JISEA Joint Institute for Strategic Energy Analysis

Electric Power Grid and Natural Gas Network Operations and Coordination

Omar J. Guerra, Brian Sergi, Bri-Mathias Hodge
National Renewable Energy Laboratory

Michael Craig
University of Michigan

Kwabena Addo Pambour, Rostand Tresor Sopgwi, Carlo Brancucci
encoord

Technical Report
NREL/TP-6A50-77096
September 2020

Contract No. DE-AC36-08GO28308

NREL Transforming ENERGY · COLORADO SCHOOL OF MINES EARTH • ENERGY • ENVIRONMENT · COLORADO STATE UNIVERSITY · Massachusetts Institute of Technology · Stanford University · University of Colorado Boulder

JISEA Joint Institute for Strategic Energy Analysis

Electric Power Grid and Natural Gas Network Operations and Coordination

Omar J. Guerra, Brian Sergi, Bri-Mathias Hodge
National Renewable Energy Laboratory

Michael Craig
University of Michigan

Kwabena Addo Pambour, Rostand Tresor Sopgwi, Carlo Brancucci
encoord

The Joint Institute for Strategic Energy Analysis
15013 Denver West Parkway
Golden, CO 80401
www.jisea.org

Technical Report
NREL/TP-6A50-77096
September 2020

Contract No. DE-AC36-08GO28308

NOTICE

This work was authored in part by the National Renewable Energy Laboratory, operated by Alliance for Sustainable Energy, LLC, for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. Funding provided by the Joint Institute for Strategic Analysis and sponsors including Kinder Morgan, Midcontinent Independent System Operator, Hewlett Foundation, Environmental Defense Fund, American Gas Association, and American Electric Power. The views expressed herein do not necessarily represent the views of the DOE, the U.S. Government, or sponsors.

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

U.S. Department of Energy (DOE) reports produced after 1991 and a growing number of pre-1991 documents are available free via www.OSTI.gov.

Cover Photos: (left to right) iStock 1032683612, iStock 531546832, NREL 53053, iStock 515519531, NREL 15727, iStock 1166645867

NREL prints on paper that contains recycled content.

Acknowledgments

This research was supervised and coordinated by the Joint Institute for Strategic Energy Analysis, ensuring it met institutional standards for objectivity, evidence, and responsiveness to the study scope. We would like to thank the following consortium of organizations for their funding and support: Kinder Morgan, Midcontinent Independent System Operator, Hewlett Foundation, Environmental Defense Fund, American Gas Association, and American Electric Power. Support does not imply endorsement; the analysis and results reported here are the sole responsibility of the authors.

For insightful comments and guidance, we thank Sule Amadu, Jim Cordaro, George H. Wayne Jr., Natalie Karas, Kristina Mohlin, Jordan Bakke, Rick Murphy, Sue Tierney, Matt Usher, and Xin Fang. This work was authored in part by the National Renewable Energy Laboratory, operated by Alliance for Sustainable Energy, LLC, for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. The views expressed in the article do not necessarily represent the views of the DOE or the U.S. Government.

List of Acronyms

BAU	Business as Usual
CBI	Cross-border import
CGS	City gate stations
DA	Day-ahead
DC	Direct current
DOE	Department of Energy
Dth	Dekatherm (equal to 1 mmBtu)
EC	Economic dispatch
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
GCV	Gross calorific value
GFPP	Natural gas-fired power plants
GNS	Gas not supplied
ID	Intra-day
IEEE	Institute of Electrical and Electronics Engineers
IID	Total number of coordinated iterations
ISO	Independent system operator
JISEA	Joint Institute for Strategic Energy Analysis
LDC	Local distribution companies
LNG	Liquefied natural gas
MILP	Mixed-integer linear programming
mmBtu	million British Thermal Units
NMAE	Normalized mean absolute error
NREL	National Renewable Energy Laboratory
NRMSE	Normalized root mean square error
NSRDB	National Solar Radiation Database
OPF	Optimal power flow
PF	Power flow
RT	Real-time
RTO	Regional transmission organizations
SDGE	San Diego Gas and Electric
TSO	Transmission system operators
UC	Unit commitment
UCED	Unit commitment and economic dispatch
UGS	Underground gas storage
VO&M	Variable operations and maintenance

Executive Summary

The operations of electricity and natural gas systems in the United States are increasingly interdependent, a result of a growing number of installations of gas-fired generators, the widespread availability of low-cost natural gas, and rising penetrations of variable renewable energy sources. This interdependency suggests the need for closer communication and coordination among gas and power system operators in order to improve the efficiency, reliability, and resilience of both energy systems.

In this report, we present findings from three studies[1] related to the coordination of natural gas and electricity system operations. We first propose and demonstrate a modeling platform for examining the interdependence of natural gas and electricity networks based on a direct current unit-commitment and economic dispatch model for the power system and a transient hydraulic gas model for the gas system. We use this platform to analyze the value of day-ahead coordination of power and natural gas network operations and to show the importance of considering gas pipeline limitations when analyzing power systems operation with high penetration of gas generators and variable renewable energy sources. **Our results indicate that day-ahead coordination can contribute to a reduction in curtailed gas in high-stress periods (such as those with large ramps in gas offtakes) and a reduction in energy consumption of gas compressor stations**, primarily from reducing demands for compressors to quickly increase pressure**.** In high renewable systems that rely on gas ramping to balance variability in wind and solar, such improvements are likely to enhance the overall reliability of the power system.

In the second study, we utilize our modeling platform to consider the U.S. Federal Energy Regulatory Commission (FERC) Order 809, issued in 2015 to improve day-ahead and intraday coordination of power and gas systems. Given the lack of research on intraday coordination and FERC's recent action, we quantify the value of improved intraday coordination between gas and electric power systems. To do so, we co-simulate coordinated day-ahead, intraday, and real-time operations of an interconnected power and natural gas test system using the platform introduced in Study 1. **We find that intraday coordination reduces total power system production costs and enhances natural gas deliverability, yielding cost and reliability benefits.** A sensitivity analysis indicates improved intraday variable renewable energy forecasts and **higher variable renewable energy capacities increase intraday coordination benefits for gas network congestion,** given the ramping requirements of gas power plants to balance out variability in renewables**.** The results of Study 2 indicate that FERC Order 809 and other policies aimed at enhancing intraday coordination between power and gas systems will likely yield cost and reliability benefits.

---

[1] Development of modeling platform for coordination of natural and electricity systems: Pambour K, Sopgwi R, Hodge B-M, Brancucci C. [The Value of Day-Ahead Coordination of Power and Natural Gas Network Operations](). Energies 2018;11:1628.

Assessment of the value of intraday coordination of natural gas and electricity systems: Craig, M., Guerra, O. J., Brancucci, C., Pambour, K. A., & Hodge, B.-M. (2020). [Valuing intra-day coordination of electric power and natural gas system operations](). Energy Policy, 141(April), 111470. https://doi.org/10.1016/j.enpol.2020.111470

Evaluation of market-based coordination of electricity and natural gas system operations: Guerra, O. J., Sergi, B., Craig, M., Pambour, K. A., Brancucci, C., & Hodge, B.-M. (2020). Coordinated Operation of Electricity and Natural Gas Systems from Day-ahead to Real-time Markets, Journal of Cleaner Production (under review), Jul 17, 2020.

Finally, in the third study we expand our modeling platform to focus on market-based coordination of electricity and natural gas system operations for a real system, namely a subset of the power and gas networks in the Front Range region of Colorado, a system where the gas generators have firm transportation contracts (i.e. these generators are not competing for interruptible capacity with other regional demand). We use real system data to evaluate the benefits of coordinated operations under different conditions, including different levels of renewable penetration and the use of time-variant, shaped flow nominations. **Our results indicate that coordination generally improves total gas deliverability, which reduces out-of-merit order dispatch in the electricity system, and that such coordination can be useful under a range of operating conditions and renewable penetrations.** Moreover, shaped flows stand to be a valuable tool for reducing gas demand that cannot be satisfied by current pipeline capacity, particularly in systems with higher penetrations of wind and solar energy sources. Together, these three studies demonstrate a pathway for integrated gas and electricity grid modeling and for studying the benefits of coordinated operations of these increasingly interdependent energy systems.

Table of Contents

List of Figures

List of Tables

1 Background: Interdependencies in Power and Natural Gas Networks

The availability of low-cost natural gas—largely a product of the shale gas revolution—has driven many electric power systems to become more reliant on natural gas. This trend has been amplified by an increasing penetration of variable renewable energy sources, as natural gas-fired power plants (GFPPs) are frequently used to offset the inherent uncertainty and variability associated with wind and solar power generation. U.S. natural gas deliveries to electric power consumers more than doubled between 2000 and 2018, with the power sector growing from 22.3% of total natural gas demand to a share of 35.5% [1,2]. Correspondingly, the share of power generation from natural gas-fired power plants has increased from 14.2% to 31.5% over the same period, while the share of generation from renewable energy—driven mostly by wind and solar power—also increased from 8.8% to 17.4% [1,2]. Although forecasts are inherently uncertain, these trends are expected to persist in the future, as shown in Figure 1.

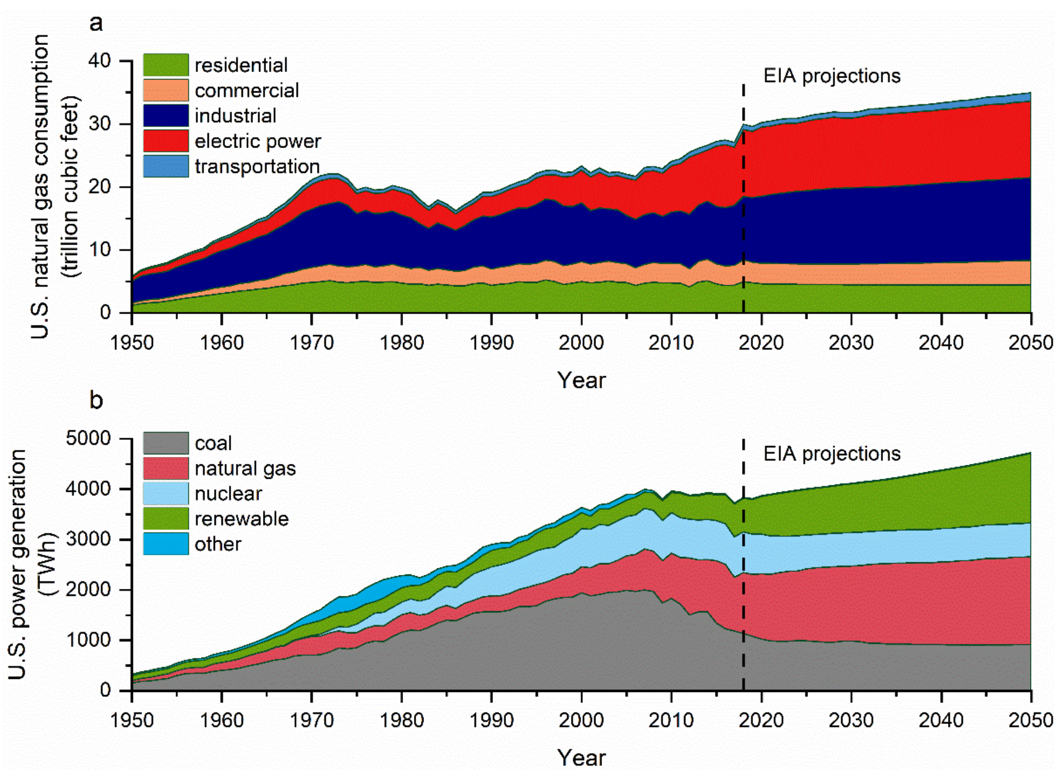


Figure 1. Historical and projected data for natural gas consumption and power generation in the United States [1,2]: (a) Natural gas consumption by sector in United States and (b) Power generation by fuel or technology.

The most significant interconnections between both energy systems exists at GFPPs and electric-driven compressors in gas compressor stations. GFPPs represent both generation entities in the power system and large consumers in the natural gas network. Gas generators require a minimum delivery pressure for operation, which, if not attained, can lead to curtailment of gas offtakes from the pipeline system, a reduction in the electrical output, and in the worst case to a complete shutdown of the GFPP [3,4]. Electric-driven compressors, in contrast, represent electric loads in the power system to propel compressors in gas compressor stations in order to increase the gas pressure for pipeline transportation. In this report, we focus mainly on the impact of GFPPs on the operation of these interdependent energy systems.

The increasing reliance on natural gas for GFPP operation poses a number of coordination and reliability challenges. In regions where gas-fired generators rely on non-firm pipeline capacity for fuel, fuel deliverability constraints might arise during periods of high gas consumption by non-generator consumers who have contracted for firm capacity (e.g., by city gate stations during periods of extreme cold temperature) [5]. Such events are most likely under severe weather conditions, when both electricity demand and natural gas consumption for heating tend to increase; historically, events like the Polar Vortex have led to gas power plants with interruptible fuel contracts being unable to obtain gas to meet their generation schedules [6–8]. Furthermore, the coincidence of gas demand for power generation and home heating may also be amplified by shifting trends in load shapes toward winter morning peaks in certain regions of the U.S., suggesting that such constraints may not be limited to only extreme weather events in the future.

Another coordination challenge relates to the increase adoption of variable renewable energy generation. The times during which GFPPs extract natural gas from the gas network and the extent to which they do so will depend strongly on their generation schedule. In other words, higher penetrations of variable renewable energy sources—such as wind and solar photovoltaic (PV) power—in the power system will not only impact how GFPPs interact within the power system, but they will also impact how they interact with the natural gas pipeline network. For instance, a large wind or solar PV power forecast error could be the cause of a large change in gas demand to be handled within the natural gas network operational and flexibility boundaries. Growing shares of variable renewable generation require greater system flexibility and ramping, which will likely lead to GFPPs experiencing larger and more frequent upward and downward ramps, as well as starting up and shutting down more often. Such requirements place strains on gas delivery infrastructure, such as pipelines and compressors, and deviate from the traditional way that natural gas networks have operated in serving the power sector.

Several options exist to mitigate fuel deliverability concerns. For instance, contract structures can be modified or different contracts can be combined to provide gas-fired generators with more firm or flexible natural gas delivery [9–11]. To address long term fuel deliverability needs, additional pipeline capacity could be built. Gas pipeline operators also possess a wide range of tools for meeting firm transportation contracts and natural gas demand—such as firm gas storage, hourly pipeline service products, firm delivery contracts, and additional pipeline infrastructure—even as those offtakes are subject to hourly demand variation.

One of these tools, enhanced coordination between power and gas systems, is also an alternative for providing flexibility in natural gas networks that does not require significant new infrastructure developments, could be implemented in the near-term, and has been the focus of U.S. federal rulemaking efforts. Improved coordination can take many forms, ranging in difficulty of implementation from improved informational exchange by aligning gas and electricity markets to fully co-optimized operations [11–13]. Benefits of coordination can include reduced consumer costs through reduced utilization of out-of-merit generators and increased grid reliability through reduced redispatch needs.

Traditionally, gas and power transmission systems have been planned and operated independently with little coordination between them because of the relatively separate nature and weak coupling of the two systems. The lack of a strong coupling between these two sectors can be attributed to a number of historical, regulatory, and legal factors. For example, there was federal statutory restrictions on the use of natural gas for electricity generation in the U.S. until 1987. Additionally, the two sectors evolved distinct business models—with the electricity sector oriented around spreading costs across all users while the gas sector traditionally investing in projects via bilateral transactions—in part due to operational, legal, and regulatory requirements related to permitting on infrastructure and cost allocation, among other things. However, the growing interdependency of these energy vectors suggests the need for models and tools to study how this trend may impact the operation of both systems, and how to improve the coordination between gas and power transmission system operators (TSOs) to increase operational efficiency and system reliability.

The coordination of natural gas and power sector networks can be studied at two distinct levels of decision-making, namely planning and operations. At the planning level, the objective is to optimize the location, capacity, and scheduling of investment decisions associated with generation or production, transmission, and storage assets in an integrated system. Previous research has explored co-planning of electric power and natural gas systems based on deterministic approaches (e.g., bi-level programming [14] and mixed integer linear [15] and nonlinear [16–18] programming). Additionally, stochastic [19] and robust [20] optimization approaches have been proposed to address the uncertainty presented in this type of planning problem, such as uncertainties in gas demand, electricity demand, and natural gas prices.

At the operational level, the objective is to improve reliability and minimize the operational costs associated with natural gas and electricity supply and natural gas supply and transportation contracts, while also minimizing load shedding or unserved natural gas [11,21–25]. Operational coordination can be addressed using either central-planning or market-based approaches. With central-planning—the approach most researched to date—the operation of the two systems is optimized simultaneously. This includes approaches using deterministic optimal power flow models coupled with steady state models of natural gas systems [26–28], deterministic integrated unit commitment and/or economic dispatch formulations based on steady state [29–31] or dynamic [22,32,33] gas models, as well as stochastic [34,35], robust [36], and interval [37,38] optimization models that address the uncertainty associated with electrical load, renewable power forecast, and outages of generation and transmission assets.

By contrast, in market-based approaches the two systems are optimized or simulated separately, with coordination occurring via the exchange of information such as prices, gas demand from generators, and gas availability from the gas network. This coordination can occur at a range of timescales—including day-ahead (DA), intra-day (ID), and real time (RT) energy markets—which evolve as uncertainty is increasingly reduced. Some of the proposed market-based approaches are based on deterministic unit commitment and/or economic dispatch formulations using steady state [39] or dynamic [40,41] gas models. Market-based approaches based on stochastic unit commitment formulations and steady state (or simplified versions of the dynamic state) gas models have been proposed to deal with uncertainty in variable renewable power generation [42,43]. Although steady state gas models can be appropriate for long-term planning [44,45], these models do not capture the potential use of and dynamics of linepack storage where applicable and thus may underestimate operational flexibility of the gas system [46,47]. Accounting for this behavior when studying the operational coordination of electric power and natural gas systems requires dynamic gas models [21,22,32]. However, dynamic gas models involve partial differential equations, complex boundary conditions, and nonlinear terms that can result in computational tractability issues for complex systems [48,49].

Although a central planning perspective offers the prospect of more optimized coordination between electric power and gas operations, currently electric power and gas markets are cleared separately and interact with limited information exchange. This makes a market-based approach perspective more realistic for capturing the operational coordination of today's electric power and natural gas systems [41,43]. Natural gas-fired power plants can purchase their fuel based on contracts (long-term or short-term) or the spot gas market, which involve uncertainties associated with gas prices and availability. One current challenge with executing market coordination is that the scheduling operations of electricity market and gas nomination cycles are currently not aligned[2][50]. Moreover, while an electric market may have between 24 and 288 "prices" for a day, for the most part the gas market has only one price for a given day. In 2015 FERC proposed Order 809 to address the issue of operational timing by creating an additional ID gas nomination cycle and shifting gas nomination cycles to better match the timing of power system markets [13].

An additional issue is that pipelines can require natural gas generators to submit a steady, nonvarying quantity of gas offtakes for each hour over the course of a day. This nomination thus represents 1/24th of daily scheduled quantities, regardless of when the generator anticipates needing the gas. This steady, nonvarying quantity of hourly gas offtakes is known as a "ratable" flow. Using ratable flows may discourage gas generators from flexible operations, as they cannot be guaranteed gas delivery above their ratable flow level and the pipeline may not have available space to hold gas not taken when generation is below that which would result from a ratable burn. In both situations, the gas generator will be subject to risk in the spot gas market. In contrast, moving to time-variant gas nominations and associated scheduling ("shaped flow") at the DA and ID market levels has been proposed as a means of improving gas and power sector coordination [51]. Although some generators and gas shippers may indeed prefer ratable flows based on the market conditions they face, providing the ability for generators to submit shaped flow nominations when they expect to ramp significantly may be a valuable option to some natural gas customers and to pipeline operators.

Given the current state of research in coordination of power system and gas networks, the goals of this study are to:

- Develop a modeling platform and a combined power–gas test system that can be used to test and benchmark different methods for addressing the simulation of interdependent gas and electricity systems,

[2] In addition to the scheduling cycles not being aligned, the economic "days" used by each sector are not the same: electric days are midnight to midnight in their respective time zones while gas is 9:00 AM Central time to 8:59 AM Central time in all time zones [77].

- Show the importance of considering the restrictions imposed by gas transmission networks when operating a large number of gas-fired generators in the electric power system,
- Demonstrate the importance of coordination between gas and power TSOs to improve the efficiency and reliability of these interdependent energy systems,
- Test whether the inclusion of intraday coordination can provide additional benefits to both gas and power sector operations,
- Evaluate the proposed modeling platform on a case study of real system data, testing the benefits of coordination for different penetrations of renewable energy; and
- Explore the potential benefits of having natural gas nominations move from being time-invariant (ratable flow) over the course of a day to time-dependent (shaped flow).

This following chapters present the methods and results from three studies related to modeling of coordination between power system and natural gas operations. Study 1 (Section 2) proposes a new modeling framework for coordination between a steady-state, direct current (DC) unit commitment and economic dispatch power systems model and a transient natural gas model, the latter of which is needed to capture important dynamics in gas network operations. This modeling framework is deployed on test system to evaluate the potential benefits of coordination between the two energy systems at the day-ahead levels.

In Study 2 (Section 3), we expand on the modeling architecture built in the first section to evaluate how the inclusion of intraday coordination might benefit system operations, similar to those proposed by FERC Order 809. Finally, in Study 3 (Section 4) we extend our modeling platform to real system data from Colorado power and gas grids in order to evaluate how coordination might impact operations. In addition, we explore the impact of coordination at different levels of renewable penetration and under scenarios in which natural gas nominations move from being time-invariant (ratable flow) to time-dependent (shaped flow).

Although this work explores these questions by drawing on data from real power and gas networks and by using commercial-grade software to model these systems, it does not capture all of the potential infrastructure and market products that gas network operators might use to serve demand and interact with power system operators. For example, gas network operators can employ firm gas storage, hourly pipeline service products, firm delivery contracts, and additional pipeline infrastructure to meet firm transportation contracts and natural gas demand in the face of variability. Although hourly variations in gas demand have historically been fairly predictable, the increasing use of natural gas for electricity generation couple with higher amounts of variable generating resources is likely to introduce additional variation and complexity. This work establishes a framework for evaluating one of the tools available to gas and power system operators—increased coordination—that can be used to address variability, and future studies should explore how additional tools or investments might assist gas operators in managing fluctuations in demand.

2 Study 1: Development of a Coordination Platform

2.1 Introduction

We introduce a coordination platform that consists of a steady-state DC unit commitment and economic dispatch model to simulate bulk power system operations and a transient hydraulic model to simulate the operation of bulk natural gas pipeline networks. Here, a steady-state electricity model combined with a transient natural gas model is appropriate because the dynamics of the electricity system are orders of magnitude faster than the dynamics of the natural gas system, and our focus is on natural gas system dynamics. The system models are implemented in two separate simulation environments, namely PLEXOS [52]—a production cost modeling tool for electric power systems—and Scenario Analysis Interface for Energy Systems (SAInt) [53–57]—an energy systems integration tool that includes a standalone steady-state and transient hydraulic gas simulator. The data exchange between the simulations is conducted by an interface that maps the power generation of gas generators in the power system with the corresponding fuel offtake points in the gas system. The information exchanged between the simulation environments includes the following:

- Day-ahead and real-time fuel offtakes of gas-fired generators in the electric power system
- Fuel offtake constraints imposed by the gas network system on the power system that are due to pressure restrictions in the gas system.

2.2 Methods

Electric transmission networks in the United States are managed by vertically integrated utilities and Independent System Operators (ISOs)/Regional Transmission Organizations (RTOs) depending on the region. These entities are responsible for clearing the regional electricity market and for scheduling the operation of power system generators to balance power system loads. In most U.S. electricity markets, the commitment and dispatch of generators are scheduled in two steps, namely, the DA scheduling and the RT balancing. The first step involves clearing the DA market eight to twelve hours before the operating day, using a unit commitment (UC) model to determine when and which generation units will be operated during the operating day and the scheduled generation of these committed units. This is done considering their operational costs and constraints, the projected power system loads and reserve requirements. The RT, on the other hand, involves clearing the real-time intraday market by solving a real-time UC and ED model typically every 5–15 min.

