Natural Gas Infrastructure Adequacy in the Western Interconnection: An Electric System Perspective

Phase 2 Report

July 2014
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Disclaimer and Acknowledgement

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Technical Advisory Group

This study was overseen by a group of advisory members:

- Beth Musich, Southern California Gas/San Diego Gas & Electric
- Clint Kalich, Avista Corporation
- Chris Worley, Colorado Energy Office
- Jan Caldwell, Northwest Pipeline
- Jim Wilde & Michael Jensen, Arizona Public Service Company
- Mark Westhoff, Kinder Morgan
- Melissa Jones, California Energy Commission
- Mia Vu, Pacific Gas & Electric
- Peter Larsen & Alan Sanstad, Lawrence Berkeley National Laboratory
- Alaine Ginocchio, Western Interstate Energy Board (WIEB)
- Steve Ellenbecker, WIEB
- Thomas Carr, WIEB

Throughout the study—a one-year undertaking that required regular and frequent meetings, one-on-one work with the contractors, and significant preparation between meetings—the TAG provided invaluable feedback and guidance that shaped the scope, results, and conclusions of this study. However, all decisions regarding the analysis were made by E3 and DNV GL. E3 and DNV GL are solely responsible for the contents of this report, and for the data, assumptions methodologies and results described herein.
Pipeline Working Group

This study also benefited from the contributions and review of representatives of a number of interstate pipeline and local distribution companies. Participating companies include:

+ Kern River Gas Transmission Company
+ Kinder Morgan
+ Northwest Natural Gas Company
+ Pacific Gas & Electric Company
+ Questar Pipelines
+ Southern California Gas/San Diego Gas & Electric
+ Southwest Gas Company
+ TransCanada Pipelines Limited
+ Transwestern Pipeline Company
+ Northwest Pipeline Company

All of the companies in the Pipeline Working Group agreed to consider contributions of modeling/analysis for the project. Because a case study approach was taken, not all pipelines were called upon for the analysis. We would like to recognize the substantial contributions made by the pipelines in the case studies:

+ SoCalGas performed transient hydraulic modeling and shared internal modeling results for quick start impacts.
+ Williams Northwest adapted a steady state hydraulic model to perform transient modeling specifically for this study.
+ TransCanada used transient hydraulic modeling on its GTN system.
+ Kinder Morgan worked closely with DNV-GL to support hydraulic modeling of its El Paso Natural Gas system.
+ PG&E analyzed linepack on its system and shared internal analysis.

Without these contributions and the collaboration of the pipelines, Phase 2 would not have been possible.
## Acronyms

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Full Form</th>
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<tbody>
<tr>
<td>BPA</td>
<td>Bonneville Power Administration</td>
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<tr>
<td>CAISO</td>
<td>California independent system operator</td>
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<tr>
<td>CCGT</td>
<td>Combined cycle gas turbine</td>
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<td>CEC</td>
<td>California Energy Commission</td>
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<td>CHP</td>
<td>Combined heat and power</td>
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<td>CIG</td>
<td>Colorado Interstate Gas Co.</td>
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<td>CPCN</td>
<td>Certificate of public convenience and necessity</td>
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<td>CPUC</td>
<td>California Public Utilities Commission</td>
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<tr>
<td>CT</td>
<td>Combustion turbine</td>
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<td>EFO</td>
<td>Emergency flow order</td>
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<td>EPA</td>
<td>Environmental Protection Agency</td>
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<td>EPNG</td>
<td>El Paso Natural Gas Co.</td>
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<td>FERC</td>
<td>Federal Energy Regulatory Commission</td>
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<td>GTCC</td>
<td>Gas Transmission Control Center</td>
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<tr>
<td>GTN</td>
<td>Gas Transmission Northwest</td>
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<tr>
<td>IID</td>
<td>Imperial Irrigation District</td>
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<tr>
<td>LADWP</td>
<td>Los Angeles Department of Water and Power</td>
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<td>LDC</td>
<td>Local distribution company</td>
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<tr>
<td>LNG</td>
<td>Liquefied natural gas</td>
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<tr>
<td>LOLP</td>
<td>Loss of load probability</td>
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<tr>
<td>MAOP</td>
<td>Maximum allowable operating pressure</td>
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<td>MinOp</td>
<td>Minimum operating pressure</td>
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<td>NAESB</td>
<td>North American Energy Standards Board</td>
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<td>NERC</td>
<td>North American Electric Reliability Corporation</td>
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<td>NOPR</td>
<td>Notice of proposed rulemaking</td>
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<tr>
<td>OFO</td>
<td>Operational flow order</td>
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<td>OTC</td>
<td>Once-through cooling</td>
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PG&E      Pacific Gas and Electric Co.
PSCo      Public Service Company of Colorado
PSE       Puget Sound Energy
PWG       Pipeline Working Group
RPS       Renewables portfolio standard
SOC       Strained operating condition
SONGS     San Onofre Nuclear Generating Station
TAG       Technical Advisory Group
TEPPC     Transmission Expansion Planning Policy Committee
WCSB      Western Canadian Sedimentary Basin
WECC      Western Electricity Coordinating Council

### Units

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<tbody>
<tr>
<td>Bcf</td>
<td>Billion cubic feet</td>
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<tr>
<td>MMcf</td>
<td>Million cubic feet</td>
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<tr>
<td>MMcf/d</td>
<td>Million cubic feet per day</td>
</tr>
<tr>
<td>MMbtu</td>
<td>Million British thermal units</td>
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<tr>
<td>MW</td>
<td>Megawatts</td>
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<tr>
<td>MWh</td>
<td>Megawatt-hours</td>
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<tr>
<td>Psig</td>
<td>Pounds per square inch</td>
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*A detailed glossary is included in the Section 6. Terms included in the glossary are shown in italics in the report the first time they are used.*
Executive Summary

This study investigates the adequacy of natural gas infrastructure in the Western Interconnection to meet the needs of its electric sector. The study is divided into two phases, each addressing a separate aspect of the natural gas infrastructure:

**Phase 1.** Will there be adequate natural gas infrastructure (interstate and intrastate), including storage, to meet the needs of the electric industry in the Western Interconnection approximately ten years in the future?

**Phase 2.** Will the gas system have adequate short-term operational flexibility to meet increased volatility in hourly electric sector natural gas demand due to higher penetrations of variable renewable resources in the Western Interconnection?

The results of Phase 1—a screening-level analysis of regional infrastructure needs—were published in March 2014.¹ This report focuses on the question presented in Phase 2 of this study.

The purpose of investigating these questions is threefold: (1) to focus the regional dialogue on the most important gas-electric coordination issues; (2) to assess the magnitude of any potential limitations of gas infrastructure to

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¹ The full Phase 1 report is available here: https://ethree.com/documents/E3_WIEB_Report_3-17-2014.pdf
support the future demands of the electric sector in the regions evaluated; and
(3) to provide guidance to policymakers, regulators, pipeline companies, utilities, generators, and electric sector planners on actions that may be needed to overcome potential challenges resulting from the increasing reliance on natural gas for power generation. With these purposes, this study is intended to provide a bridge between the two industries in the Western Interconnection, to foster communication and to educate participants on both sides of the gas-electric interface in a region where dialogue has, to date, been limited.

Historically, reliability planning in the electric sector in the Western Interconnection has focused on the adequacy of a generation fleet’s capability to meet peak electric demands. Using stochastic models, electric utilities have established planning reserve margin targets to ensure that the amount of generating capacity available throughout the year would provide for a minimal risk of loss of load for their customers. These types of traditional reserve margin metrics are typically indifferent to the type of capacity used to meet these targets: inflexible baseload resources and flexible peaking resources—and everything in between—are treated equally in the accounting of planning reserve margins.

With the recent expansion of renewable generation under state renewables portfolio standard (RPS) programs, the scope of electric reliability planning in the Western Interconnection is beginning to address not only whether the capacity of a generation fleet is sufficient to meet its peak demands but whether that same fleet has sufficient operational flexibility to meet the ramping needs and reserve requirements associated with a growing fleet of renewable resources. This new paradigm for electric resource planning—one in
which the flexibility offered by a resource provides a premium upon its value to system reliability—has become manifest in a number of recent investments in new generation resources in the Western Interconnection. New gas-fired generation resources in the West are trending towards technologies with faster ramping rates and shorter start times, despite higher up-front costs.

The timely delivery of natural gas to these plants is a natural prerequisite to their ability to provide the flexibility desired by electric system operators. As the electric sector must maintain an instantaneous balance between supply and demand, understanding limitations of gas infrastructure is crucial to ensuring that investment decisions and operational strategies used to integrate high penetrations of renewables are effective at protecting electric ratepayers against loss of load. Thus, through a collaborative process including participants from the gas and electric industries, this study considers the following questions:

- Under what operating conditions are pipelines most likely to encounter challenges related to variability of demand?
- Will the intraday variability of electric sector demand for natural gas exceed the physical capability of pipeline systems to accommodate fluctuations in demand within the operating day?
- Could additional uncertainty in the electric sector result in adverse impacts on gas system operations due to an increase in imbalances?

Due to time and resource constraints, this study cannot answer all of these questions for all western pipeline systems under all circumstances. Instead, the work relies on a case study approach to explore the impacts of high renewable penetrations on the operational flexibility of a subset of gas systems in the
Western Interconnection, identifying some potential challenges that might result. Case study results are then used to derive general conclusions about the impact of variable renewables on pipeline operations.

Guided by the findings of the Phase 1 analysis, discussions with the Technical Advisory Group (TAG), and interviews with participating pipelines in the Pipeline Working Group (PWG), this study narrows its focus to six case studies, whose geographic footprints are shown in Figure 1:

+ **Southern California**: Southern California Gas/San Diego Gas & Electric (SoCalGas) system
+ **Northern California**: Pacific Gas & Electric (PG&E) system
+ **Desert Southwest**: “Power Plant Alley” segment of El Paso Natural Gas Company Southern Mainline
+ **Pacific Northwest, West of Cascades**: I-5 Corridor of Northwest Pipeline in Western Washington
+ **Pacific Northwest, East of Cascades**: TransCanada Gas Transmission Northwest (GTN) system
+ **Colorado Front Range**: Colorado Interstate Gas (CIG) system in Colorado

While the case study approach is necessarily limited in the geographic regions and specific power system conditions that are examined, the cases selected here represent relatively extreme circumstances on the power system (very high renewable penetrations) and relatively restrictive measures available to pipeline operators (each system is assumed to manage its own variability without relying on neighboring systems). As a result, the conclusions that can be drawn about the impact of renewables on pipeline operations are broad.
Figure 1. Case studies included in Phase 2.

Existing Natural Gas Plants
- 10 MW
- 50 MW
- 100 MW
- 500 MW
- 1,000 MW

Pipeline geospatial data obtained from Platts; power plant locations from EIA
Each case study is conducted as a collaborative examination of the issues that may affect a pipeline system as the penetration of renewable resources increases throughout the electric sector in a series of steps:

- **Inputs and assumptions** for analysis are developed by E3 and DNV GL based on simulations of the electric sector over a ten-year timeframe and information shared by pipelines.

- **Technical analysis** based on these assumptions is conducted by participating pipelines or, in instances where this resource is not available, by DNV GL with oversight and guidance from pipeline representatives.

- **Conclusions and findings** are drawn through a joint review of case study results between E3, DNV GL, and the participating pipelines.

- Additionally, an **independent review** of the study process and modeling conducted using proprietary software was conducted by Lawrence Berkeley National Laboratory (LBNL) and is published as a standalone document.

To characterize the variable nature of future electric sector natural gas demand, this study relies on two scenarios developed in Phase 1: (1) the Base Case, which captures expected renewable penetrations across the Western Interconnection in 2022; and (2) the High Renewables Case, in which incremental wind and solar resources are added to evaluate operations at higher penetrations of these resources. The composition of renewable portfolios across the Western Interconnection in these two scenarios, which result in penetrations of 18% and 26%, respectively, are shown in Figure 2.
Hourly profiles of natural gas demand among electric generators are extracted from the results of production simulation analysis and superimposed onto delivery profiles to non-electric end users during peak winter periods provided by participating pipelines based on either historical or forecast data. These profiles serve as the “Reference Assumptions” for analysis in each case study and also provide the basis for a number of sensitivities investigated to highlight key relationships between the gas and electric sectors. Table 1 shows the scope sensitivities investigated in each case study.
The resulting profiles for natural gas demand were shared with participating pipelines, who voluntarily committed modeling resources and time to help characterize the impacts of the profiles on their respective systems. When pipelines were unable to commit modeling resources to support this effort, the hydraulic model of western gas infrastructure developed by DNV GL in Phase 1 was used under the oversight of participating pipelines.

This analytical approach, which combines analysis based on public information with modeling and technical work produced by pipelines using proprietary information and in-house modeling tools, is useful for addressing questions of how variability impacts pipeline systems. Engaging pipelines directly and incorporating their expertise of system operations enriches the study of the emerging issues investigated herein; unlike Phase 1 of this study, this effort is not limited by the lack of publicly available data on gas infrastructure and operations.

Through discussions with participating pipelines and the case study process, this study identifies a number of key conclusions and, in some cases,
recommendations for next steps related to the impacts of renewable integration on gas systems:

1. **Under the conditions examined in this study, meeting the variable gas demands needed to integrate high penetrations renewables is technically feasible.** The physical flexibility inherent in a pipeline system is a result of two factors: its tolerance for fluctuations in linepack and the availability of natural gas storage. Linepack, the inventory of gas stored in a pipeline, can provide flexibility to meet variable loads by absorbing small imbalances in receipts and deliveries over short time scales. Underground gas storage, where available, provides flexibility by allowing users to withdrawal gas at variable rates with limited notice to pipeline operators, mitigating the need to use linepack to absorb variability. These two factors enable gas pipeline systems to manage rapid changes in electric sector demand caused by its need to maintain instantaneous balance between supply and demand.

   **Next Step: Monitor regional balances between demand for natural gas and available capacity of pipeline systems.** This study shows how the availability of flexibility on a pipeline is directly linked to the level of utilization: a pipeline that is fully utilized cannot tolerate any variation in linepack, while a system that is not fully utilized can operate at a range of different levels of linepack. Should developments in either industry result in increased utilization of pipeline systems, electric sector planners should recognize that pipeline system flexibility may become constrained, and new investments may be needed to ensure adequate flexibility.

2. **The addition of renewable generation to an electric system reduces the overall level of gas demand while increasing its variability.** While the increase in variability creates operating challenges, the reduction in natural gas demand provides the pipeline operator with greater ability
to meet the variable demand, and the case study results indicate that
the decrease in gas demand outweighs the impact of increased
variability. The hydraulic modeling conducted demonstrates that the
reduction in demand affords the pipeline system the flexibility to
manage the increase in variability with existing physical tools (i.e.
linepack and/or storage) even under high demand conditions in the
winter heating season, when flexibility is most likely to be constrained.

Next Step: Encourage ongoing efforts to establish reliable
communications between gas and electric system operators. As
operations become increasingly variable in each industry with
increases in renewable penetration, protocols for reliable and timely
communications between the two will help each one adapt to
rapidly changing conditions in daily operations.

3. Imbalances between gas deliveries and receipts to gas systems can
cause operational challenges. Operational challenges arise when
imbalances between receipts and deliveries cause a system’s linepack to
vary beyond its designed operating range. A number of factors may
contribute to imbalances, including infrastructure contingencies, market
forces, and shipper nomination errors. Under such circumstances,
pipelines may take a number of steps—communicating directly with
customers, imposing financial penalties, or ultimately, curtailing service
to customers—in order to preserve service to others.

Next Step: Continue to explore refinements to the nominations and
scheduling process to facilitate gas system operations. In FERC’s
ongoing gas-electric coordination docket, stakeholders have
identified a number of ways in which the nominations and
scheduling process can cause friction between the two industries.
Adjustments to these conventions could mitigate some of these
challenges.
4. The intermittency and lack of predictability of renewable generation may increase the frequency and magnitude of imbalances on pipeline systems. Pipeline operators rely primarily on nominations submitted by shippers to prepare and operate the system throughout the day. As the penetrations of variable renewable resources increase, forecasting the amount of gas needed to serve gas generators will become increasingly challenging, as electric system operators account not only for load forecasting errors but also the forecasting errors of wind and solar facilities.

**Next Step:** Investigate impacts of renewable forecast error on gas nominations and scheduling. The impact of renewable generation forecast errors on the operations of gas systems will vary, depending on the physical characteristics of gas infrastructure, the composition of the renewable portfolio, and the characteristics of the electric fleet used to balance it. Efforts to quantify this impact, such as Xcel Energy's 2011 Wind Integration Study, provide valuable insight into the impacts of renewable generation on gas systems.

5. Transportation services tailored to meeting variable demands can help to facilitate renewable integration. With growth in the penetration of renewable resources, the variability and uncertainty of electric sector demands for natural gas increase. Under such circumstances, transportation services that anticipate variable delivery rates will allow gas systems to meet those loads. Hourly firm services such as those offered by the El Paso Natural Gas Co. may offer opportunities to allow gas generators to arrange for reliable transportation at a cost more reflective of service that they require, mitigating the costs of renewable integration to ratepayers.

**Next Step:** Explore transportation service options that might facilitate efficient and reliable integration of renewables. Creatively structured services could allow generators to secure the
services they need and also provide the appropriate investment signal to pipelines when necessary to trigger efficient expansion of gas infrastructure.

6. Gas generators with firm natural gas delivery contracts may not receive transportation service when they do not nominate appropriate volumes to match their needs. In Phase 1, this study reached the conclusion that gas generation that does not contract for firm transportation service may be subject to interruption during times of high gas demand. Phase 2 concludes that merely holding firm transportation service is not sufficient to guarantee firm service; shippers must also schedule natural gas deliveries early enough in the daily nomination process. Pipeline systems are limited in their abilities to absorb unscheduled demands; failure by the firm shipper to nominate appropriate volumes hinders the ability of the system to meet demands. Further, due to the rules regarding scheduling priority afforded to various services in the nomination and scheduling processes, one shipper’s un-nominated capacity may be allocated to another if it is not scheduled in the Timely cycle.

7. Gas systems in the Western Interconnection depend on their neighbors to ensure reliable operations. Phase 1 concluded that the regions of the Western Interconnection are highly interdependent in their reliance on natural gas transportation and generation infrastructure. The case study approach used in Phase 2 examines a number of systems independently, under the assumption that gas supply at interconnection points is both available and delivered on a “ratable” basis, i.e., that gas deliveries to the pipeline system are constant during all hours of the day. This is a conservative assumption, in the sense that it restricts the ability of pipeline operators to rely on a tool they have available under some circumstances today: to turn to their neighboring systems for help in managing any gas supply-demand
imbalance. At the same time, Phase 1 found that contingency events on a single pipeline could have substantial impacts on neighboring systems. While Phase 2 did not specifically investigate contingencies and their potential impacts on the broader system, the results of Phase 1 indicate that such events could create operational challenges.

**Next Step: Study renewable integration challenges under regional contingency events.** While these events are rare and are generally caused by extreme weather and supply events that are unrelated to renewable electric generation, there may be instances in which their effects are precipitated or magnified by variable renewables. Further studies may shed light on these circumstances.
1 Introduction

1.1 Goals of Study

This study investigates the adequacy of gas infrastructure in the Western Interconnection to meet the needs of its electric sector. The study is divided into two phases, each addressing a separate aspect of the natural gas infrastructure:

**Phase 1.** Will there be adequate natural gas infrastructure (interstate and intrastate), including storage, to meet the needs of the electric industry in the Western Interconnection approximately ten years in the future?

**Phase 2.** Will the gas system have adequate short-term operational flexibility to meet increased volatility in hourly electric industry natural gas demand due to higher penetration of *variable energy resources* in the Western Interconnection?

The results of Phase 1—a screening-level analysis of regional infrastructure needs—were published in March 2014. This report focuses on the question posited in Phase 2 of this study.

The purpose of investigating these questions is threefold: (1) to focus the regional dialogue on the most important gas-electric coordination issues; (2) to assess the magnitude of potential issues and the regions affected; and (3) to...
provide guidance to policymakers, regulators, pipeline companies, utilities, generators, and electric sector planners on actions that may be needed to overcome potential challenges resulting from the increasing reliance on natural gas for power generation. With these purposes, this study is intended to provide an initial bridge between the two industries in the Western Interconnection, to foster communication and to educate participants on both sides of the gas-electric interface in a region where dialogue has to date been limited.

1.2 Motivation for Study

As the dependence of the electric sector on natural gas generation has grown in recent years, conversations surrounding the importance of coordination between the electricity and natural gas industries have gained traction at a national level, attracting the attention of FERC, NERC, and other planning and regulatory agencies. Interest in this topic has grown as recent events across the country have highlighted vulnerabilities of the electric sector in its reliance upon natural gas. The most notable examples are:

+ The natural gas shortages in New England, New York, and the PJM Interconnection experienced during the last few winter heating seasons due to constraints on natural gas pipeline capacity;

+ The curtailments of gas service in Texas and the Desert Southwest following a “wellhead freeze-off” that limited gas production in the Permian and San Juan basins in February 2011; and

+ The curtailments of service to a number of non-core customers in Southern California in February 2014 due to supply shortages at the California border.
These events and the concerns surrounding them served as the motivation for Phase 1 of this study, which investigated at a broad level the degree to which the Western Interconnection may face similar challenges to those encountered in other jurisdictions.

In contrast, Phase 2 is motivated by a forward-looking concern related to the impacts of increasing penetrations of variable renewable resources in the Western Interconnection. The renewable policy goals of a number of the states in the West are among the most aggressive in the nation, and the market for renewable development in the West has grown more rapidly than in other areas. As the penetration of renewables on various portions of the Western system continues to increase to high levels, planning efforts in the electric sector have begun to confront the questions of how high penetrations of renewable generation will affect electric system operations and the need for new investments. How renewable generation will affect the timing and magnitude of the needs of natural gas generators, and the ability of gas infrastructure to meet those needs, is one of these questions.

