GRID ARCHITECTURE AT THE GAS-ELECTRIC INTERFACE

June 2017

AV Zlotnik
AM Rudkevich
RG Carter
PA Ruiz
SN Backhaus
JD Taft

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AV Zlotnik[1]
PA Ruiz[4]
AM Rudkevich[2]
SN Backhaus[5]
RG Carter[3]
JD Taft[6]

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[1] Staff Scientist, Theoretical Division, Los Alamos National Laboratory, Los Alamos, NM
[2] President and Founder, Newton Energy Group, Boston, MA
[3] Principal Software Development Scientist, Analytics Advancement Section, DNV-GL, Katy, TX
[4] Research Associate Professor, Department of Mechanical Engineering, Boston University, Boston, MA
[5] Critical Infrastructure Program Manager, Los Alamos National Laboratory, Los Alamos, NM
[6] Chief Architect – Electric Grid Transformation, Energy and Environment Directorate, Pacific Northwest National Laboratory, Richland, WA

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Abstract

Significant changes have affected U.S. natural gas markets in the last several years. Environmental regulations and price pressures from newly available natural gas supplies are increasing the reliance of the bulk electric power system on gas-fired generation. This trend is bringing attention to the architectures and coordination of the wholesale gas and electricity markets. Though these physical infrastructures and corresponding markets have existed for decades, closer coordination at the interface between these economically and physically interdependent infrastructures is needed. The changes required to bring about closer coordination of wholesale gas and electricity sectors will bring significant disruption and will require the development of new architectural frameworks as part of the ongoing Grid Modernization effort, which aims to re-engineer the power grid with advanced technology to support many new capabilities. This document describes the emerging issues at the gas-electric interface, the status quo of inter-sector coordination, and the developing regulatory environment. A review of emerging analytics technologies indicates a potential for implementing market-based architectural frameworks for gas-electric coordination.

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Acronyms and Abbreviations

ACE	Area Control Error
DAM	Day-Ahead Market
EBB	Electronic bulletin board
ED	economic dispatch
EG	electric generator
FERC	Federal Energy Regulatory Commission
ISO	Independent system operator
LDC	local distribution company
LMP	locational marginal prices
LNG	liquefied natural gas
LTV	locational trade values
MAOP	maximum allowable operating pressures
MINOP	minimum operating pressures
NAESB	North American Energy Standards Board
NERC	North American Electric Reliability Corporation
NLP	nonlinear program
OCP	optimal control problems
OFO	operational flow order
PDE	partial differential equation
RAA	Reserve Adequacy Assessment
RTM	Real-time Market
RTO	Regional Transmission Organization
UC	unit commitment

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1.0 Introduction

Significant changes have affected U.S. natural gas markets in the last several years[1-6]. Environmental regulations and price pressures from newly available natural gas supplies are increasing the reliance of the bulk electric power system on gas-fired generation[4]. This trend is bringing attention to the architectures and coordination of the wholesale gas and electricity markets[12,39]. Though these physical infrastructures and corresponding markets have existed for decades, closer coordination between these economically and physically interdependent infrastructures is needed[108,111]. The changes required to bring about closer coordination of gas and electricity markets and system operations will bring significant disruption and will require new architectural frameworks[187]. Concurrently, an effort is ongoing to re-engineer the power grid with advanced technology to support many new capabilities, which is called Grid Modernization[15-30].

1.1 Grid Modernization

Rapidly emerging new conditions are challenging existing grid structure and grid management tools, and key technologies could help resolve the widening gap in the ability to manage and operate the 21st century grid reliably[31]. This modernization will support many new goals and emerging trends that were not envisioned in the original 20th century grid. The 20th century model for the grid was a one-way electricity delivery channel from large centralized generation to passive users who have no choice of electric energy sources and with surprisingly little in the way of sensing and measurement to guide operation. Present grid modernization efforts are driving new technologies into the electricity grid at an unprecedented pace to serve a variety of new goals and emerging trends not contemplated for the 20th century grid.

Ongoing grid modernization efforts aim to

- Expand diversity and consumer choice in electricity sources, including distributed and/or clean generation such as solar photovoltaics, wind, and energy storage,
- Accommodate emerging “prosumers” (customers who both produce and consume energy),
- Enable non-utility assets such as ordinary buildings to provide services to the grid and cooperate in managing grid operations,
- Coordinate convergence of fuel, transportation, and social networks with the grid, and
- Significantly improve reliability, resilience, and security for the grid

These changes, some of which are occurring virally rather than being planned, are actually modifying the characteristics, behavior, and even the very structure of the grid, and are vastly increasing the complexity of the already complex U.S. power system. However, new technologies and new goals are reducing the effectiveness of standard methods for operating and protecting the power grid. As the gap widens between the emerging grid and traditional grid control tools, the ability of utilities to manage the grid reliability is increasingly challenged[7-14].

1.2 Convergence of Electricity and Gas Transmission Needs

One of the greatest power grid management challenges stems from the convergence of natural gas and electricity utilization, which couples the gas and electricity transmission systems through gas-fired generators[37, 39]. Historically, natural gas was withdrawn from transmission systems by local distribution companies (LDCs) and industrial consumers with little intra-day variation. The current standard is to clear bilateral transactions for fixed delivery contracts in a day-ahead market for the subsequent 24-hour period, which requires injections and withdrawals to remain in balance[35,36]. This constrains gas-fired generators, which typically serve mid-range and peak electricity loads and thus have highly variable yet high volume gas usage. They are typically supplied on non-firm, short-term gas contracts, which are subject to scheduling restrictions or curtailment by pipeline operators during stressed conditions. As a result, independent system operators (ISOs) that contract deliveries from interstate natural gas transmission systems have been presented with operational and reliability challenges. Specifically, ISOs might experience situations where the output of gas-fueled combined-cycle plants and quick-start peaking plants must be rapidly replaced by other generation sources in intra-day operation[36]. This strains the capability of ISOs to meet demand, maintain operating reserves, and ensure power system reliability[54-58]. Conversely, electric utilities play a complex role in natural gas markets because their gas demand is price sensitive[38-44]. These growing interactions present challenges that require solutions beyond traditional approaches for operation and coordination of electric power and natural gas transmission systems[40-50].

In the gas marketplace, day-ahead and intra-day bilateral gas contracts are purchased, sold, and cleared[267-270, 280]. These agreements are based on steady rated gas takes, and gas transmission companies then use this information to create operational plans. The resulting flow schedules are based on capacities rated by Federal Energy Regulatory Commission (FERC) regulations, which are estimated using steady-state flow models. Real-time pipeline control is then performed in reaction to customer behaviors that may not be communicated in advance. This approach to pipeline scheduling and control has been satisfactory when nearly all off-takers were LDCs, which are firm contract holders whose takes were more predictable and far less variable. In current markets where over half of wholesale natural gas consumers are electric power plants that purchase non-firm contracts, this approach may not be sufficient to guarantee supplies to non-firm contract buyers with highly variable demand[276, 277]. Today, operators need to make decisions in a limited time-frame based on their training and experience and possibly a handful of scenarios that were evaluated using transient simulations[271-272].