Gas transport systems, in contrast, are managed by gas transmission companies, which are responsible for ensuring reliable and economic operation of the gas transmission system. In a gas market, DA and ID bilateral agreements based on steady rated nominations exist between gas shippers[3] and transmission system operators. The DA nominations are used by gas transmission companies to develop a DA operational schedule before the actual operating day, which involves

[3] Gas shippers generally fall into five categories: (1) municipally-owned or local gas distribution companies with native load to serve; (2) gas traders who hold capacity to buy and sell gas for a profit; (3) producer marketers which hold capacity to move gas from their production locations to liquid market points (including for export); (4) end-users with relatively consistent daily and annual loads; and (5) state-regulated electric utilities which own generation and serve native load. All of these shippers make daily nominations to suit their distinct market purposes.

determining the cost-optimal settings of controlled facilities, such as compressor stations, regulator stations, valves and gas storage facilities and at the same time ensuring pressure limits and linepack requirements are fulfilled during the operating day. In RT operation, the control of the gas system is adjusted in response to changes in demand and supply based on the evaluation of a large set of look-ahead-scenarios using transient hydraulic simulation models, as well as on practical operator experience gained from years of observation and associated facility maneuvering. In the past, these changes were relatively small and could be managed quite well, as most gas customers were local distribution companies (LDC) with firm contracts and relatively constant and predictable hourly gas offtakes throughout the operating day. Presently, power generation companies account for more than half of total gas offtakes in some market regions in the United States. To the extent that power generators have contracts with pipelines, these could be either firm or interruptible depending on the availability of capacity. For those supplied by LDCs this could be via the LDCs pipeline capacity or some other mechanism. In either case, in certain markets gas suppliers could be using secondary capacity rights to deliver to the generators, as compared to firm rights.

In today's system, gas generators may ramp-up and ramp-down more frequently and unexpectedly during operations. This operating mode creates challenges for gas TSOs because gas generators may start-up and withdraw gas with short notice, leaving the gas TSO a limited amount of time to react to these changes. If this situation occurs in a moment where the gas system is in a stressed state, the gas TSO will typically curtail the gas offtakes of customers being served with non-firm contracts (e.g., GFPPs or those serving them) or being served by secondary rights to maintain reliable system operations and to ensure the delivery of gas to customers with firm contracts using primary rights (e.g., LDCs and end-users with firm contracts). Such undesired situations could be reduced and/or avoided if changes in power and natural gas systems are communicated and coordinated well in advance.

2.2.1 Power System Model

Bulk power system operations are simulated by running a production cost model in PLEXOS [52], a commercial power system modeling tool. The model solves a mixed integer linear optimization problem to optimize unit commitment and economic dispatch decisions subject to energy balance, reserve requirements, generation, transmission, and demand constraints. The model simulates bulk power system operations by modeling DA commitment decisions and the resulting RT generation recommitment and dispatch decisions. This is done by performing two simulations, one for DA and one for RT. Day-ahead commitment decisions of electricity generators that cannot be recommitted in real time are passed and enforced from the DA simulation to the RT simulation. Day-ahead commitments are simulated considering DA load, wind power, and solar power forecasts. These can lead to suboptimal commitment decisions, especially in situations when net load (load minus wind and solar PV power availability) forecast errors are large. When net load is under forecasted, generators that were not committed in the DA stage and that have fast startup times (e.g., natural gas combustion turbines) will be recommitted and started in real time to meet the electricity load unaccounted for.

The electricity grid test system is based on the IEEE 118-bus test system, depicted in Figure 2. The hourly load profile used is the historical load from the San Diego Gas and Electric balancing authority area for the year 2002 [58]. Time-synchronous wind data and forecasts were used from areas near San Diego from the Wind Integration National Dataset Toolkit [59]. Time-synchronous solar PV power data and forecasts were based on data available from the National Solar Radiation Data Base [60] and created in [61]. The test system is designed with an electricity generation mix that resembles the current California generation mixture with high shares of gas-driven electricity generation capacity. Moreover, the electricity grid test system can be modeled under three different scenarios in terms of wind and solar PV power penetration: 20%, 30%, and 40% in annual energy terms.

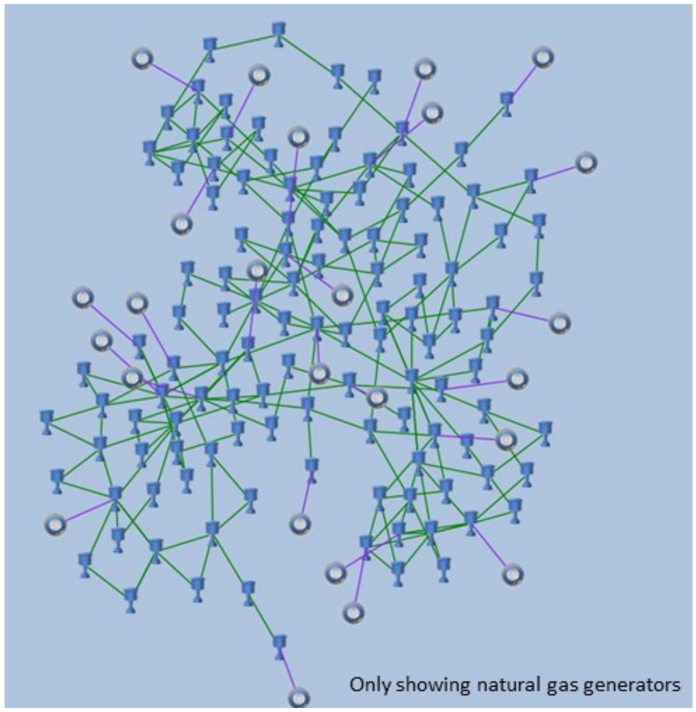


Figure 2. Topology of the IEEE 118-Bus power system network.

Table 1 shows the number of conventional generators included in the modeled test power system, as well as their combined installed generation capacity. The model also includes 10 wind power plants and 10 solar PV power plants that have different installed generation capacity depending on the penetration scenario.

Table 1. Generation Capacity Mix for Power Test System.

Generation Type	Number of Generators	Installed Capacity (MW)
Natural Gas	25	4,395
Hydro	4	1,035
Nuclear	1	238
Geothermal	2	176
Biomass	5	76
Coal	2	52
Biogas	2	45
Oil	2	43

The 25 gas power plants included in the model are of four types: steam turbine, combined cycle, combustion turbine, and internal combustion engine. The first two types are committed in the DA simulation due to their longer startup times, while the two latter types can be recommitted in the RT simulation. They can all be redispatched in RT, as long as ramping, minimum and maximum generation constraints are respected.

2.2.2 Gas System Model

The operation of gas networks is inherently dynamic. Demand and supply are constantly changing and the imbalance between these two quantities is buffered by the quantity of gas stored in pipelines, also referred to as linepack. The linepack is proportional to the average gas pressure and gives the gas system additional flexibility to react to short-term fluctuations in supply and demand. Thus, knowing the level of linepack and the pressures in the gas transport system is crucial for managing the operation of gas network. According to the law of mass conservation the linepack in a gas pipeline can only change in time if there is an imbalance between total supply and total demand, which is referred to as the flow balance. This, in turn, implies that, in order to reflect the changes in linepack, and thus the changes in pipeline pressure, a steady state model, where the flow balance is always zero (i.e., total supply is equal total demand), is inadequate. Thus, for operational studies, where the time evolution of linepack and pressure are crucial, a dynamic model for the gas system is necessary.

In this study, we reflect the behavior of the gas system by a transient hydraulic model, which is implemented in the simulation software SAInt [53]. SAInt contains a model for the most important facilities in the gas system, such as pipelines, compressor stations, regulator stations, valve stations, underground gas storage facilities, LNG terminals and other entry and exit stations. The mathematical models implemented in SAInt have been published in [53–55,62,63], where a detailed description and application of the simulation tool are given. Furthermore, the accuracy of the transient gas simulation model has been successfully benchmarked against a commercial gas simulation tool and other models in the scientific literature [54,55].

The topology of the gas network model (GNET90) used in this study is depicted in Figure 3 and the basic properties of the network are listed in Table 2.

The gas model has a total pipe length of 3,734 km, which is subdivided into 90 pipe elements. The model includes six compressor stations for increasing the gas pressure for transportation and four valve stations for controlling the gas stream, and islanding sections of the network. The pipe and non-pipe elements are interconnected at 90 nodes, where gas can be injected or extracted from the network. The 90 nodes contain three supply nodes, which include one LNG terminal with a working gas inventory of 80 Msm^3, two underground gas storage facilities with a total working gas inventory of 1,000 Msm^3, 46 gas offtake stations, which include 25 GFPPs and 17 city gate stations (CGS). The minimum delivery pressure at each GFPP is set to 30 bar-g, while the minimum pressure at each CGS is set to 16 bar-g. Gas offtake stations with minimum delivery pressure limits are subject to gas curtailment if their corresponding nodal pressure cannot be maintained above the pressure limit for a given scheduled offtake. The difference between the scheduled offtake and the actual delivered quantity are integrated over the simulation time window to yield a quantity referred to as gas not supplied (GNS), or energy not supplied if multiplied with the gross calorific value (GCV).

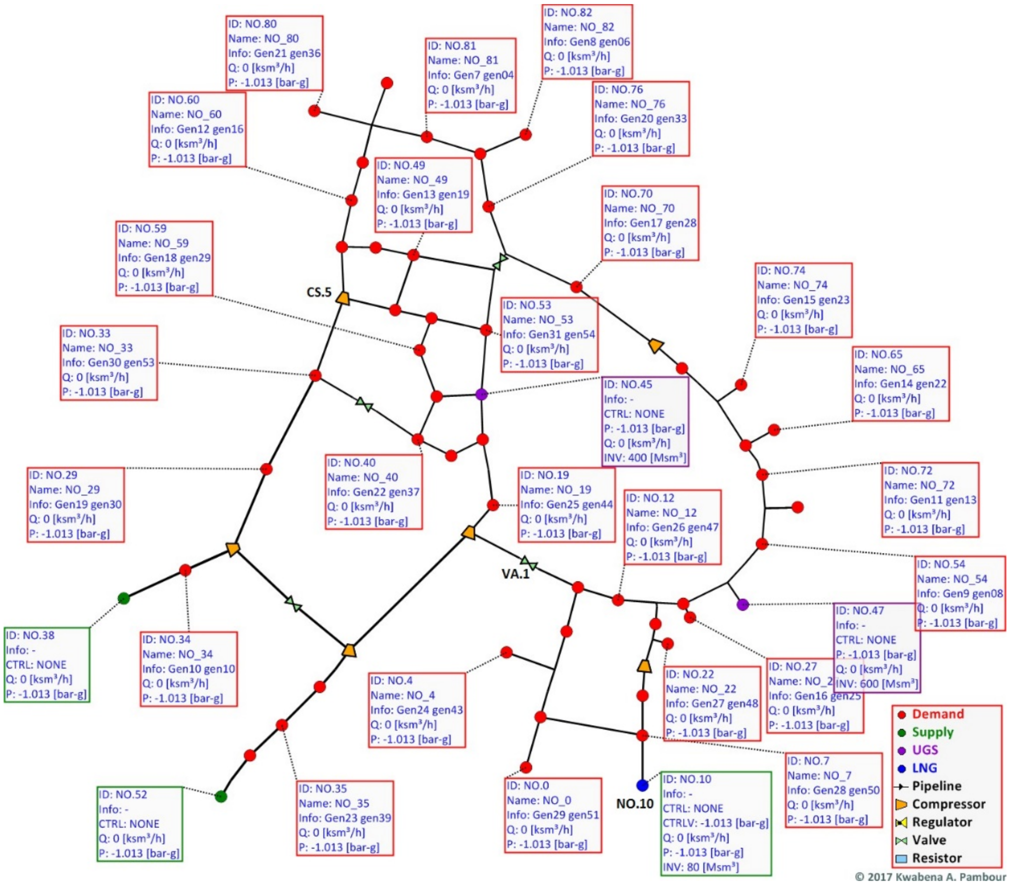


Figure 3. Topology of the GNET90 gas network. Labels with a red frame are pointing to gas-fired power plant (GFPP), labels with a green frame indicate supply nodes, and those with a purple frame underground gas storage (UGS) facilities.

Table 2. Properties of the GNET90 Gas Network.

Property	Value	Unit
Nodes	90	n/a
Pipelines	90	n/a
Compressor stations	6	n/a
Valve stations	4	n/a
Underground gas storage facilities (UGS)	2	n/a
LNG regasification terminals	1	n/a
Gas-fired power plants (GFPP)	25	n/a
City gate stations (CGS)	17	n/a
Cross-border import (CBI) stations	2	n/a
Total pipe length	3,734	km
Total geometric pipe volume	1,539,221	m^3

Property	Value	Unit
Total available compression power	240	MW
Min. pipe diameter	600	mm
Max. pipe diameter	900	mm
Min. elevation	0	(m)
Max. elevation	1,118	(m)

Furthermore, the gas system is divided into four subsystems, as shown in Figure 4.

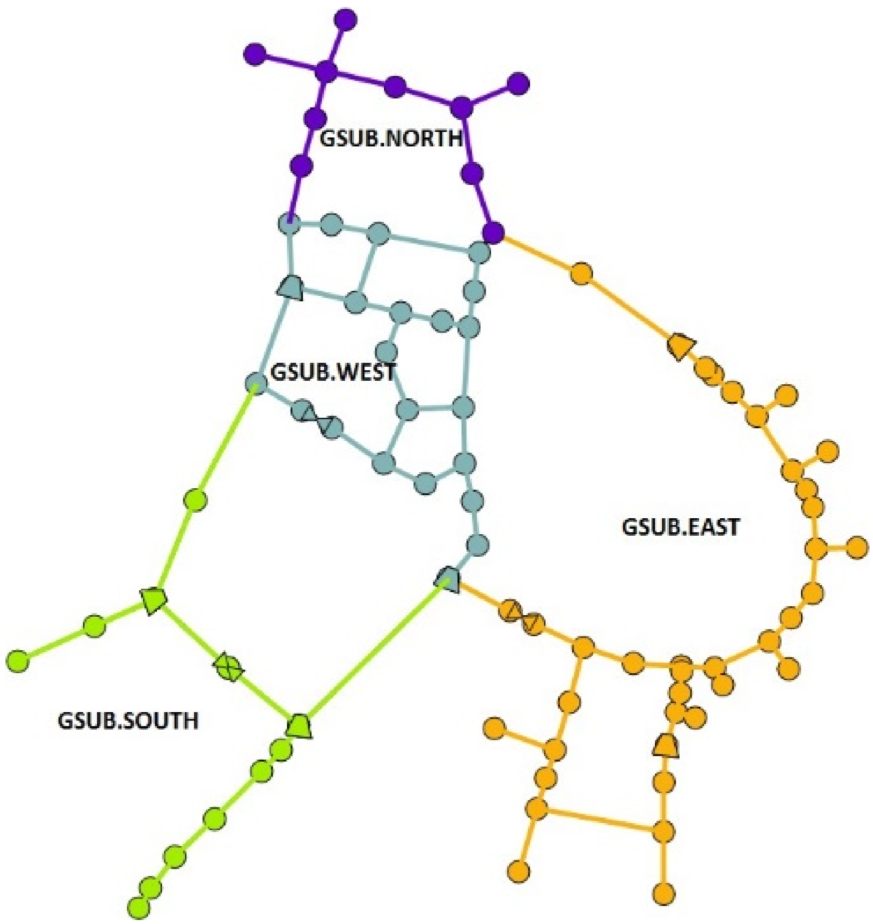


Figure 4. GNET90 gas network showing the topology of the network with the four defined subsystems.

The parameters of the subsystems (e.g., linepack and minimum pressure) are used to monitor and control the pressure and linepack of specific regions in the network and to change the control modes and set points of controlled facilities (e.g., compressor stations and valves) to maintain system operating conditions, similar to actual gas network operations.

2.2.3 Coordination Platform

The coordination platform is divided into two separate simulators that communicate and exchange data through a coordination interface implemented in SAInt, which is depicted in Figure 5.

The interface is responsible for mapping the hourly fuel offtakes of gas generators in the power system model to the corresponding fuel offtake points in the gas model and for transferring the hourly fuel offtake constraints computed by the gas simulator back to the corresponding gas generators in the power system model. Table 3 shows how the different gas generator objects in the power system model are mapped with the fuel gas offtake nodes in the gas system.

The hourly fuel offtakes of gas generators computed by PLEXOS are given in the energy units of mmBtu[4] and correspond to the amount of thermal energy required to generate electric energy for the given hour. This energy requirement is converted to an equivalent gas flow rate in reference conditions by assuming a constant gross calorific value of 38.96 MJ/sm^3 for natural gas.

The simulation of the interdependent energy systems is divided into DA and RT simulations as depicted in Figure 6. The DA simulation is first run for the power system and the resulting hourly fuel offtake profiles of gas generators are exported from PLEXOS to SAInt via the coordination interface (see Figure 5) using the mapping information provided in Table 3.

The fuel offtake profiles are then used together with the DA load profiles of other gas customers and the settings of controlled facilities to run a dynamic simulation of the gas system for the DA schedule. To run a dynamic simulation for the gas system, the initial state of the gas system has to be known. To obtain an initial state, we first run a steady state simulation and then use the solution of the steady state as an initial state to run an intermediate dynamic simulation with constant flow profiles, which eventually converges to a steady state condition. The reason for running the intermediate dynamic simulation is to ensure the right settings for all compressor stations and that constraints violated in the steady state are treated by the solver in the intermediate dynamic simulation. The solver does this by changing the control settings of affected facilities (e.g., curtailment of offtakes, if pressure violations are detected in the steady state simulation).

[4] Another unit often used in gas trading is the dekatherm (Dth), with 1 Dth = 1 mmBtu. We follow the convention of using mmBtu that is common in academic gas modeling literature, but the two are terms are interchangeable.

Table 3. Mapping Between Power System Nodes in PLEXOS and Gas System Nodes in SAInt for the 25 Gas-Fired Generators.

PLEXOS Generator ID	SAInt-Node ID#
gen04	NO.81
gen06	NO.82
gen08	NO.54
gen10	NO.34
gen13	NO.72
gen16	NO.60
gen19	NO.49
gen22	NO.65
gen23	NO.74
gen25	NO.27
gen28	NO.70
gen29	NO.59
gen30	NO.29
gen33	NO.76
gen36	NO.80
gen37	NO.40
gen39	NO.35
gen43	NO.4
gen44	NO.19
gen47	NO.12
gen48	NO.22
gen50	NO.7
gen51	NO.0
gen53	NO.33
gen54	NO.53

The results of the dynamic gas system simulation include the computed fuel offtake for gas generators, which may differ from the scheduled DA fuel offtake profile computed for gas generators in the power system model if gas curtailments were necessary to respect pressure limits in the gas system. The fuel offtake constraints computed by SAInt can be reported back to PLEXOS to recompute the DA power system simulation, which would generate a new unit commitment schedule for running the RT power system simulation.

We differentiate between two different cases which differ in terms of how the information about the fuel offtake constraints from the DA gas system simulation are used in the power system simulation. We label these situations Business as Usual (BAU) and DA-Coordination, and they are illustrated in Figure 6 and Figure 7, respectively. In the BAU case depicted in Figure 6, the fuel offtake constraints from the gas system are not utilized by the power system, while in the DA-Coordination case illustrated in Figure 7, the fuel offtake constraints are used to recompute the DA power system simulation. This provides new unit commitment solution for the generators that is then applied in the RT power system simulation.

In both cases, the fuel offtake profiles from the RT power system simulation are provided to the gas system for running a RT gas system simulation using the same procedure as for the DA simulation. The fuel offtake constraints computed for the RT gas system simulation can be sent back to the power system to analyze how the coordination between both systems impacted the operation of the power system. Although the modeling platform developed here could potentially support the exchange of other information (such as natural gas prices), we do not explore coordination behind offtakes in this study.

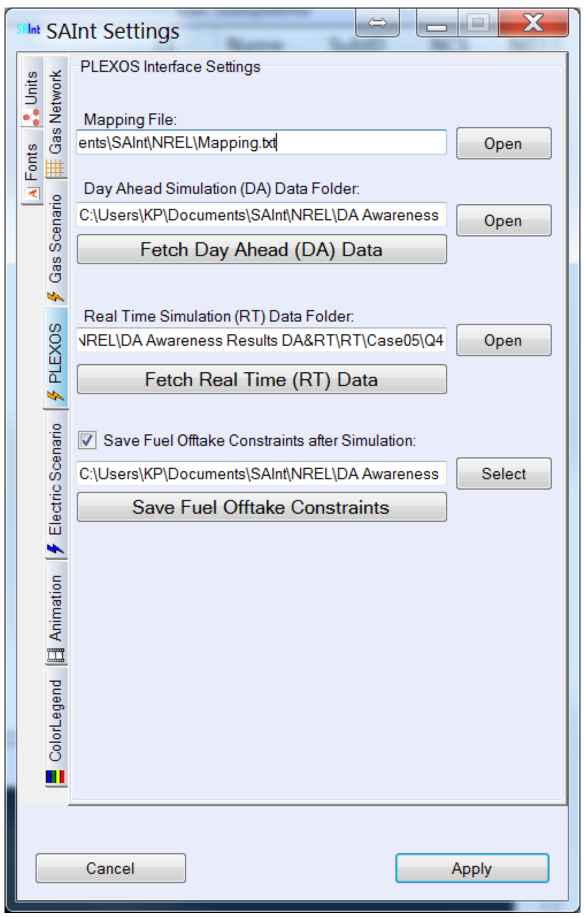


Figure 5. Snapshot of the co-simulation interface implemented into SAInt.

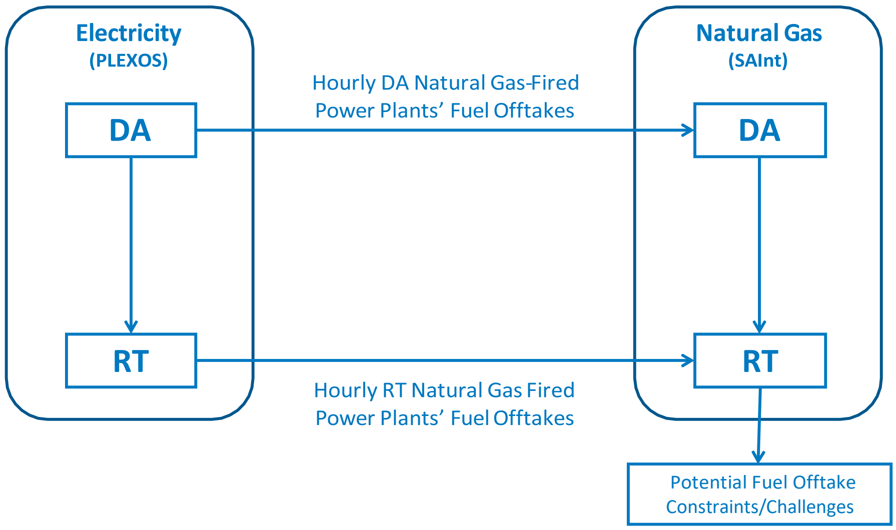


Figure 6. Simulation model for Business as Usual scenario.

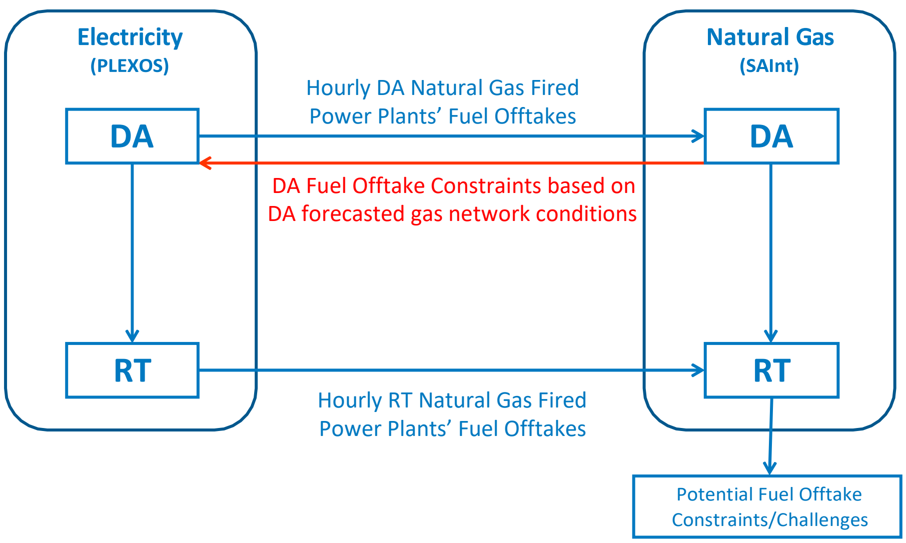


Figure 7. Simulation model for DA coordination.

2.3 Scenarios

The scenarios used to showcase the differences for the test system of our combined power and gas modeling platforms are described in the following subsections.

2.3.1 Renewable Penetration

In terms of level of wind and solar PV penetration in the generation mix of the power system, we distinguish between three wind and solar penetration levels, 20%, 30%, and 40% in terms of annual electricity generation. Figure 8 shows the share of electricity generation from wind, solar PV, and natural gas for the four weeks selected for the analysis. The annual penetrations in energy terms of variable renewable energy sources in the three scenarios correspond to 20%, 30% and 40%. The scenarios include higher penetrations of solar PV power than wind power.

Table 4 shows the wind and solar power generation capacities for the three renewable penetration scenarios. However, for the four weeks selected, the corresponding wind and solar PV penetrations do not represent the annual average and are slightly smaller than 20%, 30%, and 40%. The share of electricity generation from natural gas decreases as variable renewable penetration increases because wind and solar PV power displace electricity generation from natural gas-fired generators.