Electric generation from wind and solar sources is both variable and uncertain, requiring immediate response from dispatchable generation—mostly hydroelectric and natural gas-fired—in order to maintain grid reliability. The California ISO’s “duck chart”, reproduced in Figure 3, shows significant changes in the daily pattern of “net load”—load minus production from non-dispatchable generation—due to increased solar generation. The primary resources available for meeting these hour-to-hour demand swings in California are natural gas generators. In addition to changes in diurnal patterns, increased reliance on variable generation resources will require natural gas generation to
start up and get to full output very quickly. This raises questions about the ability of the natural gas delivery system to provide fuel for gas generators operating in these patterns.

**Figure 3. California ISO's "duck chart," illustrating the impact of high renewable penetrations on net load.**

![Net load - March 31](image)

*Figure source: CAISO 2013*

The questions raised are multi-dimensional: can the natural gas system physically respond to the increased volatility in daily and hourly gas generation? Would this require pipelines to offer different products and services from what they offer today? Would gas generators subscribe to new services that would increase their cost of acquiring fuel? These are different questions from those related to the pressing concerns identified in other regions, but they are
important for understanding the ability of the gas sector to meet the demands that the electric sector will impose upon it over the next decade.

1.3 Scope of Study

Historically, reliability planning in the electric sector in the Western Interconnection has focused on the adequacy of the generation fleet’s capability to meet peak demands. Using stochastic models, electric utilities have established planning reserve margin targets that ensure that the amount of generating capacity available throughout the year would provide for a minimal risk of loss of load for their customers. These types of traditional reserve margin metrics are typically indifferent to the type of capacity used to meet these targets: inflexible baseload resources and flexible peaking resources—and everything in between—are treated equally in the accounting of planning reserve margins.

With the recent expansion of renewable generation under state renewables portfolio standard (RPS) programs, the scope of electric reliability planning in the West is beginning to expand to address not only whether the capacity of a generation fleet is sufficient to meet its peak demands but whether that same fleet has sufficient operational flexibility to meet the ramping needs and reserve requirements associated with growing renewable penetrations. This new paradigm for electric resource planning—one in which the flexibility offered by a resource provides a premium upon its value to system reliability—has become manifest in a number of recent investments in new generation resources in the Western Interconnection. New generation resources in the West are trending
towards technologies with faster ramping rates and shorter start times—at times in spite of higher up-front investment requirements.

The timely delivery of natural gas to these plants is a natural prerequisite to their ability to provide the flexibility desired by the electric system operator. As the electric sector must maintain an instantaneous balance between supply and demand, understanding limitations of gas infrastructure to meet these needs is crucial to ensuring that investment decisions and operational strategies used to integrate high penetrations of renewables are effective and protect electric ratepayers against loss of load. Thus, through a collaborative process that includes participants from both the gas and electric industries, this study considers the following questions:

- During which times of the year are pipelines most likely to encounter challenges related to variability of demand?
- Will the intraday variability of electric sector demand for natural gas exceed the physical capability of pipeline systems to accommodate fluctuations in demand?
- Could additional uncertainty in the electric sector result in adverse impacts on gas system operations due to an increase in imbalances?

Each of these questions is addressed either through the case study development process or within one or more of the case studies. While this study cannot answer all of these questions comprehensively, the process used herein is intended to highlight potential issues that merit further investigation to facilitate interactions between the two industries as renewable penetrations increase.
Phase 1 of this study addressed gas-electric coordination across the footprint of the Western Interconnection, a region that comprises a large number of inter- and intrastate pipeline systems. Each of the pipeline systems operates with a unique set of conventions to provide service to customers with specific needs. Figure 4 shows the major pipeline systems of the Western Interconnection.

Due to time and resource constraints, this study cannot answer all of these questions for all western pipeline systems under all circumstances. Instead, the work relies on a case study approach to explore the impacts of high renewable penetrations on the operational flexibility of a subset of gas systems in the Western Interconnection, identifying some potential challenges that might result. Case study results are then used to derive general conclusions about the impact of variable renewables on pipeline operations. Guided by the findings of the Phase 1 analysis, discussions with the Technical Advisory Group (TAG), and interviews with participating pipelines in the Pipeline Working Group (PWG), this study narrows its focus to six case studies:

- **Southern California**: Southern California Gas/San Diego Gas & Electric system
- **Northern California**: Pacific Gas & Electric system
- **Desert Southwest**: “Power Plant Alley” segment of the El Paso Natural Gas Company Southern Mainline in Arizona
- **Pacific Northwest, West of Cascades**: I-5 Corridor of Northwest Pipeline in Western Washington
- **Pacific Northwest, East of Cascades**: TransCanada Gas Transmission Northwest (GTN) system
- **Colorado Front Range**: Colorado Interstate Gas system in Colorado
Figure 4. Major natural gas pipelines in the Western Interconnection.

Pipeline & storage geospatial data obtained from Platts
As this analysis breaks ground on a question that has not yet been studied in depth across the region, it does not attempt to identify every issue or challenging circumstance that will result from the electric sector’s reliance on natural gas, nor does it seek to characterize every one fully. The study’s general focus is upon characterizing the implications of higher penetrations of renewable generation on the operations of gas systems and identifying potential vulnerabilities where possible. While the case study approach is necessarily limited in the geographic regions and specific power system circumstances that are considered, the cases were designed to represent relatively extreme circumstances on the power system (very high renewable penetration) and relatively restrictive measures available to pipeline operators (each system is assumed to take care of its own variability without relying on neighboring systems for help) in order to identify potential issues that could occur rather than dismissing their possibility. As a result, the conclusions that can be drawn about the impact of renewables on pipeline operations are broad.

1.4 Limitations and Caveats

The topic of gas-electric coordination is relatively new to the Western Interconnection. As this is one of the first major investigations of the subject, it is important to establish clearly the limitations and bounds of this study so that its results and conclusions might be used appropriately by resource planners and policymakers.

First, as with Phase 1, Phase 2 of this effort is not an infrastructure expansion study; it does not attempt to identify where in the Western Interconnection new natural gas infrastructure may be needed. The decision to expand any
system rests with the shippers who would fund it and the regulators who would approve such funding and cost allocation, and would require risk assessment, economic evaluations, and other studies of local conditions that are beyond the scope of this report. The study focuses on identifying and characterizing the nature of interactions between an electric system with increasing penetrations of variable renewable resources and natural gas infrastructure with a convention of operating at stable levels throughout the day. In doing so, its goal is to promote an understanding of what issues may be of interest to electric and gas system planners and operators alike as states pursue aggressive clean energy targets.

Second, in contrast to Phase 1, the geographic scope of this phase of the study is limited. The complexity of the questions addressed and associated analysis investigated in Phase 2 necessitate focused analysis on specific gas systems rather than the regional screening approach used in Phase 1. As a result, the case study process used in this phase examines a subset of gas systems in the Western Interconnection. Where possible and justifiable, analysis conducted through each of the case studies are used to inform more general conclusions on the nature of interactions between gas and electric systems; however, because of the limited geographic scope this study cannot examine the impacts of renewable integration on gas systems across the Western Interconnection in its entirety.

1.5 Organization of Report

The scope of this report is limited to Phase 2 of the study. The remainder of this report is organized in the following sections:
Section 2 provides background on both the growing need for flexibility from gas resources in the electric sector as well as the physical and institutional characteristics of pipeline systems relevant to their ability to provide flexibility;

Section 3 describes the process and logic used to identify and develop case studies to address key questions;

Section 4 presents each case study independently, describing the specific questions and analyses conducted;

Section 5 presents the conclusions of the study, including both findings related specifically to Phase 2 and broader conclusions reached through the study as a whole;

Section 6 is a glossary that defines key terms for the gas and electric industries; and

Section 7 contains references to documents cited in this study.
2 Overview of Operations

2.1 Electric Sector Need for Flexibility

The development of renewable resources in the U.S. has been growing rapidly in recent years. Non-hydroelectric renewables’ share of total generation nearly tripled between 2004 and 2013, from 2.1% to 6.2%. In 2012 alone, more than 13,000 MW of wind and 3,300 MW of solar PV capacity were added. Investment in renewable resources has primarily been driven by: (a) state RPS targets, which place an obligation on load-serving entities to serve a specified fraction of their retail sales with renewable energy; (b) state and federal tax incentives, including accelerated tax depreciation and tax credits based on renewable energy investment or production; and (c) reduced installed costs and higher performance, which translate into lower levelized costs of electricity.

Among the U.S. states in the Western Interconnection, ten have an RPS target or goal. These policies are expected to increase renewable generation from 66 TWh in 2010 to 146 TWh in 2022, resulting in a WECC-wide renewable penetration of 14.5%. A number of factors may push renewable investment beyond the levels required by current policy, including: (1) increases in state RPS

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2 See Table 1.1 of EIA (2014).
3 See Wiser and Bolinger (2013) and Barbose et al. (2013).
4 See WECC (2011).
targets; (2) federal regulations to limit electric sector carbon dioxide (CO₂) emissions\(^5\); and (3) high CO₂ prices and/or continued renewable cost declines that lead to market-driven investment in renewable generation.

The vast majority of the incremental renewable energy required to satisfy state RPS targets is expected to come from variable energy resources—specifically wind and solar PV—that cannot be dispatched by the system operator. Higher penetrations of variable energy resources increase both the variability and uncertainty of a power system’s “net load”—electric load minus the output of non-dispatchable generation—changing the way conventional generating resources are operated. Variability and uncertainty are existing characteristics of power systems: system operators already manage load changes of several thousand megawatts during morning and evening ramps, and cannot perfectly forecast load. However, as the penetration of variable energy resources grows, the variability and uncertainty of wind and solar power will add to existing load variability and uncertainty, increasing the variability and uncertainty of net load.

Such impacts are already evident in system operations today, as shown in the five day profiles of load and net load for the California ISO (CAISO) and Bonneville Power Administration (BPA) from March 2014 in Figure 5. In California, nearly 4,000 MW of solar PV capacity has been installed since 2010; these plants have already begun to change the shape of net load materially.\(^6\) The diurnal pattern of solar generation results in a periodic, regular change to the shape of the net load. Over a similar timeframe, BPA has experienced a

\(^5\) For example, the EPA’s Clean Power Plan Proposed Rule is intended to reduce CO₂ emissions from power plants by 30 percent from 2005 levels by 2030 (EPA, 2014).

\(^6\) Based on the California Energy Commission’s Power Plant Database (CEC, 2014).
large build-out in wind generation capacity—primarily in the Columbia River Gorge. Because wind generation does not follow a periodic profile in the same way as solar does, the net load patterns in BPA vary substantially from one day to the next depending on the wind regime.

Figure 5. Hourly load and “net load” for March 24 – 30, 2014

(a) California Independent System Operator (CAISO)

(b) Bonneville Power Administration (BPA)
These types of changes result in the need for additional operational flexibility across various timescales above the levels that have been historically required. In the day-ahead time frame, load, wind, and solar forecasts are used by system operators to decide which generating units to commit. Owners of natural gas-fired generating units must assess their expected need for fuel in order to make arrangements for the supply of natural gas and submit the appropriate nominations for gas transportation. Renewables increase the net load forecast uncertainty, resulting in forecast errors that require flexible generating units to commit and dispatch in shorter time frames, and, in the case of gas-fired generators, consume more or less fuel than their scheduled quantity.

In the intra-hour time frame, variable renewables such as wind and solar require higher levels of operating reserves, commonly classified as regulation—addressing variability on timescales of a few cycles up to 5-minutes—and load-following—addressing variability on timescales of 5 minutes to one hour. Inter-hour changes in load, wind and solar will substantially change the net load shape and require flexible generators to have the upward and downward capability to meet net load ramps over multiple hours, and reduce their output to minimum levels or shut down during periods of high non-dispatchable generation.

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7 The need for additional operational flexibility does not necessarily translate into additional flexible capacity. The existing generator fleet may or may not have sufficient operational flexibility, depending on their operating characteristics, load shape, renewable profiles, and other factors.

8 See Mauch et al. (2013) for a discussion of how wind power increases net load uncertainty.

9 See Ela et al. (2011) for an extensive discussion on the impact of variable energy resources on operating reserves.

10 “Must-take” generation includes variable energy resources, combined heat and power, nuclear generation, run-of-river hydro, and thermal generation required for local electric reliability. Overgeneration occurs when “must-take” generation is greater than load plus exports.
Figure 6 below shows a sample operating day illustrating four distinct types of inter-hour flexibility challenges that the system will face under higher penetrations of variable energy resources. The dark black line near the top indicates the load that must be served during each hour, and the shaded areas represent the types of resources that are operating throughout the day.

**Figure 6. Illustrative examples of inter-hour flexibility challenges**

Four flexibility challenges are numbered in Figure 6:

1. **Downward ramping capability**: Thermal resources operating to serve loads at night must be ramped downward and potentially shut down to make room for a significant influx of renewable energy after the sun rises, in this case around 8:00 AM.
2. **Minimum generation flexibility**: Overgeneration may occur during hours with high renewable production even if thermal resources and imports are reduced to their minimum levels. A system with more flexibility to reduce thermal generation will incur less overgeneration.
3. **Upward ramping capability**: Thermal resources must ramp up quickly from minimum levels during the daytime hours and new units may be required to start up to meet a high net peak demand that occurs shortly after sundown.

4. **Peaking capability**: The system will continue to need enough resources to meet the highest peak loads with sufficient reliability.

Both the intra- and inter-hour operational flexibility challenges require dispatchable generators to more frequently start up, shut down, ramp up and down across their operating range, and operate at minimum generation levels to meet a more variable and uncertain net load shape. This necessitates generators with the following flexibility characteristics: (1) large operating range; (2) low minimum generation levels; (3) high thermal efficiency at partial load; (4) fast ramp rates in both the upward and downward direction; (5) short start up and shut down times; and (6) short minimum on and off times.

Since gas-fired generating resources, including combustion turbines, combined cycle plants and reciprocating engines, have many of these characteristics, they are often used to provide power system flexibility services, but this depends on the regional electricity mix. For example, balancing authorities in California and the Desert Southwest are likely to rely heavily upon large fleets of gas-fired plants to integrate renewables. In the Pacific Northwest, hydro resources are likely to provide a substantial source of flexibility, but non-power (i.e., environmental) constraints limit hydro flexibility. BPA has already noted that its hydro system is running out of flexibility to integrate wind power, and offers a
self-supply pilot for wind plants to procure their own balancing resources to reduce the burden on the federal hydro system.¹¹

As a result, gas-fired resources are expected to provide a significant proportion of the flexibility services needed by the power system over the next decade to integrate renewables. Electric system planners are already procuring new, flexible gas generators, and gas turbine manufacturers are responding by developing models that increase both flexibility and thermal efficiency. For example, Portland General Electric is currently developing twelve gas-fired reciprocating engines (220 MW) as a flexible capacity resource to integrate additional wind resources.¹²

One of the important characteristics of newer gas generation technologies that utilities are building for renewable integration is their start-up time: resources that can ramp up to full output in a limited amount of time provide a benefit to an operator seeking to integrate a portfolio of variable and unpredictable energy resources. As gas generation technologies have continued to improve, their start times have declined substantially to the point that new CCGTs and CTs can ramp up to full output within a window of less than half an hour. An example profile for a quick-start aeroderivative CT is compared against the start-up profile of an existing gas-fired steam turbine in Figure 7. The quick-start CT is capable of starting up and ramping to its full load in 10 minutes, whereas the steam unit requires three hours. The continued development of gas resources such as the quick-start CT will provide power system flexibility, but it

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¹¹ See BPA (2011) and Porter et al. (2013).
¹² See PGE (2014).
will also impose different demands, both in the timing and amount of gas, on the gas system than in the past.

Figure 7. Start-up profiles for a "quick-start" CT compared to a traditional plant with a three hour start.

(a) Over three hours

(b) During first twenty minutes
2.2 Gas System Operations

Gas transmission systems are designed to move large quantities of natural gas over large distances, balancing *receipts* (supply flowing on to the system) with *deliveries* (the demand for natural gas). The major components of natural gas infrastructure are shown in Figure 8. After extraction and processing, natural gas enters into the gas transmission system. Natural gas flows through pipelines in response to pressure differentials created by compressor stations located along the length of the systems; the compressors add energy to the system to overcome the frictional losses inherent in the pipeline system. Pipelines deliver gas to customers—either through *local distribution companies* (LDCs) or directly to end users—at metering stations.

Figure 8. Components of gas systems.

Image Source: Energy Information Administration (EIA)
This study focuses on the capabilities of gas transmission infrastructure. Through a series of hydraulic simulations, this section discusses the physical constraints that govern a pipeline system’s day-to-day operations and its ability to adjust to serving flexible loads. Hydraulic models, which simulate the operations of compressor stations and the resulting physical flow of gas through pipelines, are commonly used in the gas sector to analyze the operations of gas systems and to plan for infrastructure expansion. Such models may either be run in steady state, which examines a system at equilibrium with flows at constant levels, or on a transient basis, which models changes in conditions (e.g. demand, supply) over time. Despite the simplifying assumptions that it makes, steady state modeling is generally accepted as the industry standard approach for analysis of large pipeline systems; because of the complexity of transient analysis, its use to analyze large pipeline systems is limited. Nonetheless, transient hydraulic modeling is a useful tool for analysis of variability in the demand for natural gas.

Several simple transient hydraulic simulations, based on the representative pipeline system shown in Figure 9, are used to illustrate key operational characteristics of gas systems providing service to a variable load. The representative system has a total of 300 miles of pipeline of 30-inch diameter and 4 compressor stations. Each compressor station, evenly spaced along the length of the pipeline, inputs energy into the system to compress the natural gas that has lost energy through friction as it moves through the pipeline. The system has been designed to deliver a maximum of 675 million standard cubic feet per day (MMcf/d) at its western end at a pressure of no less than 525 psig.
when it is operated at an operating pressure of 850 psig at steady state. For purposes of this example, 850 psig is the assumed Maximum Allowable Operating Pressure (MAOP) of this pipeline example.

**Figure 9. Diagram of a simplified pipeline system.**

This section also relates the physical factors that govern day-to-day operations to the institutional characteristics of the gas transportation business—the structure of services, the processes used to schedule and nominate gas flows, and other interactions between pipelines and shippers that affect system operations.

### 2.2.1 PHYSICAL CHARACTERISTICS RELEVANT TO FLEXIBILITY

Natural gas demand variability is not a novel challenge for pipelines: especially in winter periods, demand for natural gas from the residential and commercial sectors varies considerably throughout the day due to the timing of heating end uses. Similarly, while some industrial users and base load power plants burn natural gas at a somewhat constant rate, it is not uncommon for industrial processes to vary and for peaking power plants to come onto the system and change their level of operation throughout the day.
Receipts to pipeline systems from gas processing plants and interconnections with other pipelines are, by contract and operating practice, “ratable”, that is, the rate at which gas flows from one pipeline system to another is constant across the entire scheduling period (e.g., 24 hours). This means that pipelines must manage their systems to accommodate any short-term differences between supply and demand to ensure ratable flows at the boundaries. Pipeline systems have two primary physical tools to accomplish this goal:

+ Management of “linepack,” the total inventory of gas contained within a pipeline, through which pipelines can allow some variations in its inventory to accommodate small differences between receipts and deliveries; and

+ Use of underground natural gas storage, which can be used to provide receipts to a system on a variable (non-ratable) basis to match the variable needs of loads.

The physical contribution of each of these tools to the flexibility of pipeline systems is illustrated through transient hydraulic modeling of the pipeline system introduced above.

2.2.1.1 Role of Linepack

One of the primary tools that allows pipeline systems to meet variable demands is the management of its linepack. Because natural gas is a compressible fluid, the rate at which gas is received to a system need not match the rate at which it is delivered on an instantaneous basis. This attribute of natural gas distinguishes it from the electric system—which requires an instantaneous balance between supply and demand—as the transportation system itself has some capability to
act as a storage resource for natural gas. When the rate of deliveries exceeds the rate of receipts, the system is being “drafted”; when receipts exceed deliveries, the system is being “packed.”

Of course, the ability of a pipeline system to manage swings in linepack is limited. A system cannot be drafted below certain levels (at the risk of violating delivery pressure obligations), nor can it be packed above certain levels (at the risk of exceeding the system’s MAOP). Further, the degree to which linepack can be used to meet variable demands is directly related to the magnitude of those demands. Because a system’s tolerance for linepack variability is directly linked to the level of gas it is used to transport, so is its flexibility: a pipeline operating at its design conditions has no flexibility to vary its linepack, but a pipeline that is being used to meet demands less than its design conditions can make use of its tolerance for variability to absorb some differences in receipts and deliveries.

In this example, when compressors are configured to deliver 675 MMcf/d, the pipeline’s linepack is 404 MMcf; because the pipeline is in steady state, this linepack is constant. When a pipeline is operated at its maximum capacity, the system cannot be operated with any other level of linepack: it cannot tolerate any variance from this inventory without either exceeding the maximum allowable pressure or falling below the minimum delivery pressure obligation, shown as point (a) in Figure 10. However, when the pipeline is used to transport a volume of gas below its maximum capacity, the system operator has some flexibility in the amount of linepack to hold. The operator can either run compressors at lower set points, corresponding to a lower level of overall linepack (point (c) in Figure 10); or the operator may choose to run compressors at higher set points, resulting in a higher level of linepack (point (b) in Figure
10). The amount of variance in linepack that a system can tolerate without violating its operating constraints is inversely related to the level of throughput, as illustrated in Figure 10. The upper frontier of this envelope corresponds to the maximum linepack a system can carry for a given level of throughput; the lower frontier is the minimum linepack; the space between the two represents the flexible range for operations.

