emptive contingency planning allows for faster reaction and greater compensation capability.

2. **Resource Adequacy Assessment:** We recommend greater transparency and clarity around procurement and supply of gas to gas-fired power plants. Having an accurate view of how much capacity and which power plants are covered by firm transport (FT) contracts as well as deals with third-party suppliers allows for better firm reserves analysis and more robust contingency planning processes. As shown above in Section 3, a significant amount of plant generation relies on interruptible transport (IT) for their gas. While this arrangement functioned adequately in the past, as gas dynamics tighten it will become increasingly important to understand how specific plants are sourced in order to fully understand which plants are at risk during a sustained disruption. Having this information explicitly provided allows for more robust contingency planning exercises, which are not currently conducted on a consistent basis at the utility/generator level.

3. **Curtailment Protocols:** We believe that there is support from both the gas and electric industries to re-visit the classification of electric generation as non-core end-use in California. Under the current protocol, power generation is often the first class of customers to be curtailed; while the difficulty of restoring residential service makes it unlikely that the entire generation customer base would be re-classified, we believe that it would be feasible to designate

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**Protocols & Procedures Improvement Recommendations**

**Figure 4.8: Recommendations for Improvement of Gas-Electric Protocols**

<table>
<thead>
<tr>
<th>Recommendations</th>
<th>Benefits</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Improved Regional Coordination</strong></td>
<td></td>
</tr>
</tbody>
</table>
- Conduct regional contingency planning exercises led by WECC to prepare for a number of disruption scenarios  
- Maximizes compensation ability for utilities across the Western Interconnection |
| **Resource Adequacy Assessment** |  
- Greater transparency of firm contracting and linkage to power plants served in firm reserve reports  
- Allows for more robust planning processes, especially as gas and power capacity dynamics tighten |
| **Curtailment Priorities** |  
- Re-visit classification of electric generation as “non-core” end-use  
- Designation of plants critical to grid reliability as core end-use  
- Ensuring that critical power plants are not the first to be curtailed allows for additional flexibility for compensation via transmission |
| **Forecasting & Execution** |  
- Require intra-day LDC core load balancing to ensure fair implementation of OFOs and penalties  
- Additional clarity around interstate pipeline curtailment protocol  
- Higher accountability for prior-day forecasting allows easier utility operation  
- Explicit interstate curtailment protocols allow for better contingency planning |
| **Gas-Electric Day Mismatch** |  
- Split weekend nomination period into daily blocks, resulting in a 7-day nomination cycle  
- A feasible step for both gas and electric sides that would minimize response lead times over the weekend period |
specific plants as critical to grid reliability and move them into the core classification, which would aid during curtailment situations.

4. **Forecasting & Execution:** We have identified a number of changes to existing protocols that could improve forecasting and execution. Currently, regulations in California only require LDCs to balance core loads against previous-day nominations for that particular day. Consequently, when the difference between the forecasted and actual demand becomes apparent, LDCs issue OFOs and lean upon the utilities and generators to adjust for any discrepancies; this makes it difficult for the utilities and generators to operate from day-to-day. The other area that we recommend adjustments regards clarity around interstate pipeline curtailment protocols. While curtailments are typically done on a pro-rata basis in the order of IT, secondary FT, and FT contracts, there are typically various exceptions to this based upon the configuration of the pipeline, as operators typically try to be flexible and avoid curtailing supply to customers who have no other possible gas source. Having these practices made explicit would allow for better and more accurate contingency planning.

5. **Gas-Electric Nomination Days:** The gas-electric nomination day mismatch continues to be a challenge for coordination between the two industries. While we view it unlikely for the two nomination schedules to become fully aligned, we suggest that the weekend nomination period be split into daily blocks, resulting in a 7-day nomination cycle. We view this as an action that would help minimize response lead times over the weekend period and as something that would be feasible to accomplish from a regulatory standpoint.