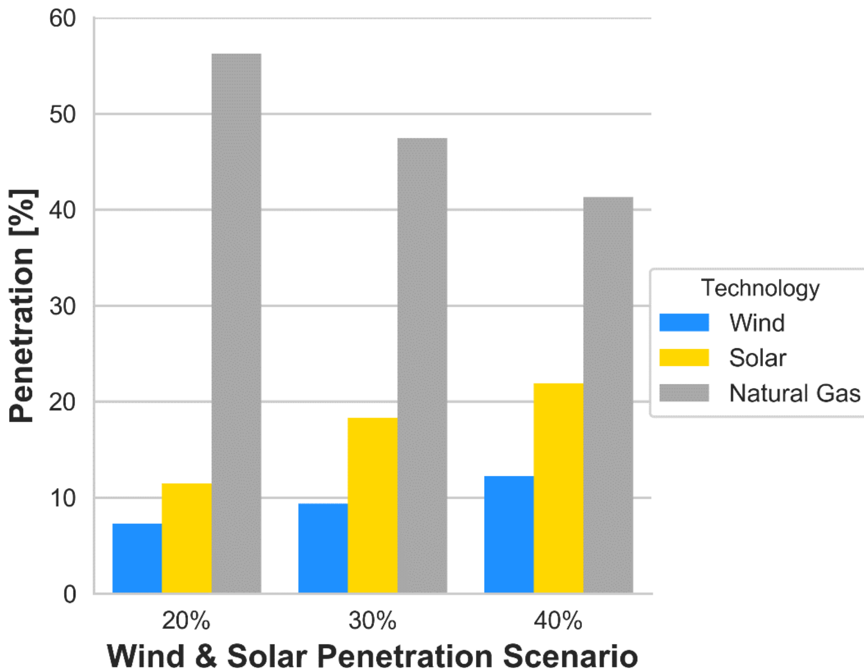


Figure 8. Overview of wind, solar and natural gas generation mix for the three studied simulation cases considering only the four selected weeks (one per quarter).

Table 4. Renewable Generation Installed Capacities in the Different Renewable Penetration Scenarios.

Renewable Penetration Scenario	Renewable Generation Installed Capacity (MW)	
	Solar	**Wind**
20%	1,114	790
30%	1,770	1,015
40%	2,176	1,354

2.3.2 Season

The simulation data for the gas and power systems are available for an entire year. However, to highlight the differences between the approaches, we select for each quarter of the year the week with the highest upward-ramp of gas-fired generators in the power system. The selection is based on the frequency and magnitude of upward-ramps. We choose to focus on the weeks with highest natural gas offtake ramps as a proxy for weeks that may experience the largest challenges from a natural gas network perspective. For each wind and solar penetration level, the following weeks were selected for the case studies:

- Q1: From January 29, 2012, 00:00 to February 5, 2012, 12:00 a.m.
- Q2: From April 1, 2012, 00:00 to April 8, 2012, 12:00 a.m.
- Q3: From September 23, 2012, 00:00 to September 30, 2012, 12:00 a.m.
- Q4: From October 28, 2012, 00:00 to November 4, 2012, 12:00 a.m.

2.3.3 Level of Coordination

For each wind and solar PV penetration level and each selected quarter, two different cases in terms of level of coordination between the gas and power systems are investigated, which we denote as follows:

- **Business as Usual (BAU):** Fuel offtake constraints computed from the DA gas system simulation are not considered in the power system simulation. DA and RT power system simulation do not take the fuel offtake constraints of the gas system into account.
- **DA-Coordination:** Fuel offtake constraints computed from the DA gas system simulation are considered in the power system simulation. The power system recomputes its DA using the fuel offtake constraints and uses the resulting unit commitment schedule for the RT simulation.

The simulation of the gas system requires additional definitions besides the fuel offtake profiles received from the power system. For instance, additional definitions of control settings with respect to specific conditions in the network. Each simulation in SAInt is modeled as a scenario, which has the following properties:

- Scenario type (steady state, succession of steady state, or dynamic simulation).
- Scenario time window (simulation start time and end time).
- Scenario time step (determines the time resolution of the simulation and thus the number of time steps computed).
- Initial State (for a dynamic simulation, an initial state of the gas network is needed).

- Scenario schedule and boundary conditions (includes all control settings and flow schedules for controlled facilities that may change in time. Settings for controlled facilities can be triggered based on certain conditions in the network, e.g., open a valve if the pressure in a region is below a certain value or increases/decreases the outlet pressure set point of the compressor if the linepack in a region is below/above a specific value).

2.3.4 Gas System Control Settings

For all gas system scenarios, we define the following control settings that depend on the conditions in the gas system during the simulation run.

Fuel Offtake Curtailment: For all fuel offtake nodes of gas-fired generators, we define a minimum pressure limit of 30 bar-g and for all city gate stations a limit of 16 bar-g. The scheduled offtake at these stations will be curtailed such that the pressure limits at the corresponding node are not violated.

Compressor Operations: Compressor Station CS.5 is used for controlling the pressure in subsystem GSUB.NORTH. If the minimum pressure in GSUB.NORTH goes below 30 bar-g, CS.5 will increase its outlet pressure by 1/15 bar-g/min to restore the pressure level in subsystem GSUB.NORTH, thus reducing risk of potential fuel offtake curtailments of gas generators in that region, which require a minimum fuel gas pressure of 30 bar-g for operation. Increasing the outlet pressure, however, comes with a cost, as the compression of gas requires energy from the driver. Thus, to reduce the energy consumption in times of reduced loads, we define an additional conditional control for CS.5, which reduces the outlet pressure set point by 1/15 bar-g/min if the minimum pressure in GSUB.NORTH is above 32 bar-g.

LNG Terminal Operations: LNG terminal NO.10 has a limited quantity of LNG in its storage tank, which is regasified and injected into the network. If the working inventory of the terminal is depleted, the terminal cannot inject gas into the network and has to shut down, until it is supplied with LNG from a LNG vessel. SAInt is able to model and schedule the arrival of LNG vessels and the discharge of LNG from the vessel to the LNG storage tank by defining the arriving time and size of the LNG vessel and the discharge rate. In all studied scenarios, the arrival of LNG vessels at NO.10 is scheduled every third and sixth day at 6:00 a.m. after the start of the simulation with an arriving vessel size of 40,000 m3 of LNG and a discharge rate of 120 m3/min.

Valve Operations: The shutdown of LNG terminal NO.10, due to the depleted working inventory may cause pressure reductions in the surrounding market area, which may eventually lead to curtailments of scheduled fuel offtakes from customers in that area, in particular, GFPPs. To avoid this undesired situation, we define control mode changes for valve station VA.1 that connects subsystem GSUB.SOUTH with GSUB.EAST. If the LNG terminal is not supplying the network with gas (i.e., control mode is OFF) and the minimum pressure in GSUB.EAST is below 30 bar-g, valve station VA.1 should open, while, if the LNG terminal is operating and the minimum pressure in the subsystem is above 32 [bar-g], the station should close in order to reduce the energy consumption of the upstream compressor station.

In addition to the control settings explained above, the simulation parameters and gas properties listed in Table 5 are applied for all studied scenarios. The time step for the dynamic simulation is set to 30 minutes; however, the time resolution is adapted by the dynamic time step adaptation method implemented into SAInt if rapid transients occur in the course of the simulation.

Table 5. Input Parameter for Transient Simulation of GNET90 Gas Network Model.

Parameter	Symbol	Value	Unit
time step	Δt	1,800	s
total simulation time	t_{max}	168	H
isothermal gas temperature	T	288.15	K
dynamic viscosity	η	10^{-5}	kg/m·s
reference pressure	p_n	1.01325	bar
reference temperature	T_n	288.15	K
critical pressure	p_{crit}	45	bar
critical temperature	T_{crit}	193.7	K
relative density	d	0.6	n/a
gross calorific value	GCV	38.96	MJ/sm^3

2.4 Results

Having developed a platform for coordination of power and gas networks, we examine the value of considering natural gas network constraints on the DA power plants commitment decisions. In this section, we present the results of a case study that highlights the differences between coordinating the gas and power systems operation at these timeframes with the current practice of limited to no coordination.

2.4.1 System-wide results

In the following section, we discuss aggregated results for the computed scenarios, which are illustrated in Figure 9 and Figure 10. Figure 9 compares the total aggregated gas not supplied (GNS) for the four quarters for the three studied wind and solar PV penetration levels and for the coordination level (BAU and DA-Coordination). As can be seen, the GNS for BAU is more than twice as high as for DA-Coordination for all wind and solar PV penetration levels, which means the coordination between the gas and power system reduced significantly the curtailment of offtakes in the gas system. Furthermore, the level of offtake curtailment in the gas system decreases with increasing wind and solar PV penetration, though one would expect the opposite, as an increased wind & solar PV penetration level is expected to increase the number of upward and downward ramp cycles, thus affecting pressure limits in the gas system. However, a reason for the observation could be that a higher wind and solar PV penetration level means less average fuel offtake of gas-fired generators, which also means less stress and higher average pressures in the gas system, which in turn makes the gas system less sensitive to potential fuel offtake ramps of gas-fired generators to back up wind and solar PV sources. Working opposite to this trend is the fact that at higher variable renewable energy penetrations, net load ramps are larger and these can cause more frequent natural gas pipeline network constraints on power plants' natural gas offtake, particularly if those ramps are not anticipated.

The reduced curtailments in the gas system in the DA-Coordination case also positively impacted the total energy consumption of compressor stations in the gas system independent of the wind and solar PV penetration level, as illustrated in Figure 10. The total energy consumption for the BAU scenario is always roughly 10% higher than in the DA-Coordination case.

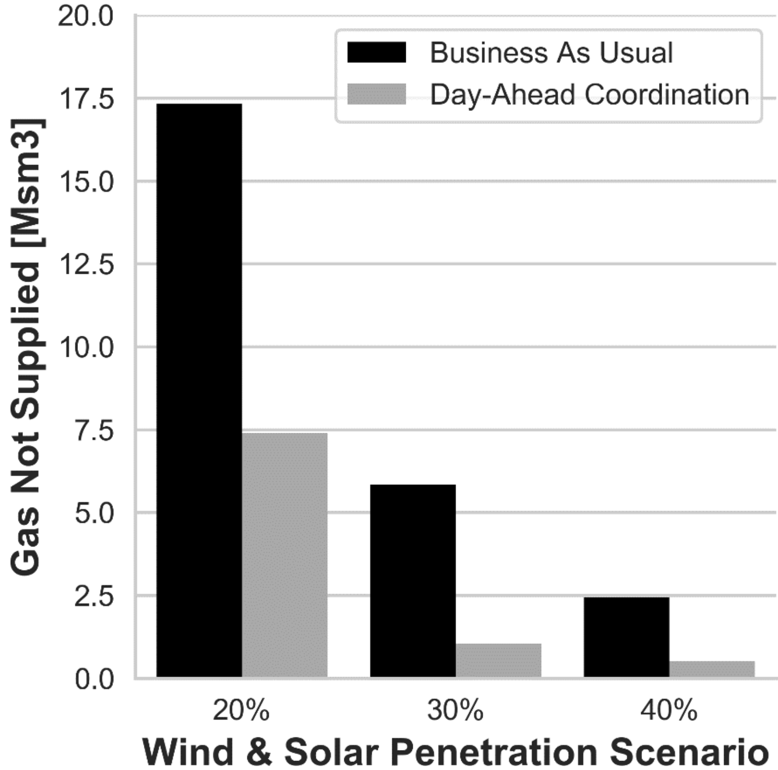


Figure 9. Gas not supplied in the BAU and Day-Ahead (DA) Coordination case. Aggregated results for four weeks (one per quarter) with highest system-wide natural gas offtake ramps.

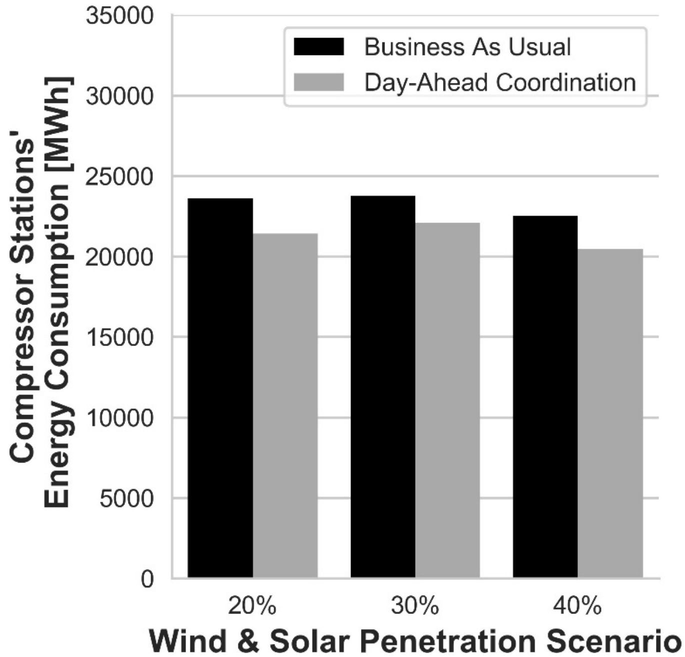


Figure 10. Total energy consumption of gas compressor stations in the Business-as-Usual and DA Coordination case. Aggregated results for four weeks (one per quarter) with highest system-wide natural gas offtake ramps.

2.4.2 Highlighted Examples

Below are a few specific examples of behavior at specific generator, gas offtake nodes, and compressors:

2.4.2.1 Fuel Offtake Curtailment

Figure 11 shows an example of fuel offtake curtailment at node NO.80 of gas generator gen36 for the DA gas system simulation for Q1 and for a 20% renewable penetration level. The top plot shows the time evolution of the nodal pressure, the middle plot compares the time evolution of the scheduled offtake profile (i.e., profile received from the results for the DA power system simulation in PLEXOS) to the actual offtake profile (i.e., offtake profile computed by the DA gas system simulation in SAInt considering the operation and pressure limits in the gas system) and the bottom plot is the cumulative quantity of gas not supplied from the start of the simulation (i.e., the integral of the area between the green (scheduled offtake, NO.80.QSET) an blue curve (actual offtake, NO.80.Q) in the middle plot). As can be seen, the scheduled offtake is curtailed whenever the pressure in node NO.80 reaches the pressure limit of 30 bar-g.

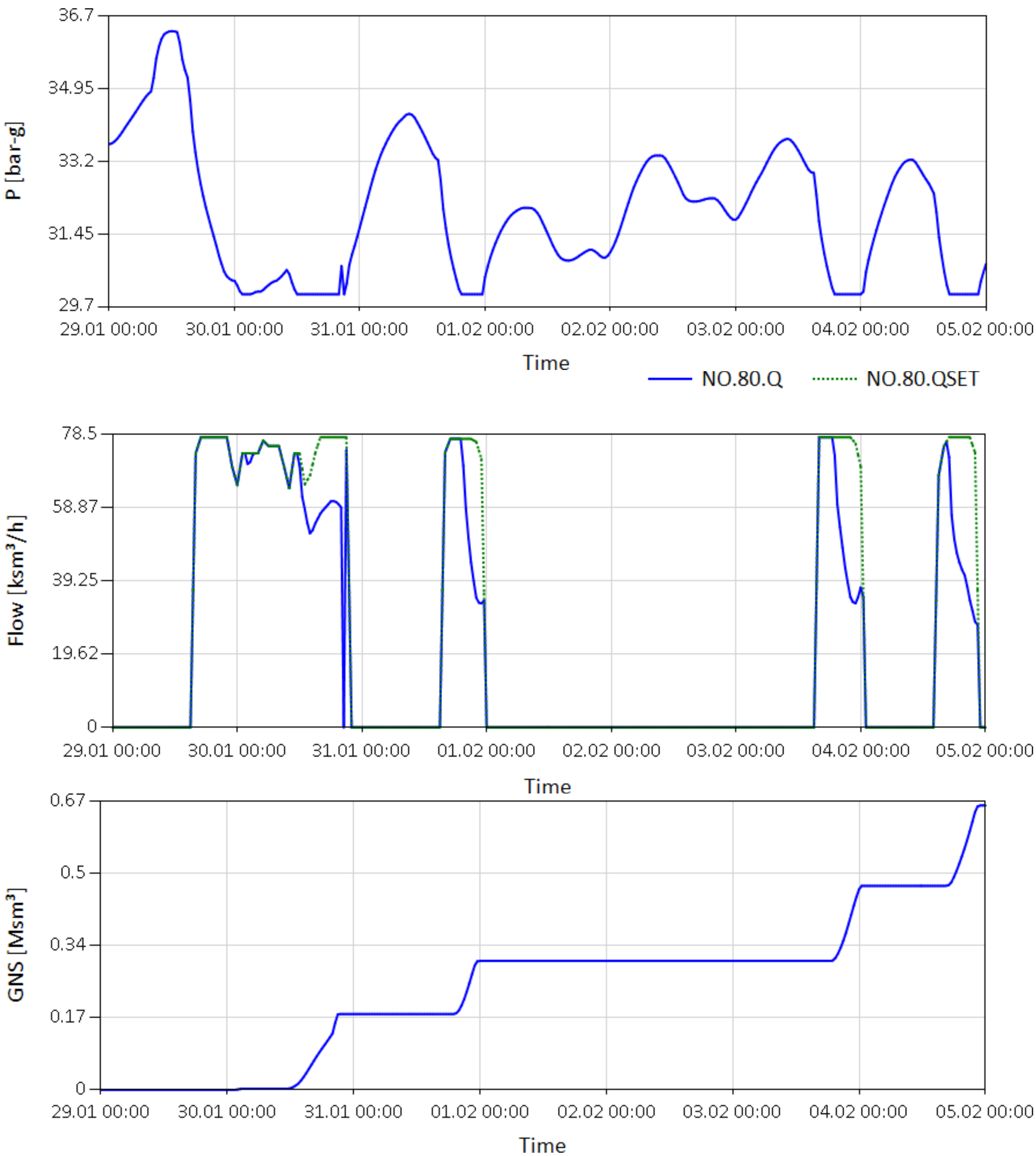


Figure 11. Time evolution of pressure, scheduled offtake (QSET), actual offtake (Q), and cumulative gas not supplied for fuel offtake node NO.80 of gas generator gen36 for DA simulation for Q1 and for a 20% wind and solar penetration.

2.4.2.2 Compressor Operations

The conditional control prescribed to compressor station CS.5 is illustrated in Figure 12 for the DA gas system simulation for Q1 and for a 20% variable renewable penetration level. The top plot shows the time evolution of the minimum pressure in subsystem GSUB.NORTH, while the center and bottom plot show the time evolution of the outlet pressure and the driver power for compressor station CS.5 respectively. As can be seen, the outlet pressure of the compressor station increases linearly if the minimum pressure in GSUB.NORTH decreases below 30 bar-g and decreases linearly if the minimum pressure in GSUB.NORTH increases above 32 bar-g. Furthermore, the energy consumption of the compressor station increases if the outlet pressure increases and decreases if the outlet pressure decreases.

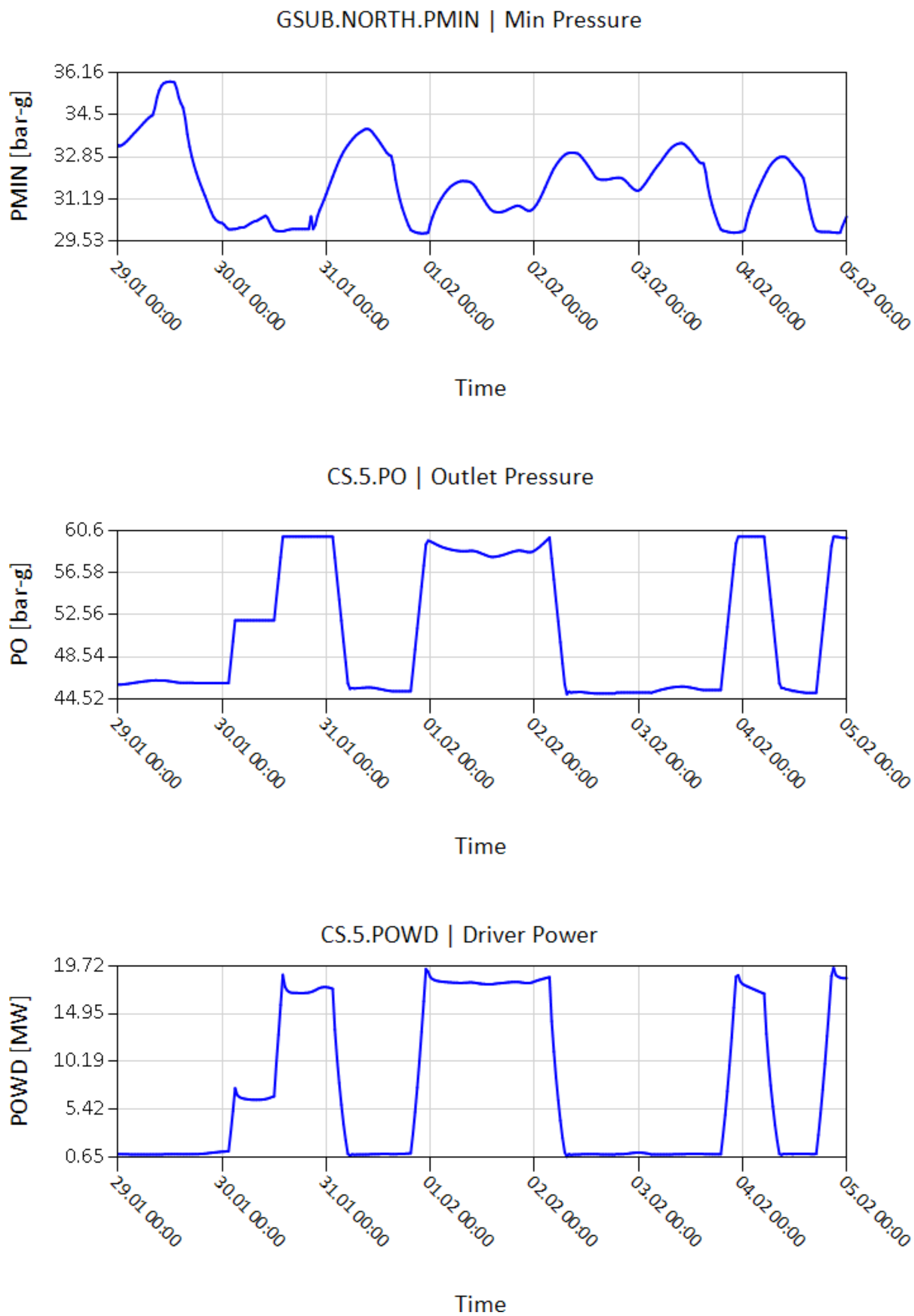


Figure 12. Time evolution of minimum pressure in subsystem GSUB.NORTH and outlet pressure and driver power for compressor station CS.5 for DA simulation for Q1 and for a 20% wind and solar penetration.

2.4.2.3 LNG Terminal Operations

We also consider the working inventory of LNG terminal NO. 10 for the DA gas system simulation for Q1 and for a 20% variable renewable penetration level. The inventory decreases almost linearly right from the start of the simulation until the working inventory is depleted, which causes the station to stop its gas supply to the network. The terminal resumes its gas supply after the arrival of the first vessel on 1 February, at 6:00 a.m. The LNG transported by the vessel is discharged and relocated to the storage tanks in the terminal as can be seen in the increasing working inventory after the arrival of the vessel. The discharge process takes approximately 5.5 h, and then the inventory starts decreasing again until the second vessel arrives.

2.4.2.4 Valve Operations

Figure 13 shows how the conditional control setting for valve station VA.1 is respected in the simulation for the DA gas system simulation for Q1 and for a 20% variable renewable penetration level, where the minimum pressure in subsystem GSUB.EAST and the control and flow rate of valve station VA.1 is plotted over time. As can be seen, the valve station is opened (i.e., control mode BP) and supplies gas to GSUB.EAST if the minimum pressure in the subsystem is below the defined pressure threshold.