**Figure 10. Illustrative envelope of allowable linepack as a function of throughput.**

To highlight the key relationships between throughput, linepack, and flexibility, an example in which this pipeline is used to serve a variable demand profile is developed. In this example, deliveries are assumed to be concentrated in a 16-hour block, during which the rate of delivery is 125% of the daily average; during
the other eight hours, the rate of delivery is 50% of the daily average. With this variable profile, the maximum daily demand that can be met by the system is approximately 530 MMcf/d; this is notably lower than the pipeline’s steady-state capacity of 675 MMcf/d, as the use of linepack on the system to meet the variable demand limits the amount of volume that the system can deliver on a daily basis.

Figure 11 shows the results of the simulation of the variable profile on the simple system over a two-day (48-hour) period. This simulation alternates between periods of drafting (when deliveries exceed receipts at 0-16 hours) and packing (when the reverse is true at 16-24 hours) but remains within the constraints of minimum and maximum pressures. Despite the fact that the daily average volume transported (530 MMcf/d) is less than the steady-state capacity (675 MMcf/d), the facilities of this system are operating at nearly maximum capacity: any incremental demand would cause pressure at the point of delivery to drop below the pipeline’s minimum obligation.
Figure 11. Transient hydraulic simulation of simple pipeline in unsteady state.

(a) Assumed receipts & deliveries

(b) System linepack

(c) Pressure at delivery point
While pipeline systems operating below capacity have some tolerance for differences in receipts and deliveries on short time scales, persistent *imbalances* between the two will create operational challenges for pipelines. To illustrate this phenomenon, the simulation shown in Figure 11 is repeated assuming a deficiency of supply of 5% (daily deliveries average 530 MMcf/d, while daily receipts average 505 MMcf/d) on the first day. With this deficiency, the system is unable to recover its linepack fully over the first twenty-four hour period while meeting the full demand.

The results of this simulation are shown in Figure 12; the solid lines indicate the result if pressure at the delivery point is allowed to drop below the minimum obligation. Under such circumstances, the pipeline is still able to meet the full load but cannot sustain pressure at the tail end of the pipe due to the physical limits of the compressors. This effect appears as a small dip below the minimum on the first day at hour 16, but on the second day, as the imbalance travels the length of the pipeline, the effect becomes more substantial despite the fact that receipts and deliveries on the second day are assumed to be balanced (see hour 40).

Rather than allowing the pressure on the system to drop below the minimum obligation, a system operator could curtail demands; this is shown in the dotted lines in Figure 12, which indicate curtailment between hours 36-40 to avoid violating minimum delivery pressure obligations. By curtailling some load once pressure has declined to the minimum obligation, the system can maintain that level of pressure while serving a lower load. As with the previous unconstrained simulation, this effect is greater on the second day than the first.
Figure 12. Transient hydraulic simulation with a 5% deficiency in receipts.

(a) Assumed receipts & deliveries (including storage withdrawals)

(b) System linepack

(c) Pressure at delivery point
2.2.1.2 Role of Natural Gas Storage

Natural gas systems make use of storage facilities to help supply customer demands. Storage facilities can be small and intended for limited use during peak periods – such as Liquefied Natural Gas (LNG) storage facilities. Or storage facilities can be large underground facilities like depleted natural gas fields, solution-mined salt domes and bedded salts or other available geological formations. Both LNG facilities and underground storage facilities have cycles where they are filled with natural gas during low demand periods and then this natural gas is withdrawn during high demand periods.

Storage facilities often have seasonal operating norms. Facilities are often filled from late spring to early fall and then used for withdrawal in the heating period (generally November through March). Underground storage facilities often begin the heating season with their highest available “withdrawal rates” (the rate at which the field can supply natural gas back into the system) and pressures. As the storage field’s volume is depleted its withdrawal rates fall such that later in the spring the fields have lower available withdrawal rates; eventually, owners of storage capacity begin injecting gas to replenish the inventory prior to the heating season.

Natural gas storage plays an important role in the provision of flexibility of natural gas transportation systems in two manners. First, natural gas within a storage reservoir that is owned or contracted by shippers can be withdrawn at a variable rate to match the rate of consumption, which limits the need for pipelines to pack and/or draft the system to balance variable loads with ratable supply. On systems with storage facilities, shippers may generally purchase this
service as a nominated storage service or a “no-notice service.” Second, pipeline companies often reserve a portion of storage capability for balancing functions, using the injection and withdrawal of natural gas as a tool to manage levels of linepack directly and, to a limited extent, mitigate imbalances between receipts and deliveries as needed.14

To illustrate the capacity of storage to allow a pipeline to manage the variability of its demands, the example above has been modified with the addition of a theoretical storage facility with withdrawal capability of 100 MMcf/d located 30 miles upstream of the point of delivery.15 As shown in Figure 13, the presence of the storage facility allows the system to maintain nearly constant balance between receipts (which include storage withdrawals) and deliveries, substantially mitigating the variations in system linepack and pressure at various points that would be experienced at the delivery point in its absence.

The resulting pressure at the delivery point stays much more stable due to the nearby storage field. The field acts as a point of supply (field is in withdrawal mode) when demands are above 530 MMcf/d and as a point of demand (field is in injection mode) when demand is below the 530 MMcf/d steady supply rate into the system. Pressures at the delivery point range between 610 psig and 743 psig when the storage field is present. They range between 545 psig and 808 psig when the storage field is not present. The system with the storage field also runs more efficiently (using less total horsepower) because compressors experience less variation in line pack that they transport to the point of delivery.

14 Of course, this balancing service comes at a cost to the shippers on a pipeline system, as the costs of reserving storage capacity for this function are generally included in the pipeline’s cost of service.
15 For illustrative purposes, the storage field is assumed to have flexibility to transition quickly between injections and withdrawals. In reality, operations of storage facilities may be more constrained than this example suggests.
Figure 13. Transient hydraulic simulation of simple pipeline system with storage.

(a) Assumed receipts & deliveries (including storage withdrawals)

(b) System linepack

(c) Pressure at delivery point
2.2.2 INSTITUTIONAL CHARACTERISTICS RELEVANT TO FLEXIBILITY

The hydraulic examples discussed above show the physical side of pipeline operations. The institutional aspects of gas transportation—what services are offered and chosen and the processes by which shippers make use of them—have evolved to allow pipelines to maintain reliable operations throughout their systems. The contractual arrangements, scheduling processes, and operational conventions used by pipelines have direct bearing on their physical ability to provide flexibility as outlined above.

2.2.2.1 Firm vs. Interruptible Service

In Phase 1, this study explored the link between a gas generator’s choice between using firm and interruptible services and the adequacy of the pipeline system to meet demands on the peak day. Because of the convention of interstate pipeline to build capacity to meet the needs of their firm customers, Phase 1 found that in areas where gas generators have contracted for firm service, pipelines would have capacity to meet daily demands under most conditions.

The choice between firm and interruptible service also has direct implications upon the flexibility of a system to meet variable demands. As discussed in the hydraulic examples above, there is a direct tradeoff between the use of the pipeline system to transport gas and its use to manage packing and drafting to accommodate variability (a pipeline operating at full capacity cannot tolerate any variance in linepack, whereas a pipeline operating below capacity can). In order to provide flexibility through linepack management in a given day, a
pipeline must have some available capacity that is not used to transport gas to a
customer.

While all interstate pipelines under FERC regulation offer traditional firm service
under the premise that gas will be received and delivered on a ratable basis,
some pipelines have incorporated additional service offerings into their tariffs to
facilitate the service of loads that vary throughout the day by allowing shippers
to reserve the capacity needed to manage anticipated intraday variability. For
example, Kinder Morgan’s El Paso system offers several firm service options to
customers seeking to meet variable loads. These contracts reflect a premium
that users seeking to meet variable loads must pay in order to reserve capacity
needed for the El Paso system to manage its linepack to allow for a variable rate
of delivery. Such tariffs can be especially useful on a system such as El Paso with
no dedicated market area storage capability.

2.2.2.2  Nominations, Scheduling, and Balancing

The hydraulic example in which receipts and deliveries are not in balance
underscores the importance of the nomination and scheduling processes in gas
systems operations. Gas transportation on interstate systems is currently
scheduled through the nomination process formalized by the North American
Energy Standards Board (NAESB). Firm and interruptible shippers have the
opportunity to submit nominations for gas transportation during four cycles,
summarized in Table 2. Within each cycle, shippers may nominate gas on
available capacity by specifying points of receipt and delivery along with a
desired volume of gas. Available capacity is allocated to shippers based on the
service used (for example, primary firm, secondary firm, interruptible).
Table 2. Summary of NAESB nomination cycles (all times in Pacific Time).

<table>
<thead>
<tr>
<th></th>
<th>Nomination Due</th>
<th>Confirmation</th>
<th>Gas Flow</th>
</tr>
</thead>
<tbody>
<tr>
<td>Timely</td>
<td>9:30 AM (day ahead)</td>
<td>2:30 PM (day ahead)</td>
<td>7:00 AM</td>
</tr>
<tr>
<td>Evening</td>
<td>4:00 PM (day ahead)</td>
<td>8:00 PM (day ahead)</td>
<td>7:00 AM</td>
</tr>
<tr>
<td>Intraday 1</td>
<td>8:00 AM (day of)</td>
<td>12:00 PM (day of)</td>
<td>3:00 PM</td>
</tr>
<tr>
<td>Intraday 2</td>
<td>3:00 PM (day of)</td>
<td>7:00 PM (day of)</td>
<td>7:00 PM</td>
</tr>
</tbody>
</table>

Because of the sequential nature of the nomination process, scheduling decisions made in earlier cycles affect the availability of capacity in subsequent cycles. In all cycles, available capacity is allocated in order of service priority: (1) primary firm; (2) secondary firm; and (3) interruptible. Schedules established for both primary and secondary firm service in each cycle are locked in for subsequent cycles (e.g. a nomination for primary firm in the Evening cycle would not displace scheduled flows for secondary firm). Interruptible service, by contrast, may be displaced (“bumped”) by firm nominations submitted in the first three cycles. In the fourth cycle, interruptible service that has already been scheduled cannot be displaced (this is referred to as the “No-Bump Rule”).

Among these four cycles, most gas transportation is scheduled during the Timely cycle, which occurs within business hours during the day ahead of gas flow. The other three cycles are generally used to make adjustments to the initial scheduled flows or to schedule alternative gas flows if a shipper is not allocated capacity in the Timely cycle; arranging supply generally becomes increasingly costly as markets are less liquid during subsequent cycles. The nomination of gas volumes in the day-ahead timeframe allows for an operator
to prepare the pipeline to meet the demands of the subsequent day. Over the
course of the gas day, the operator expects shippers to receive and deliver their
scheduled volumes of gas at the appropriate points on the system.

Maintaining a reasonable balance between receipts and deliveries over the
course of the day is critical to sustainable operations. As illustrated in the
examples above, a sustained deficiency of receipts will erode linepack to the
point that continuing to meet all demand at the necessary pressures may not be
possible; conversely, a sustained surplus will require a pipeline system to take
action to avoid exceeding MAOP.

Because of the importance of achieving balance between receipts and
deliveries, most pipelines have a number of provisions in their tariffs for
handling imbalances. Most pipelines have balancing rules that impose financial
penalties upon shippers who carry a persistent imbalance between receipts and
deliveries. The time scales on which these rules apply vary by pipeline. Some
systems require shippers to maintain a balance on a daily basis to avoid
penalties; other systems allow shippers to carry imbalances over periods up to a
month. These penalties incentivize shippers to varying degrees to maintain
balance between receipts and deliveries.

In situations where operational conditions become constrained, many pipelines
have the ability to issue “Operational Flow Orders” (OFOs) or “Strained
Operating Conditions” (SOCs) that either require physical gas flows or impose
additional penalties for imbalances to ensure that linepack remains within levels
of tolerance. Ultimately, if financial penalties are not sufficient to force
customers to match receipts with deliveries, pipelines may curtail offending parties in order to ensure reliable service to its remaining shippers.

The nature of these conventions and their relationship to the operational flexibility of a pipeline system directly relates to the ability of the system to meet the needs of the electric sector. The nominations and scheduling conventions of the gas and electric sectors result in friction between the two industries, sometimes at the expense of efficient operations. Many of the issues that result have been identified in FERC’s ongoing gas-electric coordination docket:

+ The current deadline for nominations in the Timely cycle occurs before most day-ahead electric scheduling processes in the Western Interconnection. As a result, gas generators must either: (1) arrange gas supply and transportation in the Timely cycle before receiving day-ahead dispatch instructions; or (2) wait until receiving dispatch instructions to nominate gas in a later cycle, at which point the cost of procuring gas on the spot market may increase and the availability of transportation capacity may be limited.

+ The misalignment between the start of the gas day (7:00AM PT) and the electric day (generally 12:00AM local time) when changing system conditions result in gas generators using their total scheduled volumes prior to the finish of the gas day.

+ The “No-Bump Rule,” which applies to the second intraday cycle, prevents interruptible transportation scheduled in prior cycles from being displaced by nominations under firm service agreements. This may lead to instances in which gas generators with firm service are not
able to make adjustments to their earlier nominations needed to accommodate changes in conditions in the electric sector.\textsuperscript{16}

The fact that scheduled secondary firm transportation is not “bumpable” by primary firm service in subsequent nomination cycles could lead to instances in which a shipper with firm service cannot transport gas.

The potential magnitude of this issue may grow with the penetration of variable renewable generation, whose intermittent nature imposes additional uncertainty upon gas generators seeking to identify their fuel needs. To the extent these differences may lead to imbalances between receipts and deliveries, pipelines may confront operational challenges that could ultimately result in the need to curtail gas generation.

In a recent Notice of Proposed Rulemaking (NOPR), FERC offered several proposals intended to harmonize gas-electric scheduling processes.\textsuperscript{17} The most notable aspects of the proposal, which respond directly to concerns raised by stakeholders in the gas-electric coordination docket, include:

\begin{itemize}
  \item \textbf{Proposed change to start time of gas day.} FERC offers a proposal to change the start time of the gas day from 7:00 AM PT to 2:00 AM PT. With this change, the beginning of the gas day would more align closely the gas and electric trading days, occurring before the morning ramp of electric generators in Western markets.
  \item \textbf{Proposed change to deadline for nominations in Timely cycle.} FERC has proposed to change the deadline for nominations in the Timely cycle
\end{itemize}

\textsuperscript{16} This concern was raised by the Desert Southwest Pipeline Stakeholders in comments to FERC’s gas-electric coordination docket (DSPS, 2014).

\textsuperscript{17} See FERC (2014).
from 9:30 AM PT to 11:00 AM PT to allow electric system operators to conduct day-ahead scheduling processes prior to the commencement of the gas nomination process.

- **Proposed introduction of additional intraday nomination cycles.** FERC has proposed to increase the number of intraday nomination cycles from two to four, providing shippers with additional opportunities to adjust nominations in response to changing system conditions. The “No-Bump Rule” for interruptible service would apply only to the last of the four cycles.
3 Case Study Development

The Western Interconnection is a broad and diverse region facing considerable uncertainty in the electric sector over the coming decade; analyzing every possible operational condition across its entire geographic extent is beyond the scope of this study. Instead, this study defines a set of “case studies”—investigations into specific operational concerns for the gas and electric systems—as a means of exploring potential challenges that may arise in the future. Each case study comprises an investigation, both quantitative and qualitative, into factors that might limit the flexibility of the pipeline system to meet the variable needs of the power sector.

To ensure that the case studies chosen provide valuable lessons, their selection and development was guided by a collaborative process that included direct input from both the TAG and the PWG. Discussions with the TAG and individual interviews with members of the PWG helped narrow the focus to the case studies evaluated herein; results of the Phase 1 analysis also provided indication of potential areas of interest. Case studies were chosen to focus on areas in the Western Interconnection with large amounts of gas generation capacity whose operational patterns will be impacted by growing penetrations of renewable generation. While the case studies discussed herein are not comprehensive geographically, they have been chosen for their expected utility in deriving key lessons for the gas-electric interface concerning the operational needs of the electric sector.
3.1 Scope Development

Due to time and resource constraints, this study cannot answer all of these questions for all western pipeline systems under all circumstances. Instead, a case study approach, which examines specified types of conditions on a subset of the pipeline systems in the Western Interconnection, is adopted. In order to ensure that the case studies provide valuable lessons for gas-electric coordination, E3 and DNV GL consulted with participating pipelines to choose the appropriate conditions under which to examine pipeline systems and the appropriate geographic scope with which to examine their impacts.

3.1.1 SEASONALITY

One of the initial questions considered in the case study development process is when, throughout the course of a year, pipeline systems are most likely to encounter challenges meeting variable demands in the electric sector. The study team worked directly with participating pipelines to narrow the focus of each case study to portions of the year when gas systems would be most likely to encounter challenges related to their flexibility to meet variable loads. Winter periods during which non-electric end uses (residential, commercial and industrial) experience peak demands were identified as the time of year during which the flexibility of the system is most likely to be challenged; two factors contribute to this choice:

+ The flexibility of linepack is most constrained during these high demand periods because of the direct tradeoff between throughput and flexibility; and
The expected intraday variations in demand during the winter peak is generally expected to be largest, as both the electric sector and the end use sectors experience large intraday ramps.

The discussion in Section 2 demonstrated that pipelines are more prepared to meet flexibility needs during periods of low demand than during periods of high demand. This is because the pipeline has more ability to vary the linepack to meet intra-day fluctuations in gas demand, as illustrated in Figure 10. Three pipelines from the Pipeline Working Group provided historical data summarizing daily linepack for the 2013 calendar year. The linepack at the beginning of each day for El Paso Natural Gas Co, Pacific Gas & Electric, and the Northwest Pipeline along the I-5 corridor are plotted in Figure 14. Each figure highlights the fact that pipeline systems are operated in such a manner as to carry a relatively constant amount of linepack throughout the year, regardless of the seasonal variations of the loads they serve. This means that the pipelines are better able to meet flexibility needs during the spring and fall, when demands are low, because the minimum linepack is significantly below the typical operating level. During periods of high demand, such as winter, the minimum linepack is much closer to the actual operating level, providing much less flexibility to accommodate variations in demand.
Figure 14. Historical daily linepack inventory, 2013

(a) El Paso Natural Gas Company

(b) Pacific Gas & Electric Company

(c) Northwest Pipeline (in I-5 Corridor)
It is important to note that while this study generally focuses on the flexibility of gas systems during the winter heating season for the reasons enumerated above, operational challenges are not necessarily limited to this time of year. In particular, in regions that rely on gas storage to meet demands and provide flexibility, the seasonality of gas injection and withdrawal cycles could lead to challenges at other times of the year. For instance, when gas storage inventories are low (generally at the end of the winter heating season and beginning of spring), the maximum rate of withdrawal from underground storage is reduced relative to when inventory is high. As a result, storage infrastructure may be constrained in the springtime in its ability to provide flexibility. While these types of conditions are not examined analytically in this study, this study acknowledges the possibility that issues may arise at other times of year.

3.1.2 GEOGRAPHY

Another question addressed in the case study development process is the level of geography at which it is appropriate to assess the flexibility of the natural gas system. Three levels are considered:

- **Regional scale:** a case study focused on a broad geographic region, including interactive effects between pipeline systems (e.g. Desert Southwest, Pacific Northwest);

- **System-level:** a case study focused on a single pipeline system as a whole (e.g. El Paso Natural Gas Company, Northwest Pipeline); or

- **Segment-level:** a case study focused on a particular segment or portion of a pipeline system (e.g. “Power Plant Alley,” a segment of the El Paso Southern Mainline west of Phoenix providing service to several thousand megawatts of gas generation; “I-5 Corridor,” a portion of the
Northwest Pipeline system in Western Washington that serves substantial LDC and power plant loads).

Based on interviews with pipelines, this study does not consider any case studies at a regional level, a decision motivated by two factors. First, developing a transient hydraulic model that captures the operational and institutional knowledge of multiple pipelines is beyond the analytical capability of this study, which relies primarily on the analytical capabilities of participating pipelines—each of whom has developed modeling practices and analytical methods specific to its system. More generally, pipeline systems are designed and operated to deliver and receive gas ratably at interconnections with other pipeline systems; the implication of this convention is that each pipeline manages the variability of its own loads, and that “spillover” of the impacts of variability from one pipeline to another are limited under typical operating conditions.

This study employs both system-level and segment-level analysis to investigate the questions of interest in this study. Because each pipeline has the capability to use linepack across the entirety of its system to manage variability, case studies at a system level provide important insights into the high-level operations of the gas system; at the same time, segment-level analysis is also used to analyze limited portions of larger systems in several instances to help characterize operations at a more granular level. By setting boundary conditions with guidance from participating pipelines, the narrower scope of such case studies can provide useful lessons regarding the capability of pipeline systems to meet variable loads.
3.2 Overview of Case Studies

This study considers six independent case studies that highlight key portions of the gas systems in the Western Interconnection. Case studies were chosen to focus on areas in the Western Interconnection with large amounts of gas generation capacity whose operational patterns will be impacted by growing penetrations of renewable generation. Each case study comprises an investigation, both quantitative and qualitative, into factors that might limit the flexibility of the pipeline system during periods that the electric sector would rely on generation from gas resources to accommodate higher penetrations of renewables. The six case studies examine gas systems in different parts of the Western Interconnection:

- **Southern California:** Southern California Gas/San Diego Gas & Electric system
- **Northern California:** Pacific Gas & Electric system
- **Desert Southwest:** “Power Plant Alley” segment of El Paso Natural Gas Company Southern Mainline
- **Pacific Northwest, West of Cascades:** I-5 Corridor of Northwest Pipeline in Western Washington
- **Pacific Northwest, East of Cascades:** TransCanada GTN system
- **Colorado Front Range:** Colorado Interstate Gas system in Colorado

The approximate geographic areas covered by each of the six case studies are shown in Figure 15, which shows both existing natural gas transportation infrastructure and existing gas-fired power plants throughout the Western Interconnection.
Figure 15. Approximate geographic areas examined in case studies.