Coordination between the wholesale gas and electricity sectors under today's quickly changing circumstances require the development of new architectural frameworks[104]. Indeed, the retirement of older coal and nuclear power plants and the integration of renewable resources makes this a pressing issue[89,105-109,183]. Conveniently, the significant experience gained through successful implementation of physical control and market mechanisms in the electric power industry worldwide over the past two decades provides a significant conceptual basis on which to construct the required architecture[95,238]. In particular, architectures are required for

- Auction-based market mechanisms for natural gas transmission pipeline systems
- Electricity transmission systems that adapt timing and location of gas-fired generation so that pipeline constraints are not violated in normal operation
- Communication interfaces between electricity transmission system operators and pipeline system operators.
- Intra-day market coordination for electricity and natural gas transmission infrastructures

Systems that perform these functions do not currently exist, but rather such coordination is currently done by ad-hoc communication (e.g., by phone or email list) between control room operators. Therefore, implementation of architectures that effectively perform these functions will require the development of new technologies and secure communication systems. Among the very valuable technologies and advanced concepts currently being applied to the power grid and under development for natural gas pipelines, a few stand out as key to resolving the widening gap between existing gas-electric management tools and methods, and the needs of the 21st century electricity grid. Prominent emerging technologies are[31]

- High voltage power electronics – adjustable electronics for controlling grid power flows to replace today's on/off electromechanical switches
- Fast flexible bulk electric energy storage – can act as the buffer that evens out various power fluctuations and mismatches that can occur with diverse energy sources

- Sensing and data analysis – electronic sensing and automated information extraction that will require new data collection and analysis tools
- Advanced planning and control methods and tools – new approaches using advanced control methods suitable for modern power grids and gas pipeline systems that will require next generation control technology and communication systems based on emerging pipeline control system modeling and computational mathematics

The last two items above have significant potential for positive impact to enable advanced and automated management and control of large-scale natural gas and electric power transmission systems. In particular, new auction-based market mechanisms will enable economically efficient and secure intra-day management of the U.S. gas pipeline infrastructure as it nears its capacity limits while transporting increasing volumes with higher intra-day variations in order to provide fuel for the power grid.

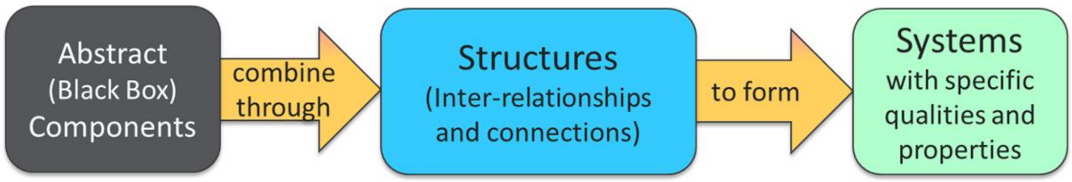
1.3 Architectural Concepts and Foundations

Development of an architectural framework for pipeline systems and gas-electric coordination mechanisms requires definition of a core architectural structure of relationships and connectivity between components and their behaviors. Specifically, as outlined in the foundational documents for grid architecture[22,23].

- Components are uniquely identifiable, non-trivial, nearly independent devices, individuals, organizations, organisms, elements, building blocks, parts, or sub-assemblies that may be collected together to cooperate or to serve a common purpose. Architectural components have externally visible properties but their internal details are hidden.
- Behaviors are the sets of processes that fulfill a specific function or purpose of a component. They constitute the range of actions and mannerisms exhibited by components in conjunction with themselves or their environment. It is the response to various stimuli or inputs, whether internal or external.
- Structures are arrangements or patterns of interlinkage of components; organization of a system; the form; the "shape" of a system. Structure is a fundamental, tangible or intangible notion referring to the recognition, observation, nature, and permanence of patterns and linkages of components. This notion may be tangible, such as a built structure, or an attribute, such as the structure of a market mechanism.
- Connectivity refers to the state of being linked or joined together so as to enable some form of exchange. Connectivity is a basic form of structure. For power grids and gas pipelines, the basic elements of exchange are energy, money, control, access, information, services, and value.
- Relationships are the means by which two entities are affiliated; they consist of collections of component behaviors. Architectural relationships consist of two classes of behaviors; these are interactions, which are mutual or reciprocal influences, and transfers, which are conveyances from one entity to another.
- Systems are sets of allied or interdependent elements forming an integrated whole.
    - A system has **components:** it contains parts that are directly or indirectly related to each other
    - A system has **structure:** its components are linked by **connectivity** and **relationships**
    - A system has **behavior:** it exhibits processes that fulfill its function or purpose and respond to stimuli

    A system has **qualities:** a set of characteristics as seen by users of the system (solution domain)

- A system has **properties:** a set of characteristics as seen by the developers and operators of a system (problem domain)



- A system architecture is the conceptual model that defines the components, structure, behavior, qualities, properties, and essential limits of a system. An architecture description is a formal representation of a system, organized in a way that supports reasoning about the structures and behaviors of the system. System architectures are written, composed or specified. Design is a different activity altogether.

This document defines the conceptual foundations for use in developing architectural views of pipeline management and gas-electric system coordination that account for physical and market operations.

1.4 Architectural Development for Pipeline Systems

The focus here is on the confluence of the natural gas and electric energy sectors. Increased use of natural gas and displacement of coal in the electric sector will reduce carbon and all other air emissions. Better coordination of the physics and economics of the two sectors will improve energy efficiency, reduce energy costs in the U.S. economy, and improve power-grid flexibility and integration of renewable energy sources. Increased efficiency in joint operations will support further reductions in imported fossil fuels through displaced use of dual-fuel generation options. The inefficiency in gas-electric coordination has been recognized in a number of industry studies and attracted attention from state and federal government and regulatory agencies[2-6,35-53,104,110-111]. The issue has also attracted interest and multiple proposed solutions from academia[62-78,87-102].

The technology that will be required to build the 21st century gas-electric coordination architecture will combine three key components:

- New algorithms for simulation, modeling and optimization of natural gas pipeline operation at the intra-day time scale,
- New mechanisms for pricing of natural gas delivered to end users, including gas-fired power plants,
- New mechanisms for coordinating gas-electric operations based on intra-day locational prices of natural gas and power.

When implemented, these new technologies and the integrating architecture will provide efficient operation of pipeline compressors for the gas-electric system and will guarantee that gas will be available to gas-fired generators at the time they need to inject power into the system and that the prices of power and gas will align to minimize the risk of operating at a loss.

The potential operational and economic benefits of coordinating the natural gas and electric sectors offer unique, near-term opportunities for the application of the results of such research and development. The objective and the challenge are to develop a business process that can merge two currently separate processes and coordinate the delivery of both energy systems without losing the functionality or the unique operational logics of either gas or electrical power. The computational and control system technology must operate within the constraints of time, space, and regulatory environment for each of the sectors in order to capture the benefits of coordinated operations[105]. These benefits come with significant technical challenges in identifying the analytic parameters and algorithmic structures that can be applied to the currently separate physical operations of these two energy sectors.

Currently, pipeline operators provide some guidance to electric grid operators on the likely feasibility of gas delivery to gas-fired generators[185]. Such limited coordination of electricity and gas markets and physical infrastructures is an inefficient process that can result in the grid operator overscheduling resources to assure system resource adequacy. This inefficiency will be exacerbated by increasing use of natural gas as a fuel for electricity generation and by necessary reliance on gas–fired generation for ancillary services to support the increasing penetration of variable renewable resources.

The objective of architectural development is to unify the analytical framework, algorithmic structures, and market design mechanism that will enable dramatically improved coordination of planning and operations of the two physical systems and markets for gas and electricity transmission based firmly on the underlying engineering physics of both delivery systems. The vision for the eventual gas-electric system architecture encompasses three major components:

- An algorithmic and software framework that will be adopted by major natural gas and power market operators. The framework should be capable of solving a number of operational and scheduling problems for improving coordinated operation of natural gas and electric systems, and will be intentionally designed as modular and flexible, anticipating its usability by different groups within market operator organizations. The framework will explicitly reflect
    - Dynamic optimization of pipeline operations that explicitly incorporates transient physical gas flow models and intra-day operational constraints,
    - Interactions between the physics of natural gas flows in pipelines serving the electrical grid and the power flow, and
    - The complex structure of periodically repeating decision cycles of generation bidding and deployment decisions and natural gas nomination decisions.
- A market design and its algorithmic software implementation capable of performing the required gas-electric coordination decisions and communication. At its core the market design proposal will have a theory of locational trade values (LTVs) for natural gas[278] and theoretical foundations for the provision of the access to certain pipeline capacity based on economic principles in addition to physical rights. The market design will provide a gas-electric coordination architecture that combines exchange of physical and locational value and/or price data between gas and electric systems otherwise managed independently, and will significantly mitigate reliability risks on both on the gas and electric side as well as the financial risks to which gas-fired generators are currently exposed. The market design mechanism must be acceptable to market participants in both the gas and electric sectors[187].
- A control and communication framework for limited sharing of operational and market data that will enable rapid market decision-making, automated scheduling, and secure operations.