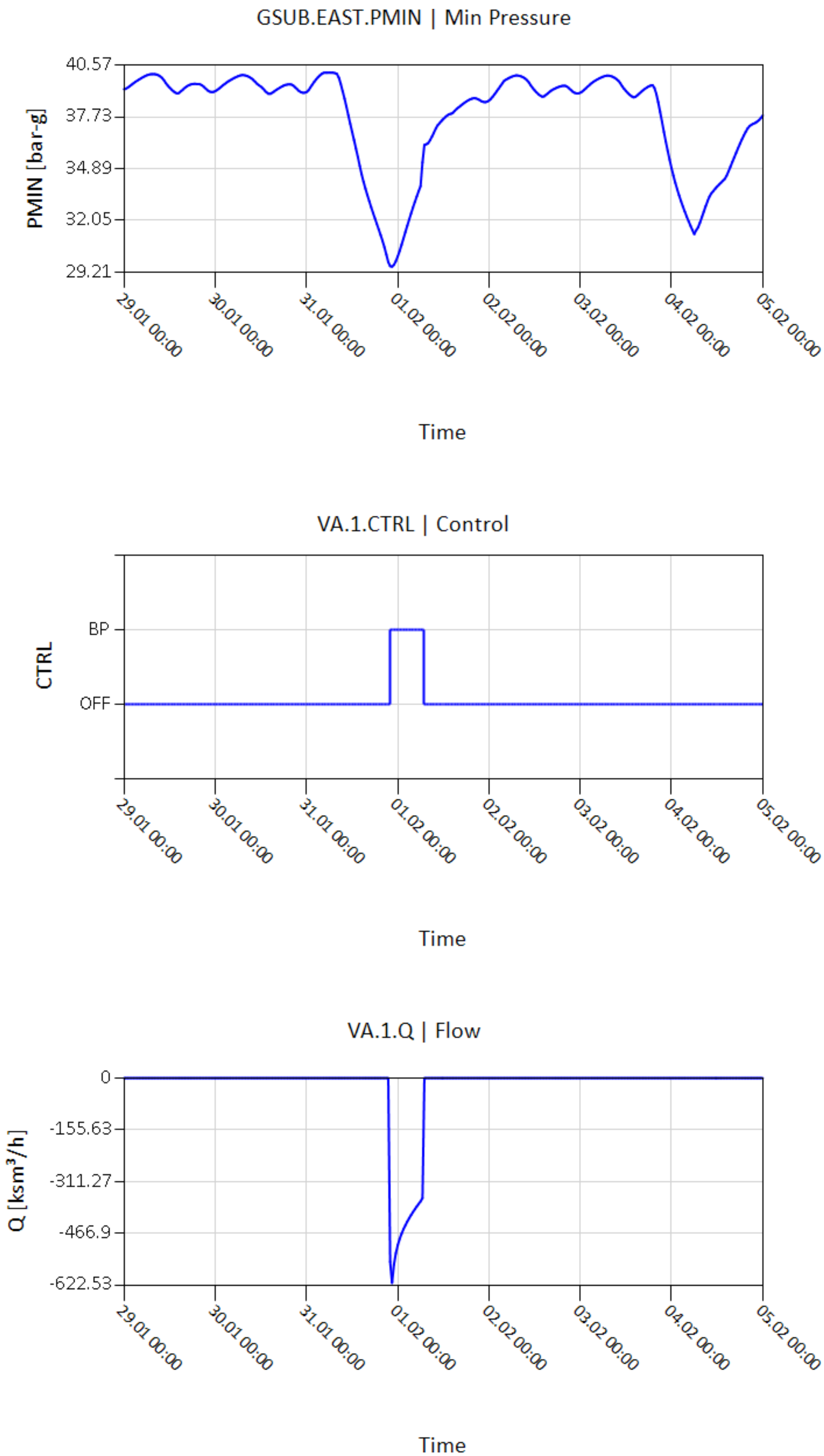


Figure 13. Time evolution of minimum pressure in subsystem GSUB.EAST and control mode and flow rate at valve station VA.1 for DA simulation for Q1 and for a 20% wind and solar penetration.

2.5 Summary of Study 1

In this part of our study, we developed a coordination platform to assess the operation and interdependence of natural gas and power transmission networks. The platform consisted of a steady state DC unit commitment and economic dispatch model to simulate bulk power system operations and a transient model to simulate the operation of bulk natural gas pipeline networks. The models were implemented in two separate simulation environments, namely the production cost modeling tool PLEXOS for electric power systems and the transient hydraulic gas system simulator SAInt. The data exchange and communication between both energy system models were established by an interface that mapped the power generation of gas generators in the power system to the corresponding fuel offtake points in the gas system.

The coordination platform was applied on a case study on an interconnected gas and power transmission network test system to examine to what extent the DA coordination between gas and power TSOs might impact the efficiency and reliability of the coupled energy systems. The two networks were interconnected at 25 gas-fired power plants, which represented generation units in the power system and gas offtake points in the gas system. The study was divided into three dimensions, namely, the level of variable renewable penetration, the period under consideration with the highest upward and downward ramp of gas generators, and, finally, the level of coordination between the gas and power system networks (DA coordination and no coordination between both energy networks). The results indicate that DA coordination between gas and power system networks contributes to a significant reduction in curtailed gas during high-stress periods (e.g., large gas offtake ramps) and up to a 9% reduction in gas consumption at gas compressor stations, for the combined test system examined here. This has implications for real natural gas and power systems where such significant reductions in natural gas curtailment and natural gas compression energy consumption reductions would lead to significant economic and reliability benefits to the both the natural gas and power systems.

3 Study 2: Valuing Intraday Coordination of Electric Power and Natural Gas System Operations

3.1 Introduction

Recognizing the need for enhanced power and gas coordination, FERC released Order 809 in April 2015 [13]. It made two major changes to improve power and gas coordination. Firstly, it shifted forward the first DA market (or nomination cycle) for natural gas so gas-fired generators in some markets could nominate gas offtakes while knowing their electricity generation schedule. Secondly, it added an extra ID gas nomination cycle so ID nominations by gas-fired generators could better reflect updated forecasts and operational conditions in the power system. In turn, power system operations can better reflect operational conditions and fuel deliverability constraints of the gas system, potentially yielding operational cost and reliability benefits.

A large amount of the literature has explored some of the benefits of coordinated markets for test systems [11,21–23,25,29,30,33,36,40]. For example, previous work by [47] quantifies economic and power and gas system reliability benefits of four different levels of coordination in DA scheduling, ranging from enhanced gas system scheduling disconnected from power system scheduling to enhanced gas system scheduling fully integrated with power system scheduling. Using a test system, they find high levels of coordination can eliminate pressure violations in the gas system at moderate to large increases in dispatch costs. Another study quantifies the value of DA coordination between power and gas systems by co-simulating a fully dynamic gas model and a DC unit commitment and economic dispatch power model [40]. They find DA coordination yields a 50% reduction by volume in gas offtake curtailments by generators due to gas network constraints.

Notably, this prior research focuses on DA coordination, but FERC Order 809 pertains to DA and ID coordination. Better understanding the value of ID coordination would improve understanding of the value of Order 809 and near-term follow-on policy opportunities. Additionally, ID coordination will likely become increasingly important as wind and solar PV penetrations increase, as ID forecast errors at high penetrations could result in significant unexpected swings in gas offtakes. Consequently, we test the sensitivity of our results to high wind and solar PV penetrations to better understand the long-term value of ID coordination.

In this section, we aim to better understand the value of improved ID coordination between electric power and natural gas systems. To do so, we model coordinated operations of an interconnected power and natural gas test system. In coordinated operations, we schedule and operate each system separately but coordinate their operations by running a transient hydraulic simulation of the natural gas network to check for gas deliverability constraints given an optimal power system schedule or dispatch, and we then reoptimize the power system given any such gas deliverability constraints. We quantify economic and reliability benefits of ID coordination by quantifying total power system production costs, power system prices, non-served gas, and RT redispatch of gas-fired generators due to gas deliverability constraints.

3.2 Methods

3.2.1 Electric Power and Gas System Coordination Platform

We build on the coordination platform outlined in Section 2, which optimizes power system operations at hourly intervals and simulates gas system operations at 30-minute intervals. For the power system, we optimize DA operations for a 24-hour optimization horizon plus a 24-hour look-ahead window, ID operations for a 6-hour optimization horizon plus a 12-hour look-ahead window, and RT operations for a 1-hour optimization horizon plus a 2-hour look-ahead window (described in additional detail below). For the gas system, we simulate DA and ID operations for the same length as the optimization horizon plus look-ahead window that we use for the power system and simulate RT operations for a 1-hour horizon. Because we simulate (rather than optimize) gas network operations (see Section 2.2.2 for details), look-ahead windows are unnecessary, but we match the lengths of power and gas runs in the day-ahead and ID markets to coordinate their operations. Our ID optimization horizon, which corresponds to 4 ID markets per day, represents a compromise between current ID operations of the power and gas networks that could be achieved in the near-term. Specifically, it corresponds to adding an extra ID gas market and synchronizing timing between power and gas systems. The co-simulation platform interleaves DA, ID, and RT operations, such that RT operations of the power and gas systems provide the initial conditions for subsequent power and gas system operations, as shown Figure 14 and Figure 15.

The coordination platform coordinates power and gas system operations in DA, ID, and RT markets. To coordinate power and gas systems, we first optimize power system operations to minimize total power system production costs (sum of variable operation and maintenance, fuel, and startup costs) while ignoring gas system constraints. From those optimized power system operations, we extract hourly fuel offtakes for each gas-fired generator and then input those offtakes to a dynamic gas simulation that accounts for transient hydraulics. This gas simulation returns maximum fuel offtakes the gas system can provide to each gas-fired generator. These maximum fuel offtakes can indicate one of two situations. They might be less than fuel offtakes output by the prior power system optimization, indicating gas-system-driven curtailment of gas-fired generators relative to the economically optimal power system dispatch that ignores gas system constraints. Or they might be equal to fuel offtakes output by the prior power system optimization, indicating no curtailment of gas-fired generators relative to the economically optimal power system dispatch. Consequently, when we again dispatch the power system (“coordinated dispatch”), we limit gas-fired generators’ fuel offtakes to the maximum offtakes output by the gas simulation for curtailed generators, and we allow the optimization to increase or decrease fuel offtakes for non-curtailed generators. This process captures how gas network limitations might require increases or decreases in gas-fired generators’ operations and reflects separate operation of power and gas systems. It also expands on our previous work (presented in Section 1 of this report) where we only model DA coordination and only limit gas offtakes (rather than allowing increased generation at non-curtailed generators) [40].

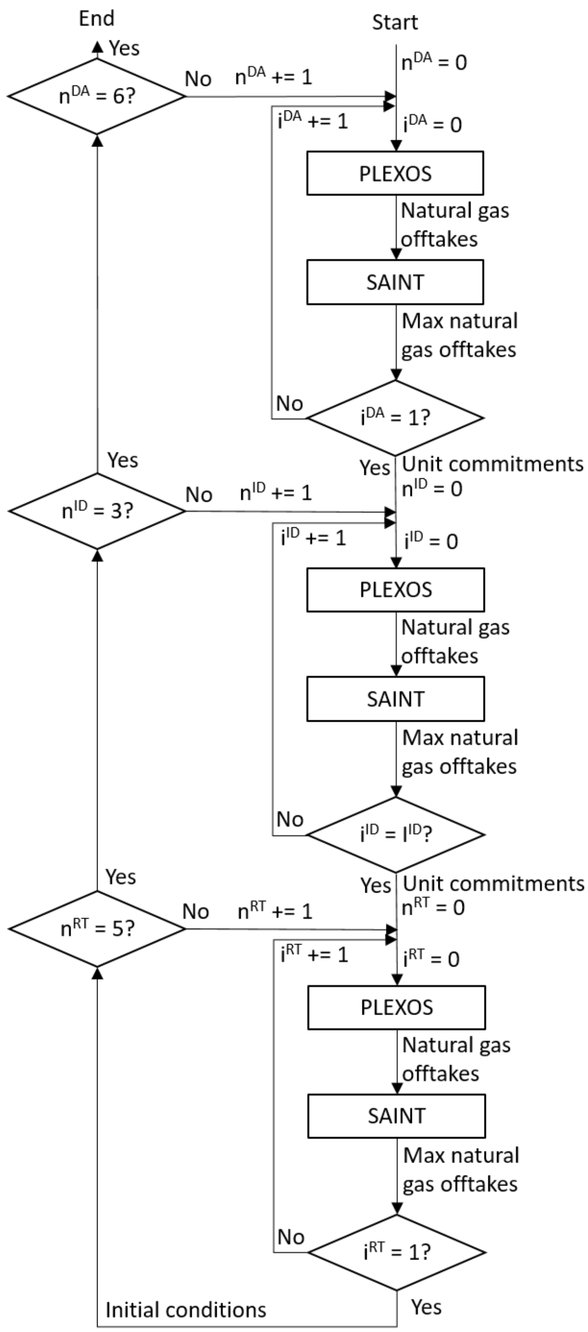


Figure 14. Schematic of coordination platform for electric power and gas system for each week analyzed nDA indicates the day, whereas nID and nRT indicate the ID and RT run number within each day. IID indicates the total number of coordinated iterations, so equals 0 and 1 when not coordinating and coordinating ID operations respectively. iDA, iID, and iRT indicate the coordinated iteration number.

In the coordination platform, moving from DA to ID and from ID to RT has two effects: (1) wind and solar PV forecasts are updated, and (2) commitments of some electric generators are fixed. With respect to forecast improvements, we assume a 50% uniform improvement in wind and solar PV electricity generation forecasts from DA to ID, and then a 100% improvement from ID to RT. In other words, we assume perfect wind and solar PV generation forecasts in the RT market, meaning that the predicted amount of available wind and solar PV generation in the RT market is exactly the amount that would actually be available. With respect to commitments, depending on the generator type and associated flexibility, generators' commitments may be fixed to DA commitments or may be recommitted in the ID and/or RT markets. We fix DA commitments of biomass, coal, and gas steam turbines (relatively inflexible generators) in ID and RT markets, and fix ID commitments of natural gas combined cycle and biogas facilities (relatively flexible generators) in RT markets.

3.2.2 Market Horizons and Linkages

Figure 15 depicts interconnections between DA, ID, and RT power and gas model runs. After the first period, all DA, ID, and RT runs are initialized with coordinated RT run results. Coordination entails passage of fuel offtakes from the power system optimization to the gas system model and then passage of maximum fuel offtakes from the gas system simulation to the power system model. Note that as explained in the main text, these max fuel offtakes indicate which power plants we curtail and which we allow to increase (or decrease) their power output. Unit commitment decisions from DA and ID runs are passed to ID and RT runs respectively. Note that after each RT coordinated power system optimization (light blue boxes), we pass resulting fuel offtakes to SAInt again to determine non-served natural gas.

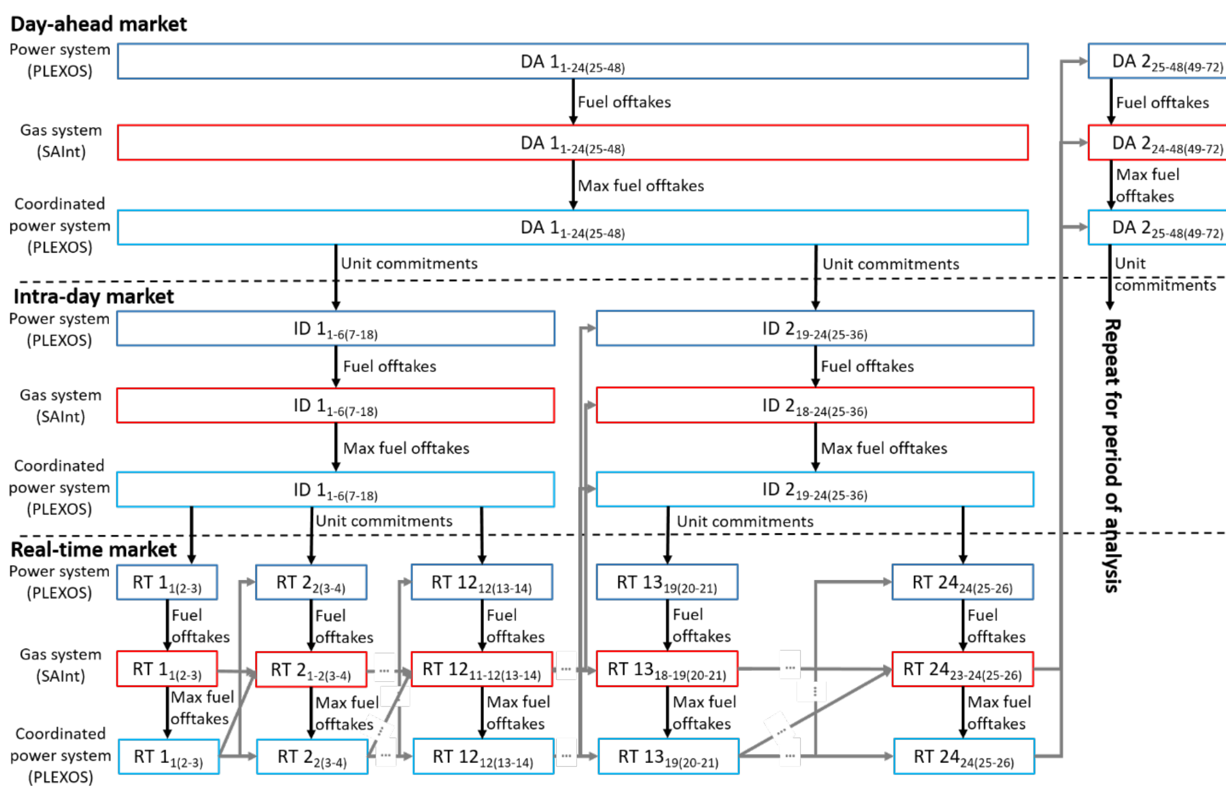


Figure 15. Diagram showing horizons and linkages between DA, ID, and RT markets. Adjacent to each market label (DA, ID, or RT) are two sets of numbers, one outside and one within parentheses (e.g., DA$_{x(y)}$). The number outside parentheses (x in DA$_{x(y)}$) indicates hours included in the optimization horizon, while the number within parentheses (y in DA$_{x(y)}$) indicates hours included in the look-ahead horizon. Dark and light blue boxes indicate optimization of power system operations using PLEXOS, with dark and light blue boxes indicate uncoordinated and coordinated optimizations respectively. Red boxes indicate simulation of gas system operations using SAInt. Arrows between boxes indicate data passed from the prior to next model run. Black arrows indicate passage of information related to fuel offtakes, maximum fuel offtakes, or unit commitments on an hourly basis for the entire horizon, while gray arrows indicate passage of initial conditions.

3.2.3 Test System

For our test system, we use a modified version of the IEEE 118-bus test system described in Section 2.2 [40]. The 118-bus test system includes 186 transmission lines interconnecting the 118 electrical buses in a single region. With respect to power system data, we augment the 118-bus test system with additional wind and solar PV generators and synchronous load, wind, and solar PV data. By adding wind and solar PV generators, we achieve a system with a moderate wind and solar PV penetration (22% by installed capacity), better representing real-world power systems in the United States [64–66]. Hourly electricity demand comes from San Diego Gas and Electric (SDGE), while time-synchronous wind and solar PV forecasted and realized electricity generation come from the Wind Integration National Dataset Toolkit and the National Solar Radiation Database for sites close to SDGE's service territory [40,59,67]. Table 6 summarizes installed capacity by fuel type. Of the 25 natural gas-fired plants, 11 (2.4 GW) are combined cycle, 11 (1.6 GW) are combustion turbine, and the remaining 3 (0.4 GW) are steam turbine or internal combustion engine.

Table 6. Number and Total Installed Capacity of Power Plants by Fuel Type in Test System.

Power Plant Fuel Type	Number of Power Plants	Total Installed Capacity (MW)
Natural Gas	25	4,395
Hydro	4	1,035
Solar	10	999
Wind	10	704
Nuclear	1	238
Geothermal	2	176
Biomass	5	76
Coal	2	52
Biogas	2	45
Oil	2	43
Total	**63**	**7,763**

We also augment the 118-bus test system by adding a natural gas network, which includes 90 nodes, 90 pipelines, 6 compressor stations, 4 valve stations, 2 underground gas storage facilities with a total working inventory of 1,000 Msm^3, 3 supply nodes including 1 liquified natural gas regasification (LNG) terminal with a working gas inventory of 80 Msm^3, and 17 city gate stations with hourly demand profiles. Of total gas consumption of roughly 86 million mmBtu in our system, city gate stations account for most gas consumption (62%), followed by gas-fired generators (roughly 16% but varies with versus without ID coordination), industry (14%), and exports (8%). With respect to supply, underground storage accounts for most (52%), followed by imports (32%) and the LNG terminal (16%).

We connect all 25 gas-fired power plants in the power system to the gas network. In total, the gas pipelines span 3,700 km and vary in diameter from 600 to 900 mm, and the compressor stations have a total available compression power of 240 MW. City gate stations and gas-fired power plants have minimum delivery pressures of 16 and 30 bar-g respectively. We assume a constant gross calorific value of 41.25 MJ/sm^3 for natural gas.

3.2.4 Power System Modeling

We optimize power system operations in the DA, ID, and RT markets with a unit commitment and economic dispatch (UCED) model in PLEXOS [52,68]. The UCED model minimizes power system operational costs subject to several constraints, including energy balance, reserve requirements, generator, and transmission constraints. We represent the transmission system using a DC-OPF approximation with fixed shift factors. We run the day-ahead UCED using forecasted wind and solar PV electricity generation, the real-time UCED using realized wind and solar PV electricity generation, and the intraday UCED with an assumed uniform improvement from forecasted to realized wind and solar PV electricity generation of 50% [69,70]. When determining coordinated power and gas operations, natural gas-fired generators are also subject to maximum fuel offtake constraints determined by gas system simulations in DA and ID runs.

3.2.5 Gas System Modeling

To capture the inherently dynamic operations of the gas network, we simulate transient hydraulics of the gas network using SAInt [53], which has been extensively validated and benchmarked [54,71]. The transient hydraulic pipeline model in SAInt is based on a system of one-dimensional nonlinear hyperbolic partial differential equations, derived from the laws of conservation of mass, momentum, and energy as well as the real gas law. The gas compressibility factor is computed from the Papay equation whereas the friction factor is calculated using the equations derived by Hofer [55]. In addition, SAInt models the control and constraints of the most important controllable facilities in the natural gas system, including gas compressor stations, metering and pressure reduction stations, underground gas storage facilities, and gas entry and exit stations. Users customize control and interactions between these facilities using an event-based control mode logic [54,55,71].

Through this dynamic simulation, we capture how constant changes in supply and demand affect pipeline pressures and linepack, the latter of which buffers short-term imbalances between supply and demand. Conversely, steady-state models of gas network operations [29,30] poorly approximate actual operations by assuming a zero-flow balance (i.e., total gas supply equals total gas demand), so we do not use them here. By simulating transient hydraulics, we solve a gas flow rather than optimal gas flow problem. This simulation of gas pipeline operations given certain constraints reflects common practice in the natural gas industry, which unlike the power sector does not typically use production cost optimization to determine operations and dispatch. Additionally, capturing transient behavior of gas networks within an optimization problem is the subject of ongoing research, particularly at real-world scales [48]. Given the applied nature of our research, we therefore chose not to solve for an optimal gas flow. To balance computational requirements with capturing the relatively slow response time of gas networks in our dynamic simulation, we use a time step of 30 minutes. Transient hydraulic simulation requires initial conditions, which we obtain from the prior simulation after the first period. For the first period, we initialize the simulation with a quasi-steady-state simulation.

3.2.6 Quantifying Value of Improved Intraday Coordination

To quantify the value of greater ID coordination between gas and electric power systems, we compare RT power and gas system metrics with and without ID coordination (i.e., when ID power system operations are and are not constrained by natural gas availability per ID gas network operations). We conduct our analysis for four weeks of the year, the one week per season that has the highest upward ramp in gas-fired generation (a proxy for power and gas coordination challenges) as determined by prior work [40]. Table 7 summarizes demand each week and Figure 16 provides the timeseries of hourly electricity demand for each week of our analysis. SDGE has a relatively flat seasonal demand profile, which might lead us to underestimate the value of ID coordination in systems with significant seasonal demand differences.

Table 7. Key Electricity Demand Values by Week. Wind and Solar Generation and Net Demand Descriptors Assume Dispatched Wind and Solar Generation Equal Maximum Potential Wind And Solar Generation, Although Our Used Model Permits Curtailment.

Week	1/29/2012	4/1/2012	9/23/2012	10/28/2012
Demand (MWh)	334,930	320,760	405,710	341,130
Net Demand (MWh)	276,650	221,660	347,340	288,510
Wind + Solar Generation (% of Demand)	17	31	41	15
Peak Demand (MW)	2,970	2,750	3,790	3,010
Peak Net Demand (MW)	2,940	2,640	3,680	2,990
Max Demand Ramp Up (MW/h)	350	270	340	430
Max Demand Ramp Down (MW/h)	-300	-280	-330	-300
Max Net Demand Ramp Up (MW/h)	560	370	290	430
Max Net Demand Ramp Down (MW/h)	-330	-330	-370	-300
Max Wind + Solar Penetration (% of Demand)	53	79	35	44

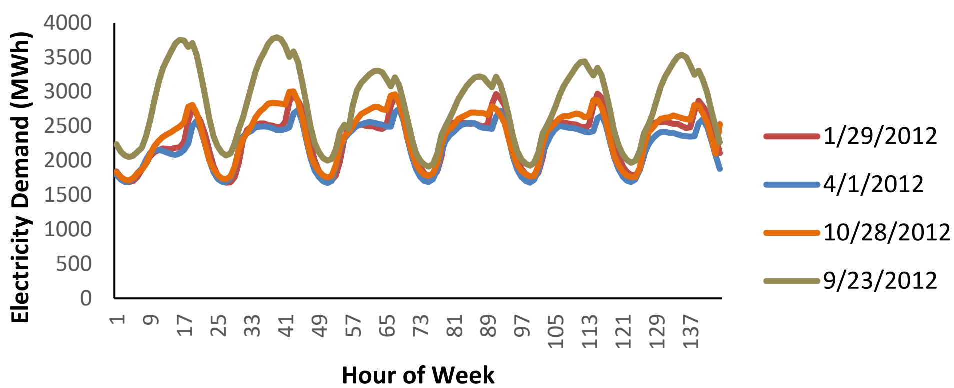


Figure 16. Time series of electricity demand in each week of our analysis.