Pipeline geospatial data obtained from Platts; power plant locations from EIA
3.3 Description of Case Study Process

Each case study is a collaborative examination of the issues that may affect a pipeline system as the penetration of renewable resources increases throughout the electric sector:

- **Inputs and assumptions** for analysis are developed by E3 and DNV GL based on simulations of the electric sector over a ten-year timeframe and information shared by pipelines.\(^{18}\)

- **Technical analysis** based on these assumptions is conducted by participating pipelines or, in instances where this resource is not available, by DNV GL with oversight and guidance from pipeline representatives.

- **Conclusions and findings** are drawn through a joint review of case study results between E3, DNV GL, and the participating pipelines.

- Additionally, an **independent review** of the study process and modeling conducted using proprietary software was conducted by Lawrence Berkeley National Laboratory (LBNL) and is published as a standalone document.

This analytical approach, which combines analysis based on public information with modeling and technical work produced by pipelines using proprietary information and in-house modeling tools, is useful for addressing questions of how variability impacts pipeline systems. Engaging pipelines directly and incorporating their expertise of system operations enriches the study of the emerging issues investigated herein; unlike Phase 1 of this study, this effort is

\(^{18}\) Inputs and assumptions for analysis are closely linked to scenarios developed in Phase 1 of study. The development of the scenarios that serve as the foundation for this work is described in detail in that report.
not limited by the lack of publicly available data on gas infrastructure and operations.

### 3.3.1 INPUTS AND ASSUMPTIONS

For each case study, inputs and assumptions regarding the demand for natural gas in both the electric sector and among non-electric end users (residential, commercial, and industrial customers) were developed on an hourly basis. These assumptions represent hourly rates of consumption over a period of one or more days that would be tested for its impact on pipeline system operations.

Assumptions for the variability of gas demand in the electric sector were developed based on production simulation analysis of the electric sector. During Phase 1 of this study, E3, GL, and the TAG developed a set of scenarios with which to characterize the potential future needs of gas generators in the Western Interconnection. Three alternative futures for the electric sector were studied:

- **Base Case**, reflecting current electric sector policy and industry trends;
- **High Coal Retirements Case**, reflecting a West-wide shift from coal to gas generation through the assumed retirement of half the coal capacity in the Base Case; and
- **High Renewables Case**, which captures the potential for penetrations of renewable generation above current policy targets by adding additional wind, solar, and geothermal resources throughout the Western Interconnection.
In Phase 1, which evaluated the potential magnitudes of demand for natural gas during peak winter conditions, the Base Case and the High Coal Retirements Case were the focus of the analysis. Phase 2, which investigates the impacts of variability of gas demand on system operations, focuses on the Base Case and the High Renewables Case; the WECC-wide generation from renewable resources in each scenario is shown in Figure 16. From each simulation, profiles of electric sector operations during specific winter days that exhibit large ramps in net load (and gas generation) are chosen for technical analysis. Operations are compared under the Base Case and High Renewables Case, which shows increased variability in natural gas demand for electric generation. The comparison between the two cases provides the basis for deriving general conclusions about the impacts of high penetrations of variable renewable generation on natural gas pipeline operations.

**Figure 16.** Composition of WECC-wide renewable portfolios, Base Case and High Renewables Case.
Profiles for gas demand among other direct end users—residential, commercial, and industrial customers as well as gas supplied to other pipelines at interconnects—were developed based on historical and/or forecast information provided by participating pipelines. Hourly rates of consumption—generally for a high demand winter period—were provided by pipelines to combine with the electric sector assumptions developed independently.

Receipts and deliveries between neighboring pipeline systems are assumed to be ratable, reflecting the current scheduling conventions of the industry. The implication of this assumption is that this study assumes each system must manage the variability of its own loads and neither provides assistance to nor incurs any adverse impacts from circumstances on neighboring systems. Because some neighboring pipeline systems hold balancing agreements with their neighbors through which they provide mutual assistance when possible, this is a conservative assumption.

The combination of electric sector demands from production simulation modeling and the assumed demands for non-electric end uses are described as the “Reference Assumptions” for each case study. Because of the study’s general focus on flexibility during the winter season, the Reference Assumptions across all case studies represent ramping events in the power sector that occur during a winter period of high demand for natural gas. In addition to studying the operations of the Base Case and the High Renewables Case under these Reference Assumptions, a number of different sensitivities are evaluated as
well. The sensitivities considered within each case study generally fall into three categories:

+ **Sensitivities on size of electric sector ramps:** because the profiles for natural gas demand derived from production simulation analysis may not represent the most extreme ramps that a gas fleet integrating high penetrations of renewables might experience, these sensitivities layer incremental ramping need on top of either the Base Case or High Renewables Case electric sector profiles.

+ **Sensitivities on supply-demand balance:** initial analyses presume that, at a system level, the receipts to the system will be in balance with deliveries on a daily basis, reflecting the convention of scheduling on a daily basis; these sensitivities investigate the impacts on the system if scheduled receipts do not align with deliveries (particularly in the case of a deficiency of receipts).

+ **Sensitivities on non-electric gas demand:** the initial cases evaluated assume high demands among non-electric end uses consistent with extreme winter weather conditions; these sensitivities explore the implications for gas systems if the ramps in the electric sector occur at other levels of non-electric demand.

Not all sensitivities are evaluated in each case study, nor are they applied to both the Base Case and High Renewables Case in each. Rather, based on the availability of modeling resources of participating pipelines and the concerns specific to each case study, a subset of sensitivities are selected for investigation. Table 3 summarizes the sensitivities that are addressed within each case study.
Table 3. Summary of cases and sensitivities addressed within each case study.

<table>
<thead>
<tr>
<th>Reference Assumptions</th>
<th>Southern California</th>
<th>Northern California</th>
<th>Desert Southwest</th>
<th>Pacific Northwest, West of Cascades</th>
<th>Pacific Northwest, East of Cascades</th>
<th>Colorado Front Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>S sensitivity: Increased Electric Sector Ramp</td>
<td>✓ ✓ ✓ ✓ ✓ ✓ ✓</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sensitivity: Supply-Demand Imbalance</td>
<td>✓ ✓ ✓ ✓ ✓ ✓</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sensitivity: Level of Non-Electric Demand</td>
<td>✓ ✓ ✓ ✓ ✓ ✓</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

3.3.2 TECHNICAL ANALYSIS

The quantitative portions of the case studies rely primarily on the analytical capabilities of participating pipelines to assess the operational implications of the profiles of demand developed as inputs to each case study—or, where not possible, hydraulic analysis by DNV GL is used to supplement the case studies. The use of modeling tools and data managed and maintained by the pipelines themselves is necessitated in this study for several reasons. First, unlike the electric sector, there is limited data in the public domain that would enable analysis of the impacts of variability on pipeline system operations. Second, the systems analyzed themselves are very complex, and each system’s operational conventions are unique to its characteristics; as a result, the operational expertise of each system is necessary to ensuring the credibility of the analytical results.
Table 4. Analytical methods used in each case study

<table>
<thead>
<tr>
<th>Case Study</th>
<th>Analytical Method</th>
<th>Technical Lead</th>
</tr>
</thead>
<tbody>
<tr>
<td>Southern California</td>
<td>Transient hydraulic analysis</td>
<td>SoCalGas</td>
</tr>
<tr>
<td>Northern California</td>
<td>Analysis of linepack inventory</td>
<td>PG&amp;E</td>
</tr>
<tr>
<td>Desert Southwest</td>
<td>Transient hydraulic analysis</td>
<td>DNV GL</td>
</tr>
<tr>
<td>Pacific Northwest, West of Cascades</td>
<td>Transient hydraulic analysis</td>
<td>Northwest Pipeline</td>
</tr>
<tr>
<td>Pacific Northwest, East of Cascades</td>
<td>Transient hydraulic analysis</td>
<td>TransCanada Pipelines</td>
</tr>
<tr>
<td>Colorado Front Range</td>
<td>Qualitative review</td>
<td>n/a</td>
</tr>
</tbody>
</table>

It is worth noting that the modeling tools and techniques utilized by the pipelines to study the impacts of variability are different—and thus, a uniform methodology for analysis is not applied across all case studies. The level of detail used to analyze the capability of a system to absorb variability varies considerably—from full transient hydraulic modeling with specific meter stations represented to broader analyses of system-wide linepack variability throughout the day. Notwithstanding the differences in methodologies used to examine the impacts of variability, the general questions addressed by each method are parallel.

3.3.3 CONCLUSIONS AND FINDINGS

In each case study, conclusions and findings are drawn jointly by the study team and the participating pipeline through a review of modeling results. The results of each case are interpreted and used to derive key lessons to characterize the impacts of renewable generation on gas system operations.
Since, in a number of case studies, inputs for non-electric demands—which make up the majority of gas demand modeled in most case studies—are derived directly from observed historical conditions, conclusions are also drawn by comparing the results of analysis against the observed operations of pipeline systems during these historical windows. Where possible, this comparison allows the results of this study to highlight potential changes in how systems may operate as the penetrations of renewable resources in the electric sector increase.

3.3.4 INDEPENDENT REVIEW

When possible, this study has made use of publicly available data in order to encourage continued and open collaboration among gas and electric stakeholders. However, in the case of operational modeling conducted for Phase 2, much of the analysis in the case studies relies on modeling tools maintained by pipeline companies that are not available to the public. Lawrence-Berkeley National Laboratory (LBNL), as a member of the TAG, voluntarily served in a role as an independent observer of the study process with the participating pipelines, reviewing the process and discussing the scope and procedure of the modeling exercise with each pipeline. The results of LBNL’s review of the study are published as a standalone document.
4 Case Studies

Case studies are presented with the following structure, which organizes each one into six subsections:

1. **System Overview**: description of key physical and institutional characteristics of the gas system;

2. **Regional Electric Sector Outlook**: discussion of key changes that may affect variability of gas demand in the power sector in the next decade;

3. **Development of Reference Assumptions**: details on the development of hourly natural gas demand profiles used to analyze each system’s capability;

4. **Analytical Methods**: description of the modeling tools and techniques used to analyze the profiles for natural gas demand;

5. **Analytical Results**: presentation and discussion of modeling results; and

6. **Summary**: an overview of key lessons learned through the case study.

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19 In the case study of the Colorado Front Range—a qualitative investigation of gas-electric coordination issues—the ‘Analytical Methods’ and ‘Analytical Results’ sections are replaced by a qualitative review.
4.1 Southern California

4.1.1 SYSTEM OVERVIEW

This case study focuses on the Southern California Gas Co./San Diego Gas & Electric Co. (SoCalGas) intrastate system in its entirety, which provides gas service to a large number of end use and electric customers in Southern California. The SoCalGas system receives gas at interconnections with a number of interstate pipelines that transport gas to California, including El Paso Natural Gas, Transwestern Pipeline Company, and Kern River Pipeline Company; the system’s total receipt capacity from these interconnections is 3.9 Bcf/d. SoCalGas also owns and operates a number of storage resources, whose combined withdrawal capability (3.6 Bcf/d) provide balancing flexibility and allow the system to meet higher seasonal demands.

The gas infrastructure of the SoCalGas system is shown in Figure 17. The backbone system delivers gas to a number of local transmission systems throughout the service area of SoCalGas. Several of the local transmission systems provide service to substantial amounts of gas generation capacity; in particular, the local transmission systems in both the LA Basin and San Diego serve a large number of gas generators. For this reason, these systems will be closely monitored throughout the course of the case study.
Figure 17. Map of SoCalGas system.

Under the regulation of the California Public Utilities Commission (CPUC), SoCalGas provides service to customers under a core/non-core model. Core customers—typically residential and smaller commercial customers—purchase bundled service from the gas utility and receive the highest priority of service. Non-core customers—most larger industrial customers and all electric generators—purchase transportation service from SoCalGas but receive a lower priority of service and may be interrupted if necessary to preserve service to the utility’s core customers. While the SoCalGas system is designed with the capacity to meet all core and firm non-core demands under a 1-in-10 winter
weather condition, electric generators would be one of the first classes of customers to lose service the event that operational challenges arise.  

4.1.2 REGIONAL ELECTRIC SECTOR OUTLOOK

The gas generators served by SoCalGas comprise a large portion of the gas generation in the CAISO as well as most gas plants in the Los Angeles Department of Water and Power (LADWP) and Imperial Irrigation District (IID) balancing authority areas. Over the coming decade, a number of factors will impact both the amount of gas generation served in this region and its patterns of operation. A number of these potential changes would impact the character of natural gas demand among electric generators served by SoCalGas, requiring the system to provide new levels of flexibility.

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20 A more detailed discussion of the regulatory model under which SoCalGas (and PG&E) provide service to customers in California is discussed in the Phase 1 report.
First, California’s policy-driven pursuit of aggressive renewable targets will impact the daily operational patterns of gas generators operating to serve the state’s load. In 2012, California’s three major investor-owned utilities served 23% of retail load with renewable generation, and each has contracted for a large portion of the generation it will need to comply with the state’s 33% target in 2020. Figure 19 compares the two scenarios evaluated in this study against the state’s current portfolio of renewable resources (as of 2013) and the current 33% planning portfolio developed by the California Public Utilities Commission (CPUC) under its 2014 Long Term Procurement Proceeding (LTPP). With the precipitous drop in the cost to install solar photovoltaics, solar generation is expected to constitute a large portion of renewable development in the state over the coming decade. The CPUC’s 33% portfolio, developed based on the most recent contracting activities of the state’s investor-owned utilities,
includes 14.5 GW of solar resources, an amount that falls between this study’s Base Case (10 GW) and High Renewables Case (17 GW). The output pattern of solar generation fundamentally transforms the shape of the state’s net load, creating the need for a flexible fossil fleet that can ramp up and down to mirror the diurnal pattern of net load.

Figure 19. Comparison of existing and potential future California renewable portfolios

Over this same period, the fleet of gas generators served by SoCalGas may change notably as well. Plans for new gas generators to replace plants retiring to comply with the state’s once-through-cooling (OTC) regulations will result in a more efficient and faster-ramping fleet. The recent retirement of the San Onofre Nuclear Generating Station (SONGS) has created an additional need for

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21 Data inputs for the CPUC LTPP can be obtained from the CPUC’s LTPP history (CPUC, 2014).
new capacity, and while the plan for its replacement has not yet been finalized, it is likely to include some new gas generation.

Among new investments in gas-fired generation in southern California, there has been a trend towards technologies offering quick-start capability, in part motivated by the apparent need for flexibility to integrate the increasing penetration of renewable generation. A large amount of the recently installed capacity, as well as a number of planned additions, utilize quick-start technologies. Where new capacity is added to the southern California system to meet local reliability needs, quick-start technologies may be selected. The potential proliferation of quick-start units in the southern California region is one of the focuses of this case study, as it introduces new and rapid changes in system demand that traditional gas generators do not create.

One of the concerns raised by SoCalGas in the case study process was the potential impact of coincident start-ups of quick-start gas generators in its system. Internal studies by SoCalGas, shown in Figure 20, indicate that the rapid increase in gas demand associated with quick-start plants could cause pressure drops at a rate that is unprecedented in today’s operations and that could test the flexibility of system operators. The pressure drops associated with the quick start units are of concern not for their magnitude but for their rate: as gas system operators seek to maintain pressures throughout the system within operable ranges, the appearance of such a rapid rate of pressure drop is difficult to distinguish from events that could pose a threat to the system’s reliability—namely, a ruptured pipeline or gas leak—that would require the operator’s immediate action to preserve service to other parts of the system. Thus, while such rapid state changes are not technically infeasible for the pipeline system,
they create new challenges for system operators and suggest the need for close coordination between electric and gas system operators.

**Figure 20. SoCalGas analysis of quick-start impacts.**

![Pressure Surrounding Facility](image)

### 4.1.3 DEVELOPMENT OF REFERENCE ASSUMPTIONS

The Southern California case study explores the ability of the SoCalGas system to meet natural gas demand under a 1-in-10 cold winter day under both the Base Case and the High Renewables Case. This condition is chosen for analysis in order to explore whether the SoCalGas system has the flexibility needed to serve gas generators whose output varies considerably over the course of a day due to high penetrations of solar generation while also supplying the high heating-driven loads of its core customers.

Natural gas demand for the electric sector is based on the winter days in the Base Case and the High Renewables Case that exhibit the highest amount of
intraday variability in natural gas burn at power plants during the winter season. The net electric load and the corresponding dispatch of natural gas plants on the day selected for analysis is shown in Figure 21a and b, respectively; these days were selected both for the relatively high level of overall demand as well as the high level of intraday variability resulting from the diurnal output of solar generation.

The assumed hourly natural gas demand among non-electric end uses is provided as an input to the study by SoCalGas, and it comprises both the core and non-core demands across the entirety of the SoCalGas system. The assumed loads reflect SoCalGas’ forecast of end use loads under a 1-in-10 cold winter day in 2022. The combination of the simulated gas demands of the electric sector and the assumed demand profile for non-electric end uses for the SoCalGas cold winter day is shown in Figure 21c for the Base Case and the High Renewables Case.
Figure 21. Development of SoCalGas Reference Assumptions, Base Case & High Renewables Case.

(a) Hourly electric net load in California

(b) Electrical output from gas generators served by SoCalGas

(c) Total natural gas consumption served by SoCalGas
4.1.4 ANALYTICAL METHODS

The study team worked closely with SoCalGas to evaluate the potential impacts of higher penetrations of renewable generation on its system. SoCalGas conducted transient hydraulic modeling of its system operations for four different conditions: (1) Base Case; (2) High Renewables Case; (3) High Renewables Case with additional quick-starts ("High Renewables Case Quick Start Sensitivity"); and (4) High Renewables Case with a deficiency of supply to the system ("High Renewables Case Imbalance Sensitivity"). The range of conditions evaluated in this case study is summarized in Table 5.

Table 5. Scope of SoCalGas case study.

<table>
<thead>
<tr>
<th></th>
<th>Base Case</th>
<th>High Renewables Case</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reference Assumptions</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Sensitivity: Size of Electric Sector Ramp</td>
<td>✗</td>
<td>✓</td>
</tr>
<tr>
<td>Sensitivity: Supply-Demand Balance</td>
<td>✗</td>
<td>✓</td>
</tr>
<tr>
<td>Sensitivity: Level of Non-Electric Demand</td>
<td>✗</td>
<td>✗</td>
</tr>
</tbody>
</table>

The transient hydraulic model used to develop analysis for this study captures the entire SoCalGas system, including the backbone infrastructure, local transmission systems, and storage facilities. Of particular importance to this study are the operations of the local transmission systems that provide service to electric generators, many of which are concentrated in the LA Basin and San Diego. Accordingly, pressure is monitored and reported at key locations on each of these local transmission systems. The maintenance of pressure within minimum and maximum limits at these points is one of the key metrics by which the adequacy of the system is assessed.
The model used in this case study is commonly used by SoCalGas in its own system planning efforts. When conducting analysis through transient hydraulic modeling, SoCalGas evaluates the “success” of the simulation by several criteria:

+ System linepack is fully recovered over the course of the simulation;
+ All facilities (e.g. pipelines, compressor stations) remain within the limits of their capacities; and
+ No Maximum Allowable Operating Pressures (MAOPs) or Minimum Operating Pressures (MinOPs) are violated in the simulation.

The failure to meet any of these criteria is an indication that the system cannot meet all loads under the assumptions of the simulation; under such circumstances, curtailment of some loads may be necessary to preserve service to customers with the highest priority of service.

4.1.5 ANALYTICAL RESULTS

The results of simulations of the Base Case and High Renewables Case over a 24-hour period from 6AM to 6AM are summarized in Figure 22: (a) hourly demand; (b) hourly receipts, including both supply at pipeline interconnects and withdrawals from storage; (c) pipeline pressure in the LA Basin; and (d) pipeline pressure in San Diego. Both simulations were deemed “successful” by all standards used by SoCalGas to evaluate its system: linepack is fully recovered, no facilities exceed capacity, and no MAOPs or MinOPs are violated over the course of the day.
Figure 22. SoCalGas simulation results, Base Case and High Renewables Case.

(a) SoCalGas system demand

(b) SoCalGas total receipts (including interconnects & storage)

Note time scale begins and ends at 6AM
(c) Pressure at San Diego

(d) Pressure at West LA Basin

Note time scale begins and ends at 6AM
As neither the Base Case nor the High Renewables Case simulations exhibited dramatic pressure drops associated with quick-start gas generators notwithstanding the presence of a number of such units in each case, the study team and SoCalGas examined a sensitivity to the High Renewables Case in which the output from quick-start units was increased in both the morning and the evening. The total daily demand was increased from 4,783 MMcf/d (High Renewables Case) to 5,094 MMcf/d (High Renewables Case Quick Start Sensitivity), a substantial increase in magnitude. Even with this large increase in total demand, the SoCalGas system was able to serve all demands in the Quick Start Sensitivity, summarized in Figure 23, while meeting the criteria for a successful simulation. However, the simulation does reveal increased rates of pressure drop coincident with the start-up of the additional units modeled.

While the results indicate that these pressure drops are technically feasible on the system—pressure at no point drops below the minimum operating pressure—these rates of change are unprecedented in normal operations today and signal the possibility of a new challenge for system operators.
Figure 23. SoCalGas simulation results, High Renewables Case and High Renewables Case Quick Start Sensitivity.

(a) SoCalGas system demand

(b) SoCalGas total receipts (including interconnects & storage)

Note time scale begins and ends at 6AM
(c) Pressure at San Diego

(d) Pressure at West LA Basin

Note time scale begins and ends at 6AM
In each of the cases presented so far, the modeling framework has assumed a daily balance is maintained between receipts and deliveries. SoCalGas staff conducted a second sensitivity on the High Renewables Case that explores the implications of this assumption, evaluating the ability of the system to meet this pattern of demand when the supply is limited for two days (Figure 24).