1.5 Impacts of Gas-Electric Architecture Development

Several studies have suggested that gas-electric infrastructure constraints can be alleviated with incremental expansion of natural gas pipeline capacity, LNG imports, and electric transmission that enables imports from outside the region, particularly to New England[44,45,50-52]. Alternatives include liquefied natural gas (LNG) peak-shaving capacity and dual-fueled generation[48,49]. Another approach involves demand-side management, more frequent gas supply nominations, and concurrent market clearing[50-52]. Both infrastructure expansion and market synchronization would leave physical operation of the systems to continue under current practices, which are not flexible enough to react to generator requirements and lack coordination across systems and regions[53]. Moreover, these measures are expensive, especially the capital investment required for significant infrastructure expansion. In contrast, advanced modeling, simulation, control, and optimization techniques coupled with modern market design approaches[281-282] that have been proven to be successful in the power sector would cost far less.

The current industry practices likely under-utilize pipeline system capacity. Indeed, historical load and price analyses indicate that the Northeast Unites States experienced gas supply stress, observed as spot market basis spikes, when gas load levels approached 75% of existing firm contract capacity[44]. This load level is conventionally identified as the constraint capacity threshold[59]. In contrast, physically realistic models of gas network flow transients on the time-scale of power system operations will lead to powerful new methods that will significantly increase the operating capacity, efficiency, and security of gas transmission systems[85,184]. These novel optimization methods yield not only more efficient operational schedules for pipeline compressors, but also natural gas LTVs at all nodes of the gas pipeline network[278]. Similarly to locational marginal prices (LMPs) in electric networks[54,238], development of LTVs creates a foundation for displacing rigid priority-based rules for allocating pipeline capacity among shippers with efficient rules of providing access to pipeline capacity based on economics. Furthermore, establishment of intra-day LTVs concurrent with electric LMPs provides a foundation for replacing existing gas-electric coordination mechanisms based on service priorities with an economically efficient coordination mechanism based on prices.

Once implemented, the 21st century gas-electric architectural framework will profoundly impact the operations and economics of the joint gas and electric infrastructure. In particular, a successful implementation will

- Facilitate development of efficient gas-fired generating technology as a displacement of the U.S. coal-fired fleet, and with that significantly reduce emissions of carbon dioxide and other harmful pollutants;
- Improve efficiency in the operation of the natural gas delivery infrastructure, and reduce natural gas use as a compressor fuel;
- Reduce transmission congestion in electric and natural gas networks through coordinated simultaneous congestion management of both networks;
- Increase the reliability of the operations of the gas-electric infrastructure, particularly at times when both systems are under stress such as during extreme weather conditions or catastrophic events;
- Facilitate integration of variable renewable resources through the increased flexibility of the gas-fired generating fleet and its ability to provide ancillary services;
- Reduce natural gas and electricity delivery costs and prices and help to mitigate combined gas and electricity price spikes[255,256,258];
- Provide more precise investment signals for infrastructure expansion via consistent location and time-dependent natural gas and electricity prices, and lead to a reduction in investment costs[74,88]; and
- Provide coordinated electric and natural gas prices to better facilitate development of distributed gas powered micro-generators (for example in Combined Heat and Power and HVAC implementations). Competition for natural gas between distributed generation and large central station power plants becomes very relevant when all electric and natural gas costs are accounted for properly.

Quantifying the benefits of the gas-electric architectural framework with respect to the status quo prior to implementation is difficult. However, the magnitude of the impact is expected to be very large. A rough estimate using 2014 statistics of energy consumption and prices in the United States indicate that a 1% reduction in wholesale natural gas prices could save U.S. consumers over $2 billion per year in natural gas and electricity costs. Preliminary analyses performed on a benchmark model that combines a standard IEEE electric test network[235] with a natural gas test network indicate that modernization of gas pipeline system operations and development of a gas-electric architectural framework will likely result in far more than a 1% reduction in wholesale natural gas prices[184,189], As these studies demonstrate, moving from the current steady-state based operational policy to dynamically optimized intra-day operation restores gas system feasibility and security in cases where the system is infeasible under current practice, and thus would eliminate the dramatic price spikes for gas and power seen in recent years.

2.0 Regulatory Change and Gas-Electric Coordination

Economic, technological, and political factors have encouraged the extensive installation of gas-fired power plants in the United States, which has caused electric systems to depend heavily on reliable gas supplies.[36-53] This has greatly strengthened the interdependence between the electric power and natural gas industries. Recently, the intra-day fluctuations in pipeline loads that arise from changes in gas-fired electric power plant operation have become particularly problematic. The procedures used by power system operators to decide when, where, and at what level electric generators (EGs) are committed to operate are described below. Particular emphasis is placed on the evolving role played by gas-fired generators. Recent FERC policy changes that aim to improve operational coordination between the two industry sectors are summarized as well.

2.1 Background and Coordination Status Quo

New extraction technologies, cheaper gas, and other factors have led to widespread installation of gas-fired electric power plants and caused the electric power grid to depend on reliable gas supplies. Recently, natural gas has eclipsed coal as the largest fuel source for electric power production in the United States. Gas-fired generators are advantageous for meeting peak electric loads and providing rapid-response contingency power. However, these attributes can cause high and unpredictable intra-day variability in offtakes from gas transmission pipelines. These new conditions create challenges for current methods for flow scheduling and real-time physical control. The resulting impacts on pipeline efficiency, capacity, and security often translate to gas price fluctuations, supply disruptions, and increased operating expenses. Better coordination between the electric power generation and natural gas transmission industries would mitigate some of these problems. However, coordination between power and gas industry markets and intra-day planning of physical operations is nontrivial.

In the gas marketplace, day-ahead and intra-day bilateral gas contracts are purchased, sold, and cleared. These agreements are based on steady rated gas takes, and gas transmission companies then use this information to create operational plans. The resulting flow schedules are based on capacities rated by FERC regulations, which are estimated using steady-state flow models. Real-time pipeline control is then performed in reaction to customer behaviors that may not be communicated in advance. This approach to pipeline scheduling and control is satisfactory when nearly all customers were LDCs, which are firm contract holders whose takes were more predictable and far less variable. In current markets where over half the gas customers are electric power plants who purchase non-firm contracts, this approach may not be sufficient to guarantee supplies to non-firm contract buyers with highly variable demand. Today, operators need to make decisions in a limited time-frame based on their training and experience, and possibly a handful of scenarios that were evaluated using transient simulations.

Regional electricity markets are cleared by ISOs that determine time-dependent generator commitment and dispatch schedules to balance production with forecasted electric loads. The result is a day-ahead schedule that determines when all power plants on the system are online and how much electricity they produce. This market is cleared by solving a large-scale optimization problem in which these variables are decided on an hourly basis. Production must also be re-adjusted in near real-time to balance loads, and this is done by solving another optimization problem every 5 to 15 minutes. If loads unexpectedly increase, the production of a gas-fired power plant may be quickly ramped up. The resulting changes in power flows quickly re-adjust throughout the entire power system. Thus, electricity market clearing and operational decisions take place on a faster time-scale, and the physical effects propagate faster throughout the system, than in the case of natural gas.

Users of both power and gas markets make transactive decisions based on inexact information regarding actual upcoming load volumes, spatiotemporal distribution patterns, and prices. The contracts generated in both markets will thus only approximate the actual conditions the two industries must deal with operationally. Because both markets and operations are faster in the power sector, the uncertainties in electricity loads compound the uncertainties in pipeline planning, resulting in a cascading effect. This impact on pipeline operations increases the uncertainty in gas availability and pricing, which in turn compounds the uncertainty in electric power plant commitment and dispatch.