3.2.7 Sensitivity Analyses

Given increasing penetrations of wind and solar power in most U.S. power systems, we test the sensitivity of our results to two key renewable parameters. First, we double hourly wind and solar PV installed capacity on our system from a combined 22% to 44% of total installed capacity. Second, we increase the ID renewable generation forecast improvement from 50% to 80%.

3.3 Results

3.3.1 Findings on Intraday Coordination

Across weeks and with and without ID coordination, we observe no non-served or dump energy or reserve shortages in real time in the power system, indicating supply and demand are in balance on an hourly basis and reserve requirements are completely fulfilled. Table 8 provides generation by fuel type summed across all weeks, which largely does not change with or without ID coordination. Natural gas provides over half of the generation mix, followed by nuclear, solar, wind, and hydropower. Oil provides negligible electricity generation.

Table 8. Rough Share of Generation by Fuel Type as a Percentage of Total Generation (1,403 GWh).

Fuel Type	Share of Total Generation (%)
Natural Gas	55
Solar	11
Nuclear	10
Wind	8
Geothermal	7
Hydro	5
Biogas	2
Coal	1
Biomass	1
Oil	0

Figure 17 illustrates how ID coordination changes RT generation by fuel type. In the week beginning April 1, or the week with the least electricity demand, ID coordination has no effect on generation by fuel type, indicating negligible gas network constraints in that week with or without ID coordination. In the remaining three weeks, ID coordination results in more natural gas-fired generation, mostly at the expense of more-expensive biomass-fired generation.

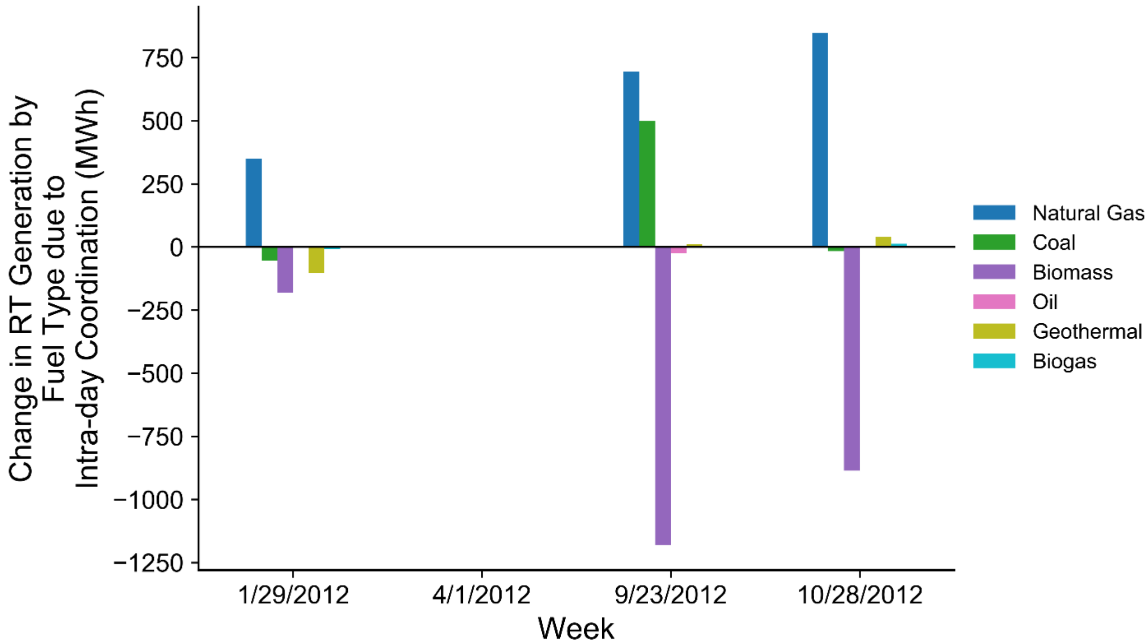


Figure 17. Change in RT electricity generation by week and fuel type with versus without ID coordination. Generation changes for all fuel types equal zero in the week beginning April 1, and generation changes for nuclear, wind, solar, and hydropower equal zero for all weeks. Generation changes for a given fuel type and week equal less than 1% of total weekly demand (see Table 7).

To better understand these observed changes in generation by fuel type, we quantify Figure 18 (top) how ID coordination changes redispatch of gas-fired generation during RT coordination, or the change in gas-fired generation during RT dispatch after accounting for gas network constraints. Regardless of ID coordination, numerous generators experience some redispatch during RT operations in response to gas network constraints. One generator, gen04, accounts for most redispatch, as it experiences significantly more gas delivery constraints than other generators. In response to curtailments at gen04 and other generators, some gas-fired generators increase their generation. Conducting ID coordination reduces redispatch due to RT coordination of nearly all generators. For instance, gen04 and gen36 experience roughly 50% and 10% respectively, of the redispatch changes due to ID coordination. By reducing curtailments, ID coordination also reduces the need for increased generation by other generators. Viewing redispatch by week rather than by generator (Figure 18, bottom) indicates ID coordination reduces redispatch of gas-fired generators during RT coordination in each week.

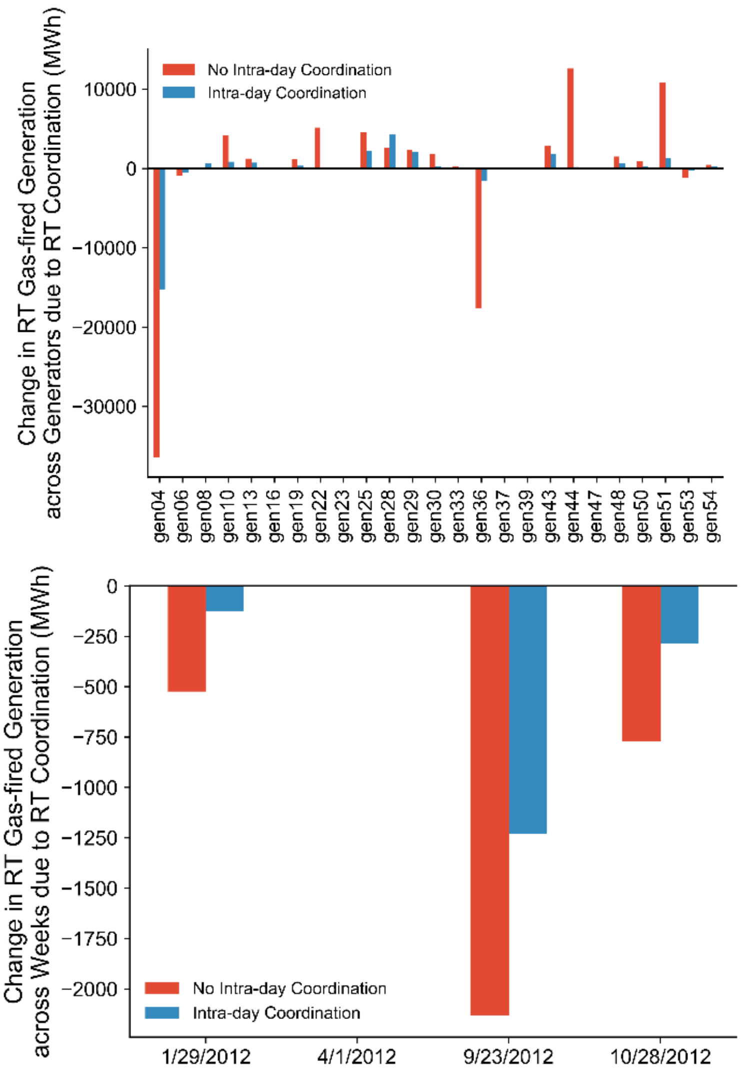


Figure 18. Change in gas-fired generation from RT pre- to post-coordination dispatch when ID power and gas coordination is performed (blue bars) and is not performed (red bars). The change in gas-fired generation is aggregated across weeks by generator (top) and across generators by week (bottom).

Figure 18 indicates how gas-fired generation changes in the RT market from the first to second power system dispatch after accounting for gas network constraints. However, because we approach this problem using a coordination platform that accounts for the full dynamics of the natural gas system, we can also account for natural gas offtakes resulting from the second ("coordinated") dispatch which might still not be fully deliverable due to gas network constraints. The quantity of this "non-served gas" is quantified in Figure 19. Non-served gas varies significantly across weeks, ranging from roughly nothing in the week with the least electricity demand to 225 thousand mmBtu (roughly 1% of total gas demand) in the week with the greatest electricity demand. In the three weeks with non-served gas, ID coordination reduces it by 65% or greater, indicating significant benefits of ID coordination for reducing gas network constraints in real time.

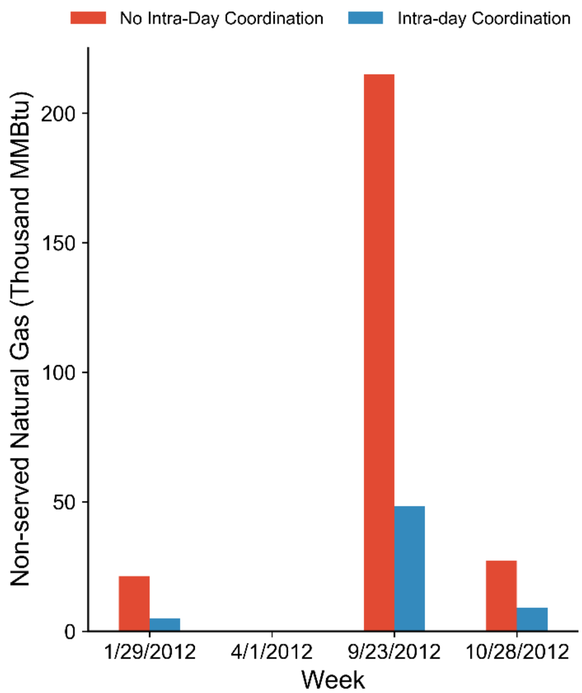


Figure 19. Non-served natural gas, or natural gas offtakes by gas-fired generators that cannot be delivered by the gas network, summed across generators by week with and without ID coordination. No non-served natural gas occurs in either coordination scenario in the week beginning April 1.

We quantify two types of monetary benefits that arise from ID coordination reducing RT gas network constraints. First, constraints can reduce the overall quantity of delivered gas, reducing revenues earned by the pipeline operator or gas supplier. In our analysis, ID coordination reduces total non-served gas by roughly 200 thousand mmBtu, which would increase revenues of the entities delivering that gas by $300,000 to $1,000,000 at gas prices of $1.5–$5/mmBtu, respectively[5]. Second, RT gas network constraints can result in start-up and operation of out-of-merit generators, increasing costs relative to a situation where no gas network constraints existed. By reducing RT gas network constraints (as demonstrated above), ID coordination can mitigate these cost increases by reducing RT out-of-merit start-ups and dispatches. Figure 20 illustrates RT total power system production costs with and without ID coordination by week. In the week beginning April 1, total power system production costs do not change, as no gas network constraints exist and ID coordination has no effect on operations that week. In all other weeks, ID coordination reduces total power system production costs by 1%–4%. Of those production cost reductions, 15%–25% are due to start-up cost reductions and 75%–85% are due to variable generation cost reductions.

[5] This range roughly corresponds to projections from the EIA's Annual Energy Outlook for the high and low gas price scenarios through 2020 after converting to $2020 [2]. At the time of this writing, Henry Hub gas prices were $2.4 per mmBtu.

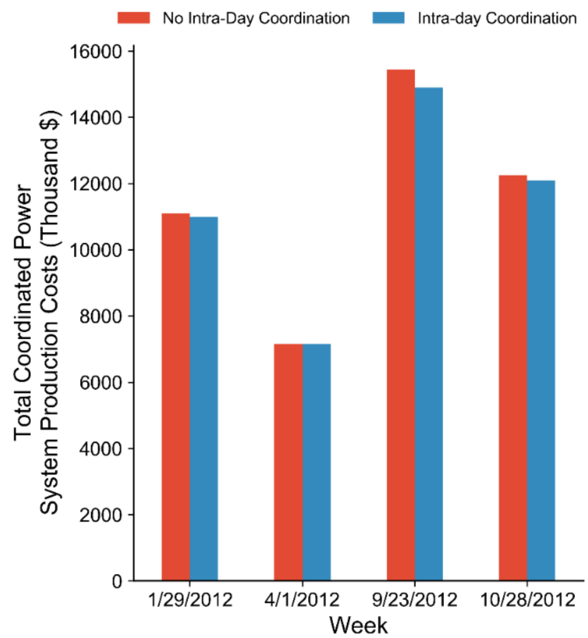


Figure 20. Total RT power system production costs with and without ID coordination by week.

3.3.2 Sensitivity Analyses

We test the sensitivity of our results to two key parameters: (1) an 80% (instead of 50%) forecast improvement for wind and solar generation from DA to ID market and (2) a doubling of wind and solar PV installed capacity from a combined 22% to 44% of total installed capacity.

3.3.2.1 Sensitivity to 80% Forecast Improvement

Figure 21 depicts RT total power system production costs and non-served natural gas for an assumed 80% uniform forecast improvement for wind and solar PV generation from the DA to ID. At an 80% ID wind and solar PV forecast improvement, ID coordination reduces non-served gas by 2–20 percentage points more than at a 50% ID forecast improvement, as the greater forecast improvement enables better ID commitment decisions of gas-fired generators. Consequently, non-served gas with ID coordination is 50%–99% less at an 80% forecast improvement than at a 50% forecast improvement. In fact, ID coordination with an 80% renewable generation forecast improvement eliminates non-served gas in one week and nearly eliminates it in the two others week. Thus, we find the value of ID coordination improves with better ID forecasts. We do not observe a similar benefit for reducing power system production costs, which are less than 1% different between forecast improvement values with and without ID coordination.

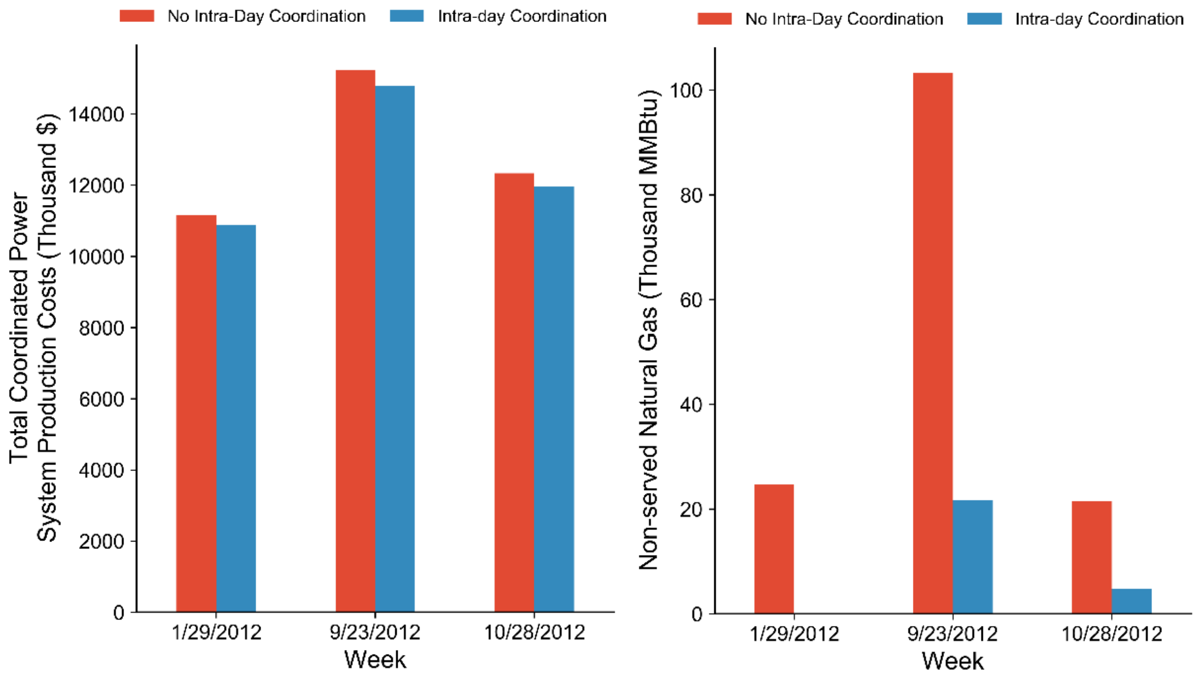
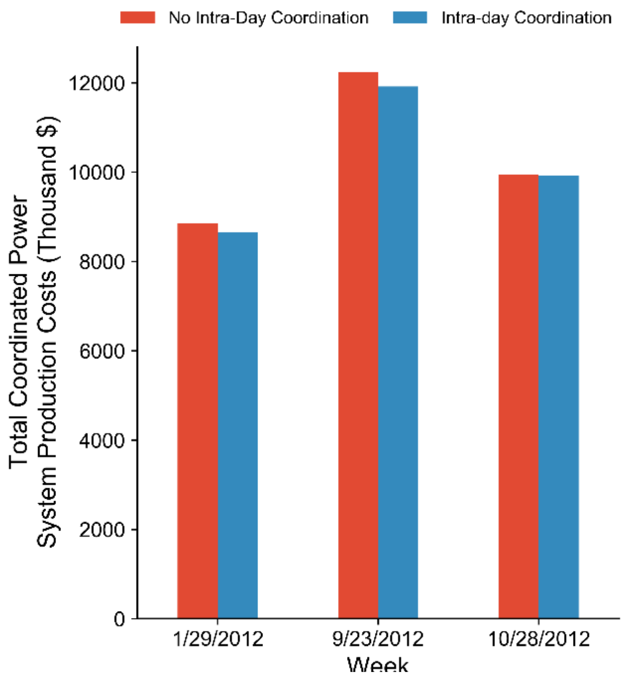


Figure 21. Total RT power system production costs (left) and non-served natural gas summed across generators (right) by week with and without ID coordination by week assuming a uniform 80% (instead of 50%) forecast improvement for wind and solar generation from DA to ID market.

3.3.2.2 Sensitivity to Doubling Renewable Capacity

Figure 22 depicts the same types of results for a doubling of wind and solar PV installed capacity from a combined 22% to 44% of total installed capacity. Doubling renewable energy generation capacity reduces power system production costs (by roughly 20%) and non-served gas (by greater than 75%) regardless of ID coordination because of renewable energy's low generation costs and reduced need for gas-fired generation. Intraday coordination yields similar reductions (in percentage terms) in power system production costs at both renewable generation levels. Conversely, ID coordination reduces non-served gas by 15–30 percentage points more at the higher renewable generation level, such that it virtually eliminates non-served gas in two weeks and nearly eliminates it in the other week. These results highlight greater gas network congestion benefits of ID coordination with less overall gas network utilization.



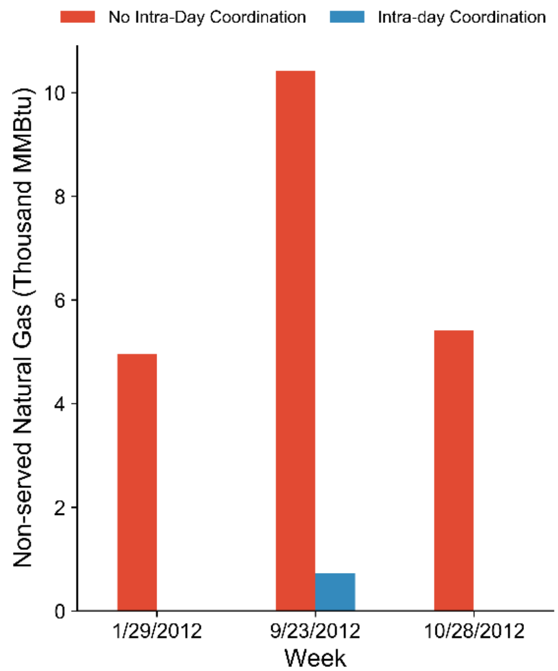


Figure 22. Total RT power system production costs (left) and non-served natural gas summed across generators (right) by week with and without ID coordination by week in the doubled renewable energy scenario.

3.4 Summary of Study 2

In this work, we coordinate power and gas operations by optimizing power system dispatch and simulating natural gas flows using a dynamic gas network model. We found significant benefits from ID coordination through reduced RT redispatch of gas-fired generators and through reduced increased gas deliverability to natural gas generators. Both metrics indicate ID coordination reduces RT gas network constraints and unexpected curtailment of gas-fired generators. Reduced RT deliverability constraints, in turn, facilitate increased revenues for pipeline operators and/or gas marketers and reduced total power system production costs, yielding consumer benefits. Via sensitivity analysis, we found greater reductions in gas network constraints with better ID renewable energy forecasts and at greater renewable energy penetrations, suggesting greater value of ID coordination with ongoing renewable growth.

The benefits of ID coordination will likely vary with the flexibility of the power and gas systems in question. In gas systems, market-area gas storage and gas storage co-located with gas-fired generators can provide significant flexibility. In our gas system, roughly 50% of the supplied gas came from underground storage facilities. Systems with less available storage could experience greater benefits of ID coordination. In power systems, flexibility is often derived from gas-fired generators, but it could instead be sourced from other technologies such as electricity storage and demand response or from dual-fuel capabilities. Storage and demand response penetrations will likely increase to compensate for variability in renewable energy generation in low-carbon systems [72]. In so doing, these technologies might also mitigate gas network constraints. Many generators already use dual-fuel capabilities, but they could be more widely adopted to mitigate short-term gas network delivery concerns. Future research should explore how the value of coordination interacts with the flexibility of each system.

The motivation for this analysis was to understand the benefits of an added ID market per FERC Order 809, which generally aims to improve ID gas and electricity coordination. Our results indicate Order 809 will likely yield gas deliverability and cost benefits. As gas and electric power systems become increasingly intertwined, these benefits might increase and place further importance on ID coordination. Other policies and regulations that facilitate coordination between electricity and natural gas network planners and operators will likely become more valuable in terms of economics and reliability as penetrations of natural gas-fired and variable renewable energy shares of electricity generation increase in power systems in the United States and around the world. Future research should quantify the benefits of ID coordination on a real interconnected power and gas system, which would yield a better overall analysis of FERC Order 809 benefits.

Several other opportunities for future research exist. First, to address concerns regarding sufficient flexibility in the natural gas system to support large changes in fuel offtakes at high renewable penetrations, future research should analyze dynamic natural gas system operations under large unexpected deviations in wind and solar PV generation from forecasts. Second, while we employ a fully dynamic gas network simulation, other research has used simplified representations of the gas network through linearization and omitted features. Future research should quantify when and to what extent these two approaches produce diverging results. Finally, this research focuses on operations that do not involve contingencies (e.g., losses of transmission lines or generators). Future research should quantify the extent to which ID coordination could mitigate the consequences of these actions.

4 Study 3: A Case Study of Coordinated Electricity and Natural Gas Operations in Colorado

4.1 Introduction

In the final study of this report, we apply our coordination platform to study the benefits of coordination for a real system, namely a model of the Colorado electric power and gas systems. In this system, the gas generators have firm transportation contracts, meaning that these generators are not competing for interruptible pipeline capacity with other regional demand. Two scenarios are evaluated, including the following:

- A 2018 generation mix, with approximately 33% generation from natural gas and 27% from combined wind and solar PV power
- A projected generation mix for 2026, with about 25% generation from natural gas and 52% from combined wind and solar PV power.

In addition to evaluating the benefits of coordination between the two systems, we also explore whether introducing time-variant (shaped flow) nominations to the gas network can help improve operations of the two systems.

4.2 Overview of the Coordination Framework

This section reviews the methods used to design our coordinated natural gas and power system simulation. We first provide an overview of coordination structure, after which we describe the modeling behind both the power system and the gas network. Finally, we provide details on the case study used for the analysis.

4.2.1 Algorithm for Coordinated Operation

Algorithm 1 (Figure 23) provides a high-level overview of the proposed framework for the coordination between the electricity and natural gas systems at each DA, ID, and RT market level. In each market run, the power system is initialized using conditions from the previous RT solution. Lower level markets (i.e., ID and RT) take unit commitment information from the appropriate upper level market. Data on forecasts for wind and solar PV power—which vary in accuracy by market level—and load are also obtained for the appropriate period. We then run the power system optimization to determine the least-cost set of generators needed to meet system load given system conditions.

From the initial power system run, we obtain and pass relevant inputs—such as nominations for natural gas offtakes from generators—to the gas simulation. After running the gas simulation, we compare feasible delivered gas quantities with the nominations from the power system. In cases where nominations are greater than delivery amounts, we impose a constraint on the nominations for that plant in the next cycle. We then rerun the power system optimization, which is now coordinated with gas simulation input. These coordinated power system results are then provided to the gas simulation for final verification of feasibility, from which final metrics (including unserved gas) are estimated.