In this additional case, while the demand for natural gas is 4,783 MMcf/d, the supply is limited to 3,871 MMcf/d. The difference between these two values places a substantial strain on the gas system. Over the course of the first day, the imbalance between receipts and deliveries draws down linepack on the system. However, despite the fact that linepack is drawn down steadily, the impact on pressure in the LA Basin or San Diego does not appear immediately; reasonable pressures are maintained in the LA Basin throughout the entire first day and in San Diego through much of the first day as linepack physically shifts towards loads. This does not, however, indicate a properly functioning system: the impact of the drawn-down linepack appears in San Diego at the end of the first day and begins to impact the LA Basin on the second. This phenomenon reflects an important characteristic of gas systems: because of the slow-moving nature of natural gas, such an imbalance event may not impact loads immediately but creates challenges for continued operations.

For illustrative purposes, this simulation has been allowed to run far beyond the point at which system operators would intervene to preserve service to core customers in order to show the impact of an imbalances on a gas system. Rather than allowing such a persistent and substantial imbalance to draw down linepack, operators would intervene to curtail non-core customers as needed to preserve their service under such circumstances. Because electric generators fall
into this category, they would be at risk for curtailment during this type of event.

In this example, the cause of the imbalance is not specified. However, a number of factors could result in a large imbalance between receipts and deliveries:

+ **Supply constrained by market forces.** A large amount of the gas transported among markets on the North American continent flows in response to price differentials among the various hubs. Generally, the North American markets are well-integrated and connected to a degree that market forces themselves do not lead to supply shortages; however, under exceptional circumstances, this may not be the case. During the record cold winter of 2014, when prices in eastern gas markets rose to levels as high as $100/MMBtu, Southern California experienced a shortage of gas supply at its border. With California consumers apparently unwilling to pay higher prices, marketers diverted supply to markets with scarcity prices throughout the continent. Ultimately, the limited supply at the border resulted in the need to curtail non-core customers on the SoCalGas system, which included a number of electric generators.

+ **Upstream infrastructure contingencies.** In Phase 1, this study explored the risks of an infrastructure contingency and reached the conclusion that the failure of some element of gas infrastructure in one region or system could have important consequences on neighboring regions or systems. Such an event on an upstream pipeline could directly limit the ability of a consumer or shipper to schedule gas for receipt on a downstream system.
Figure 24. SoCalGas simulation results, High Renewables Case Imbalance Sensitivity.

(a) SoCalGas system demand

(b) SoCalGas total receipts (including interconnects & storage)

Note time scale begins and ends at 6AM
4.1.6 SUMMARY

Note time scale begins and ends at 6AM
This section summarizes the results of the case study of the SoCalGas system.

+ Growing penetrations of solar PV result in diurnal ramping of gas generators served by SoCalGas. Current trends in renewable procurement in California would result in changes in the net load shape that are regular and periodic; high levels of output from solar in the middle of the day cause flexible gas generators to ramp down in the morning and up in the evening. As a result, the demand for gas among electric generators will decrease, but its variability throughout the day increases.

+ Transient hydraulic simulations indicate that the SoCalGas system can handle ramps needed for renewable integration. In both the Base Case and the High Renewables Case, the SoCalGas system successfully met all demands while maintaining sufficient delivery pressures throughout the system and fully recovering linepack during 1-in-10 winter weather conditions.

+ Timing of solar generation facilitates recovery of linepack after morning peak for gas demand. The upward ramp of solar generation in the morning (and the commensurate downward ramp in gas generation) occurs just after the morning peak demand for natural gas. As a result, higher penetrations of solar generation allow gas operators to recover pressure and linepack throughout the system more quickly, which helps prepare the system for the second evening peak in gas demand.

+ With increased investments in quick-start generators to facilitate renewable integration, SoCalGas may experience greater changes in pressure than historically observed. The electric sector’s recent affinity for quick-start gas-fired generators may result in changes to gas system operations as new quick-start plants are dispatched for renewable integration. The start-up of these plants causes dramatic pressure drops
if the plants are located on the local transmission system; in such an environment, establishing protocols for communications between gas and electric operators may allow for more reliable service.

+ **Ensuring adequate supplies of gas flowing to the SoCalGas system is necessary to preserve service to customers.** The ‘Imbalance’ sensitivity investigated in this case study highlights the importance of ensuring a reasonable balance between receipts and deliveries to the system. Ensuring that gas shippers have proper incentives to maintain an appropriate balance will facilitate system operations.

+ **In the event of operational challenges, electric generators will be among the first to be curtailed.** From the perspective of gas-electric coordination, it is important to note that the core/non-core model under which SoCalGas provides service to customers results in some vulnerability to electric generators, who, as non-core customers, would be among the first to lose service if the need to curtail deliveries arose. Despite the fact that this analysis does not reveal any major disconnects, prudent planning in the electric sector must recognize this vulnerability.

### 4.2 Northern California

#### 4.2.1 SYSTEM OVERVIEW

This case study focuses on the gas generators and other loads served by PG&E’s intrastate system, shown in Figure 25. PG&E’s gas transportation infrastructure comprises both the backbone transmission system, made up of large diameter high pressure pipelines and storage facilities, and the local transmission systems, smaller diameter pipelines that typically operate at lower pressures. The main components of the backbone system include (1) the Redwood Path,
which interconnect with the TransCanada GTN and Ruby pipelines at the northern California border; (2) the Baja Path, which interconnects with the El Paso Natural Gas Company, Kern River, Questar Southern Trails, and the SoCalGas/SDG&E system in southern California; and (3) the Bay Area Loop, a network of pipelines in the Bay Area where the northern and southern systems meet; and (4) a number of storage facilities that are directly connected to the backbone systems. The total withdrawal capabilities of storage fields connected to PG&E’s system is approximately 3,800 MMcf/d; of this total, most capability is either allocated to core customers or contracted to third-parties; PG&E reserves 75 MMcf/d of injection and withdrawal capability for balancing purposes.
In notable contrast to the SoCalGas system, where many gas generators are located on the LA Basin and San Diego Local Transmission systems, many of the gas generators served by PG&E are located directly on the backbone system. PG&E’s backbone-differentiated tariff, originally instituted for cost allocation purposes, continues to encourage new gas generators to interconnect to the
backbone system, where they receive high-pressure delivery service at lower cost.22 This characteristic has important implications for the overall flexibility of the system, as, with fewer generators located on small diameter and/or lower pressure parts of the system, PG&E has fewer local constraints in providing service to gas generators than SoCalGas to the south.

PG&E’s Gas Transmission Control Center (GTCC) manages the operations of the transmission system. To ensure that the backbone and local transmission systems can deliver gas to customers at sufficient delivery pressures, the GTCC seeks to maintain its linepack within an acceptable range.23 Operators at the GTCC have several tools to accomplish this task:

+ A portion of PG&E’s storage capability is reserved for balancing purposes. PG&E may use up to 75 MMcf/d of withdrawals and/or injections to make adjustments to linepack.

+ Generally, PG&E requires its customers to balance receipts and deliveries on a monthly basis. However, PG&E also establishes upper and lower limits on its linepack for the start of the gas day; if linepack is outside of those limits, PG&E may issue an Operational Flow Order (OFO), imposing economic penalties on customers who do not balance their receipts and deliveries to within a specified tolerance on a daily basis.24

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22 Gas generators served by PG&E receive service under Gas Schedule G-EG (PG&E, 2014b), which offers different rates to customers that connect at the Backbone level and those that connect to Local Transmission systems.

23 The current operational status of the PG&E system can be viewed on PG&E’s Pipe Ranger website (PG&E, 2014a).

24 The limits at which OFOs are triggered are well within the absolute minimum and maximum inventory limits required by the PG&E system to operate reliably. The absolute limits on PG&E’s system inventory vary considerably depending on a number of system conditions, so a single limit cannot be used.
In the event that system conditions threaten reliability of service to core customers, PG&E may call an Emergency Flow Order (EFO). An EFO imposes even more severe penalties on gas users for unauthorized use.

While EFOs are rare events, PG&E’s operators use balancing storage and OFOs throughout the year to ensure that linepack remains within the tolerance of the system.

The service provided by PG&E to electric generators is designated as “non-core.” Like SoCalGas, PG&E provides bundled service to its “core” customers, who receive the highest priority of service. In the event of operational challenges or capacity limitations, PG&E will call an OFO to balance receipts and deliveries; however, if adverse conditions persist, non-core customers, which includes both electric generators and larger industrial users, are at immediate risk of curtailment.

4.2.2 REGIONAL ELECTRIC SECTOR OUTLOOK

The gas generators served by PG&E are located within the northern portion of the CAISO as well as the Balancing Area of Northern California (BANC) and the Turlock Irrigation District (TIDC). Because many of the changes expected in the electric sector in California are guided by state-level policy, gas generators in northern California face a similar outlook to those located on the SoCalGas system described in Section 4.1.2. Specifically:

As California’s pursuit of aggressive renewable goals continues, gas generators served by PG&E will be increasingly used for hourly ramping to accommodate higher penetrations of solar generation (see Figure 19).
With the retirement of OTC gas generators and other aging infrastructure, new gas generators with faster start times and ramping capabilities have become the default new investment for capacity.

Like Southern California, the operations of the existing gas fleet will adjust as the penetrations of renewable generation—especially solar PV—increase.

### 4.2.3 DEVELOPMENT OF REFERENCE ASSUMPTIONS

Like the case study of Southern California, the examination of the PG&E system focuses on the impact of increasing solar penetrations in the state on the need to ramp gas generators to follow the diurnal pattern of solar generation during the winter period when non-electric demand is high. Because Northern and Southern California are closely electrically integrated, the build-out of solar in the southern part of the state will affect generation throughout.

The operations of gas generators evaluated within this case study are based on the same day from the production simulation examined in the Southern California case study: a day of high electric load and high solar output. In the Base Case, the dispatch of gas plants in Northern California mirrors the net load, showing a slight decline in output in the middle of the day and an upward ramp at the end of the day. This pattern is exacerbated in the High Renewables Case. These patterns are shown in Figure 26a and b.

The demand from gas generators in Northern California is combined with gas demand from end users assumed under a cold winter weather event. PG&E provided aggregate hourly demand for its residential, commercial, and industrial customers on December 9, 2013 (the day of PG&E’s highest historical demand,
which corresponds to roughly 1-in-10 cold weather conditions). Total gas demand based on these assumptions, including all core and non-core loads, is shown in Figure 26c.

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25 The system composite temperature for December 9, 2013 was 37.2°F. For reference, PG&E’s 1-in-10 design criteria is 34°F.
Figure 26. Development of PG&E Reference Assumptions, Base Case & High Renewables Case.

(a) Hourly electric net load in California

(b) Electrical output from gas generators served by PG&E

(c) Total natural gas consumption served by PG&E
4.2.4 ANALYTICAL METHODS

The study team worked directly with PG&E staff to analyze the impacts of the events of the Base Case and High Renewables Case upon the linepack inventory over the course of the day. Additionally, PG&E staff assisted with the development and analysis of two sensitivity cases to the Base Case in order to explore potential stressors to the system: (1) a Base Case event with an increased evening ramp (“Base Case Ramp Sensitivity”), and (2) a Base Case event with a persistent shortage of natural gas supply (“Base Case Ramp Sensitivity with Imbalance”). The scope of analysis conducted in this case study is summarized in Table 6.

Table 6. Scope of PG&E case study.

<table>
<thead>
<tr>
<th></th>
<th>Base Case</th>
<th>High Renewables Case</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reference Assumptions</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>Sensitivity: Size of Electric Sector Ramp</td>
<td>✓</td>
<td>✗</td>
</tr>
<tr>
<td>Sensitivity: Supply-Demand Balance</td>
<td>✓</td>
<td>✗</td>
</tr>
<tr>
<td>Sensitivity: Level of Non-Electric Demand</td>
<td>✗</td>
<td>✗</td>
</tr>
</tbody>
</table>

The analytical method used to evaluate the impacts of variable loads on the PG&E system highlights the importance of linepack management across the system. Instead of using a transient hydraulic model to examine individual components of the system, the method used in this case study examines the fluctuations in inventory that the system as a whole would experience over the
course of the day. This simple method, requiring only a profile for natural gas demand and several simple assumptions, is described in four steps below:

1. **Develop supply assumptions.** The assumed rate of supply of natural gas to the system is calculated as the average of the hourly demand across the day. The study assumes that gas is received to the system at this rate throughout the day so that the variability of load is managed entirely with linepack. This assumption is conservative: while receipts at the interconnects with interstate pipelines can be assumed to be ratable, withdrawals from underground storage on PG&E’s system may mitigate some of the swings in linepack by providing for variable rates of withdrawal throughout the day.

2. **Calculate hourly net pack/draft.** The hourly net change in linepack is calculated as the difference between the hourly rate of demand and the assumed constant rate of supply: a positive difference implies a draft on the system, whereas a negative difference reflects an increase in linepack.

3. **Calculate linepack across the day.** The linepack throughout the day is calculated by tracking the cumulative amount of packing and drafting across all hours. The result of this step is a forecast of hourly linepack.

4. **Compare hourly linepack to OFO limits.** This comparison is made for the sake of understanding whether the modeled results would imply an operational challenge for the pipeline system. PG&E’s minimum and

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26 PG&E does not currently use transient hydraulic models to analyze its backbone systems.
maximum OFO limits are within the absolute limits for linepack, so the system can tolerate some excursions beyond these bounds; however, a large or sustained excursion would merit further investigation.

Linepack fluctuation calculated using this method is conservative, as the assumption that supply is ratable understates the flexibility that the storage resources contribute to the system. In this respect, the resulting fluctuations in linepack likely are greater than would be expected in reality for given profiles of demand.

4.2.5 ANALYTICAL RESULTS

The assumed hourly rates of demand (deliveries) and supply (receipts) and the resulting linepack across the days selected for analysis from the Base Case and High Renewables Case are shown in Figure 27. Under both scenarios, linepack does not vary beyond the minimum or maximum OFO limits in any hour, indicating that the system is fully capable of managing the variability of these shapes through the flexibility afforded by linepack.
Figure 27. PG&E hourly demand, supply, and linepack; Base Case and High Renewables Case.

(a) PG&E system demand

(b) PG&E system linepack

Note: both scenarios assume ratable receipts equal to average daily demand
As shown in Figure 27b, variations in linepack throughout the day are driven by the patterns of daily load. In the nighttime, the system is packed while demands are relatively low in preparation for the morning peak (12AM – 6AM). The morning peak, driven largely by direct end users of gas, coincides with a large draft on the system (6AM – 10AM). This is followed by another period of relatively low demand during which the system’s linepack recovers (10AM – 4PM) in preparation for the second evening peak before linepack returns to the starting level. This analysis prompts several observations:

- Linepack variability in both scenarios is not substantially different from conditions experienced today. The majority of the linepack variability is a result of the intraday variability of core residential and commercial loads, which account for 74% of total daily demand and 78% of hourly peak demand in the Base Case.

- The difference between the starting level of linepack in the calculated scenarios and the level of linepack for the December 9, 2013 historical day is a result of assumptions made for this study. For the calculation of linepack in the case study, PG&E recommended assuming that the linepack at the start of the electric day would begin in the middle of the range (4,150 MMcf/d). However, when GTCC operators anticipate a particularly high daily demand, one step that may be taken to prepare the system is to build up linepack to high levels prior to the morning peak; this was done by operators in preparation for the high demand of December 9, 2013.

- While a higher penetration of solar generation require additional ramping from gas generators, it also allows the system a greater opportunity to recover linepack to facilitate upward ramps. Between 10:00 AM and 4:00 PM, the linepack increases by more in the High Renewables Case than it does in the Base Case. Because larger amounts
of solar generation in the middle of the day allow gas generators to reduce output and/or shut down, the system recovers linepack more quickly after the morning peak, which better prepares the system to meet the second daily peak.

In both the Base Case and the High Renewables Case production simulation results, the amount of ramping required of the gas units served by PG&E is limited, especially in comparison to the gas fleet served by SoCalGas. However, production simulation models have limitations in their utility for identifying operational patterns for small numbers of units, and the fleet served by PG&E, much of which operates within the CAISO’s integrated California market, could plausibly be called upon to respond in a larger degree to the net load ramp that results from higher penetrations of solar. To test the impact of such an increased ramp, a sensitivity in which PG&E’s gas generators serve 40% of the three-hour net load ramp—roughly equal to PG&E’s electric load-ratio share in the state—was studied; the results of this sensitivity in comparison to the Base Case are shown in Figure 28.
Figure 28. PG&E system demand, supply, and linepack; Base Case and Base Case Ramp Sensitivity.

(a) PG&E system demand

(b) PG&E system linepack

Note: both scenarios assume ratable receipts equal to average daily demand
The addition of incremental demand in the evening in this scenario does fundamentally alter the patterns of linepack throughout the day: because the increase in the evening peak increases the proportion of total daily consumption that occurs in the latter half of the day, the system builds up and carries a higher level of linepack throughout the day in preparation for a larger draft when the evening ramp occurs. However, notwithstanding the increased rates of packing and drafting at certain times of the day, linepack remains within the bounds of the minimum and maximum OFO limits.

Each of the prior analyses relies on the premise that the amount of gas flowing on to the system will balance the demand over the course of the day, allowing linepack to recover to its original position. To explore the impacts of an event in which the two are not balanced, linepack is calculated for a second sensitivity, which pairs the demand of the Ramp Sensitivity with the supply assumption of the Base Case. The resulting imbalance causes a net draft on the system, and the inventory at the finish of the period is close to the minimum OFO inventory.
Figure 29. PG&E system demand, supply, and linepack; Base Case and Base Case Ramp with Imbalance Sensitivity.

(a) PG&E system demand

(b) PG&E system linepack

Note: both scenarios assume ratable receipts equal to average daily demand in the Base Case (which results in a deficiency in the 'Imbalance' scenario)
4.2.6 SUMMARY

A number of key points emerge from the analysis of the gas system of PG&E:

+ Growing penetrations of solar PV result in diurnal ramping of gas generators served by PG&E. The change in California’s net load shape as a result of current trends in renewable procurement is regular and periodic: high penetrations of solar in the middle of the day result in gas generators ramping down in the morning and up in the evening. As a result, the demand for gas among electric generators will decrease, but its variability throughout the day increases.

+ At higher penetration, daily patterns of linepack variability on PG&E system are not substantially different from those observed on today’s system. Because electric generation represents a small share of total natural gas demand during peak periods, the impacts of higher renewable penetrations on total natural gas demand are limited. The shape of non-electric demands during such events is still the major driver of fluctuations in linepack, which do not appear to change substantially from historical operations under higher renewable penetrations.

+ Unanticipated needs for ramping capability from gas generators served by PG&E could cause deviations in linepack that would fall outside of normal operating range. To the extent that unexpected or unscheduled ramping events in the electric sector occur, the PG&E gas system’s linepack would not necessarily recover over the course of the day.

+ If adverse circumstances arise in operations, service to electric generators served by PG&E would be among the first customers to be curtailed. Like electric generators receiving service from SoCalGas, electric generators using the PG&E system are designated as non-core
customers. As a result, should adverse circumstances arise, electric generators would be among the first customers to be curtailed in order to preserve service to core customers.

4.3 Desert Southwest

4.3.1 SYSTEM OVERVIEW

The El Paso Natural Gas (EPNG) pipeline connects the Permian and San Juan production basins to gas markets in the southwest and southern California. Unlike a number of other western pipeline systems, EPNG does not have any market area underground storage facilities—the geologic formations in the southwest are not suitable to underground gas storage, and none of the pipelines in the region have storage facilities close to market areas—and so the variability of loads served by the EPNG pipeline must be managed entirely through the variations of system linepack throughout the day. The mid-range total linepack of the EPNG system is approximately 7,700 MMcf.

The reliance of the EPNG pipeline upon its linepack to meet variable loads is reflected in the structure of the services it offers to shippers, which have been designed with two goals in mind: (1) to ensure that sufficient physical capability exists so that useable linepack is sufficient to manage variability of firm loads; and (2) to promote appropriate balancing of receipts and deliveries so that linepack remains within reasonable bounds of tolerance from one day to the next.

While the standard firm service offered by pipelines presumes that the shipper will receive and deliver gas on a ratable basis—deviations are allowed subject to
the operator’s ability to accommodate variability—EPNG additionally offers Hourly Firm Transportation Service tailored to meet the needs of shippers with anticipated variable loads.\textsuperscript{27} In addition to providing firm daily transport capacity, the hourly service options allow shippers to contract for peak hourly rates of flow and the duration at which these peak flows may be maintained. To account for the added capacity requirements of these variable loads (see Section 2.2.1), EPNG has derived a “capacity premium” associated with different profiles for hourly service. The capacity premium is added to the daily contract quantity in order to ensure the availability of enough capacity to provide for sufficient useable linepack to allow EPNG to balance variable demands and ratable supplies. Purchasing hourly firm transportation from this system ensures that the physical capability of the infrastructure itself will be adequate to meet the variable needs of a given load; however, it is important to note that gas systems are built to meet firm load, and this framework does not ensure the pipeline will be capable of meeting interruptible loads.

The case study of the EPNG pipeline focuses specifically on “Power Plant Alley,” a segment of the Southern Mainline between the Casa Grande and Wenden compressor stations in southwestern Arizona. This segment of pipeline delivers gas to LDCs that serve loads in the Phoenix area and provides direct service to over 6,000 MW of combined cycle gas generation, including the Arlington Valley, Gila River, Harquahala, Mesquite, and Red Hawk power plants. Additionally, this segment carries gas bound for California. At the Wenden compressor station it joins with the Havasu Crossover (a segment of pipeline that typically flows gas south from the Northern Mainline); from this point, the

\textsuperscript{27} El Paso Natural Gas Company, FERC Gas Tariff, Third Revised Volume No. 1A, Rate Schedule FT-H
pipeline continues to the California border, where it interconnects directly with the SoCalGas and North Baja Pipeline systems at its western terminus.

Figure 30. Map of 'Power Plant Alley'

(a) El Paso Natural Gas Company System

(b) Power Plant Alley
4.3.2 REGIONAL ELECTRIC SECTOR OUTLOOK

The future operations of gas generators in Power Plant Alley are best understood within the context of broader changes in the electric sector across the Desert Southwest as a whole. The composition of the electric fleet in the Desert Southwest, both for the historical year of 2012 and under the future scenarios evaluated in this case study, is shown in Figure 31. The region’s large gas fleet provides capacity needed to meet high summer peak demands associated with cooling loads; much of this fleet sits idle throughout the rest of the year.