Moreover, for efficient grid operation, the time-dependent schedules of gas-fired generators often call for them to burn their nomination over only part of the contract interval, even if gas transmission planning is most efficient under steady withdrawal throughout the contract interval. The gas-fired generator schedule may also be changed to compensate for unexpected events throughout the electric grid, such as weather-related changes to wind-farm output. Such variation and unpredictability in timing and volume can be extremely challenging to pipeline operators. Because the largest variation and uncertainty in gas transmission is now caused by gas-fired electric power plants, it is useful for the gas sector, and especially interstate pipeline operators, to consider the regulatory environment, market clearing, and operations of electric power systems.

The lack of coordination between the natural gas and electric power sectors has become an issue of concern in many quarters, and recent regulatory changes attempt to address this. FERC Order 787 relaxes the information barriers between interstate pipelines and ISOs[46], while FERC Order 809 requires better synchronization of gas and electricity markets in addition to the exchange of operational schedules[266]. These FERC regulatory changes empower the engineering groups in both industries to coordinate intra-day operations of gas pipelines with their customers in the electric power sector. The daily operational behavior of the electric industry is now of crucial concern to gas operations, yet the processes generating this behavior are not broadly and deeply understood within the pipeline management and operations community at present. Conversely, pipeline operations are often only superficially understood within the electric industry.

The following section contains a high-level overview of market operations in the United States electric industry, and in particular how the daily generator scheduling procedures used by ISOs affect gas pipeline operations[185]. This will cast light on the decisions regarding when and where gas-fired generators are activated, and how their power production is modulated. An explanation of the generator commitment procedure and its impact on gas consumption by gas-fired power plants is intended to provide pipeline operators more insight into daily power plant behavior, and to give perspective on potential cross-industry joint simulation/optimization. The effect of these factors on gas pipelines will be discussed in the context of the recent FERC regulations, and operational scenarios will be examined to show the implications of regulatory, technological, and industry developments. Furthermore, specific information may be obtained from the electric industry that could help predict pipeline operators predict which power plants are likely to alter the volume of their gas takes during the current operational day, the times when this unscheduled operation is most likely to occur, and the likelihood of a specific gas-fired generator deviating from its scheduled day-ahead gas takes. Improved inter-sector communication would be most beneficial when implemented together with transient optimization techniques for pipeline flow control on the time-scale of intra-day power system operations.

2.2 Gas-Electric Interaction Issues

Gas transmission companies usually experience two main issues with gas-fired power plants. First, generators may quickly come online without providing enough warning for the pipeline to pack the system with additional supply. Second, gas-fired power plants are often scheduled to burn their total daily nomination in a shorter time than the steady ratable contract stipulates. Therefore, pipeline operators must decide what to do with supply scheduled for power plant use while the plant is offline and where to get extra supply while the plant is online. Additional capacity must be reserved for moving around the extra supply, using for example line pack or storage withdrawals. However, line pack and storage capacities are limited, and LDCs have traditionally used all available capacity at times of their peak demand. As firm contract holders, LDCs have a priority on line pack capacity.

Periods of simultaneous high demand for gas for both power and non-power usage often lead to power plants attempting to draw more gas than the servicing pipeline can provide given its other firm contracts. A typical consequence is that the plant pulls down the pipeline pressure so far that the facility can no longer draw the gas it needs for full operation, and/or deliveries to other pipeline customers with firm service contracts may not be fulfilled. When pipeline pressure is too low, a gas-fired generator cannot run or must reduce output. When supplies are tight, pipelines may issue an operational flow order (OFO) that will restrict generators to only their scheduled quantity, or else they will be shut off by the pipeline. For example, the power plant may be scheduled to be available for dispatch for only 16 hours, and offline for 8 hours, even though the supply contract is purchased for 24 hours at a steady rated take. When demand for gas is low, pipelines will often allow generators to overdraw their scheduled quantities. However, when demand is very low, the pipelines may issue an OFO that requires generators to take at least their scheduled quantities regardless of their cumulative imbalance positions. Such an OFO will often force power grid operators to activate more expensive generating reserves.

As a result of the growing dependence of power systems on reliable natural gas supplies, the wholesale prices of electric power and natural gas have become closely related. This is illustrated in Figure 1 for the New England region, and has been observed in European markets as well[252]. Gas-fired power plants play a complex role in the natural gas market because their demand is price sensitive. Thus, the lack of coordination between the gas transmission sector and electricity markets, whose demand could quickly change, can cause a misallocation of resources that is exacerbated under extreme conditions. Several examples are identified below, and also describe interdependence effects and market contrasts.