Although we focus on passing information related to constraints on gas delivery, this framework could be used to pass other information between entities, such as spatially-defined marginal prices. Because most gas operators do not use location-based pricing, we focus on gas constraints in this work; future studies might consider how to integrate pricing signals across the gas and power system models [24,25].

```
Inputs: Markets_DA, ID_H, RT_H,
Markets_ID ←24/ ID_H, Markets_RT ← ID_H / RT_H
for iter_DA = 1 to Markets_DA
    run electricity DA market
    update parameter Offtakes_DA_PM, Commit_DA
    run DA gas market with nominations from Offtakes_DA_PM
    update Offtakes_DA_GM,
    UnserGas_DA ← Offtakes_DA_PM - Offtakes_DA_GM
    rerun electricity DA market w/ constraint from Offtakes_DA_GM
    update parameter Offtakes_DA_PM, Commit_DA
    rerun gas DA market with nominations from Offtakes_DA_PM
    update Offtakes_DA_GM,
    UnserGas_DA ← Offtakes_DA_PM - Offtakes_DA_GM
    fix commitments for ST-coal/ST-gas units using Commit_DA
    for iter_ID = 1 to Markets_ID
        run electricity ID market
        update Offtakes_ID_PM, Commit_ID
        run gas ID market with nominations from Offtakes_ID_PM
        update Offtakes_ID_GM,
        UnserGas_ID ← Offtakes_ID_PM - Offtakes_ID_GM
        rerun electricity ID market w/ constraint from Offtakes_ID_GM
        update parameter Offtakes_ID_PM, Commit_ID
        rerun gas ID market with nominations from Offtakes_ID_PM
        update Offtakes_ID_GM,
        UnserGas_ID ← Offtakes_ID_PM - Offtakes_ID_GM
        fix commitments for CC-gas units using Commit_ID
        for iter_RT = 1 to Markets_RT
            run electricity RT market
            update parameter Offtakes_RT_PM, Commit_RT
            run gas RT market with nominations from Offtakes_RT_PM
            update Offtakes_RT_GM,
            UnserGas_RT ← Offtakes_RT_PM - Offtakes_RT_GM
            rerun electricity RT market w/ constraint from Offtakes_RT_GM
            update Offtakes_RT_PM, Commit_RT
            rerun gas RT market with nominations from Offtakes_RT_PM
            update Offtakes_RT_GM,
            UnserGas_RT ← Offtakes_RT_PM - Offtakes_RT_GM
        end for
    end for
end for
```

Figure 23. Algorithm 1: Coordination of electric power and gas system (implemented in Python).

4.2.2 Modeling of the Power System

We use the commercially available production cost modeling tool PLEXOS to optimize power system operations in the DA, ID, and RT markets [73]. The optimization of power system operations consists of the minimization of the total production cost—including costs associated with fuel, variable operations and maintenance (VO&M), and start up and shut down—associated with the unit commitment and economic dispatch decisions. The unit commitment and economic dispatch problems are formulated in PLEXOS as mixed integer linear programming (MILP) models based on the DC-OPF. The DA electricity market is simulated with a 24-hour optimization horizon using hourly resolution plus an additional 24-hour look-ahead window. Similarly, the ID and RT markets are simulated with 8-hour and 1-hour optimization horizons and 16-hour and 2-hour look-ahead windows, respectively. The relative optimality gap was set to 0.1%.

The DA market simulations use forecasted wind and solar PV generation profiles, while the ID market simulations are based on a given assumed uniform forecast improvement from the DA wind and solar PV forecasts. On the other hand, RT market simulations use realized wind and solar PV generation profiles. Furthermore, the DA commitments of coal and gas steam turbines, which are relatively inflexible generators, are fixed in the ID and RT markets. In contrast, natural gas combined cycle units, which are relatively flexible generators, are recommitted in the ID market, with those commitments fixed in the RT market, while gas combustion turbines can recommit in RT.

4.2.3 Modeling of the Natural Gas System

We employ the commercially available gas network simulation tool SAInt [53] (see Section 2.1.2) to perform a transient hydraulic simulation of the operation of the natural gas system. SAInt consists of a system of one-dimensional, nonlinear hyperbolic partial differential equations, obtained from the laws of conservation of momentum, mass, and energy as well as an equation of state for real gases. The transient simulation accounts for the effects of variations in gas supply and demand on the pipeline pressure and linepack, the latter of which can be used to offset short-term imbalances between natural gas demand and supply.

By modeling transient hydraulics, SAInt solves a gas flow simulation instead of an optimal gas flow problem. Accordingly, SAInt does not guarantee optimal dispatch of the natural gas system. This approach is, however, similar to simulations that gas system operators use to inform dispatch, and thus captures how today's pipeline operators might respond to coordinate operations with the power sector.

To capture the relatively slow dynamics of the natural gas system, the dynamic simulations use 30 minutes time steps. The initial conditions for the transient hydraulic simulations are obtained from the prior gas network simulation after the first timestep; for the first timestep, a quasi-steady-state simulation is used to provide the initial condition of the dynamic simulation.

4.3 Case Study

We test our coordination framework on a case study using data from Colorado's power and natural gas systems. The PLEXOS model for the power system is adapted from a model developed previously for the Western Electricity Coordinating Council [74]. This model is roughly representative of the 2018 Colorado grid and includes 2 regions; 1,476 buses; and 1,841 transmission lines, along with just under 21 GW of generating capacity.

Because the value of coordination is likely to increase with higher penetrations of wind and solar PV power sources, we also test our framework on a version of the Colorado system with higher renewable penetrations. To achieve this, we adjust the installed generation capacity of coal, wind, and solar PV technologies to represent the projected generation mix in Colorado by 2026 [75]. The corresponding annual generation mix and installed generation capacity are described in Figure 24 and Table 9 respectively. Generation from wind and solar PV power plants increases from 27% to 52% in the 2018–2026 timeframe; generation from coal decreases from 39% to 22% and generation from natural gas decreases from 33% to 25% during the same timeframe.

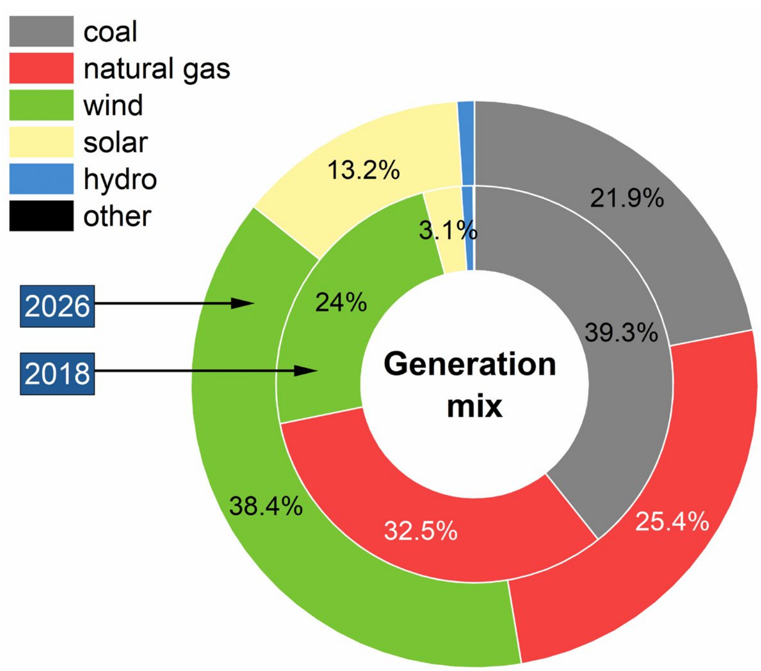


Figure 24. Colorado's generation mix in 2018 based on current Colorado fleet, benchmarked to actual generation levels; 2026 fleet based on plans developed by Western Resource Advocates to meet Xcel targets [75]**.** Generation profiles for new wind and solar plants are assumed to be same as the existing plants, which total generation scaled up to match the new capacity.

Table 10 provides forecast errors for wind and solar PV power generation from DA to RT markets, including the normalized mean absolute error (NMAE) and the normalized root mean square error (NRMSE). Wind power forecast errors metrics are higher than those for the solar PV, reflecting higher uncertainty in wind availability; we note however that nighttime hours were not removed from the calculations of the solar PV power forecasting errors, which deflates forecast errors for solar PV. Additionally, wind and solar PV power forecast improvements from DA to ID markets was assumed to be 20% [70].

Table 9. Installed Capacity of Power Plants in the Colorado's Power System [74]**.**

Technology	Year	Installed Capacity (GW)
Coal	2018	3.88
	2026	2.42
Gas	2018	7.58
	2026	
Wind	2018	6.02
	2026	9.81
Solar	2018	2.25
	2026	9.88
Hydropower	2018	0.73
	2026	
Other	2018	1.5
	2026	

Table 10. Forecast Error Values for Wind and Solar Generation Profiles from DA to RT Markets.

Metric	Forecast Error (%)		Reference Forecast Error (%) [76]	
	Wind	Solar	Wind	Solar
Normalized mean absolute error (NMAE)	10.6	7.4	3.6–6.2	1.1–2.4
Normalized root mean squared error (NRMSE)	4.5	2.2	4.7–8.0	2.7–6.1

For the gas model, we use data from a natural gas network operator in Colorado covering most of the Front Range region of the state. The data include details on pipelines, compressors, supply, and offtake nodes; a simplified schematic of the gas network is provided in Figure 25. The offtake nodes include gas generators representing about 70% of the natural gas generator offtakes from the PLEXOS model, as well as information on demand profile for local distribution and other contractual obligations consumption. Data on the minimum delivery pressures for offtake nodes and operating constraints for compressors (e.g., maximum driver power, compression ratio) are accounted for as operational constraints in the gas simulation. The data also include information on the hourly demand from contractual obligations other than natural gas generators, such as local distribution companies (LDCs) that distributed natural gas for heating.

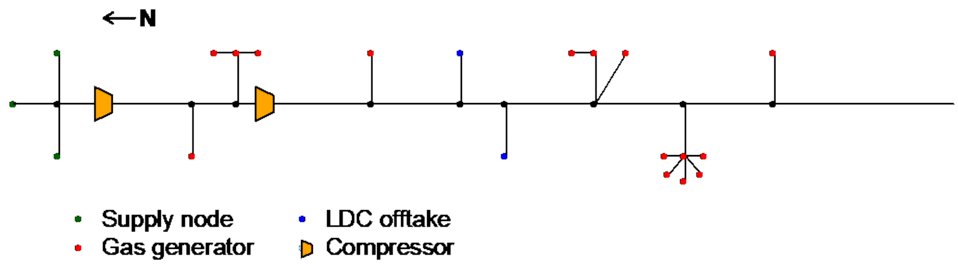


Figure 25. A simplified diagram of the gas network in the Front Range region of Colorado.

To keep the model tractable, we test our case study on four weeks for 2018 and 2026. We select one week from each season (spring, summer, fall, and winter) in which the natural gas demand from the power sector is highest, as these weeks are likely to be the times when coordination between the two systems is critical. The selected weeks are as follows:

- June 2–8 (spring)
- July 14–20 (summer)
- November 17–23 (fall)
- December 12–18 (winter)

Finally, we also test scenarios intended to explore the effects of moving from ratable to shaped flows in the gas cycle nominations. In the ratable flow setup, gas offtakes from the DA and ID power system model are averaged across the optimization window, and this average is submitted to the gas model (RT flows are still allowed to fluctuate by hourly). In the shaped flow setup, hourly gas offtakes are submitted as hourly nominations directly from PLEXOS to SAInt. Figure 26 provides and illustration of the difference between ratable and shaped flow nominations.

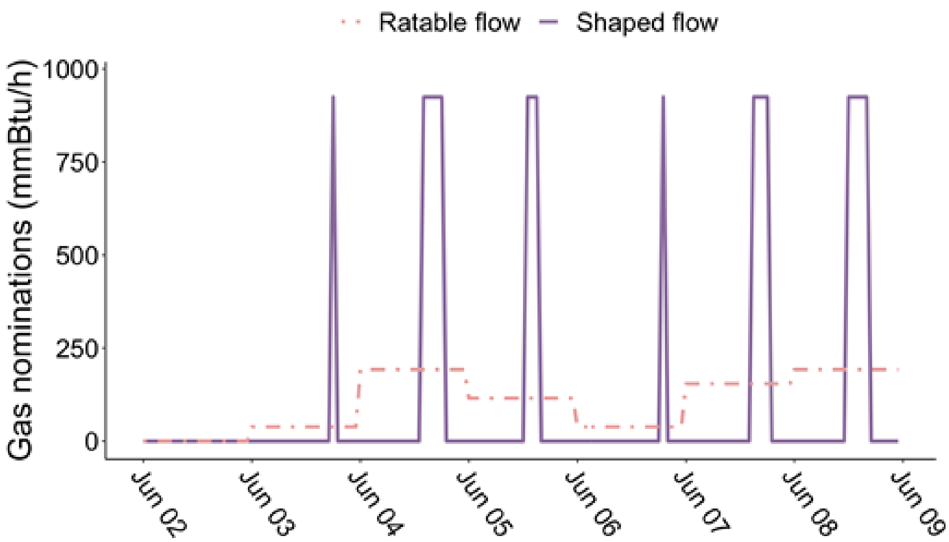


Figure 26. Hourly natural gas nominations from one combustion turbine during the June week. The plot illustrates the difference between ratable gas nominations—in which the nomination submitted to the pipeline operator is the average of hourly gas offtakes over 24 hours, with each hour representing 1/24th of the total daily offtake—which serves as the current default, and shaped flow nominations—in which nominations are allowed to vary by hour.

4.4 Results

To discuss the results, it is helpful to provide the following terminology to describe analysis at different levels of iteration between the power and gas models:

- **Power system only:** results from the first iteration of the power system model, before any communication with the gas network.
- **Co-simulation:** results after simulating gas offtakes from the power system model in the gas network; indicates whether gas be delivered but has not yet reoptimized the power system in response to gas constraints.
- **Coordination:** results after rerunning the power system in response to constraints from the gas simulation.

To explore the value of coordinated operations, we examine the dispatch of generators under different levels of coordination. We characterize unserved load—cases where generation is insufficient to meet load that might require out-of-market operator interventions—that occurs from curtailed gas generator operations. Finally, we quantify unserved natural gas due to gas network constraints. Although the DA and ID markets are important for capturing uncertainty and the evolution of commitments in dispatch, we focus on presenting results from RT markets, as those most closely represent the final decisions of the system.

4.4.1 Power System Operations with and without Coordination

Figure 27 provides total hourly generation by fuel type for the July and November cases using ratable flows. July represents a week with sustained, high electricity demand coupled with low renewable generation availability, resulting in high demand for offtakes from natural gas generators over multiple hours. The November case represent a period of high wind variability, with some hours of little generation from wind and other hours in 2026 where wind needs to be curtailed. A similar plot of the June and December weeks is supplied in Figure 28.

Before coordinating with the natural gas network (i.e., power system only), PLEXOS dispatches a mix of coal, natural gas, wind, and solar PV to meet total load in both weeks. In the 2026 case, less coal is dispatched due to a combination of plant retirements and increased renewable generation, the variability of which reduces the incentive for dispatching coal plants with relatively long minimum up times. Natural gas combined cycle and combustion turbines are used throughout the week to meet demand when wind output is reduced; as a result of increased wind generation and reduced generation from coal, natural gas ramps frequently through the 2026 case. Although higher penetrations of solar reduce the need for peaking gas generation in the middle of the day in 2026, low wind availability in the June and July weeks results in increased average gas generation in the evening hours when solar PV generation is unavailable.

When simulating the gas offtakes from the power sector in the gas network (co-simulation), we find a number of hours when the gas requested by generators cannot be delivered and generation must be curtailed due to gas deliverability constraints. If unaddressed through out of market operator interventions, these curtailments would translate into fairly large amounts of unserved load toward the end of the week. However, redispatching the power system based on these constraints (coordination) enables a shift away from gas offtakes at constrained nodes, increasing gas generation and decreasing unserved load.

Total unserved load by week, year, and coordination scenario is summarized in Figure 29. There is virtually no unserved energy in the initial power system optimization (power system only); however, when gas curtailments are imposed from constraints in the gas network (co-simulation), large amounts of unserved load occur. This represents generation that cannot be delivered by gas generators and would either need to be left unserved or rectified using potentially costly out-of-market interventions by the system operator. If the power system is reoptimized based on input from the gas network (coordination), the amount of gas curtailment and unserved load is substantially reduced, although still higher than the unconstrained initial dispatch. With the exception of the summer week (July), unserved load tends to be higher in 2018 relative to 2026, reflecting the increase amount of renewable generation coupled with no assumptions of load growth.

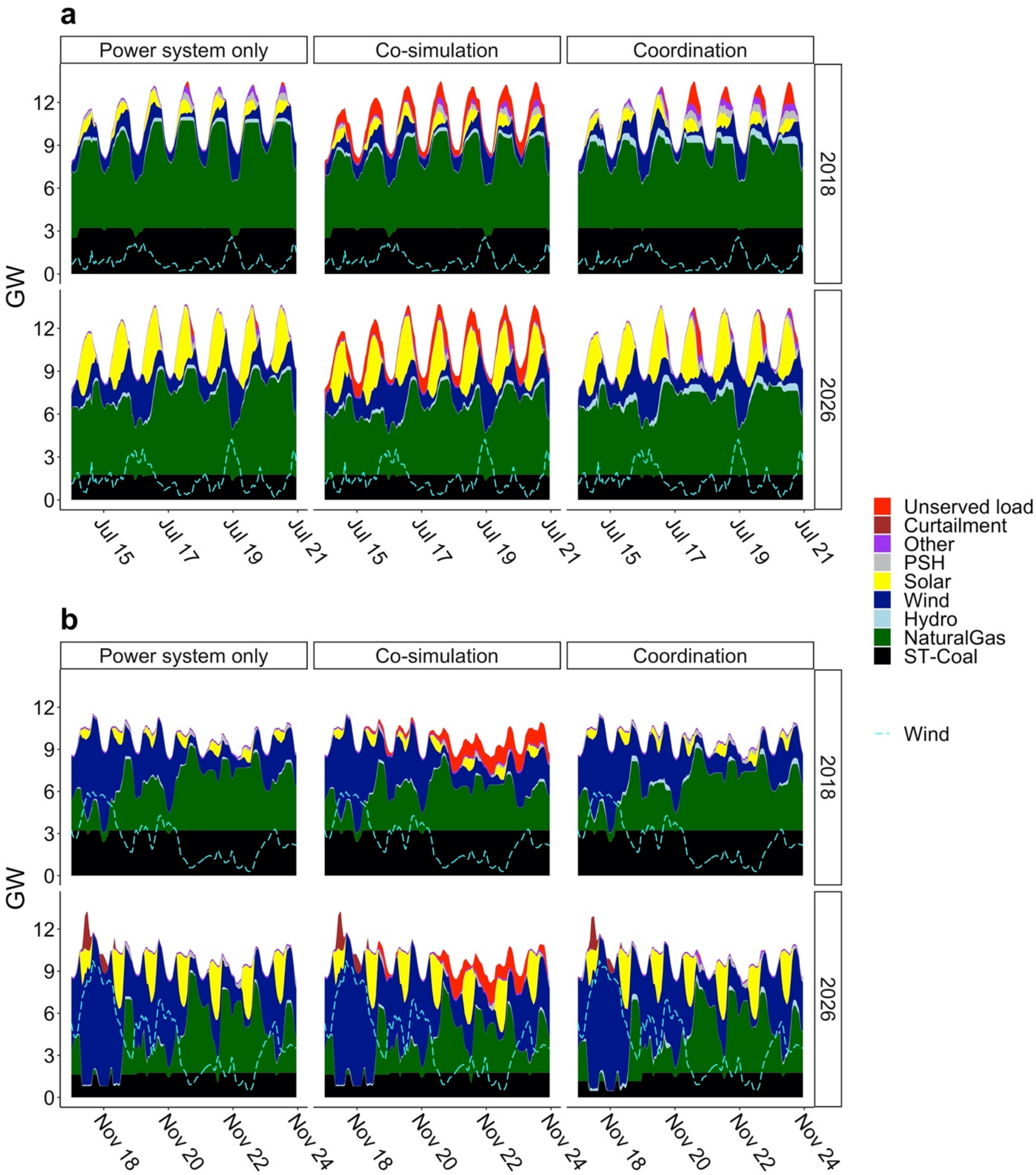


Figure 27. Hourly RT dispatch by fuel type for the July (a) and November (b) scenarios at different levels of coordination (power system only, co-simulation, and coordination). Curtailed gas generation at the co-simulation and coordination levels is treated as unserved load. The dashed line illustrates available wind generation, highlighting its variability. Dispatch results are shown for scenarios using ratable flows at the DA and ID levels but are similar with shaped flows.

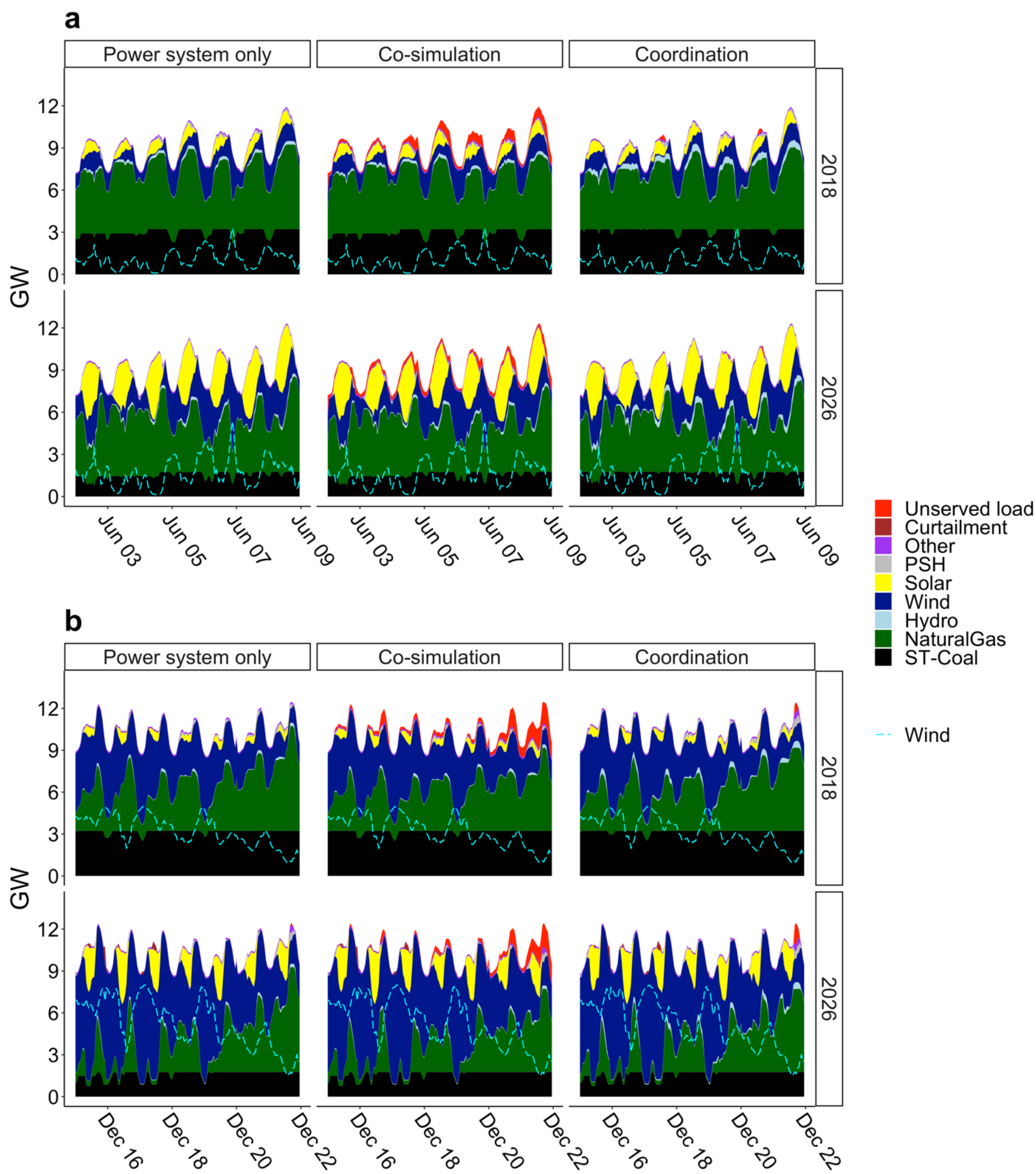


Figure 28. Hourly RT dispatch by fuel type for the June (a) and December (b) scenarios at different levels of coordination (power system only, co-simulation, and coordination). Curtailed gas generation at the co-simulation and coordination levels is treated as unserved load. The dashed line illustrates available wind generation, highlighting its variability. Dispatch results are shown for scenarios using ratable flows at the DA and ID levels but are similar with shaped flows.