Figure 31. Installed generating capacity, Desert Southwest.

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28 The ‘Desert Southwest’ includes balancing authorities in Arizona, New Mexico, and Southern Nevada.
Historically, the penetration of renewable generation in the Desert Southwest has been relatively low. However, substantial expansion is expected in the coming decade as the southwestern states pursue renewable goals. In particular, Arizona’s RPS targets—10% in 2020 and 15% in 2025—are expected to drive substantial new investments in renewable generation in the Desert Southwest. Solar PV is expected to meet the majority of the region’s needs for renewable power due to the region’s limited endowment of competitive alternatives among other renewable technologies.

The expected changes in net load due to renewable development are of a similar nature to those expected in California, as the predictably periodic output of a large fleet of solar generation offsets a portion of electric load in the middle of the day. The change in the shape of net load will result in increased ramping among the region’s combined cycle units, which operate on the margin throughout the entire year.

4.3.3  DEVELOPMENT OF REFERENCE ASSUMPTIONS

As solar technologies represent the largest likely source of new renewable generation in the Desert Southwest, the gas plants in Power Plant Alley, which represent a large share of the region’s combined cycle capacity, may cycle to greater depth throughout the day to accommodate the output of new solar facilities. The variable needs of the generators in Power Plant Alley are represented by an hourly profile that captures the impact of solar generation in the Base Case and High Renewables Case. For each case, a January day that exhibits both high overall demand and high hourly variability is selected.
In addition to serving these power plant loads, the Southern Mainline also delivers gas to LDCs serving loads in the Phoenix area and also transports gas to southern California at Ehrenberg, where it interconnects with the SoCalGas and North Baja systems. The natural gas demand of LDCs in the region is modeled based on the data for historical period of December 13-15, 2013 provided by Kinder Morgan. The downstream demands of the pipeline to transport gas to California are assumed to be 400 MMcf/d (on a ratable basis), an amount that is consistent with firm obligations. Figure 32 shows the development of this profile for the middle day of the three-day window evaluated in this case study.
Figure 32. Development of Power Plant Alley Reference Assumptions, Base Case & High Renewables Case.

(a) Hourly electric net load in Desert Southwest

(b) Electrical output from gas generators served in Power Plant Alley

(c) Total natural gas consumption served in Power Plant Alley
4.3.4 ANALYTICAL METHODS

To study the impacts of the variable needs of gas generators on gas infrastructure in Power Plant Alley, a transient hydraulic model of the El Paso system between the Wenden and Casa Grande compressor stations was developed by DNV GL with oversight from Kinder Morgan. The model captures constraints on the operations of the two compressor stations as well as the four parallel pipelines between them using publicly available data purchased for use in this study from Platts.

Table 7 shows the scope of this case study. In addition to evaluating the capability of Power Plant Alley against the Reference Assumptions developed above, the hydraulic model developed by GL was used to test the sensitivity of the findings to key assumptions regarding the level of “through-flow” to Wenden. None of the cases examined in this case study presume a deficiency of receipts.

Table 7. Scope of Power Plant Alley case study.

<table>
<thead>
<tr>
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<th>Base Case</th>
<th>High Renewables Case</th>
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<tbody>
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<tr>
<td>Sensitivity: Size of Electric Sector Ramp</td>
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<td>Sensitivity: Supply-Demand Balance</td>
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<tr>
<td>Sensitivity: Level of Non-Electric Demand</td>
<td>✓</td>
<td>✓</td>
</tr>
</tbody>
</table>

Because this case study examines a limited portion of a larger system (for which linepack is managed within the day across the system as a whole), establishing appropriate boundary conditions for this study at the Casa Grande and Wenden compressor stations has a direct impact on the analysis’ findings and is critical to
the study's credibility. Assumed pressure and flow constraints at each of these boundary points were developed by Kinder Morgan as plausible representations of the capability of the upstream pipeline (prior to Casa Grande) and the needs of the downstream system (after Wenden).

Upstream of Casa Grande, the EPNG system comprises hundreds of miles of large diameter pipeline whose linepack contributes to the flexibility of the system as a whole. In comparison to the amount of demand located downstream of the Casa Grande compressor, the demands upstream on the southern Mainline have historically been relatively small. Accordingly, to capture the fact that the upstream system may play an important role in managing the variability of gas demand in Power Plant Alley, the amount of gas flowing through the Casa Grande compressor station was allowed to vary throughout the simulation; however, to capture real-world capacity limitations of upstream facilities, an instantaneous limit on the available flow of gas at Wenden of 1,500 MMcf/d was enforced in the model. If this rate was exceeded the simulation changed its mode of operation and held the 1,500 MMcf/d rate, allowing the 850 psig discharge pressure to drop.

The target delivery at Wenden was set to be 700 psig. This target minimum pressure—as well as a 640 psig target minimum pressure for the taps to the power plants—serves as minimum pressure boundary conditions and is assumed necessary for the pipeline to meet its delivery pressure obligations at the California border. The success of the various simulations is evaluated on the

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29 While this has been true historically, new demands may also be placed on upstream infrastructure by growing demand for exports to Mexico. The operational impact of this development is not evaluated in this study; however, as discussed in Phase 1, it is important for electric sector regulators and planners to understand the potential impacts of the growth of demand for exports on the gas systems of the Desert Southwest.
basis of their ability to maintain sufficient pressure to meet these obligations without exceeding the capacity of any of the facilities in Power Plant Alley.

4.3.5 ANALYTICAL RESULTS

The study’s aim is to examine the impact of throughput on the ability of the network to serve its power and non-power demands while also taking into account some real limitations that can occur further east of the Casa Grande compressor station. The hydraulic simulations of both the Base Case and the High Renewables Case are shown in Figure 33.
Figure 33. Power Plant Alley, Base Case & High Renewables Case simulations.

(a) Total deliveries (to Phoenix, Power Plant Alley, Wenden)

(b) Pressure at Casa Grande (upstream of Power Plant Alley)

(c) Pressure at Wenden (downstream of Power Plant Alley)
Under the assumption of 400 MMcf/d of through-flow to Wenden, both cases were found to be feasible: at no time was the downstream pressure at Wenden insufficient to meet its minimum obligation. In order to evaluate the sensitivity of these results to key input assumptions, parametric analysis of the assumed rate of through-flow to Wenden was conducted. In both the Base Case and the High Renewables Case, this input was varied from 250 to 500 MMcf/d in increments of 50 MMcf/d.\(^3\) Table 8 and Table 9 summarize the results of this analysis, showing the lowest pressure reached at both Wenden and at the pressure taps to the power plants over the course of the three day simulation. In cases where either of these values fell below the required minimum (700 psig for Wenden, 640 psig for power plant taps), the case was flagged as infeasible.

Table 8. Parametric analysis of through-flow to Wenden, Base Case.

<table>
<thead>
<tr>
<th>Assumed Flow from Power Plant Alley to Wenden (MMcf/d)</th>
<th>Lowest Simulated Pressure at Wenden (psig)</th>
<th>Lowest Simulated Pressure at Power Plant Taps (psig)</th>
<th>Scenario Feasible</th>
</tr>
</thead>
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<tr>
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</tr>
<tr>
<td>500</td>
<td>617</td>
<td>630</td>
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</tbody>
</table>

Because the Havasu Crossover, which generally delivers gas to Wenden from the EPNG North Mainline, can contribute another 600 MMcf/d of flow, these values correspond to flows of gas moving westward to California of 850 to 1,100 MMcf/d.
Table 9. Parametric analysis of through-flow to Wenden, High Renewables Case.

<table>
<thead>
<tr>
<th>Assumed Flow from Power Plant Alley to Wenden (MMcf/d)</th>
<th>Lowest Simulated Pressure at Wenden (psig)</th>
<th>Lowest Simulated Pressure at Power Plant Taps (psig)</th>
<th>Scenario Feasible</th>
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<tr>
<td>500</td>
<td>696</td>
<td>707</td>
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</table>

The results of this parametric analysis illustrate several key findings clearly:

- **There is a direct tradeoff between flexibility and throughput.** The higher the level of through-flow assumed to Wenden, the more constrained the system’s operations appear. In both cases, with each increase in through-flow to Wenden of 50 MMcf/d, the lowest pressure observed at Wenden decreases, approaching and eventually violating the minimum constraint at higher levels of throughput. As the through-flow increases, the pipeline’s operations become increasingly constrained, yet the same amount of linepack is needed to manage the segment’s variability.

- **The reduction in demand that results from increased renewable penetrations outweighs the increase in variability.** While loads in the High Renewables Case are more variable than those in the Base Case, they are lower on average. Comparing results between the two for a
given level of throughput shows that the reduction in demand outweighs the increase in variability. For instance, in the Base Case, gas infrastructure is unable to sustain a through-flow to Power Plant Alley of 450 MMcf/d without violating pressure constraints, but this same level of through-flow is feasible under the High Renewables Case. In fact, at each level of through-flow, the lowest pressures observed at Wenden are higher under the High Renewables Case than under the Base Case—an indication that the system is less constrained in its operations.

4.3.6 SUMMARY

The case study of Power Plant Alley is summarized as follows:

+ **A substantial portion of the flexible gas-fired generation capacity in the Desert Southwest is located in ‘Power Plant Alley.’** Power Plant Alley, a segment of the El Paso Southern Mainline, provides service to over 6,000 MW of combined cycle gas-fired generation capacity—roughly a third of the combined cycle capacity in the Desert Southwest in the 2022 Base Case.

+ **As the penetration of solar increases in the Desert Southwest, these plants may be dispatched to accommodate changes in the shape of net load.** Increased penetration of solar PV in the Desert Southwest reduces net load in the middle of the day, impacting the need for ramping from flexible gas generators.

+ **Hydraulic simulations indicate that service of the variable demands of combined cycle plants in Power Plant Alley is technically feasible at reasonable levels of through-flow.** While the parametric sensitivity analysis identified operational challenges at high levels of through-flow to Wenden, these levels of through-flow are higher than current needs to meet delivery obligations to California.
Hourly firm services offered by EPNG could be used to ensure sufficiency of pipeline capacity needed for ramping. EPNG’s hourly firm services allow shippers with variable needs such as those of the gas generators evaluated in this case study to reserve sufficient capacity to provide the flexibility needed to meet variable loads.

4.4 Pacific Northwest, West of Cascades

4.4.1 SYSTEM OVERVIEW

This case study focuses on the Interstate 5 (I-5) Corridor in western Washington, a region served by the Williams Northwest Pipeline, the only major pipeline west of the Cascades. Figure 34 shows the Northwest Pipeline system and gas-fired generating resources located in the I-5 Corridor. The area’s gas demands are met by gas supplies flowing south from British Columbia through the Sumas compressor station and west through the Columbia River Gorge from Plymouth (near the pipeline’s interconnect with the GTN system at Stanfield). During the winter, these gas flows are supplemented by withdrawals from the Jackson Prairie underground storage facility. Jackson Prairie, which is co-owned by Avista, Puget Sound Energy (PSE) and Northwest Pipeline, contains 25 Bcf of working natural gas storage capacity and provides a maximum of 1,150 MMcf/d of withdrawal capacity.31 PSE also owns and operates a large share of the gas-fired generation capacity located in the study area.

31 Only a portion of Northwest Pipeline’s share is used for balancing purposes; the remainder is available to shippers under Northwest Pipeline’s SGS-2F and SGS-2I tariffs.
4.4.2 REGIONAL ELECTRIC SECTOR OUTLOOK

The current generation fleet of the Pacific Northwest, as well as the future fleets examined in the Base Case and High Renewables Case, is shown in Figure 35. The region’s large hydroelectric fleet, developed over multiple decades by the US Army Corps of Engineers and the Bureau of Reclamation, accounts for the majority of generating capacity and load served in the region, but load growth and clean energy policies have triggered development of gas and renewable resources in the past decade.
The installed capacity of gas-fired generation in the Pacific Northwest is currently around 10,000 MW, about 16% of the region’s installed capacity (of this total, roughly half is served in the I-5 Corridor). Natural gas’s share of generating capacity is small relative to other regions due to the region’s large endowment of hydroelectric resources. However, some additional gas resources are expected to be built over the coming decade to meet continued load growth, replace the energy and capacity of retiring coal resources and provide additional power system flexibility, resulting in a growing reliance on gas as the marginal fuel.

As of 2012, the region included approximately 6,000 MW of wind generation, much of which is concentrated in the Columbia River Gorge. The development of wind resources has primarily been supported by Oregon and Washington's RPS targets: Oregon requires 25% of retail sales to be met with renewables by
2025, and Washington requires 15% by 2020. California’s RPS program has also contributed to wind investments in the region, as utilities in California have entered into long-term contracts with wind facilities in the Pacific Northwest.

Developers are expected to continue bringing additional wind generation online over the coming decade due to the region’s strong resource potential in the region and the need for utilities to procure additional renewables to meet final RPS levels. This continued growth in wind capacity is reflected in this study, which contains 12,100 MW of wind in the Base Case and 19,700 MW of wind in the High Renewables Case. Higher wind penetrations will impact regional electric system operations in several ways, including: (a) additional variability, which affects how gas generators ramp to meet the net load; and (b) wind power forecasting challenges, which increases the uncertainty of gas generators about how much gas they need to nominate. These two challenges are the focus of this case study.

4.4.3 DEVELOPMENT OF REFERENCE ASSUMPTIONS

The Pacific Northwest already contains a large amount of installed wind capacity, and this is expected to increase beyond current levels to meet existing renewable portfolio standard targets and any potential increases in RPS goals. There have already been periods where wind generation has met a large proportion of electric load, and then decreased significantly (often to zero), requiring increased output from thermal and hydroelectric resources.\textsuperscript{32} This

\textsuperscript{32} Because most wind plants in the Pacific Northwest are located in the Columbia River Gorge, their operations are highly correlated with one another.
type of event raises the question of whether regional gas infrastructure will be able to ramp up in response to declining wind output during electric peak loads.

Production simulation outputs were used to identify a five-day period where wind generation supplied a large proportion of electric load, and then decreased significantly, requiring a rapid increase in generation from natural gas (and other sources of generation) to meet the extreme net load ramps. Figure 36a shows the regional net load in the Pacific Northwest during the event of the sudden decline in wind generation in the Base Case. The response of natural gas generation located in the I-5 Corridor during the same three-day period is depicted in Figure 36b. The power output of the gas fleet is less than 500 MW at 3:00AM (hour 50), and then increases to over 3,600 MW across an eight-hour window during the morning of day two. During this window, eight combined cycle plants, totaling 3,000 MW, start up and ramp to maximum capacity.

To understand how the variability of the electric sector’s demand affects the flexibility of the existing natural gas system, electric sector demand from this five-day profile is combined with historical non-electric loads. Northwest Pipeline provided historical hourly data for I-5 loads connected to the Northwest Pipeline system during December 2013. Figure 36c summarizes the hourly gas demand for the electric and non-electric sectors. The increase in electric sector demand during the morning of day three coincides with residential heating loads, pushing up system demand to nearly 2,500 MMcf/d.

---

33 Northwest Pipeline provided total gas demand (electric and non-electric) for all metering stations in the I-5 Corridor over the period from December 1-11, 2013, from which electric consumption was subtracted based on hourly data from the U.S. EPA’s Continuous Emissions Monitoring System (available from EPA (2014b)).
Figure 36. Development of I-5 Corridor Reference Assumptions (five day period), Base Case.

(a) Hourly electric net load in Pacific Northwest

(b) Electrical output from gas generators served in I-5 Corridor

(c) Total natural gas consumption served in I-5 Corridor
Figure 37. Development of I-5 Corridor Reference Assumptions (five day period), High Renewables Case.

(a) Hourly electric net load in Pacific Northwest

(b) Electrical output from gas generators served in I-5 Corridor

(c) Total natural gas consumption served in I-5 Corridor
4.4.4  ANALYTICAL METHODS

Northwest Pipeline developed and calibrated a transient hydraulic model replicating historical operations in the I-5 corridor based on the period from December 3-7, 2013. During this period, the Northwest Pipeline served relatively high winter demand among both electric and non-electric users, as cold weather triggered high end-use demands while gas generators operated at high capacity factors. To assess the operational impacts of an unexpected ramp in gas demand due to a change in wind output, Northwest Pipeline conducted three simulations: (a) the 2013 historical period, which simulates historical operations and includes actual electric and non-electric loads from December 3-7, 2013; (b) the 2022 Base Case, which uses 2013 non-electric loads and applies electric sector gas demand from the Base Case for a period including a large downward ramp in wind generation; and (c) the 2022 High Renewables Case, which includes an even larger quantity of wind generation that offloads a portion of gas generation capacity.

Table 10. Scope of I-5 Corridor case study.

<table>
<thead>
<tr>
<th></th>
<th>Base Case</th>
<th>High Renewables Case</th>
</tr>
</thead>
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<td>Reference Assumptions</td>
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<td>✓</td>
</tr>
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<td>✗</td>
</tr>
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<td>Sensitivity: Supply-Demand Balance</td>
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<td>✓</td>
</tr>
<tr>
<td>Sensitivity: Level of Non-Electric Demand</td>
<td>✗</td>
<td>✓</td>
</tr>
</tbody>
</table>

4.4.5  ANALYTICAL RESULTS

The Northwest Pipeline model estimates the system line pack and receipts at nodes across the system required to deliver gas to serve loads and maintain
system pressure. In the simulations carried out by Northwest Pipeline, the hourly rates of demand (deliveries) vary, as depicted in Figure 38a. Deliveries in the Base and High Renewables cases are generally lower than the 2013 historical period during the first two days, as gas generators that operated during the historical period are off to accommodate high wind output in the Base Case and High Renewables Case. However, there is a large upward ramp in modeled electric sector gas demand as wind output declines and electric load increases on the morning of the third day.

Figure 38b,c, and d show the primary hourly simulation results: receipts at Sumas, storage withdrawals from Jackson Prairie, and system line pack. The simulation results show small differences in Sumas receipts, while changes in withdrawals from Jackson Prairie during this period capture most of the variation from historical demand. System line pack is slightly higher in the 2022 cases relative to the 2013 historical period during the hours preceding the ramp event, but the difference is relatively small.
Figure 38. Northwest Pipeline hourly demand, supply, and linepack, Base Case and High Renewables Case.

(a) Northwest Pipeline system demand

(b) Receipts at Sumas
These results suggest that meeting such an upward ramp in gas generation of this magnitude is technically feasible. These results are not surprising, given that the majority of gas-fired generators have firm transportation service, which
inherently means that the pipeline system is sized to deliver gas up to the level of each plant’s firm commitments.34

The response of Jackson Prairie as modeled in this simulation reflects its physical capabilities; however, it is important to note that most of the capacity of Jackson Prairie is allocated directly to shippers and is not available to Northwest Pipeline for balancing purposes. As a result, while the model indicates the technical feasibility of this scenario, in reality, the changes modeled here would rest upon the shippers withdrawing gas from Jackson Prairie to nominate the appropriate volumes to meet demands.

As noted above, the 2022 simulations cover a period that begins with high wind output and low gas generation, but as wind output rapidly decreases, multiple gas generators turn on and ramp up to their maximum capability. This is in contrast to the 2013 historical period, where most gas plants operated in a “baseload” capability to serve electric heating loads across the entire five-day period. This change in the gas demand profile for power plants - from a relatively constant demand to a more variable demand - affects pressure at the point of delivery.

Figure 39 shows the demand for natural gas and the resulting pressure at the River Road power plant, a 250 MW CCGT. River Road’s demand for natural gas is relatively constant during the 2013 historical period, but, in the Base Case, the plant is offline for over 36 hours and then quickly pulls gas to produce power as wind generation drops off. While River Road is offline, simulated pressure is 30

34 Among those plants that do not have firm service in the I-5 Corridor, maintaining a reserve of backup fuel is a common practice to ensure the availability of the plant.
to 50 psig higher, which better prepares the system for a major draw, and pressure drops by ~30 psig when deliveries spike to over 60 MMcf/d.

Figure 39. Demand and pressure at River Road, Base Case (compared to historical)

(a) Deliveries to River Road

(b) Pressure at River Road
The hydraulic analysis discussed above demonstrates that Northwest Pipeline system has the capability to manage the variability in gas demand that results from large ramps in wind generation but does not address the uncertain nature of wind generation and the impact it may have on the accuracy of gas nominations and scheduling. As the penetration of renewables such as wind and solar grows, the intermittent and unpredictable qualities of those resources may contribute to challenges in scheduling and nominating the correct volumes of gas and could, as a result, contribute to imbalances.

Figure 40, derived from wind forecast data published by the Bonneville Power Administration, illustrates how wind forecast errors over the course of the gas day may impact the nomination of natural gas by electric generators. The top component shows the actual hourly wind output throughout the gas day, and the wind forecast at the time of nomination. The hourly wind forecast errors are shown below, with positive errors (over-forecast) in green and negative errors (under-forecast) in red. The component at the bottom of the figure contains the cumulative wind forecast error throughout the day, with the final bar representing the daily quantity of energy that must compensate for wind forecast errors (2275 MWh, or 95 MW on an average basis across the day).
Figure 40. Wind Power Forecast Error over the Gas Day

**Hourly Wind Output (MW)**

**Hourly Wind Forecast Error (MW)**

**Cumulative Wind Forecast Error (MWh)**
Based on this framework, Figure 40 shows the histogram of historical wind forecast errors expressed as a percentage of installed capacity (sustained over the course of the day). While a large concentration of the daily forecasts are clustered towards the center of the distribution, the tails indicate the potential for the largest plausible “missed” forecasts. For the data gathered in this effort, the 97.5th and 99th percentiles, representative of extreme wind over-forecast events, are 14% and 18% of the installed wind capacity, respectively, representing approximately 2,700 and 3,400 MW of generation during each hour of the day that must be made up by flexible hydroelectric and natural gas generation in the High Renewables Case.