**Conclusions**

The results of this study highlight the potential risks to the gas-electric system in the Western Interconnection as forecasted retirements and higher renewable generation pose a key challenge to reliability. Both the modeling scenarios and recent real-world events point towards a system being pushed to its limit, indicating that the Western Interconnection is at an important crossroads in its trajectory:

- Recent events stemming from unexpected pipeline outages and gas supply freeze-offs are indicative of a gas-electric system already under considerable stress, which has been significantly exacerbated by restrictions on the operation of Aliso Canyon
- Despite expected increases in renewable generation, regional gas burn is expected to increase over the forecast period driven by baseload coal and nuclear retirements as well as steady load growth
- The configuration of the gas-electric system combined with the potential closure of Aliso Canyon creates region-wide reliability issues centered around the markets concentrated in Southern California and Phoenix; disruption scenarios revolving around a DSW pipeline rupture or Permian/San Juan Basin supply freeze-offs routinely result in unserved energy and/or unmet spinning reserves.
- Other regions in the Western Interconnection are more resilient to major gas system disruptions, largely owing to increased compensation capabilities stemming from availability of market-area gas storage and alternative sources of energy including reliance on the region's robust interstate transmission system
- The existing strain on the system indicates that even modest changes to working assumptions such as fossil fuel plant closures or natural gas storage limits could rapidly exacerbate existing challenges; natural gas support will continue to be necessary to ensure system reliability while achieving policy goals.

Consequently, the development of a balanced portfolio of mitigation options is critical to assure system reliability in a changing power landscape. Maintenance and new investments in gas and electric infrastructure are necessary to meet both near-term needs and bulk power system capacity needs:

- A combination of mitigation options will be needed to ensure system security and reliability: investment in gas infrastructure and storage, renewable generation, battery storage, demand response programs, and dual-fuel generation.
- Mitigation modelling sensitivities demonstrate the DSW and Southern California markets’ reliance on Aliso Canyon, further underlining the importance of the implementation of a portfolio of the mitigation options previously mentioned (especially in a future where the facility has been retired)
- Improved coordination of gas and electric industries’ operating practices will be critical for maximizing compensation capability and ability to respond to both business-as-usual and sustained disruption scenarios
Moving these changes forward will require buy-in at all levels (e.g. gas pipeline operators, utilities, generators, PUCs, NERC, NAESB, FERC) in order to effectively improve existing protocols and procedures.
The study was split into 10 discrete tasks in order to allow for a flexible approach to home in and focus upon the key aspects and vulnerabilities as they became apparent during our study, with numerous workshops to ensure engagement of the stakeholder advisory teams. These 10 tasks can be categorized into four separate but highly interconnected work streams:

- **Project Setup & Preparation (Task 1):** In order to ensure project alignment and focus on the most important concerns relevant to the key stakeholders, the project team established a team structure and avenues of communication early on to facilitate information flow and make sure all feedback was captured.

- **Vulnerability Analysis & Scenario Runs (Tasks 2, 3, 4, 5, 6):** The project team modified and reconciled the three internal models of AURORA, GPCM®, and NGfast to reflect the 2026 WECC Common Case, which served as the basis for the analysis conducted in the study. A first pass view of vulnerabilities was formulated and subsequently refined using work from previous studies as well as input from gas and electric stakeholders. A subset of 10 scenarios for modeling analysis was agreed on, upon which the project team tested and improved the modeling approach first in the Desert Southwest (“DSW”) before extending to the rest of the Western Interconnection. After thorough validation of the approach and the results, the project team was able to calculate the unserved energy and unmet spinning reserves resulting from each disruption scenario. This impact was then translated into an associated economic impact.

- **Gas Contracting Analysis & Existing Protocols Risk Identification (Tasks 7, 8):** In parallel, the project team conducted an analysis of existing gas contracting positions held by all utilities and generators in the Western Interconnection to provide a view on the region’s reliance on interruptible transport (“IT”) contracts. Additionally, this exercise allowed for the refinement of existing contracting datasets critical for improving the accuracy of our modeling scenarios in the above work stream. Contracting data was validated through interviews and discussions with the regional gas and electric stakeholders, who also provided insights and views towards friction areas and pressure points within existing processes and protocols that hindered their daily operations.

- **Mitigation Options Analysis & Recommendations (Task 9, 10):** After identifying the key vulnerabilities and quantifying their impacts, the project team analyzed cost and capability for multiple options to assess situations for which each would be most applicable. Additionally, the team provided actionable recommendations for existing
processes and protocols for facilitating coordination in order to aid contingency planning and responses as well as improve daily operations
Appendix B: Glossary

**Associated Gas**: A form of natural gas which is found with deposits of petroleum, either dissolved in the oil or as a free gas cap above the oil in the reservoir.