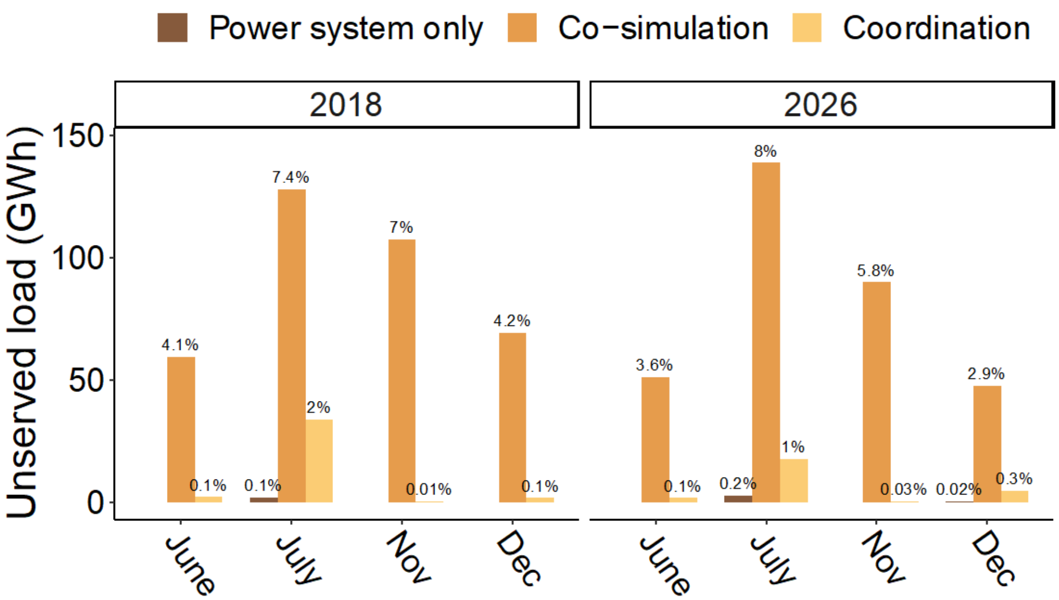


Figure 29. Total unserved load by week, year, and coordination scenario (power system only, co-simulation, and coordination). Numbers indicate unserved load as a percentage of total load that week. Results are shown for scenarios using ratable flows at the DA and ID levels but are similar with shaped flows.

Without accounting for the cost of unserved energy or out-of-merit operator intervention to handle shortages in supply, we find that the total cost increase when moving from the power system only to the coordination case is relatively small. Depending on the week of analysis, coordination increases total system costs by 0.5%–4.3% for a system with total weekly costs around $33-43 million per week in the power-system only case, with the largest cost increases occurring in the July and November cases. Costs come in part from increased fuel costs and VO&M expenses as less-efficient generators are dispatched to meet generation curtailment from other gas generators. In addition, because gas offtake constraints can vary substantially by hour, imposing gas constraints can increase costs associated with start-ups. However, start-up and VO&M are a small fraction of total costs, with fuel expenses dominating. Although start-up costs increase from 2018 and 2026 as more ramping is required to balance renewables, these increase costs are dwarfed by the cost savings from avoided fuel. If the cost of out-of-merit power sector interventions are valued at $2,000 per MWh[6], coordination reduces operator intervention costs from $730 million to $75 million in 2018 and from $650 million to $50 million in 2026; these savings substantial outweigh the additional cost from re-dispatch in the coordination case.

4.4.2 Delivered and Unserved Natural Gas from the Gas Network

Coordination between the electric power and natural gas systems not only reduces the need for costly redispatch, but also serves to reduced unserved natural gas. Figure 30 illustrates total delivered and unserved natural gas by gas network node across all weeks for the co-simulation and coordination scenarios. Under the coordination scenario, gas generators at stressed areas of

[6] This number is based on the supply price cap in DA and RT wholesale markets as set by FERC in Order 831, and represents the price limit for incremental energy offers that grid operators can include in their calculation of locational marginal prices: https://ferc.gov/sites/default/files/2020-06/RM16-5-000.pdf

the network (i.e., Nodes 29 and 31) reduce their demand, thus greatly reducing the amount of unserved natural gas at those locations. The reduced nominations from these two nodes enables generators at other nodes to increase their offtakes, compensating for the reduction in generation from other nodes. Notably, most unserved gas is concentrated at these two nodes, which are located just north of the second compressor station (see diagram in Figure 25). This junction serves as a bottleneck for gas being delivered from the north end of the system—where the supply is located—to the south end where most of the demand is concentrated.

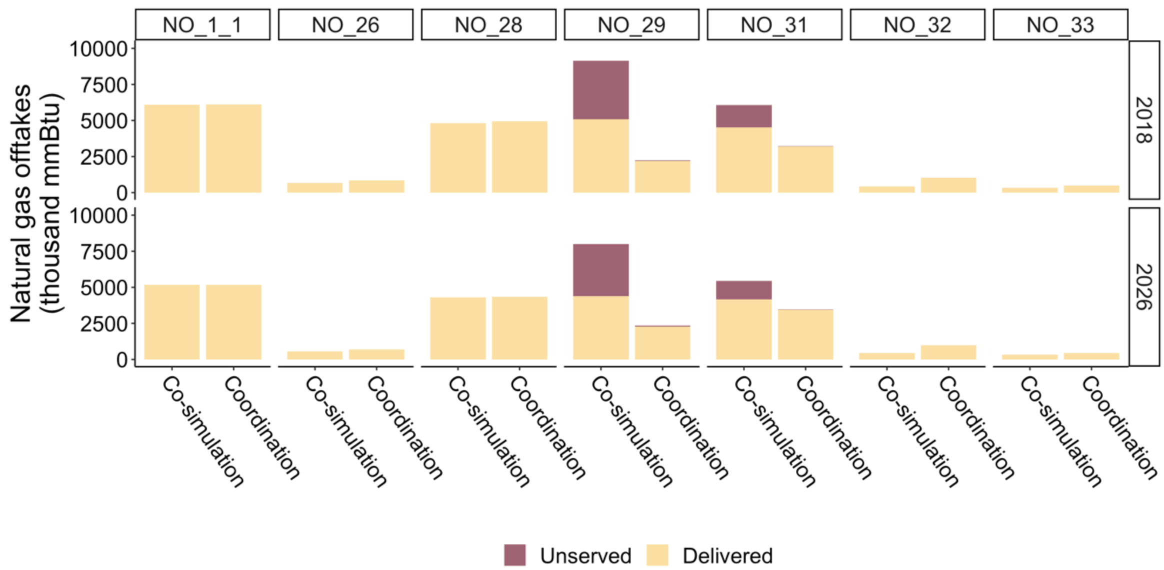


Figure 30. Total RT delivered and unserved natural gas by gas network node (see map in appendix) across all scenario weeks, by coordination scenario for both 2018 and 2026. Results are shown for scenarios using ratable flows at the DA and ID levels but are similar with shaped flows.

Figure 31 summarizes hourly delivered and unserved natural gas in the RT market at the co-simulation stage (i.e., after SAInt is used to curtail unavailable gas but before redispatch of the power system through coordination). Gas delivery is divided into demand from natural gas generators in the power sector and demand from LDCs and other contracted demand. Gas demand from the power sector is highest in the June and July weeks, when net load in the power sector is highest due to high demand and relatively low wind availability. Despite the fact that total demand from generators is about 20% lower in the November and December weeks relative to July, peak gas demand is only 6% lower in the fall and winter cases relative to the summer. Furthermore, although total natural gas demand declines from 2018 to 2026, peak demand in the November and December weeks increases by 3%–7%; this shift reflects the need to accommodate ramping by natural gas generators to meet larger swings in renewable generation availability, which is dominated by wind in the November and December weeks.

Figure 31 also highlights some of the patterns in unserved natural gas from the gas network. In the 2018 June and July cases—when demand from gas generators is highest—unserved natural gas follows a diurnal pattern, peaking during the middle of the day when demand for gas is highest from the power sector. In contrast, there is more volatility in unserved gas in the November and December cases; in these scenarios, gas demand fluctuates on the basis of wind availability. As more variable renewable resources are introduced into the system in the 2026 scenario, the variability in unavailable natural gas increases in all weeks. In the June and July cases, the correlation of renewable energy and unserved natural gas decreases from about -0.16 and -0.18 in 2018 to close to -0.59 and -0.44 in 2026; this reflects an increasingly strong inverse correlation between the variables as more renewables are added to the system. The inverse correlation between the two remains high across the two years for the November and December case (between -0.75 and -0.83), but the standard deviation of hourly unserved gas increases by 13% for the November week, indicating higher volatility.

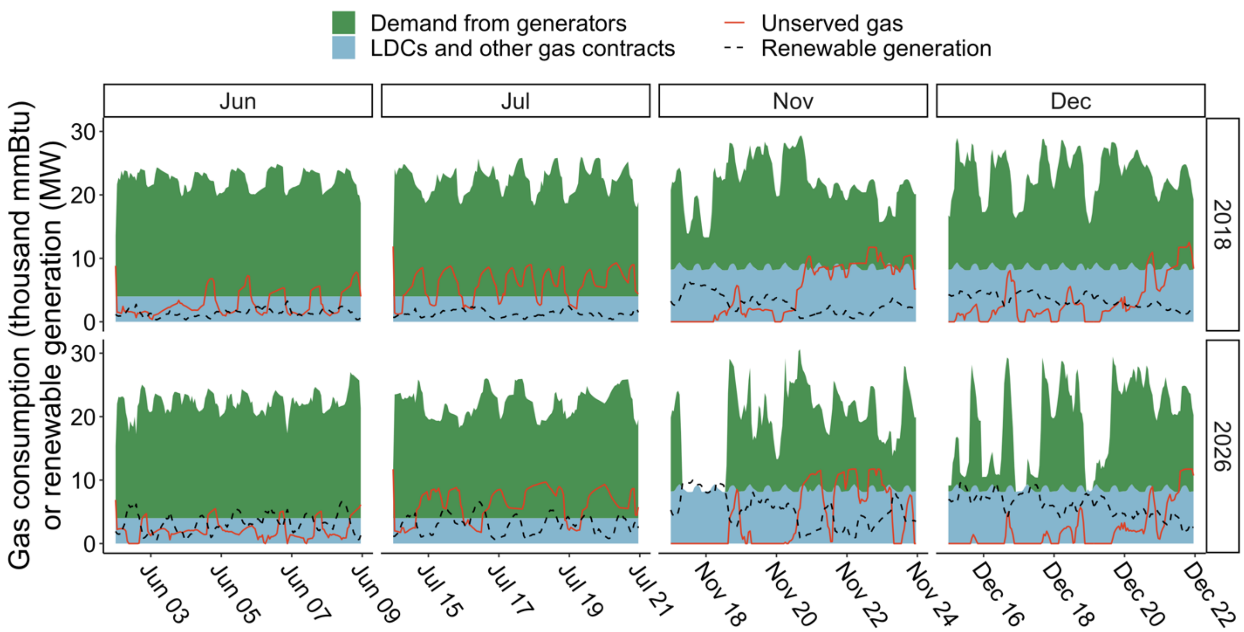


Figure 31. Total gas offtakes by generators and other contracted demand (e.g., LDCs) from the gas network at the RT co-simulation level. Contracted demand based on historical data from the gas network operator. Offtakes are shown for each week and year run. Lines indicate the corresponding amount of unserved gas (in thousand mmBtu) and the amount of available renewable generation (in MW).

Although the June and July weeks are comparable to November and December in terms of the total quantity of unserved natural gas, the factors leading to unserved gas are different. In June and July, high gas offtakes levels from gas generators across consecutive days means that the system is operating at high capacity. The system is thus primarily constrained by the need to move gas through the system while also maintaining pressure constraints at all the nodes. With multiple consecutive hours of high demand, the system does not draw down from linepack to fulfill offtakes in order to ensure it can meet pressure requirements at offtake nodes.

In contrast, the November and December weeks are characterized by high demand but high variability. In these scenarios, unserved gas seems driven in part by pressure and power constraints at one of the main compressor stations used to move gas from supply in the north to demand in the south. All the hours with the compressor operating at its maximum power occur in November (about 30% of hours in the week in 2018) or December (about 6% of hours). The median unserved gas in those hours is 1–2 orders of magnitude larger than when the constraint is nonbinding, suggesting that this compressor serves as a bottleneck for the ramping required by gas generators. Unlike the June and July weeks, the system frequently meets gas demand from generators by drawing down from linepack. This is possible because of higher variability, meaning that diminished linepack can be replenished in hours when wind generation returns and demand for gas offtakes is reduced.

Figure 32 illustrates the change in total unserved natural gas between the co-simulation and coordination scenario for each week and year modeled. The plot demonstrates that total unserved gas in the co-simulation scenario is highest in July—when demand is highest—but is relatively evenly split across the weeks modeled. Just one round of redispatch of the power sector based on communication of constraints from the gas model (i.e., the coordination scenario) serves to reduce unserved gas by upwards of 97% relative to co-simulation. After accounting for changes to gas consumption based on redispatch, the reduction of nonserved gas in the coordination scenario increases total delivered natural gas by approximately 4.4%.[7] If natural gas prices are $2.5/mmBtu, this increase in delivered gas would represent an additional $1.7 million in revenue for the entities responsible for delivering natural gas for these four weeks ($1 million using a gas price of $1.5/mmBtu and $3.3 million with a price of $5/mmBtu).

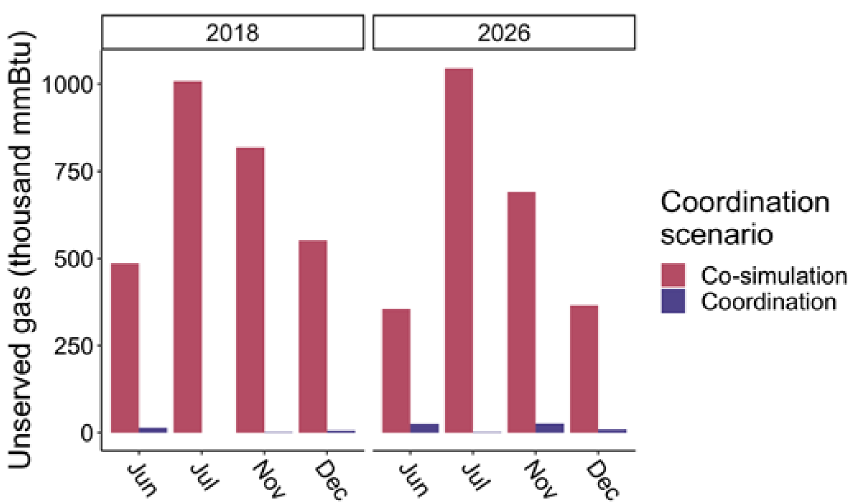


Figure 32. Total unserved natural gas (in thousand mmBtu) by week for the co-simulation and coordination scenarios; results are shown using ratable flows by simulation week and year.

[7] This estimate includes redispatch of plants within the gas network modeled as well as increased gas offtakes from generators that are in the power system but outside the gas network. Although dispatch from out of network generators increases with coordination, total offtakes from these plants typically represents less than 30% of all offtakes in any given week.

Figure 33 presents the difference in unserved gas across simulations using ratable and shaped flows for the DA and ID markets. Generally, ratable flows lead to more unserved gas than the use of shaped flows in both the co-simulation and coordination stages. Under co-simulation, ratable flows result in about 4% more unserved gas in 2018 and comparable amounts in 2026. Although total unserved gas is greatly reduced in the coordination scenario, we find that ratable flows result in almost three times more unserved gas in the 2026 case. This is likely due to the fact that the higher penetration of renewables in 2026 results in greater ramping requirements (see Figure 34); these higher ramping requirements are better accommodated when more temporally granular offtake nominations are passed to the gas network in the forward looking DA and ID markets.

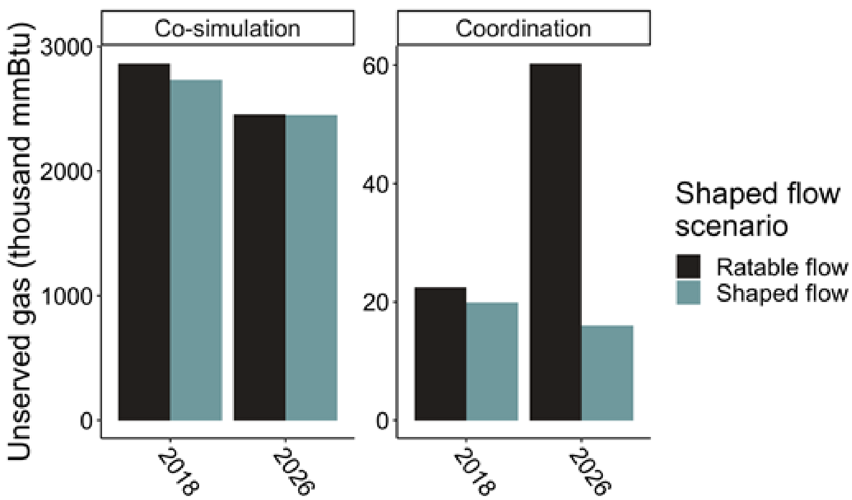


Figure 33. Total unserved natural gas (in thousand mmBtu) when using constant flows at the DA and ID market levels (ratable) or when allowing hourly gas offtakes from generators in those markets (shaped flow). Both scenarios allow hourly offtakes at the RT market levels. Results are shown for both run years and the co-simulation and coordination scenarios; note the difference in the scale of the y-axis across the panels.

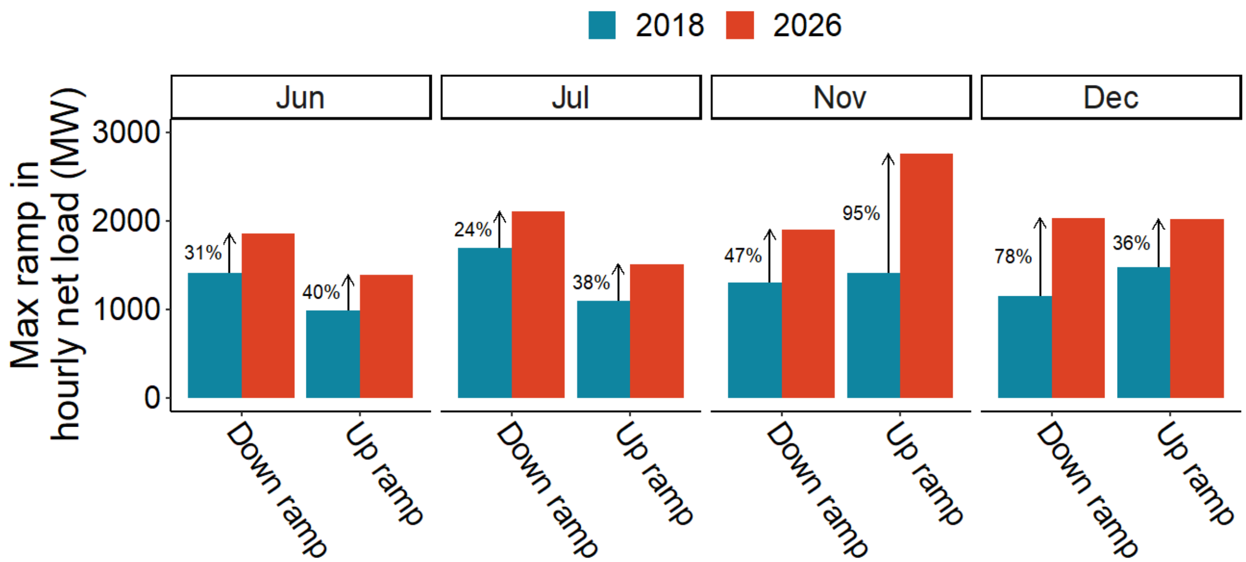


Figure 34. Largest up and down ramps in net load (MW) in 2018 and 2026. Ramping requirements increase in the 2026 scenario with the increased reliance on generation from wind and solar.

4.4.3 Effect of Coordination on Emissions

Although the coordination of power-sector and natural gas pipeline operations is likely to provide operational benefits, another aspect to consider is how such coordination would affect system carbon emissions. Here we focus on carbon dioxide emissions (CO_2), a greenhouse gas that serves as the primary contributor to climate change. To evaluate this impact, we estimate CO_2 emissions by plant using a combination of heat rate information and carbon content of natural gas, coal, and oil [74]. Since unserved load would likely be addressed by system operator intervention and additional plant dispatch, we also include estimates of emissions from remaining unserved load using the system-wide average emissions rate.[8]

Figure 35 illustrates the estimated change in CO_2 from coordination for each of the case study weeks and years of analysis, along with the associated penetration of wind and solar during that scenario. The figure illustrates that the effect of coordination on CO_2 emissions varies depending on the characteristics of the system and the time period of the analysis. For all of the 2018 system cases, coordination of the gas and power systems results in increased CO_2 emissions, although the total magnitude of increase varies by the week of analysis. In these cases, constraints in the natural gas network led to redispatch of previously out-of-merit generators in the power system; this generally means relying on less efficient generators, leading to higher emissions levels.

In the 2026 case with higher renewable energy penetrations, results are more mixed. Coordination in the June and July cases—times when electricity demand is at its highest and the

[8] This approach likely underestimates emissions from these operator interventions to address unserved energy since lower emitting resources tend to be lower in merit order. Of the cases we analyze, only the July scenarios have significant amounts of unserved energy after coordination.

system is most stressed—continues to yield increased emissions. However, in the November and December cases, coordination reduces CO_2 emissions by enabling the system to plan around greater ramping requirements. In the November scenario, better gas delivery and dispatch of natural gas power plants results in a 22% reduction in curtailment of wind and solar, which in terms results in less fuel consumption by fossil generators and thus fewer emissions. This illustrates the potential for gas and power sector coordination to increase gas system flexibility and facilitate renewable integration and carbon emissions reductions.

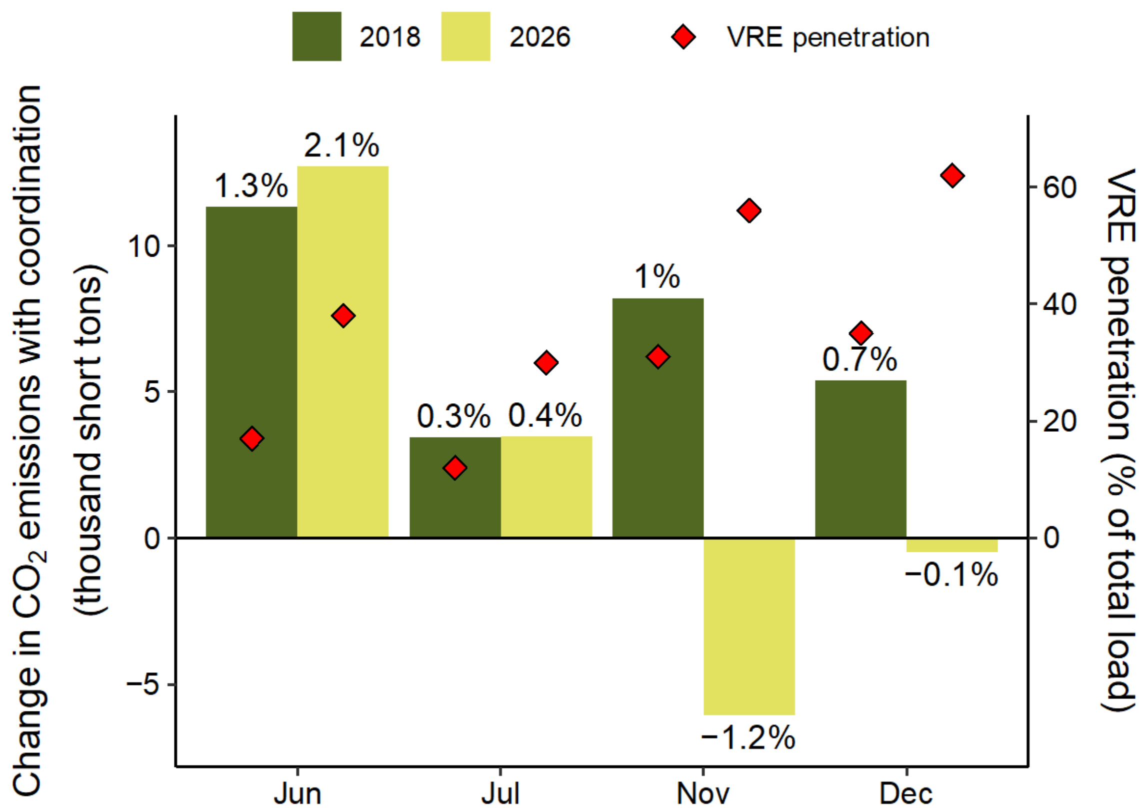


Figure 35. Change in carbon-dioxide (CO2) emissions from the power system only scenario to the coordination scenario for each week and run year; positive numbers indicate that coordination results in increased CO2 emissions. Percentages at the top of each bar indicate the change in emissions as a percent of power system only emissions. Diamonds correspond to the right axis and indicate the system penetration of variable renewable energy (VRE) for that week as a fraction of total load. Results shown for real time results when using shaped flows.