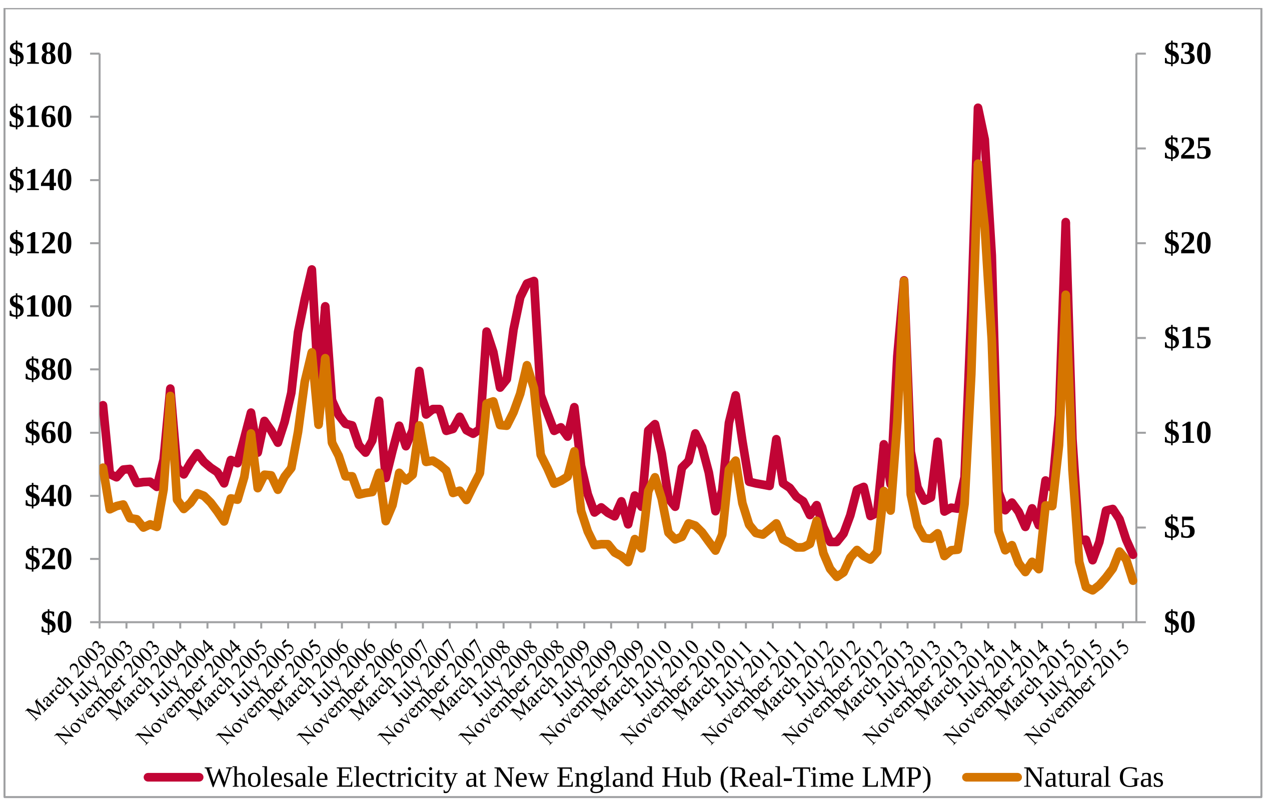


Figure 1. Natural Gas and Electricity Prices are Linked. Source: ISO-NE

2.2.1 Polar Vortex or Southern Heat Wave

A phenomenon has been observed in several recent years in which a shortage of electric power resources occurs during the winter season in the Northeastern United States. As a result of the "polar vortex" effect, in which regional temperatures suddenly drop and stay low for days, consumers increase their demand for both gas and electricity for heating. This causes LDCs to increase their gas consumption and utilize nearly all of their transportation rights. This leaves very little transportation capacity for non-firm contract holders, so that gas-fired power plants in the region must raise their price bids to ISOs dramatically. This effect can be seen clearly as price spikes in December to February of 2013, 2014, and 2015, shown in Figure 1. The polar vortex problem can also be aggravated by the lack of inter-sector communication regarding energy pricing. Gas-fired power plants in locations with adequate line pressure (e.g. in the West) will submit lower bids to the ISO than power plants in locations where non-firm contract holders are at risk of curtailment (e.g., in the East). The Western power plants could thus be dispatched to generate when electricity demand is peaking in the East, causing power flows from West to East to hit line flow limits. The Western plants will procure additional gas supplies, although it is more effective overall to transmit gas to the East. This may cause an imbalance in gas availability without a corresponding adjustment in price, and the problematic generator dispatch may continue to worsen the situation, leading even to blackouts[43]. Alternatively, during the summer months when demand for natural gas for heating is low, suppliers use transportation rights to move gas into low-pressure storage in aquifers or salt formations. This process cannot be quickly reversed, because significant energy is required to re-pressurize the stored gas. In the event of a sudden increase in regional temperature that may then be prolonged for several days, an increase in electricity usage for air conditioning may occur. A gas-fired generator may be dispatched to compensate for this increased demand exactly at the time when the gas storage facility is leaving little transportation capacity available on regional pipelines.

2.2.2 Interdependence Effects

The installation of electric-powered gas compressors, rather than (or in addition to) turbines that draw their power by burning gas from the pipeline, may be required to satisfy emissions restrictions or other environmental regulations[103]. Such gas compression stations that depend on electric power may constitute a significant load on the power grid, and may be subject to electric power curtailment at times of peak electricity demand during the summer season. However, the reliability of gas supplies is most critical to the grid at exactly those peak periods[50]. Situations have occurred where electric curtailment warnings were sent to a compressor station without realizing that the station was needed for adequately supplying a gas-powered generating plant. If this situation had not been recognized and avoided, it would have led to a much greater impact on the grid than the electric power curtailment was intended to mitigate. Adequate communication and a degree of mutual understanding between industries are needed to prevent this sort of situation. Alternatively, a *winter* failure of a power plant may cause an outage at an electrically-powered compressor station, which could lead to under-pressurization of a pipeline at a time of peak gas demand from gas-fired generator plants even if they are firm contract holders[274].

2.2.3 Discrepancies between Markets and Physics

Several aspects of current methods for gas pipeline operations lead to the issues described above. First, the market clearing, flow scheduling, and planning of physical operations are conducted consecutively rather than jointly. The contracts sold in the regulated market are bilateral agreements between traders who may not be equipped to account for complex physical considerations. Flow scheduling methodologies are usually based on steady-state models, and day-ahead physical operational plans often are as well. Consequently, even though estimated gas-fired power plant burn schedules with hourly time-granularity are often available, such temporal information may remain unused. Instead, transient, time-dependent factors concerning varying physical flows could be taken into account in real-time only on a reactive, local, ad-hoc basis. In order to overcome the challenges of increasing and more variable loads, a promising approach is to integrate market and physical operations in the gas industry. This would involve obtaining space- and time-dependent prices and flow schedules simultaneously by solving optimization problems that account for forecasted transient conditions in the day-ahead market. Subsequent re-adjustments of prices and flow schedules could be made in real-time (hourly) spot markets. Clearing the natural gas market in this way would determine the price at a given location in a pipeline network based on the physical ability to deliver gas there. Furthermore, this approach, when realized, will greatly aid in coordinating markets and operations in the natural gas and electric power transmission sectors. The regulatory changes initiated to support such initiatives are described below.

2.3 Recent Regulatory Changes

In November 2013, FERC finalized Order 787 authorizing interstate gas pipeline and electric transmission operators to voluntarily share non-public, operational information in order to promote reliable service or operational planning on either the public utility's or pipeline's system. This order allows an ISO to share estimated gas withdrawal schedules of generators on its system with the operator of the servicing pipeline. Moreover, in April of 2015, FERC issued Order 809, which requires synchronization of gas and electricity markets in addition to the exchange of operational schedules. It requires ISOs to time their day-ahead schedules so that gas-fired generators have time to buy gas within nomination cycle deadlines. These orders are examined in more detail below.

2.3.1 FERC Order 787 (Nov 15, 2013)

To put recent orders into context, recall the broad restructuring of the interstate pipeline industry in the United States mandated by FERC Order 636 in April 1992[268]. The major policy goal was to enhance competition in the natural gas industry and to ensure that adequate and reliable service is maintained. Subsequent orders have refined the market structure into its current form. A crucial aspect of this market is to ensure a level playing field for the information available to all buyers and sellers of gas transportation. Any non-uniformities in information access, or “inside information” known to particular market agents, can lead to gaming of the market to the great detriment of all other parties. Hence, certain information was designated as “public”, but strong restrictions were put into place about what non-public information could be shared and by what entities.

However, from an engineering perspective, sharing less data makes it more difficult to operate these complex interconnected networks in a resilient and efficient manner. As gas pipelines and the electric grid became more tightly coupled, the engineering problems associated with these information barriers increased. Recognizing these problems, FERC undertook an extended process with industry participants to create new standards and issue FERC Order 787, released in June 2014[46]. This order explicitly *allows and encourages* broad flexibility in information sharing between interstate gas pipelines and the interstate electric transmission industry. It is worth reading the following excerpt directly from the order. The language is clear and unequivocal:

> “[FERC 787] *amends the Commission’s regulations to provide explicit authority to interstate natural gas pipelines and public utilities that own, operate, or control facilities used for the transmission of electric energy in interstate commerce to share non-public, operational information with each other for the purpose of promoting reliable service or operational planning on either the public utility’s or pipeline’s system. The revised regulations will help maintain the reliability of pipeline and public utility transmission service by permitting transmission operators to share information with each other that they deem necessary to promote the reliability and integrity of their systems.”*

The full text of the order contains many examples of the general type of situation where information sharing could help, for instance:

> *"… electric transmission operator may find it valuable to know whether the interstate natural gas pipeline will be able to provide a non-uniform flow rate to meet the demands on the electric system. By the same token, it may be valuable to an interstate natural gas pipeline to know the demands that may be placed on its transportation system by gas-fired generators and whether such demands may cause a problem with its ability to deliver gas to other customers."*

The document makes it clear that this is

> "*not just during emergencies, but also for day-to-day operations, planned outages, and scheduled maintenance"* and includes *"actual, anticipated, or potential effects"*.

However, the Commission also explicitly rejected the idea of envisioning and enumerating all the exact situations in which information sharing could possibly be done. Instead they gave a broad, flexible authority to the industrial players to decide what can be shared by operators. On the other hand, the commission addresses the prevention of market gaming by implementing an inflexible "No-Conduit" rule that enumerates information sharing that may *not* be made, such as with internal or external marketers.

> *"[FERC] is intentionally permitting the communication of a broad range of non-public, operational information to provide flexibility to individual transmission operators, who have the most insight and knowledge of their systems*
>
> *…*
>
> *informational needs of system operators vary by region and, therefore, a specific and exhaustive list of permissive communications that may be relevant in one region may not address the communications and operational needs of transmission operators in another region. The Commission also recognizes that the informational needs of transmission operators may evolve over time as the generation mix in regions change and as transmission operators develop further insight into, and gain additional experience with, gas and electric coordination issues.*
>
> *…*
>
> *transmission operators should feel confident in their ability to engage in robust communications with each other, subject to the No-Conduit Rule, whenever necessary to promote reliable service…".*

It should also be noted that some situations technically blocked by the no-conduit rule, such as communicating with a power plant separated from a pipeline by an LDC, can be addressed by revising individual tariffs. So there is a potential for even more flexibility beyond the already broad scope of communication FERC encourages. By granting this flexibility, FERC explicitly empowers the industry to be creative in determining what information to share, and how to use it. It is recognized that understanding of what information to share is only tentatively understood and may change with experience, and some of the technology to take advantage of broader information availability may not have even been developed yet.