**Basin**: Basin region. Includes Nevada and Utah.

**Bcf**: Billion cubic feet.

**Bcfd**: Billion cubic feet per day.

**BPS**: Bulk Power System.

**CPUC**: California Public Utility Commission. Regulates services and utilities, protects customers, safeguards the environment, and assures Californians’ access to safe and reliable utility infrastructure and services. Essential services regulated include electric, natural gas, telecommunications, water, railroad, rail transit, and passenger transportation companies.

**Demand Response (DR) Program**: Programs being used by some electric system planners and operators as resource options for balancing supply and demand by providing opportunities and incentives for consumers to reduce or shift electricity usage during peak periods.

**DOT**: Department of Transportation.

**DSW**: Desert Southwest region. Includes New Mexico, Arizona, and Texas.

**EPNG**: El Paso Natural Gas pipeline. Owned by Kinder Morgan and transports natural gas from the San Juan, Permian, and Anadarko basins to California, Arizona, Nevada, New Mexico, Oklahoma, Texas, and northern Mexico.

**FERC**: Federal Energy Regulatory Commission. Independent agency that regulates the interstate transmission of natural gas, oil, and electricity. FERC also regulates natural gas and hydropower projects.

**Freeze-off**: Phenomenon where below freezing temperatures cause production shutoff when wellhead gas flow is blocked by formation of ice.

**FT**: Firm Transportation. FT contracts ensure pipeline capacity on a firm basis and are generally not subject to reduction or interruption.

**GTN**: Gas Transmission Northwest. Gas pipeline that transports WCSB and Rockies gas to Washington, Oregon, and California.

**IT**: Interruptible Transportation. IT contracts are subject to curtailment or interruption due to operating conditions or pipeline capacity constraints.

**KRGT**: Kern River Gas Transmission. Gas pipeline that transports gas from southwestern Wyoming, through Utah and Nevada, to the San Joaquin Valley near Bakersfield, California.

**Line Pack**: A procedure for allowing more gas to enter a pipeline than is being withdrawn, thus increasing the pressure and effectively creating storage.

**LDC**: Local Distribution Company. Regulated utilities involved in the delivery of natural gas to customers within a specific geographic area.

**Mmbtu**: Million British thermal units.
**Mmcfd**: Million cubic feet per day.

**N-1**: Refers to a contingency involving the unexpected failure or outage of a system component.

**N-2**: Refers to a contingency involving two unexpected failures or outages of system components.

**NAESB**: North American Energy Standards Board.

**NERC**: North American Electric Reliability Corporation. Non-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

**OFO**: Operational Flow Order.

**PHMSA**: Pipeline and Hazardous Materials Safety Administration

**PNW**: Pacific Northwest region. Includes Washington, Oregon, and Idaho.

**PV**: Photovoltaic.

**Rockies**: Rockies region. Includes Colorado, Montana, South Dakota, and Wyoming.

**RPS**: Renewable Portfolio Standard. Regulation that requires the increased production of energy from renewable energy sources.

**SoCalGas**: Subsidiary of Sempra Energy responsible for distributing and servicing natural gas to Central and Southern California.

**Spinning Reserves**: On-line reserve capacity that is synchronized to the grid system and ready to meet electric demand within 10 minutes of a dispatch instruction. Needed to maintain system frequency stability during emergency operating conditions and unforeseen load swings.

**TW**: Transwestern pipeline. Owned by Energy Transfer and transports natural gas from the San Juan, Permian, and Anadarko basins to California, Arizona, Nevada, and New Mexico.

**WCSB**: Western Canadian Sedimentary Basin. A key oil and gas producing basin in Western Canada.

**WECC**: Western Electricity Coordinating Council. Non-profit corporation that exists to assure a reliable BPS in the Western Interconnection. Approved by FERC as the regional entity for the Western Interconnection, and possesses authority from NERC to create, monitor, and enforce reliability standards.

**WECC 2026 Common Case**: Forecast produced by WECC that represents the expected loads, resources and transmission topology 10 years in the future from a given reference year. For this study, v1.5 was used as the basis for analysis.