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

Phase 2 Report
Executive Summary

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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 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 benefitted 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 Corporation
+ 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.
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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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.

Pipeline geospatial data obtained from Platts; power plant locations from EIA

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