**Figure 41. Frequency of daily wind power forecasting errors for the BPA system and distribution fit to the observed data.**

The data from BPA suggests that wind forecast errors could represent a substantial portion of the installed wind capacity, but the impact of wind forecast error on gas under-nominations warrants further study.
4.4.6 SUMMARY

The case study of the I-5 Corridor is summarized as follows:

+ Higher penetrations of wind generation cause large net load ramps when wind output changes rapidly; production simulation indicates that gas generation will meet some portion of these ramps in the winter. This is a significant departure from historical electric sector operations during the wintertime, when the Pacific Northwest has relied on both baseload and peaking gas-fired generation to help meet winter peak demands.

+ Hydraulic modeling indicates that the gas system could accommodate these large gas ramps in part due to the flexibility of Jackson Prairie, but this would require shippers to nominate withdrawals to match demand. The portion of Jackson Prairie’s capacity that is reserved by Northwest Pipeline for balancing is relatively small. However, to the extent that shippers with contractual rights to stored gas volumes make use of the flexibility of the facility, the physical flexibility exists to balance large upward ramps on the system.

+ During periods of high wind output, most if not all gas generators are offline, which allows the gas system to pack up the line and prepare itself for a major draw. When gas generators are off in the I-5 Corridor, the simulation shows the Northwest Pipeline maintaining higher pressure throughout the simulation when compressors are operated as they were historically, which readies the system to meet notable increases in demand when the gas generators start up as wind output ramps down. From the perspective of the gas system, operators will have to evaluate the tradeoff between how high to maintain pressure (or linepack) throughout the system and the cost of running compressors to sustain those higher pressures.
Wind forecast errors will contribute to inaccuracies in gas nominations, the impacts of which warrant further study. A full analysis of the impact of wind forecasts on gas nominations in this study footprint is beyond the scope of this study, but relatively simple analysis of wind forecasts indicate that the size of the average forecast error on some days could contribute to inaccuracies. Further investigation is necessary to determine whether such an issue will result in imbalances that pose operational challenges to gas infrastructure.

4.5 Pacific Northwest, East of Cascades

4.5.1 SYSTEM OVERVIEW

This case study examines the implications of variable power plant loads upon the operations of TransCanada’s GTN pipeline. The GTN pipeline, shown in Figure 42, connects Canadian gas supplies with the northern California border, serving a number of LDC and power plant loads in between. Kingsgate, the pipeline’s northern terminus, is the main point of receipt, where gas from Canadian production basins flows on to the system. Along its length, the pipeline provides service to a number of power plants. Most plants served by GTN are located near Stanfield near the pipeline’s junction with the Northwest Pipeline (Hermiston, Calpine, and Coyote Springs); the pipeline also provides service to the Lancaster combined cycle further north and the Klamath Cogeneration facility at the California-Oregon Border.
Figure 42. Map of GTN system

Legend
- Gas-Fired Generator
- Gas Storage Facility
- Compressor Station
- Pipeline

Kingsgate (interconnects with Foothills)
Stanfield (interconnects with Northwest Pipeline)
Turquoise Flats (interconnects with Ruby)
Malin (interconnects with PG&E)
The GTN pipeline is different from the other systems examined in the case studies in several regards. First, the large majority of deliveries made by GTN are to interconnects with other pipeline systems (e.g. Northwest Pipeline, PG&E, Tuscarora) rather than to direct end users and LDCs. As a result, a large portion of the demand for gas from the GTN system is effectively ratable, in contrast to the variable profiles of direct end users and electric generators. Second, unlike a number of other systems examined through the case study process, the GTN system is not connected to any underground storage resources. Consequently, the system relies entirely on fluctuations in linepack to balance variable loads.

The GTN system was originally developed to connect natural gas production in Alberta’s Western Canadian Sedimentary Basin with gas markets in California. A substantial portion of the pipeline’s receipt capacity at Kingsgate (approximately 2,950 MMcf/d)\(^{35}\) was contracted for delivery to the PG&E system at Malin. However, recent expansions of other pipelines competing for California markets and changes to the regional dynamics of natural gas markets have transformed the utilization of the GTN system. Most recently, the development of the Ruby Pipeline, which connects with GTN at its southern terminus and the PG&E system at Malin, has contributed to declining use of the GTN system as a long-haul transport system linking Alberta and California markets (see Figure 43).

\(^{35}\) See GTN, 2006.
Due to its changing contract profile and the evolution of gas market dynamics in the Western Interconnection, the operations of the GTN system today differ dramatically from historical patterns. While the system still achieves relatively high utilization at times, there have also been recent periods when it has experience historically low levels of throughput. Additionally, with the construction of the Ruby Pipeline, GTN has updated its tariff to include backhaul services from Turquoise Flats (at the point of interconnection with Ruby) and has been used to transport gas from south to north. Because of these changes, this case study examines the GTN system at times of high demand but also within the context of its changing role in the Western Interconnection.

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36 See GTN, 2012.
4.5.2 REGIONAL ELECTRIC SECTOR OUTLOOK

The outlook for gas generation served by the GTN system is best understood within the context of the electric sector in the Pacific Northwest as a whole. The same factors that will affect gas generators operating in the I-5 Corridor—namely, increased needs for ramping as wind generation continues to grow as a share of the region’s portfolio under state policy targets—will impact gas plants operating along the length of the GTN system. Section 4.4.2 contains a more detailed description of expected changes in the Pacific Northwest and their implications for regional gas generators.

4.5.3 DEVELOPMENT OF REFERENCE ASSUMPTIONS

Because of the high penetration of wind generation expected in the Pacific Northwest, the case study focuses on the operations of gas generators served by GTN during periods in which large upward ramps of gas generation occur. The Reference Assumptions for analysis of the GTN system examine situations in which the gas plants served by the pipeline ramp up to high levels of output while the pipeline in response to rapidly changing system conditions—most notably, due to the intermittency of wind generation in the Pacific Northwest. To capture such a dynamic, a five-day winter period from the Base Case and High Renewables Case production simulation results was extracted during which regional wind generation experienced large ramps that were met, in part, by large changes in generators operating along the GTN pipeline. The dynamics of regional net load and the response of gas generators served by GTN are shown in Figure 44 and Figure 45 for the Base Case and High Renewables Case, respectively.
Assumed deliveries to non-electric users (including both end users and interconnects with other pipelines) are based on the historical deliveries from December 26-30, 2013, a period during which the GTN system experienced a relatively high level of utilization. A large share of these deliveries are at interconnects to other pipeline systems; because pipeline systems are assumed to manage their own variability entirely, these deliveries are assumed to be ratable throughout each day. The ultimate resulting hourly demand profiles for natural gas are also shown in Figure 44 and Figure 45 for the Base Case and High Renewables Case, respectively.
Figure 44. Development of GTN System Reference Assumptions (five day period), Base Case.

(a) Hourly electric net load in Pacific Northwest

(b) Electrical output from gas generators served by GTN

(c) Total natural gas consumption served by GTN

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Figure 45. Development of GTN System Reference Assumptions (five day period), High Renewables Case.

(a) Hourly electric net load in Pacific Northwest

(b) Electrical output from gas generators served by GTN

(c) Total natural gas consumption served by GTN
4.5.4 ANALYTICAL METHODS

The operational patterns of gas generators served by GTN in the Base Case and the High Renewables Case are analyzed by TransCanada using the pipeline’s transient hydraulic model that simulates operations across the entirety of the system. The model relies on inputs for specified profiles for receipt and delivery and is used to determine usage patterns for each compressor station along the pipeline’s length to serve the demands. This model is used to evaluate four cases, as summarized in Table 11. In addition to analysis of the Base Case and the High Renewables Case using the Reference Assumptions, TransCanada conducted sensitivity analysis on two key inputs. First, whereas the analysis of Reference Assumptions presumes that shippers nominate the appropriate volumes of gas for their daily levels of consumption, TransCanada examines the impact of an extended imbalance between receipts and deliveries on its system’s operations (‘Base Case Imbalance Sensitivity’). Second, motivated by the evolving role of the GTN pipeline in the Western Interconnection, TransCanada studied a sensitivity on the level of non-electric demand, examining the pipeline’s operations when the pipeline’s flow is very low compared to its total capability (‘Base Case Low Flow Sensitivity’).37

37 This sensitivity is developed based on the operational experience of the GTN pipeline from February 27 – March 3, 2014.
The success of each simulation is evaluated by examining the pressure at power plants: power plants served by GTN generally require a minimum pressure of 550 psig to operate. \(^{38}\) To the extent that pressure at the power plants remains above this level throughout the simulation while also allowing the pipeline to deliver gas to its interconnects with other systems, the simulation is deemed successful.

### 4.5.5 ANALYTICAL RESULTS

The results of the transient simulations of the Reference Assumptions for the Base Case and High Renewables Case are summarized in Figure 46, which shows the profile of demand across the five-day period and the system’s resulting fluctuations in linepack needed to manage the variability of demand. In both cases, all demands across the system were met while maintaining relatively stable linepack while also delivering gas to each plant above 550 psig.

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\(^{38}\) Many of the plants served by GTN use interruptible service and thus do not have formal pressure agreements with the pipeline.
Figure 46. GTN hourly demand and linepack, Base Case and High Renewables Case.

(a) GTN pipeline system deliveries

(b) GTN pipeline system linepack

Figure 47 shows, for the same simulation, the rate of delivery to and the delivery pressure at the Carty Generating Station, a proposed 450 MW gas generator currently under development by Portland General Electric that would
be located near the Stanfield interconnect with Northwest Pipeline. In the results of electric sector production simulation modeling, the Carty plant is frequently dispatched for its ramping capability; its use of modular reciprocating engines allows it to reach its full level of output very quickly.

In the Base Case, the Carty plant turns on twice to meet net load variations; in the High Renewables case it turns on only once. Each start-up corresponds with a drop in the delivery pressure at the plant, as indicated in Figure 47b. Despite the rapid changes in conditions on the pipeline, the pressure throughout each simulation remains far above 550 psig, the assumed minimum needed to support operations at the Carty plant.
Figure 47. Hourly gas deliveries and delivery pressure at Carty Generating Station, Base Case and High Renewables Case.

(a) Deliveries to Carty Generating Station

(b) Delivery pressure at Carty Generating Station

A sensitivity that explores the potential impact of a sustained imbalance on the system’s operations was also evaluated; the results are shown in Figure 48. In the ‘Imbalance’ sensitivity, a deficiency of 50 MMcf/d—approximately equal to
the daily fuel needs of a 250 MW gas generator—was assumed to persist over the course of the simulation. The impact of the resulting imbalance between receipts and deliveries is a nearly persistent decrease in linepack over the course of the five-day simulated period, as shown in Figure 48b.

The downward trend in linepack highlights the importance of the nominations process in allowing a pipeline to schedule flows appropriately to match the demand for natural gas. In the example here, the pipeline’s linepack drops below 2,900 MMcf/d—the desired minimum on the GTN system—on the fourth day of the simulation. The length of time before such an imbalance results in the operational challenges depends, of course, on several factors:

+ **The magnitude and duration of the imbalance.** In this example, the pipeline is able to tolerate the imbalance for several days before it pushes linepack beyond the desired tolerance. However, a larger imbalance could not be handled over the same time horizon, as it would draw down linepack at a faster rate.

+ **The conditions on the pipeline when the imbalance begins.** In the transient simulations conducted in this study, the linepack begins very close to 3,100 MMcf; however, the GTN system frequently operates with a linepack closer to 3,000 MMcf. If the same imbalance occurred in this environment, the system could not tolerate it for the same length of time.
A second sensitivity on the Base Case that examines the GTN system’s ability to meet the same demands in the electric sector during a low flow condition (i.e. low deliveries to non-power end users and interconnects with other pipelines) is
also examined; the resulting system conditions are summarized in Figure 49. Both simulations were successful—linepack was maintained at relatively stable levels across the simulation horizon, and delivery pressure at each power plant remained above 550 psig. A comparison between these two simulations reveals several key dynamics:

+ The fluctuations in linepack between the Base Case and the Low Flow Sensitivity are similar. Because most of the deliveries on the GTN system are made to interconnects with other pipelines (and are assumed to be ratable), the changing output of electric generators along the pipeline is the main source of variability in natural gas demand on the pipeline. As a result, variations in linepack across the system as a whole are not likely sensitive to the level of deliveries to non-electric users.

+ The level of linepack in the Low Flow Sensitivity is slightly lower than the Base Case. The lower level of linepack on the system reflects the common choice by system operators to limit the use of compression on the system when demand is lower, which allows the system to conserve fuel and operate more efficiently. As variability on a gas system increases, its operator will have to evaluate the tradeoff between the operational costs of keeping systems at high levels of linepack and the potential for rapid increases in demand to determine the appropriate level of linepack to maintain in the system throughout the year. In the Low Flow sensitivity, the slightly lower level of linepack allows the system to operate more efficiently while still remaining prepared for the upward ramps of the power sector.
Figure 49. GTN hourly deliveries and linepack, Base Case and Base Case Low Flow Sensitivity.

(a) GTN pipeline system deliveries

(b) GTN pipeline system linepack
4.5.6 SUMMARY

The key points of the case study of the GTN system include:

+ **As penetration of wind in the Pacific Northwest grows, flexible generators will be needed to accommodate large, irregular ramps.** In contrast to other regions, where large net load ramps are compensated primarily by gas generation, the Pacific Northwest meets a portion of its ramping needs with its large hydroelectric fleet. Nonetheless, production simulation analysis indicates that gas-fired resources, operating on the margin in the winter, will provide some of the ramping capability needed to integrate wind generation in the region.

+ **The GTN system—with no natural gas storage facilities—will rely on the flexibility of its linepack to meet the variable needs of the electric generators it serves.** In three of the transient simulations conducted in this case study, the GTN system was able to meet the variable needs of electric generators by allowing for fluctuations in linepack. The GTN system is distinct from many others throughout the Western Interconnection because the majority of deliveries it makes are to interconnects with other pipeline systems; as a result, while electric generation is a small part of the overall demand on the system, it is one of the main sources of intraday variability.

+ **Prudent management of linepack requires operators to balance system flexibility with operating costs.** In the Low Flow sensitivity, the GTN pipeline met all demands across the system while maintaining a slightly lower level of linepack than in the Base Case. Maintaining a higher level of linepack when demand is low makes a system better prepared for rapid and/or unexpected upward ramps but also comes at a cost to the pipeline (and ultimately to shippers) of burning additional fuel for the necessary compression. As penetrations of renewables increases, system operators will need to understand the nature of
potential variable needs from electric generators on their systems to evaluate this tradeoff appropriately.

+ **Failure to nominate and schedule gas to meet the needs of electric generators could create adverse operating conditions.** As illustrated in the Imbalance sensitivity in this case study, imbalances between receipts and deliveries can cause adverse operating conditions on a pipeline and may require curtailment of load. The nature of the imbalance—both its magnitude and its duration—will ultimately determine whether it can be tolerated by a pipeline system.

### 4.6 Colorado Front Range

#### 4.6.1 SYSTEM OVERVIEW

This case study focuses on the Colorado Front Range, an area served by the Colorado Interstate Gas (CIG) pipeline system. Unlike the other case studies included in this report, this case study is qualitative in nature and does not include technical analysis of the gas system in the region. Notwithstanding the lack of quantitative analysis, this case study is included in order to highlight the combined actions of the CIG pipeline and Xcel Energy (Xcel, the region’s major electric utility) to facilitate gas-electric coordination in a region that has already achieved the integration of a high penetration of wind generation while relying on natural gas resources for operational flexibility.

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39 In addition to delivering gas to the Front Range of Colorado, the CIG system also transports substantial volumes of gas bound for eastern markets to interconnections with other interstate pipeline systems.
The Colorado Interstate Gas pipeline system provides transportation service to the Front Range, linking production basins in Wyoming and northeast Colorado with the loads of LDC and intrastate pipeline operators. Unlike a number of other western pipeline systems, the CIG system consists of relatively smaller diameter pipelines, which physically limits the amount of useable linepack in comparison to large diameter pipelines; the flexibility of the Colorado Interstate Gas system to meet variable loads instead results primarily from the significant injection and withdrawal capabilities of underground storage facilities located to the east and south of Denver.

In addition to providing service to LDCs, the CIG system also transports gas to a number of gas power plants throughout the region. Most of the power plants are located in a region described by Xcel as the “Natural Gas Delivery Core Area”: a region with an interconnected network of pipelines and storage facilities where the company has substantial flexibility to shift gas among generators in response to their needs. The Natural Gas Delivery Core Area is indicated in Figure 50.
4.6.2 REGIONAL ELECTRIC SECTOR OUTLOOK

The Rocky Mountain region consists of a diverse mix of coal, gas, hydro and renewable generating resources. The composition of the regional fleet, both in 2012 and in the future scenarios evaluated in this study, is summarized in Figure 51.
Most of the region's generation has historically come from coal resources, but state and federal policies, changing economic conditions, and growing environmental preferences, have prompted coal's share decline in recent years in favor of gas and wind generation. The Public Service Company of Colorado (PSCo) balancing authority already contains over 2,000 MW of wind, developed primarily to meet Colorado’s RPS target, which requires investor-owned electric utilities to meet 30% of load with renewable resources by 2020.

The trend of additional gas and wind generation is expected to continue over the coming decade as coal plants retire or are repowered with natural gas and utilities procure additional renewables to meet Colorado’s RPS goals. The level of wind in 2022 (3300 MW) is similar to the amount assessed by Xcel in a previous wind integration study that this case study uses to assess the impact of wind generation on gas operations.
4.6.3 DEVELOPMENT OF REFERENCE ASSUMPTIONS

Like the Pacific Northwest, the Rocky Mountain region has a rich endowment of wind potential, and renewable development in the region has focused on harvesting this potential to meet Colorado’s renewable portfolio goals. This case study focuses on the impact of the intermittency of this growing source of energy: rapid changes in meteorological conditions can lead to large swings in the output from wind facilities.

To develop a profile of gas demand during a significant ramping event, the results of the production simulation analysis of the Base Case and High Renewables Case were reviewed to identify periods in which wind output changes rapidly. The search for such events focused on the winter months, when LDC loads on the system would also be high, limiting the flexibility offered by the natural gas storage facilities along the Front Range. A three-day period from the Base Case and the High Renewables Case in January, in which both cases showed a substantial decline in wind generation, was chosen. The net load and corresponding output from gas generators in the Base Case are shown in Figure 52a and b, respectively; the same metrics for the High Renewables Case are shown in Figure 53a and b.

The demand for gas at power plants is combined with non-electric demand profiles in the region provided by Kinder Morgan. Historical loads from the period December 5-7, 2013 are used in this analysis. The morning heating peak on the second day of this historical period coincides directly with the upward ramp in gas generation as wind generation drops rapidly. The ultimate resulting profiles for total gas demand in the region for the Base Case and High Renewables Case are shown in Figure 52c and Figure 53c, respectively.
Figure 52. Development of Front Range Reference Assumptions (three day period), Base Case.

(a) Hourly electric net load in the Rocky Mountain Front Range

(b) Electrical output from gas generators in the Front Range

(c) Total natural gas consumption in the Front Range
Figure 53. Development of Front Range Reference Assumptions (three day period), High Renewables Case.

(a) Hourly electric net load in the Rocky Mountain Front Range

(b) Electrical output from gas generators in the Front Range

(c) Total natural gas consumption in the Front Range
4.6.4 QUALITATIVE REVIEW

The analysis above illustrates how high penetrations of wind generation may ultimately impact patterns of demand for natural gas in the Rocky Mountain region. While quantitative analysis of the gas system’s abilities to meet these variable demands is not included in this study, this study does note the steps undertaken by Xcel, in collaboration with CIG, to prepare its electric system for potential challenges at the gas-electric interface and to ensure electric reliability.

4.6.4.1 Portfolio Management of Gas Transportation Services

In order to provide reliable gas service to its gas-fired generators, Xcel actively manages a portfolio of transportation contracts with CIG to provide service to its gas generators. Xcel relies on a combination of firm transportation capacity, gas storage, and backup fuel to ensure that gas generators will have access to fuel when needed. Specifically, many of the electric generators operated by Xcel are located in Xcel’s “Natural Gas Delivery Core Area”—as indicated in Figure 50, the region between Cheyenne, WY and Denver, CO. Xcel’s portfolio of firm transportation contracts for delivery in this area, coupled with the capability of the numerous storage facilities located in the market area where gas can be injected and withdrawn with short or no notice, provides for a substantial degree of flexibility in the supply of gas to electric generators.  

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40 Additional detail on Xcel’s gas transportation contracting practices are described in the testimony of Curtis Dallinger and John T. Welch in support of Xcel’s 2011 Electric Resource Plan (Xcel 2012a, b & c).
When existing gas infrastructure is insufficient to meet the needs of new gas generators, Xcel’s resource planners recognize that expansions of natural gas infrastructure may be needed to provide reliable service to gas plants. In 2013, in response to growing gas loads across all sectors in the Front Range, CIG and Xcel jointly developed the High Plains Expansion pipeline to increase deliverability of gas to the region.

Xcel’s portfolio strategy to procuring transportation service ensures the existence of the capacity needed to serve its gas generators, but it does not guarantee that the capacity will be available in day-to-day operations. Due to differences in sequences and timing of scheduling decisions made by gas and electric system operators, the capacity contracted by Xcel for service of its gas generators may be allocated to other shippers. This may occur if Xcel does not nominate gas in the day-ahead timeframe, in which case the capacity held by Xcel could be allocated to shippers with secondary firm service.