2.3.2 FERC 809 (April 16, 2015)

Another important FERC order increases the electric industry's scheduling flexibility by increasing the number of the intraday gas nomination cycles (from 2 to 3) and introducing multi-party gas transportation contracts. Timing of the gas nominations cycles has been better harmonized with the needs of the electric industry and their volatile loads.

In response to Order 809, the North American Energy Standards Board (NAESB) has issued the updated gas nomination schedule given in Table 1 below[280]. Although the new schedules are an immense improvement for electric planning, the increase in the number cycles adds to the analysis burden on gas transmission companies. They must make more frequent decisions regarding available capacity, and these decisions must be made in a shorter time frame than before. FERC recognized the problem of limited decision time, and tried to space the cycles adequately far apart:

> *"… there needs to be sufficient time between the scheduled quantity posting of one cycle and the nomination deadline for the next cycle to enable shippers to review their transportation needs prior to the next nomination deadline"*

Regardless, the intervals are shorter than in past years, and any technical tools to make this easier for the pipelines would be welcome. Note that the 3 intraday intervals are actually the minimum number that must be offered. If a pipeline has adequate resources to effectively offer even tighter nomination schedules, it may do so. Software tools might well be an enabler for such advances.

> *"Individual pipelines may offer additional scheduling opportunities beyond the standard nomination cycles"*

In order for these FERC orders to produce improved coordination as intended by the Commission, decision makers in the gas transmission industry must understand the decision making processes in the electric power transmission sector. The following section contains a short tutorial on how market clearing and physical operations may take place within the electric power transmission industry.

Table 1. Standard NAESB Gas Nomination Cycles (Eastern Standard Time)[280]

Nomination Cycle	Nomination Deadline	Notification Time	Nomination Flow Begins
Timely	2:00 pm	5:30 pm	10:00 am next day
Evening	7:00 pm	11:00 pm	10:00 am next day
Intraday 1	11:00 am	2:00 pm	3:00 pm current day
Intraday 2	3:30 pm	6:30 pm	7:00 pm current day
Intraday 3	8:00 pm	11:00 pm	11:00 pm current day

2.4 Power System Operations and Reliance on Gas Pipelines

Electric power systems in the United States are usually managed by ISOs or Regional Transmission Organizations (RTOs), which are non-profit corporations. Each such authority is responsible for operating high-voltage electric power transmission systems for a region consisting of one or more states, where it also administers the wholesale electricity markets, and manages the power system planning process. A hallmark of an ISO's independence is that its employees, management, and board of directors do not have any financial interest in any of the companies participating in its markets. In addition, ISOs do not own any transmission lines, distribution lines, or power plants, do not buy or sell electricity, do not profit from the markets that they administer, have no role in setting energy or environmental policy, do not favor any fuel or technology, and do not take any position regarding the siting of new natural gas pipelines or electric transmission lines. ISOs also have no financial or other connection to the natural gas industry other than to coordinate with pipeline operators when needed to ensure system reliability.

Day-ahead market clearing for power systems is conducted by solving optimization problems that incorporate time-dependent constraints on generator flexibility and determine adequate allocation of reserve resources. Additional optimization problems are solved in real time to ensure that electric power production is balanced with loads, while power flows do not exceed thermal limits on any active lines, and grid stability is secure in the event of line and generator outages. These procedures are described in detail below, using as an example the market operations schedule for an ISO in New England[54,56]. Much of the uncertainty in the activity of gas-fired power plants is related to their use as reserves. The reserve requirements mandated by North American Electric Reliability Corporation (NERC) guidelines are summarized below.

2.4.1 Reserve Requirements

All bulk power systems need reserve capacity to be able to respond to contingencies, such as those caused by unexpected outages. Operating reserves are the unloaded capacity of generating resources, either online or offline, which can deliver electric energy within 10 or 30 minutes.

Each ISO maintains a minimum level of reserves to be in compliance with NERC guidelines. These requirements are designed to protect the system from the impacts associated with the loss of generation or transmission equipment. In New England, the ISO must maintain a sufficient amount of reserves to be able to recover from the loss of the largest single system contingency within 10 minutes. This requirement is referred to as the total 10-minute reserve requirement. Additionally, reserves must be available within 30 minutes to meet 50% of the second-largest system contingency. Adding this additional requirement to the total 10-minute reserve requirement comprises the total system reserve requirement. Between 25% and 50% of the total 10-minute reserve requirement must be synchronized to the power system. The exact amount is set by the system operators, and this amount is referred to as the 10-minute spinning reserve requirement. The rest of the total 10-minute reserve requirement can be met by 10-minute non-spinning reserves. The remainder of the total reserve requirement can be served by 30-minute operating reserves. In addition to the system wide requirements, 30-minute reserves must be available to meet the local second contingency in import-constrained areas, i.e. areas into which electric transmission line capacity is limited.

In addition, the ISO is required to meet contingency response criteria, which are designed to ensure adequate response in the case of a large single source supply loss. Such contingency response allows the system operators to quickly restore system reserve margins and position the system for a second large single source supply loss. Currently, the ISO is required to recover Area Control Error (ACE) within 15 minutes of a large single source loss greater than 500 MW. ACE is the difference between scheduled and actual electrical generation within the control area on the power grid, which takes frequency bias into account. The ISO must restore ten-minute reserves within 90 minutes of recovering ACE or falling below the ten-minute reserve requirement. Additionally, the ISO must restore total operating reserves within 240 minutes of falling below the total operating reserve requirement.

2.4.2 Day-Ahead Scheduling

The first step in the generation dispatch process occurs through a financially binding Day-Ahead Market (DAM). The DAM is a forward market that operates one day prior to the operating day, which is a standard 24-hour calendar day. The function of the DAM is to provide a mechanism for load and generators to hedge against real-time price volatility. In addition to pricing, the DAM clearing results provide a base unit commitment (UC) schedule for the operating day that includes hourly dispatch levels for each committed resource. This UC schedule determines when generators must be available for dispatch. The market is cleared by first solving the UC optimization problem, which is a mixed-integer program. The results of the UC optimization problem are then used as inputs to the economic dispatch (ED) optimization problem, which determines the dispatch level for each committed resource. The inputs to the UC problem are offers representing a generator's costs of operation, which include no-load costs, start-up costs, and incremental energy costs. In the ED problem, only a generator's incremental energy offers are considered. These costs are offered by all large electric power generators on the system managed by the ISO.

At 10:00 a.m. on the day prior to the operating day, the DAM bidding window closes. At this time all supply offers, demand bids, increment/decrement (virtual) offers, and external transactions that have been entered for the next operating day are fixed. The ISO then has up to three and a half hours to clear the DAM and post results between 12:00 p.m. and 1:30 p.m.

As soon as the DAM results are posted, the Re-Offer period opens and remains open until 2:00 p.m. During the Re-Offer period, generators not committed in the DAM have the ability to change their start-up and no-load costs as well as their incremental energy offers. Generators that have been committed in the DAM, however, can only change their incremental energy offers. One of the objectives of the Re-Offer period is to give generators the ability to update their offers and costs for spot market fuel prices, which may have changed from 10:00 a.m. to 2:00 p.m. The Re-Offer period also allows generators not committed in the DAM to self-schedule as a price-takers in the Real-Time Market[56]. The timing schedule of this bidding process is given in Table 2; the timing of the scheduling processes are illustrated in Figure 2.