4.5 Summary of Study 3

In this part of our study, we examined the benefits of coordinating a subset of Colorado's natural gas and power system operations. We employed an approach in which a power sector optimization model communicates information to a gas network simulation. Even though this approach likely underestimates the benefits of coordination relative to a centralized optimization model, we pursue this approach because it best approximates how current power and gas operators make decisions. We explored the benefits of coordination from the perspectives of both the power system planner and the gas operator, and we also investigated whether introducing shaped flows in forward-looking markets provides benefits to the system.

We find there are substantial benefits to coordination between the two sectors. It substantially reduces instances of curtailed generation from gas, reducing the need for potentially costly out-of-merit operator interventions or the possibility of unserved electricity demand without a substantial increase in power system costs. From the gas system perspective, we find that much of the constraint occurs at several "choke points," but that total delivered gas can be increased through coordination, potentially increasing gas revenues.

Our results suggest that gas constraints may be driven by different factors. In the June and July cases, gas constraints are driven by sustained high demand from gas generators. In the November and December cases, high demand from nonpower sector users coupled with higher ramping that is due to wind variability in Colorado can result in pressure or compressor constraints. The latter becomes increasingly important in future systems, which are expected to have higher shares of generation from variable renewable sources. DA and ID markets that encourage time-variant gas nominations (i.e., shaped flows) may become increasingly valuable for reducing gas curtailment in systems with higher penetrations of renewable resources.

This part of our study focuses on a case study of the Colorado power and gas networks; although these findings likely extend to other systems, future work should explore the potential benefits of coordination for different regions. Furthermore, our study focuses on just four weeks for the sake of computational tractability. As we selected the four weeks with highest predicted gas offtakes—and thus the weeks most likely to be gas-constrained—our results of the benefits of coordination may be higher than other weeks. Furthermore, we use realistic but deterministic estimates of uncertainty from renewable generation in the forward-looking DA and ID markets. Future work should consider the benefits of coordination for different periods and should further investigate how uncertainty in net demand affects operations of the two systems.

One limitation of our analysis is that our gas network data do not include all gas generators in the system. Although we capture more than 70% of gas offtakes from the system, future efforts should consider how to realistically capture constraints across multiple gas networks through coordination.

Our work builds on various efforts to provide realistic modeling of power system and gas network coordination. Although both power system and gas network operators stand to potentially benefit from increased coordination, additional policies or incentives may be needed to realize these benefits. Our study finds that total gas delivery is improved with coordination, but it may be that not all gas operators benefit in all scenarios. For instance, coordination may shift generation and gas offtakes to a different gas network, reducing revenues of one at the expense of another and raising questions of what incentives are needed to encourage coordination from both entities. Though ratable flows are increasingly inflexible for dealing with variable renewable resources, they simplify operations for gas operators and may even benefit entities who hold primary gas contracts and are able to sell excess capacity to gas-power electric generators on the more expensive spot market. Gas pipeline operators typically also offer more complex forms of service structures which may provide firm gas while managing time-variant flows. Additional policies or efforts to more closely link gas and power sector markets using prices or different gas service designs in systems may thus be needed to realize the system-wide benefits of coordination. Of course, not all systems may require or even benefit from such linkages, and regulators and policy makers must consider how such coordination will impact different customer groups beyond just gas pipeline operators and gas generators when evaluating how coordination will improve operations.

5 Overall Conclusions

As electricity and gas networks continue to grow more interdependent into the future, there is an increasing need for modeling the interactions between these two systems. This report presents the findings from three related studies that develop a novel platform for coordination of these two systems and subsequently employ that platform to evaluate the benefits of coordinated operations. By integrating a transient gas model with unit commitment and economic dispatch power system model, this study provides insight into how these two systems might be jointly modeled at the bulk gas transmission and power system operations level.

Although the analysis in this report primarily focuses on test or relatively small systems (i.e. the Colorado gas and power network), we believe the findings presented here have broader technical and policy implications. For example, Study 2 found significant benefits from ID coordination of gas and power networks, providing some supporting evidence that FERC Order 809 will likely yield gas deliverability and cost benefits. In Study 3, we find that transitioning to time-variant gas nominations (shaped flows) can unlock further benefits of coordination, particularly for systems with high levels of renewable energy penetrations.

It is important to note that many of the conclusions draw from this work may be context specific. For example, in Study 3 we find that the drivers of non-served natural gas varied greatly depending on the week of analysis due to variations in system load, natural gas demand, and renewable resource availability. Different systems are likely to have different levels of flexibility, both in natural gas delivery (e.g. linepack capacity, transmission constraints, the availability of underground storage, and the mix of firm and interruptible transportation contracts held by gas generators) and in electricity sector operations (e.g. available of flexible ramping, ability to manage load). Accordingly, the benefits of coordination are likely to vary by system, and more modeling is needed to understand these dynamics for different systems. This collection of studies in this report provide a framework to guide such integrated modeling, as well as some demonstrative example illustrating the potential benefits that may result from coordination of these two systems.

The studies in this report do not capture all of potential infrastructure and market products that gas network operators might use to serve demand, including firm gas storage, hourly pipeline service products, firm delivery contracts, and additional pipeline infrastructure. These tools help gas pipeline operators meet firm transportation contracts and natural gas demand, even as those offtakes are subject to hourly demand variation. Although hourly variations in gas demand have historically been fairly predictable, the increasing use of natural gas for electricity generation couple with higher amounts of variable generating resources is likely to introduce additional variation and complexity. This work focuses on the benefits of coordination between the gas and power sector for addressing that increased variability, and future studies should explore some of these additional tools that might be useful for gas operators to address fluctuations in demand.

Several other opportunities for future research exist. First, to address concerns regarding sufficient flexibility in the natural gas system to support large changes in fuel offtakes at high renewable penetrations, future research should analyze dynamic natural gas system operations under a wider range of weather conditions, including ones that include large unexpected deviations in wind and solar PV generation from forecasts. Second, while we employ a fully dynamic gas network simulation, other research has used simplified representations of the gas network through linearization and omitted features. Future research should quantify when and to what extent these two approaches produce diverging results.

This analysis focuses on the role of coordination, and thus does not capture all of potential infrastructure and market products that gas network operators might use to serve demand, including firm gas storage, hourly pipeline service products, firm delivery contracts, and additional pipeline infrastructure, all of which should be evaluate in terms of their usefulness in enabling gas operators to address fluctuations in demand. Furthermore, this research focuses on operations that do not involve contingencies (e.g., losses of transmission lines or generators), and future work should quantify the extent to ID coordination might mitigate the consequences of these actions. Analyzing the value of coordination for different system configurations and topologies—including ones with higher levels of renewable resource, more capability for gas and electricity storage, and in region such as New England with highly stressed gas networks—is likely to provide additional insights. Additional work might also connect how coordination at operational levels impacts investment and capacity expansion decisions, and how new market structures can enable coordination through market prices for both gas and electricity. Finally, this work addresses some of the technical implications of coordinated operations, but more analysis is needed to understand potential institutional or policy barriers to realizing those benefits, such as changes to the gas transportation market or updates to pipeline tariffs.

6 References

[1] U.S. Energy Information Administration (EIA). Total Energy: Annual Energy Review 2019. https://www.eia.gov/totalenergy/data/annual/index.php (accessed February 12, 2020).

[2] U.S. Energy Information Administration (EIA). Annual Energy Outlook 2019: Reference case tables 2019. https://www.eia.gov/outlooks/aeo/.

[3] Carter R, Backhaus S, Hollis A, Zlotnik A, Chertkov M, Giacomoni A, et al. Impact of regulatory change to coordinate gas pipelines and power systems. PSIG Annu. Meet. 2016, vol. 13, 2016.

[4] Wallooppillai R, Laud M-L. Planning For Power: Pipeline Design To Meet Gas-Fired Power Plant Needs. PSIG Annu. Meet., Pipeline Simulation Interest Group; 2003.

[5] ISO New England. Operational Fuel-Security Analysis. vol. 134. 2018. https://doi.org/10.1007/978-3-319-71837-8_5.

[6] Shahidehpour M, Yong Fu, Wiedman T. Impact of Natural Gas Infrastructure on Electric Power Systems. Proc IEEE 2005;93:1042–56. https://doi.org/10.1109/JPROC.2005.847253.

[7] Babula M, Petak K. The Cold Truth: Managing Gas-Electric Integration: The ISO New England Experience. IEEE Power Energy Mag 2014;12:20–8. https://doi.org/10.1109/MPE.2014.2347611.

[8] Saldarriaga-C. CA, Salazar H. Security of the Colombian energy supply: The need for liquefied natural gas regasification terminals for power and natural gas sectors. Energy 2016;100:349–62. https://doi.org/10.1016/j.energy.2016.01.064.

[9] Chen H, Baldick R. Optimizing Short-Term Natural Gas Supply Portfolio for Electric Utility Companies. IEEE Trans Power Syst 2007;22:232–9. https://doi.org/10.1109/TPWRS.2006.889144.

[10] Duenas P, Leung T, Gil M, Reneses J. Gas–Electricity Coordination in Competitive Markets Under Renewable Energy Uncertainty. IEEE Trans Power Syst 2015;30:123–31. https://doi.org/10.1109/TPWRS.2014.2319588.

[11] Zlotnik A V, Rudkevich AM, Carter R, Ruiz PA, ... Grid architecture at the gas-electric interface. 2017.

[12] Massachusetts Institute of Technology (MIT Energy Initiative). Growing Concerns, Possible Solutions: The Interdependency of Natural Gas and Electricity Systems 2013.

[13] FERC. Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities: Order No. 809 n.d. https://ferc.gov/sites/default/files/2020-06/RM14-2-000_0.pdf (accessed July 1, 2020).

[14] Zeng Q, Zhang B, Fang J, Chen Z. A bi-level programming for multistage co-expansion planning of the integrated gas and electricity system. Appl Energy 2017;200:192–203. https://doi.org/10.1016/j.apenergy.2017.05.022.

[15] Unsihuay-Vila C, Marangon-Lima JW, de Souza ACZ, Perez-Arriaga IJ, Balestrassi PP. A Model to Long-Term, Multiarea, Multistage, and Integrated Expansion Planning of Electricity and Natural Gas Systems. IEEE Trans Power Syst 2010;25:1154–68. https://doi.org/10.1109/TPWRS.2009.2036797.

[16] Salimi M, Adelpour M, Vaez-ZAdeh S, Ghasemi H. Optimal planning of energy hubs in interconnected energy systems: a case study for natural gas and electricity. IET Gener Transm Distrib 2015;9:695–707. https://doi.org/10.1049/iet-gtd.2014.0607.

[17] Chaudry M, Jenkins N, Qadrdan M, Wu J. Combined gas and electricity network

expansion planning. Appl Energy 2014;113:1171–87. https://doi.org/10.1016/j.apenergy.2013.08.071.

[18] Qiu J, Dong ZY, Zhao JH, Meng K, Zheng Y, Hill DJ. Low Carbon Oriented Expansion Planning of Integrated Gas and Power Systems. IEEE Trans Power Syst 2015;30:1035–46. https://doi.org/10.1109/TPWRS.2014.2369011.

[19] Qiu J, Dong ZY, Zhao JH, Xu Y, Zheng Y, Li C, et al. Multi-Stage Flexible Expansion Co-Planning Under Uncertainties in a Combined Electricity and Gas Market. IEEE Trans Power Syst 2015;30:2119–29. https://doi.org/10.1109/TPWRS.2014.2358269.

[20] Shao C, Shahidehpour M, Wang X, Wang X, Wang B. Integrated Planning of Electricity and Natural Gas Transportation Systems for Enhancing the Power Grid Resilience. IEEE Trans Power Syst 2017;32:4418–29. https://doi.org/10.1109/TPWRS.2017.2672728.

[21] Chaudry M, Jenkins N, Strbac G. Multi-time period combined gas and electricity network optimisation. Electr Power Syst Res 2008;78:1265–79. https://doi.org/10.1016/j.epsr.2007.11.002.

[22] Correa-Posada CM, Sanchez-Martin P. Integrated Power and Natural Gas Model for Energy Adequacy in Short-Term Operation. IEEE Trans Power Syst 2015;30:3347–55. https://doi.org/10.1109/TPWRS.2014.2372013.

[23] Devlin J, Li K, Higgins P, Foley A. A multi vector energy analysis for interconnected power and gas systems. Appl Energy 2017;192:315–28. https://doi.org/10.1016/j.apenergy.2016.08.040.

[24] Rudkevich A, Zlotbik A, Ruiz P, Goldis E, Beylin A, Hornby R, et al. Market Based Intraday Coordination of Electric and Natural Gas System Operation. Proc. 51st Hawaii Int. Conf. Syst. Sci., vol. 9, 2018, p. 2585–94. https://doi.org/10.24251/HICSS.2018.327.

[25] Rudkevich A, Zlotnik A, Li X, Ruiz P, Beylin A, Goldis J, et al. Evaluating Benefits of Rolling Horizon Model Predictive Control for Intraday Scheduling of a Natural Gas Pipeline Market. Proc. 52nd Hawaii Int. Conf. Syst. Sci., 2019, p. 3627–36. https://doi.org/10.24251/HICSS.2019.438.

[26] Seungwon An, Qing Li, Gedra TW. Natural gas and electricity optimal power flow. 2003 IEEE PES Transm. Distrib. Conf. Expo. (IEEE Cat. No.03CH37495), vol. 1, IEEE; 2003, p. 138–43. https://doi.org/10.1109/TDC.2003.1335171.

[27] Unsihuay C, Lima JWM, de Souza ACZ. Modeling the Integrated Natural Gas and Electricity Optimal Power Flow. 2007 IEEE Power Eng. Soc. Gen. Meet., IEEE; 2007, p. 1–7. https://doi.org/10.1109/PES.2007.386124.

[28] Martinez-Mares A, Fuerte-Esquivel CR. A Unified Gas and Power Flow Analysis in Natural Gas and Electricity Coupled Networks. IEEE Trans Power Syst 2012;27:2156–66. https://doi.org/10.1109/TPWRS.2012.2191984.

[29] Li T, Eremia M, Shahidehpour M. Interdependency of Natural Gas Network and Power System Security. IEEE Trans Power Syst 2008;23:1817–24. https://doi.org/10.1109/TPWRS.2008.2004739.

[30] Cong Liu, Shahidehpour M, Yong Fu, Zuyi Li. Security-Constrained Unit Commitment With Natural Gas Transmission Constraints. IEEE Trans Power Syst 2009;24:1523–36. https://doi.org/10.1109/TPWRS.2009.2023262.

[31] Qadrdan M, Abeysekera M, Chaudry M, Wu J, Jenkins N. Role of power-to-gas in an integrated gas and electricity system in Great Britain. Int J Hydrogen Energy 2015;40:5763–75. https://doi.org/10.1016/j.ijhydene.2015.03.004.

[32] Chiang N-Y, Zavala VM. Large-scale optimal control of interconnected natural gas and

electrical transmission systems. Appl Energy 2016;168:226–35. https://doi.org/10.1016/j.apenergy.2016.01.017.
[33] Zlotnik A, Roald L, Backhaus S, Chertkov M, Andersson G. Coordinated Scheduling for Interdependent Electric Power and Natural Gas Infrastructures. IEEE Trans Power Syst 2017;32:600–10. https://doi.org/10.1109/TPWRS.2016.2545522.
[34] Qadrdan M, Wu J, Jenkins N, Ekanayake J. Operating Strategies for a GB Integrated Gas and Electricity Network Considering the Uncertainty in Wind Power Forecasts. IEEE Trans Sustain Energy 2014;5:128–38. https://doi.org/10.1109/TSTE.2013.2274818.
[35] Chen R, Wang J, Sun H. Clearing and Pricing for Coordinated Gas and Electricity Day-Ahead Markets Considering Wind Power Uncertainty. IEEE Trans Power Syst 2018;33:2496–508. https://doi.org/10.1109/TPWRS.2017.2756984.
[36] He C, Wu L, Liu T, Shahidehpour M. Robust Co-Optimization Scheduling of Electricity and Natural Gas Systems via ADMM. IEEE Trans Sustain Energy 2017;8:658–70. https://doi.org/10.1109/TSTE.2016.2615104.
[37] Bai L, Li F, Cui H, Jiang T, Sun H, Zhu J. Interval optimization based operating strategy for gas-electricity integrated energy systems considering demand response and wind uncertainty. Appl Energy 2016;167:270–9. https://doi.org/10.1016/j.apenergy.2015.10.119.
[38] Qiao Z, Guo Q, Sun H, Pan Z, Liu Y, Xiong W. An interval gas flow analysis in natural gas and electricity coupled networks considering the uncertainty of wind power. Appl Energy 2017;201:343–53. https://doi.org/10.1016/j.apenergy.2016.12.020.
[39] Cui H, Li F, Hu Q, Bai L, Fang X. Day-ahead coordinated operation of utility-scale electricity and natural gas networks considering demand response based virtual power plants. Appl Energy 2016;176:183–95. https://doi.org/10.1016/j.apenergy.2016.05.007.
[40] Pambour K, Sopgwi R, Hodge B-M, Brancucci C. The Value of Day-Ahead Coordination of Power and Natural Gas Network Operations. Energies 2018;11:1628. https://doi.org/10.3390/en11071628.
[41] Zhao B, Zlotnik A, Conejo AJ, Sioshansi R, Rudkevich AM. Shadow Price-Based Co-Ordination of Natural Gas and Electric Power Systems. IEEE Trans Power Syst 2019;34:1942–54. https://doi.org/10.1109/TPWRS.2018.2879801.
[42] Alabdulwahab A, Abusorrah A, Zhang X, Shahidehpour M. Coordination of Interdependent Natural Gas and Electricity Infrastructures for Firming the Variability of Wind Energy in Stochastic Day-Ahead Scheduling. IEEE Trans Sustain Energy 2015;6:606–15. https://doi.org/10.1109/TSTE.2015.2399855.
[43] Ordoudis C, Pinson P, Morales JM. An Integrated Market for Electricity and Natural Gas Systems with Stochastic Power Producers. Eur J Oper Res 2019;272:642–54. https://doi.org/10.1016/j.ejor.2018.06.036.
[44] Üster H, Dilaveroğlu Ş. Optimization for design and operation of natural gas transmission networks. Appl Energy 2014;133:56–69. https://doi.org/10.1016/j.apenergy.2014.06.042.
[45] Guerra OJ, Calderón AJ, Papageorgiou LG, Siirola JJ, Reklaitis G V. An optimization framework for the integration of water management and shale gas supply chain design. Comput Chem Eng 2016;92:230–55. https://doi.org/10.1016/j.compchemeng.2016.03.025.
[46] Chiang N-Y, Zavala VM. Large-scale optimal control of interconnected natural gas and electrical transmission systems. Appl Energy 2016;168:226–35. https://doi.org/10.1016/j.apenergy.2016.01.017.
[47] Zlotnik A, Roald L, Backhaus S, Chertkov M, Andersson G. Coordinated Scheduling for

Interdependent Electric Power and Natural Gas Infrastructures. IEEE Trans Power Syst 2017;32:600–10. https://doi.org/10.1109/TPWRS.2016.2545522.
[48] Ríos-Mercado RZ, Borraz-Sánchez C. Optimization problems in natural gas transportation systems: A state-of-the-art review. Appl Energy 2015;147:536–55. https://doi.org/10.1016/j.apenergy.2015.03.017.
[49] Osiadacz AJ, Chaczykowski M. Comparison of isothermal and non-isothermal pipeline gas flow models. Chem Eng J 2001;81:41–51. https://doi.org/10.1016/S1385-8947(00)00194-7.
[50] Craig M, Guerra OJ, Brancucci C, Pambour KA, Hodge B-M. Valuing intra-day coordination of electric power and natural gas system operations. Energy Policy 2020;141:111470. https://doi.org/10.1016/j.enpol.2020.111470.
[51] Peress NJ, Karas N. Aligning U . S . Natural Gas and Electricity Markets to Reduce Costs , Enhance Market Efficiency and Reliability Authors. 2017.
[52] Energy Exemplar. PLEXOS 2019. https://energyexemplar.com/solutions/plexos/ (accessed February 12, 2020).
[53] encoord. SAInt 2.0 n.d. https://encoord.com/SAInt.html.
[54] Pambour KA, Erdener BC, Bolado-Lavin R, Dijkema GPJ. An Integrated Simulation Tool for Analyzing the Operation and Interdependency of Natural Gas and Electric Power Systems. PSIG Annu. Meet., 2016.
[55] Addo K, Bolado-lavin R, Dijkema GPJ. An integrated transient model for simulating the operation of natural gas transport systems. J Nat Gas Sci Eng 2016;28:672–90. https://doi.org/10.1016/j.jngse.2015.11.036.
[56] Pambour K, Cakir Erdener B, Bolado-Lavin R, Dijkema G. Development of a Simulation Framework for Analyzing Security of Supply in Integrated Gas and Electric Power Systems. Appl Sci 2017;7:47. https://doi.org/10.3390/app7010047.
[57] Pambour KA, Cakir Erdener B, Bolado-Lavin R, Dijkema GPJ. SAInt – A novel quasi-dynamic model for assessing security of supply in coupled gas and electricity transmission networks. Appl Energy 2017;203:829–57. https://doi.org/10.1016/j.apenergy.2017.05.142.
[58] CAISO. California ISO Open Access Same-time Information System (OASIS) n.d. http://oasis.caiso.com/mrioasis/logon.do (accessed July 7, 2020).
[59] Draxl C, Clifton A, Hodge B-M, McCaa J. The Wind Integration National Dataset (WIND) Toolkit. Appl Energy 2015;151:355–66. https://doi.org/10.1016/j.apenergy.2015.03.121.
[60] Sengupta M, Weekley A, Habte A, Lopez A, Molling C. Validation of the National Solar Radiation Database (NSRDB) Preprint. 2015.
[61] National Renewable Energy Laboratory, Economics E and E. Western Interconnection Flexibility Assessment. 2015.
[62] Pambour K, Cakir Erdener B, Bolado-Lavin R, Dijkema G. Development of a Simulation Framework for Analyzing Security of Supply in Integrated Gas and Electric Power Systems. Appl Sci 2017;7:47. https://doi.org/10.3390/app7010047.
[63] Pambour KA, Cakir Erdener B, Bolado-Lavin R, Dijkema GPJ. SAInt – A novel quasi-dynamic model for assessing security of supply in coupled gas and electricity transmission networks. Appl Energy 2017;203:829–57. https://doi.org/10.1016/j.apenergy.2017.05.142.
[64] California Energy Commission. Tracking Progress n.d. https://www.energy.ca.gov/data-reports/tracking-progress (accessed July 1, 2020).
[65] ERCOT. Report on the Capacity, Demand and Reserves (CDR) in the ERCOT Region ,

2019-2028. 2018.
[66] Southwest Power Pool. 2017 Annual Report 2017. https://www.spp.org/documents/56850/2017 annual report - webv3.pdf (accessed July 1, 2020).
[67] Sengupta M, Xie Y, Lopez A, Habte A, Maclaurin G, Shelby J. The National Solar Radiation Data Base (NSRDB). Renew Sustain Energy Rev 2018;89:51–60. https://doi.org/10.1016/j.rser.2018.03.003.
[68] Foley AM, Ó Gallachóir BP, Hur J, Baldick R, McKeogh EJ. A strategic review of electricity systems models. Energy 2010;35:4522–30. https://doi.org/10.1016/j.energy.2010.03.057.
[69] Brancucci Martinez-Anido C, Botor B, Florita AR, Draxl C, Lu S, Hamann HF, et al. The value of day-ahead solar power forecasting improvement. Sol Energy 2016;129:192–203. https://doi.org/10.1016/j.solener.2016.01.049.
[70] Hodge B-M, Brancucci Martinez-Anido C, Wang Q, Chartan E, Florita A, Kiviluoma J. The combined value of wind and solar power forecasting improvements and electricity storage. Appl Energy 2018;214:1–15. https://doi.org/10.1016/j.apenergy.2017.12.120.
[71] Kwabena Addo Pambour. Modelling, simulation and analysis of security of supply scenarios in integrated gas and electricity transmission networks. 2018.
[72] Denholm P, Hand M. Grid flexibility and storage required to achieve very high penetration of variable renewable electricity. Energy Policy 2011;39:1817–30. https://doi.org/10.1016/j.enpol.2011.01.019.
[73] Energy Exemplar. PLEXOS 2019.
[74] Brinkman G, Jorgenson J, Ehlen A, Caldwell JH. Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California. Golden, CO (United States): National Renewable Energy Laboratory/Center for Energy Efficiency and Renew; 2016. https://doi.org/10.2172/1235548.
[75] Overturf E, Farnsworth G. Colorado Energy Plan Explained. West Resour Advocates n.d. https://westernresourceadvocates.org/blog/colorado-energy-plan-explained/ (accessed February 12, 2020).
[76] Hodge B-M, Brancucci Martinez-Anido C, Wang Q, Chartan E, Florita A, Kiviluoma J. The combined value of wind and solar power forecasting improvements and electricity storage. Appl Energy 2018;214:1–15. https://doi.org/10.1016/j.apenergy.2017.12.120.
[77] Rudkevich A. Gas-Electric Co-Optimization (GECO): Presentation to the Electricity Advisory Committee Meeting. 2017.