To address this potential challenge, Xcel recently submitted a proposal for an enhancement of firm service in comments submitted to FERC’s ongoing gas-electric coordination docket.41 Xcel’s proposal would allow firm shippers the opportunity to reserve their contracted capacity at the commencement of the nominations and scheduling process by making a small capacity payment. The associated capacity would be allocated to the shipper holding the firm contract, regardless of whether the gas was needed in real-time operations. This adjustment would allow electric operators to ensure the availability of contracted pipeline capacity even as scheduling decisions in the electric sector

41 Xcel Energy, 2011.
are made in real-time to accommodate the variable output of intermittent
generators.

4.6.4.2 Gas Storage Wind Integration Costs

Other case studies in this report explore the impacts of daily imbalances on the
operations of natural gas pipeline systems; while comparable analysis is not
conducted in this case study, Xcel has published its own study characterizing the
impacts of the intermittency of wind generation on gas system operations. In
2011, Xcel evaluated the integration costs associated with a portfolio of 3,000
MW of wind generation—an amount similar in magnitude to the to the region’s
projected wind build-out under current policy goals; as part of this effort, Xcel
examined the impacts of inaccuracies in gas nominations resulting from errors
in wind forecasting.42 While the lens through which this impact is evaluated—
the costs imposed on electric ratepayers—does not directly reflect the impact of
intermittent renewables on gas system operations, the results of this study are
nonetheless instructive of the magnitude of the operational challenge that
results from gas nomination inaccuracies.

Xcel’s study of the wind integration costs associated with inaccuracies in gas
nominations are calculated under the assumption that Xcel would utilize gas
storage resources to provide balancing flexibility for the inaccuracies. Over- and
under-nominations change the amount of gas that is injected and withdrawn
from Xcel’s gas storage inventories. With a portfolio of 3,000 MW of wind
generation, Xcel calculated the wind integration cost of gas nomination

42 Xcel Energy, 2011.
inaccuracies to be $0.17/MWh. In comparison, the wind integration costs resulting from the impacts of intermittency on electric system operations were $3.92/MWh—more than twenty times larger; these results are summarized in Figure 54. These results indicate that while the uncertainty of wind generation does result in gas nomination errors, the costs of managing those errors in this geographic region are relatively small.

Figure 54. Results of Xcel 2011 Wind Integration Study (3,000 MW wind generation)

4.6.5 SUMMARY

The case study of the Front Range is summarized as follows:

+ Most of the gas generating capacity in the Front Range region is located in Xcel’s flexible “Natural Gas Delivery Core Area.”
Gas Core Delivery Area, which comprises an interconnected network of pipelines and storage fields along the Front Range, has substantial operating flexibility that allow Xcel to deliver gas to and shift supplies among the many gas plants located in the region.

+ **With higher penetrations of wind generation, demand for natural gas from electric generators will become increasingly variable.** The profiles of natural gas demand developed in this case study indicate the need for ramping from gas generators in response to changing output from wind generators. Of particular interest is the fact that despite the fact that variability clearly increases in the High Renewables Case—the large upward ramp in gas generation increases from 2 to 3 GW from the Base Case—the utilization of gas resources at peak is similar between the Base Case and the High Renewables Case.

+ **Electric system planners and operators in the Rocky Mountain region have already taken steps to ensure adequacy of gas infrastructure to meet evolving needs of electric generators.** Xcel maintains a portfolio of contracts for firm transportation and no-notice storage service with the goal of ensuring that its gas resources will have sufficient fuel security to meet peak needs in the winter. Xcel Energy is also an active participant in FERC’s gas-electric coordination docket, and recently proposed an enhancement to firm service that would allow it to ensure that it could reserve its firm capacity to meet needs of gas generators in real time.

+ **Wind integration modeling conducted by Xcel shows that wind forecast errors do introduce inaccuracies to gas nominations, but these costs are minor relative to other costs introduced by wind’s variability and uncertainty.** In its wind integration study, Xcel determined that the inaccuracies in daily gas nominations resulting from the forecast error of wind generation resulted in incremental costs resulting from the use of natural gas storage to balance the errors. The
cost calculated by Xcel ($0.17/MWh) was relatively small compared to other components of wind integration associated with the impact of intermittency and variability on electric system operations ($3.92/MWh).
5 Conclusions

5.1 Summary of Findings

The case study process used to investigate the implications of variable demands for natural gas in the power sector informs a number of general conclusions:

Under the conditions examined in this study, meeting the variable gas demands needed to integrate high penetrations renewables is technically feasible. The physical flexibility inherent in a pipeline system is a result of two factors: its tolerance for fluctuations in linepack and the availability of natural gas storage. Linepack can provide flexibility to meet variable loads by absorbing small imbalances in receipts and deliveries over short time scales. The availability of this flexibility is directly linked to the level of utilization: a pipeline that is fully utilized cannot tolerate any variation in linepack, while a system that is not fully utilized can operate at a range of different levels of linepack. Underground gas storage, where available, provides storage by allowing users to withdrawal gas at variable rates with limited notice to pipeline operators, which facilitates the balancing of variable deliveries with receipts and mitigates the need to use linepack to absorb variability. These two factors allow gas systems to provide physical flexibility that can support rapid changes in the electric sector as it maintains instantaneous balance between supply and demand despite the fact that natural gas moves at a relatively slow speed through natural gas pipelines.
The addition of renewable generation to an electric system reduces the overall level of gas demand while increasing its variability. While the increase in variability creates operating challenges, the reduction in natural gas demand provides the pipeline operator with greater ability to meet the variable demand, and the case study results indicate that the decrease in gas demand outweighs the impact of increased variability. The hydraulic modeling conducted indicates that the reduction in demand generally allows a pipeline system the flexibility to manage the increase in variability with existing physical tools (i.e. linepack and/or storage) even under high demand conditions, when flexibility is most likely to be constrained.

Imbalances between gas deliveries and receipts to gas systems can cause operational challenges. One of the fundamental premises of the regulatory model under which pipelines provide transportation service is that shippers will arrange for both the receipt and delivery of natural gas; ensuring a reasonable balance between the two is critical to reliable operations. Operational challenges may arise when imbalances between receipts and deliveries cause a system’s linepack to vary beyond its range of tolerance. A number of factors may contribute to such imbalances, including infrastructure contingencies, market forces, and errors in the scheduling and nominations processes. Under such circumstances, pipelines may take a number of steps—communicating directly with customers, imposing financial penalties, or ultimately, curtailing service to customers—in order to preserve service to others.

The intermittency and unpredictability of renewable generation may increase the frequency and magnitude of imbalances on pipeline systems. Pipeline operators rely primarily on nominations submitted by shippers to prepare and operate the system throughout the day. As the penetrations of unpredictable renewable resources increase, forecasting the amount of gas needed to serve gas generators at the
necessary time will become an increasing challenge, as electric system operators will have to account for not only the forecast errors associated with load but those of wind and solar as well. Efforts to revise the scheduling and nominations processes—already underway with the support of FERC and NAESB—to facilitate coordination between the gas and electric sectors may help to mitigate this potential challenge.

+ **Transportation services tailored to meeting variable demands will facilitate renewable integration.** With increases in the penetration of renewable resources, the variability and uncertainty of electric sector demands for natural gas will increase. Under such circumstances, transportation services that anticipate variable rates of delivery will allow gas systems to meet those loads. Already, no-notice transportation service paired with underground storage is an important contributor to the flexibility of a number of systems throughout the Western Interconnection; however, additional services such as the hourly firm transportation service offered by the El Paso Natural Gas pipeline could allow generators to purchase services more closely aligned with their needs and ultimately encourage efficient expansion of pipeline infrastructure.

+ **Gas generation with firm contracts may not receive transportation service if it does not nominate appropriate volumes to match its needs.** In Phase 1, this study found that gas generation that does not contract for firm transportation service may be subject to interruption during times of high gas demand. The investigation in Phase 2 shows that holding a firm contract does not provide a guarantee of service. Pipeline systems are limited in their abilities to absorb unscheduled demands; failure by the firm shipper to nominate appropriate volumes hinders the ability of the system to meet demands. Further, due to the intricacies of the nomination and scheduling processes, a firm shipper’s
capacity may be allocated to others if it is not scheduled in the first nomination cycle.

+ **Gas systems in the Western Interconnection depend on their neighbors to meet scheduled obligations to ensure reliable operations.** Phase 1 concluded that *the regions of the Western Interconnection are highly interdependent in their reliance on natural gas transportation and generation infrastructure*. The case study approach used in Phase 2 of this study examines a number of systems independently, making assumptions about the availability of gas supply at interconnections to reflect the fact that pipelines generally plan (and operate) to meet delivery obligations to neighboring systems. At the same time, Phase 1 found that contingency events on a single pipeline could have substantial impacts on neighboring systems. While Phase 2 did not specifically investigate contingencies and their potential impacts on the broader system, the results of Phase 1 indicate that such events could create operational challenges.

### 5.2 Next Steps

The conclusions drawn by this study suggest a number of valuable next steps:

+ **Investigate impacts of renewable forecast error on gas nominations and scheduling.** This study identifies renewable forecast error as one factor that could contribute to imbalances between scheduled and actual deliveries to electric generators. However, detailed analysis of the impact of renewable forecast error on the scheduling and nominations processes is beyond the scope of this study, which focuses first on analysis of the physical characteristics of pipeline systems. The impact of renewable forecast error on the operations of gas systems will
vary by jurisdiction, depending on both the composition of the renewable portfolio and the characteristics of the fleet used to balance it. Efforts to quantify this impact, such as the 2011 Wind Integration Study undertaken by Xcel Energy, provide valuable insight into the impacts of renewable generation on gas systems.

Conduct detailed regional and local studies of gas infrastructure under higher renewable penetrations. The study concludes that it is physically feasible for pipeline systems to accommodate swings in gas generation caused by variable renewables even under the most constrained conditions, i.e., during times of high throughput. However, further study of additional operating conditions could be instructive to rule out the possibility that problems could occur under conditions that have not historically been challenging for pipeline operations. Moreover, this study does not address the investment that may be required to ensure that any specific segment of a pipeline system does not become constrained. As electric sector ramping needs continue to increase due to higher penetrations of renewables, and fast-ramping gas generators continue to be developed, pipeline companies will need to conduct detailed studies of infrastructure needs in specific areas to ensure continued reliable natural gas service.

Continue to monitor regional balances between demand for natural gas and available capacity of pipeline systems. One of the key findings of the analysis conducted in this study is the tradeoff on gas pipelines between throughput capability and operational flexibility. Understanding where pipelines have available capacity could help efficient siting of new generation investments to extract the maximum flexibility from existing gas infrastructure. Additionally, should changes in the electric sector (e.g. coal replacement with natural gas) or other developments (e.g. increased exports to Mexico, development of LNG export terminals) result in increased utilization of pipeline systems,
electric sector planners should recognize that the flexibility of pipeline systems may become more constrained. Continuing to monitor the balance between natural gas demand and the capability of pipeline systems will help electric and gas system planners harvest the flexibility of existing infrastructure and identify needs for expansion.

+ **Continue to explore refinements to the nominations and scheduling process to facilitate gas system operations.** One of the important results of the analysis conducted in this study is the affirmation of the importance of balancing in a pipeline’s day-to-day operations. In FERC’s ongoing gas-electric coordination docket, stakeholders have identified a number of ways in which the current conventions for nominations and scheduling can impede the ability of gas generators to schedule the necessary volumes to match their demands. Adjustments to these conventions could mitigate some of these challenges, reducing existing friction between the two industries. In this regard, FERC’s NOPR is an important step in the effort to harmonize scheduling processes across the two industries; continuation of these ongoing efforts will facilitate gas-electric coordination.

+ **Support ongoing efforts to establish reliable communications between gas and electric system operators.** Historically, many of the operating decisions in both the gas and electric sectors have been made in advance of the operating day. However, with increasing penetrations of variable energy resources, whose output can change dramatically and unpredictably, operational conditions in the electric sector can change rapidly. Establishing channels and protocols for reliable and timely communications will help operators in each industry prepare for and react to changes and conditions in each system that will accompany increasing penetrations of variable energy resources in the electric sector. For example, gas system operators would benefit from knowledge of current and forecasted output of variable energy...
resources, allowing them to position linepack in preparation for changes in electric system conditions; similarly, electric system operators would benefit from information on constraints on pipeline systems, allowing them to schedule alternative resources for operations as necessary.

+ **Explore transportation service options that might facilitate efficient and reliable integration of renewables.** As the operations of gas generators become increasingly variable at higher penetrations of renewables, the necessary deliveries of gas will become less and less ratable. Hourly firm services such as those offered by the El Paso Natural Gas Co. may offer opportunities to allow gas generators to arrange for reliable transportation at a cost that better reflects the nature of the service that they require, mitigating the costs of renewable integration to electric ratepayers. A “one-size-fits-all” solution is unlikely, as the types of services that make sense will vary based on the characteristics of gas pipeline and storage infrastructure and the operational needs of gas generators. Creatively structured services could allow generators to secure the fuel they need and also provide the appropriate investment signal to pipelines when necessary to trigger efficient expansion of gas infrastructure.

+ **Study renewable integration challenges under regional contingency events.** While these events are rare and are generally caused by extreme weather and supply events that are unrelated to renewable electric generation, there may be instances in which their effects are precipitated or magnified by variable renewables. Further studies may shed light on these circumstances.
6 Glossary

**Backbone system:** a term used by California’s intrastate gas pipelines to describe a network of larger diameter pipelines that transport large volumes of gas from points of receipt at or near the California border to large end users and local transmission systems (see also ‘Local transmission’).

**Backup fuel:** a natural gas power plant that has the capability to switch from generating with natural gas to an alternative fuel (e.g. oil).

**Balancing authority:** an entity responsible for the operation of an electric power system through the balancing of supply and demand to meet NERC reliability standards.

**Capacity release:** a mechanism by which firm shippers voluntarily release all or part of their capacity to replacement shippers. This is done through a secondary market where the capacity is offered at any price.

**Combined cycle (CCGT):** see ‘Gas-fired generators.’

**Combined Heat and Power (or cogeneration):** a natural gas facility that can simultaneously generate electricity and useful heat.

**Combustion turbine (CT):** see ‘Gas-fired generators.’

**Core:** A designation for a set of customers in California that receive natural gas delivery service comparable to “firm service” from LDCs in other states.
**Delivery:** a volume of gas that is removed from a pipeline system, either for the purpose of direct use or transfer to another system.

**Design day:** a design criterion used by LDCs that represents the coldest day over some historical period (often several decades) used to determine the highest expected demand for natural gas among end uses during extreme cold weather.

**Electric day:** the daily period over which electric generators are scheduled and dispatched to serve load; the electric day generally begins at midnight local time.

**Electronic bulletin boards:** A computerized interface through which pipelines display and impart information to shippers.

**Emergency Flow Order (EFO):** a mechanism invoked by pipeline operators if deliveries to end-use customers are threatened due to supply and/or capacity shortages. If shippers do not bring receipts and deliveries into balance, they may face hefty fines and/or supply curtailment.

**End use consumption:** Gas consumption associated with the direct use of natural gas (e.g. residential, commercial, and industrial)—in contrast to gas consumption for power generation.

**Firm transportation:** Natural gas transportation service that is intended to be available at all times. Under a firm transportation service agreement, a shipper agrees to pay a pipeline rates based on its full cost of service and in return is entitled to the use of that capacity at its discretion to transport a specified daily volume of gas between a primary receipt point and a delivery point.

  + **Primary firm:** capacity associated with a firm contract in which gas is nominated at the primary receipt and delivery points.
  + **Secondary firm:** capacity associated with a firm contract in which the receipt and/or delivery points are modified in the nomination; scheduled after primary firm nominations.
**Force majeure:** an extreme event whose impacts on parties are beyond their control (e.g. infrastructure contingency); such events release pipelines from their obligation to meet the demands of their firm shippers.

**Gas day:** the daily period over which gas flows are scheduled; the gas day is standardized across the North American continent by NAESB and begins at 7:00AM.

**Gas-fired generators:** Electric generators that use natural gas as the primary fuel for the production of electricity:

- **Combined cycle:** a gas generating technology that uses a combination of combustion turbines and steam turbines to achieve high efficiencies.
- **Combustion turbine:** a gas generating technology in which the combustion of natural gas drives a turbine to produce electricity; generally these plants have relatively low efficiencies and are used for peaking purposes.
- **Reciprocating engine:** a small, modular gas generation technology with quick start-up and large ramping capabilities.
- **Steam turbine:** a gas generating technology in which the combustion of natural gas is used to produce steam to drive a turbine.

**Hydraulic model:** a pressure-based model used in the natural gas industry to simulate the operations of a pipeline system. Hydraulic models may be used to analyze steady-state or transient systems:

- **Steady state:** a system in which conditions are not changing through time.
- **Transient:** a dynamic system in which conditions are changing over time.

**Imbalance:** a situation where pipeline receipts and deliveries are not equal.

**Independent system operator (ISO):** an entity responsible for coordinating, controlling, and monitoring an electrical power system. ISOs often encompass
multiple utilities and operate to minimize costs while ensuring electric reliability.

**Interruptible transportation:** natural gas transportation service offered by pipelines to shippers provided there is excess or unreserved capacity. Interruptible service is generally offered at a discount to firm service given its unreliable nature. Under FERC regulation, the cost of interruptible service will vary between the full cost of service and the variable cost of transporting the gas.

**Lateral:** a segment of pipeline that diverts from a main transportation line to serve a particular customer or entity.

**Linepack:** the total inventory of gas stored within a pipeline, through which pipelines can allow some variation in its inventory to accommodate small differences between receipts and deliveries.

- **Packing:** instantaneous receipts exceed instantaneous deliveries and linepack is increasing
- **Drafting:** instantaneous deliveries exceed instantaneous receipts and linepack is decreasing

**Local distribution company (LDC):** an entity that is responsible for the direct distribution of natural gas to customers inside a citygate. Most customers served by LDCs are residential and commercial users, but LDCs also provide service to industrial users and electric generators.

**Local transmission:** a term used by California’s intrastate gas pipelines to describe a network of smaller diameter pipelines that receive gas from a backbone system and distribute it to customers for consumption (see also ‘Backbone system’)

**Loss of load probability:** the probability in a given time period that electric demand will exceed available supply.
Mainline: a large segment of pipeline responsible for the transportation and throughput of large volumes of natural gas across long distances

Marketer: a middleman in the gas transportation business that provides liquidity to the market by both purchasing from producers and selling to end-users

Maximum allowable operating pressure (MAOP): the maximum pressure under which a pipeline can operate while preserving the integrity and safety of the pipeline.

Minimum Operating Pressure (MinOP): the minimum pressure at which a pipeline can operate before the risk of violating delivery pressure obligations.

Merchant generator: an electric generator operated by an independent power producer that supplies power subject to prevailing economic conditions in the electric industry.

Nomination: a schedule for the receipt and delivery of a certain volume of gas at specified points on a gas system submitted by a shipper to facilitate gas scheduling. Nominations are generally submitted in four sequential cycles standardized by NAESB:

- **Timely:** the first (and most liquid) cycle occurs in the day ahead of gas flow;
- **Evening:** the second cycle occurs in the evening of the day ahead of gas flow;
- **Intraday 1:** the third cycle occurs at the beginning of the gas day; and
- **Intraday 2:** the fourth cycle occurs in the middle of the gas day.

No-bump rule: a gas scheduling convention that establishes the priority with which shippers receive service in the nomination and scheduling process: in the first three standard NAESB cycles, shippers with firm transportation have priority over interruptible shippers—even if interruptible gas flows were scheduled in a prior cycle; however, under current rules, in the Intraday 2 cycle,
scheduled interruptible flows cannot be “bumped” by nominations for firm transportation.

**No-notice transportation service:** pipeline transportation service available to shippers on a limited notice basis, usually associated with withdrawals from storage facilities.

**Non-core:** a designation for a set of customers in California that receive lower level priority service than core customers

**Once-through cooling:** power plants that intake water for cooling to increase thermal efficiency, often causing disruptions to local ecosystems and/or straining limited water supplies

**Operating reserves:** capacity held by an electric system operator to maintain balance between load and generation within each hour (e.g. regulation and load-following).

**Operational Flow Order (OFO):** a mechanism used by pipeline operators to protect the integrity of the system during times of stress that imposes financial penalties on shippers who do not achieve a specified balance of receipts and deliveries (see also ‘Strained Operating Condition’)

**Planning reserve margin:** the reserve generating capacity that an electrical load serving entity will procure beyond peak load

**Production simulation:** a class of models that take a given electric infrastructure (real or hypothetical) and set of electric loads and dispatch the infrastructure to meet the loads in a least-cost manner given all relevant constraints

**Ratable:** gas flows that are constant throughout the day (e.g. a pipeline that receives a quantity of gas ratably throughout the day receives gas at a constant rate)

**Receipt:** a volume of gas that is brought on to a pipeline system by a shipper.
Reciprocating engine: see ‘Gas-fired generators.’

Renewables portfolio standard (RPS): a statutory mandate of electric energy that must be served by renewable energy resources.

Secondary market: a market through which firm shippers can release excess capacity to replacement shippers.

Shipper: any entity that transports natural gas on a pipeline: LDCs, industrial customers, marketers, etc.

Spot market: a financial market where energy or other commodities are traded for immediate delivery.

Steam turbine: see ‘Gas-fired generators.’

Strained Operating Conditions (SOCs): a mechanism used by pipeline operators to protect the integrity of the system during times of stress that imposes financial penalties on shippers who do not achieve a specified balance of receipts and deliveries (see also ‘Operational Flow Order’)

Transmission Expansion Planning Policy Committee (TEPPC): a group responsible for the long term analysis of transmission projects necessary for grid reliability in the WECC. TEPPC develops and maintains production simulation databases of the WECC on two-year cycles for the purposes of these studies; this study uses TEPPC’s 2022 Common Case, developed in 2012, to analyze gas consumption in the electric sector.

Variable energy resources: electric generating resources that cannot be dispatched by system operators due to the variable and uncertain nature of their output (e.g. wind and solar generation).

Western Electricity Coordinating Council (WECC): one of eight NERC regions that is responsible for the establishment, monitoring, and enforcement of
electric reliability standards. The WECC encompasses 11 western states and parts of Canada and Mexico.
7 References