Table 2. ISO Scheduling Time (New England - Eastern Time)[56]

Day-Ahead (DA) Energy Market Step	Deadline Starting in 2013	Previous Deadline
Participant bids to supply DA energy	10:00 am	12:00 pm
ISO posts DA results	12:00 – 1:30 pm	4:00 pm
Re-offer period for participants	From post time until 2:00 pm	4:00 – 6:00 pm
ISO completes reserve adequacy analysis (RAA) process	5:00 pm	10:00 pm

2.4.3 Reserve Adequacy Assessment

Using the most recent incremental energy offers, the ISO next conducts the Reserve Adequacy Assessment (RAA) process. The purpose of the RAA is to ensure that sufficient capacity will be available to meet real-time energy demand, reserves, and regulation requirements. The RAA process marks the final interface between the DAM clearing and real-time operations. The initial RAA is published at 5:00 p.m. on the evening prior to the operating day, and each generator receives its expected schedule for the next operating day (12:00 a.m. - 12:00 a.m.). The schedule is a forecast only. It is not binding and will likely change during the real-time dispatch. The RAA process is continually updated at set intervals throughout the operating day, with updates to real-time unit commitments as necessary to account for unexpected events, load forecast error, generation scheduling deviations, unplanned equipment (generation or transmission) outages, and contingency response. Figure 2 shows the day-ahead scheduling timeline for both the DAM and RAA process.

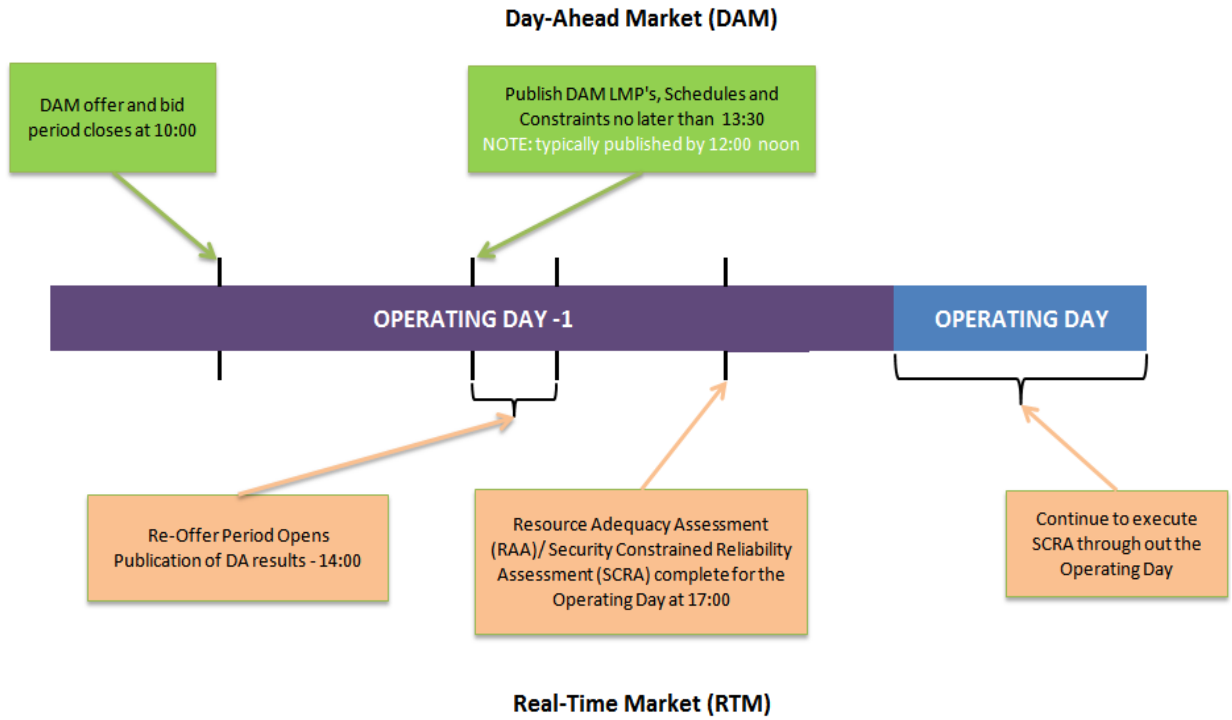


Figure 2. Day-Ahead Scheduling Timeline[56]

2.4.4 Real-time Balancing

During the operating day, the ISO re-dispatches all generating units every 5-15 minutes through the Real-Time Market (RTM), or spot market, in order to meet energy demand, reserves, and regulation requirements. All units committed in the DAM, RAA process, and in the Real-Time Unit Commitment process are included in the dispatch. The Real-Time Unit Commitment process runs every 15 minutes and commits additional qualified fast-start resources as needed throughout the operating day. Qualified fast-start resources are generating units that can start-up within 30 minutes and meet several other operating requirements. During the operating day, generators can update their offers up until 30 minutes prior to the hour in which the offer would apply. One of the objectives of providing generators the ability to update their offers intraday is to allow them to reflect the real-time cost of fuel in their offers. In addition, intraday reoffers allow generators not committed in the DAM or RAA process to self-schedule as price-takers in the RTM. If the intraday reoffer deadline has passed for an hour (30 minutes prior to the hour in which the offer would apply), the ISO allows generators to call the control room directly to request a self-dispatch level and an effective time. Such requests are honored if they do not cause or worsen a reliability constraint.

2.4.5 Real-time Contingencies

When the ISO has insufficient notice of service interruptions, the system operator will take steps to ensure that either sufficient replacement capacity with available fuel has been committed, or sufficient fast-start generation with on-site fuel or no-notice fuel delivery is available off-line. During these situations, the ISO will commit as many generation resources as necessary to meet the forecasted demand and reserve requirements. These resources are committed in order according to the cost of committing the resource. As the peak demand period for the operating day approaches, fewer resources are available for commitment due to their operating requirements. If there are not enough resources available to commit during the operating day, the ISO will use emergency procedures to maintain reliable operation of the power system, up to and including the shedding of firm load. The resources that are typically called upon during these times are coal- and oil-fired power plants with access to fuel stored on-site. As natural-gas-fired power plants have displaced coal- and oil-fired resources over the last decade, the volume of fuel maintained in inventory by these resources has declined and the infrastructure to deliver fuel to these resources has been used less frequently. As a result, many coal- and oil-fired generators have shifted to the same type of "just in time" fuel inventory management that is prevalent in the natural gas system. However, when the electric and natural gas systems are simultaneously stressed, such as during long stretches of extreme cold weather, the energy available from coal- and oil-fired generators will also likely be limited.

2.4.6 The Generation Mix

Presently, the generation mix in North America is undergoing rapid change, including a transition to natural gas. For example, the change in New England's generation fleet over the past 15 years is shown in Figure 3. The region's reliance on natural gas to generate electricity has continued to increase over the last decade along with the retirements of coal, oil, and nuclear power plants and increasing levels of wind and solar resources and energy-efficiency measures. Since 1997, 80% of all new online capacity has been natural-gas-fired along with almost 65% of all new proposed generation. Last year, natural-gas-fired power plants produced just under half, or 49%, of all electricity generated in New England. This amount is up from 15% in 2000, and is more than any other fuel source in the region. Currently, during typical load periods, nearly the entire fleet of dispatchable resources is made up of gas-fired generators, and a portion of the fast-start generators that would be called on to respond to a contingency are also dependent on natural gas. Conversely, the combined use of coal and oil has fallen dramatically over the same period, from 40% to 6%. Today, coal- and oil-fired resources rarely operate. By 2019, the region will have lost more than 10% of its current capacity with the retirement of 4,200 megawatts of power plants that do not use natural gas. In addition, as much as 6,000 MW of aging coal- and oil-fired power plants are at risk of retirement. These plants rarely operate and are typically only called on to run during the summer during peak load times, or in the winter when either natural gas pipelines are constrained or natural gas price spikes make them economical.

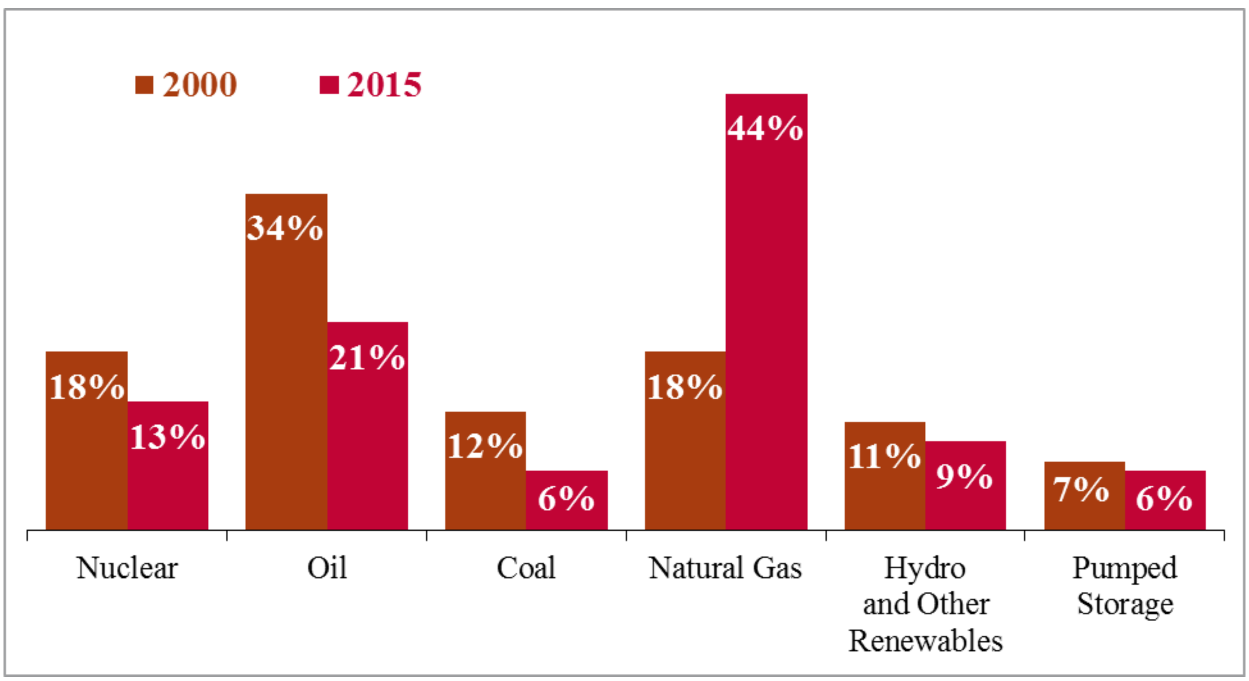


Figure 3. Installed Electric Energy Production Capacity in New England; Source: 2015 CELT Report, Summer Seasonal Claimed Capability (SCC) Capacity; Other renewables include landfill gas, biomass, wind, solar, municipal solid waste, and miscellaneous fuels

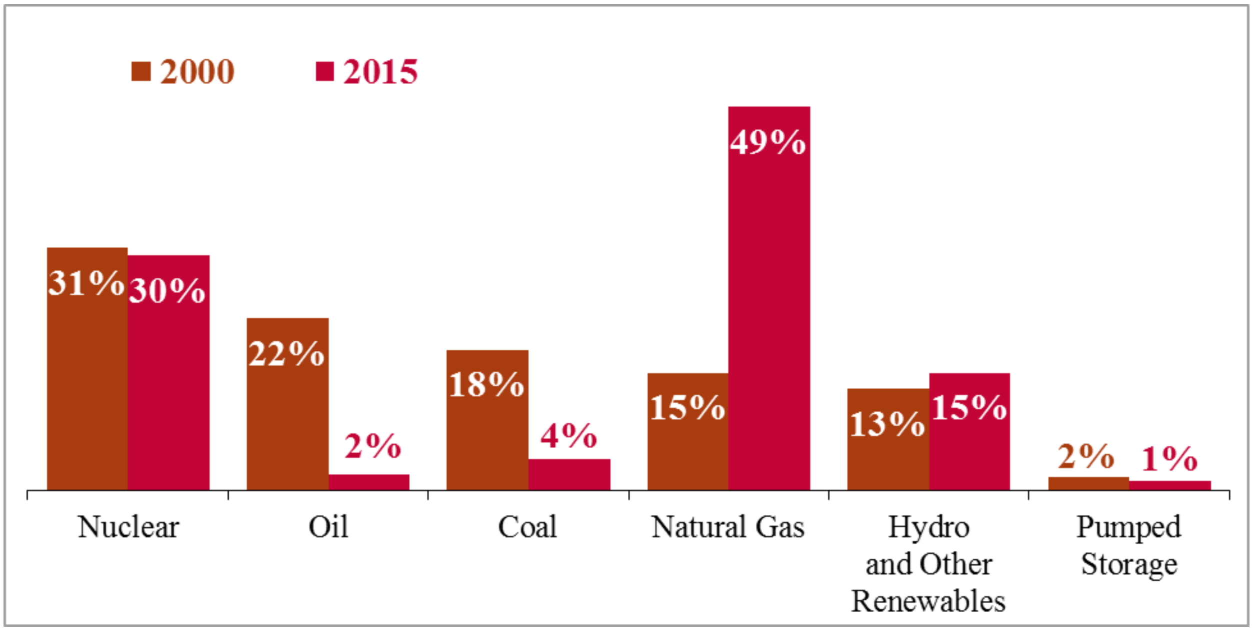


Figure 4. Electric Energy Production by Fuel Source. Source: ISO New England Net Energy and Peak Load by Source**; other renewables include landfill gas, biomass, wind, solar, municipal solid waste, and miscellaneous fuels**

The retiring coal, oil, and nuclear plants will likely be replaced by more natural gas plants and wind. The installed electric energy production capacity in New England is compared for the years 2000 and 2015 in Figure 3, and the regional electric energy production by fuel source is compared for these years in Figure 4. This transformation to a predominantly natural gas fleet has been driven in part by the fact that new natural-gas-fired power plants are highly efficient, relatively easy to site, and less expensive to build and run than other types of power plants. In addition, increased production of natural gas from the Marcellus Shale, located just west of New England, has made low-priced natural gas available to the region.

2.5 Pipeline Operations & Analytics Technology

In general, pipeline operations are less automated and decision cycles occur over slower time-scales than what is done for power grid operations. Gas control engineers and technicians maintain secure system with limited predictive information and greater reliance on their extensive training and experience operating a particular system. Interaction with the power grid causes faster changes in pressures and flows throughout a pipeline system than what has been experienced traditionally in gas delivery to LDCs.

2.5.1 Pipeline Physical Control

There are four general options for operators to control the flow of gas through a pipeline system. These are (1) opening or closing valves to change the system connectivity, (2) adjusting regulators that decrease line pressure, (3) running gas compressors to boost line pressure, and (4) injecting gas into or withdrawing gas out of storage fields. Planning engineers must model the ability of controllers to manipulate flows and line pressures using valves, regulators, and gas compressors carefully. These control adjustments are subject to complex system constraints, which include maximum allowable and minimum operating pressures (MAOP and MINOP), maximum flow through city gates, and maximum compressor power and discharge temperature. Finally, the total line pack in the system must be recovered at the end of each operating day.[267] Line pack refers to the total mass of gas in the system, which also corresponds to the amount of energy available from that gas. Other physical and engineering restrictions, market structures, and regulatory factors also limit the information and actions that are available to gas controllers. For example, flows at custody transfer points from inter-state pipelines are kept as steady as possible and are generally changed in response to market adjustments. Physical limitations also prevent fast changes in the rate at which flowing supplies are brought into the system. Therefore, while the supply entering the system at custody transfer interconnections must be kept nearly constant throughout each 24-hour gas day, the gas offtakes by customers may be highly variable, especially by electric generation loads.

2.5.2 Pipeline Flow Scheduling – the Challenges to Automation

The interface between physical and market operations in the pipeline industry is currently connected by the processes of scheduling, balancing, and confirmation. These activities require numerous and complex communications between many entities that interact with pipelines, as illustrated in Figure 5. In order to coordinate these interactions, the pipeline accepts nominations, schedules flows, and then performs an iterative process of checking flow feasibility and re-scheduling before confirming with the counter-party. The final scheduled quantities are posted after the confirmation deadline.

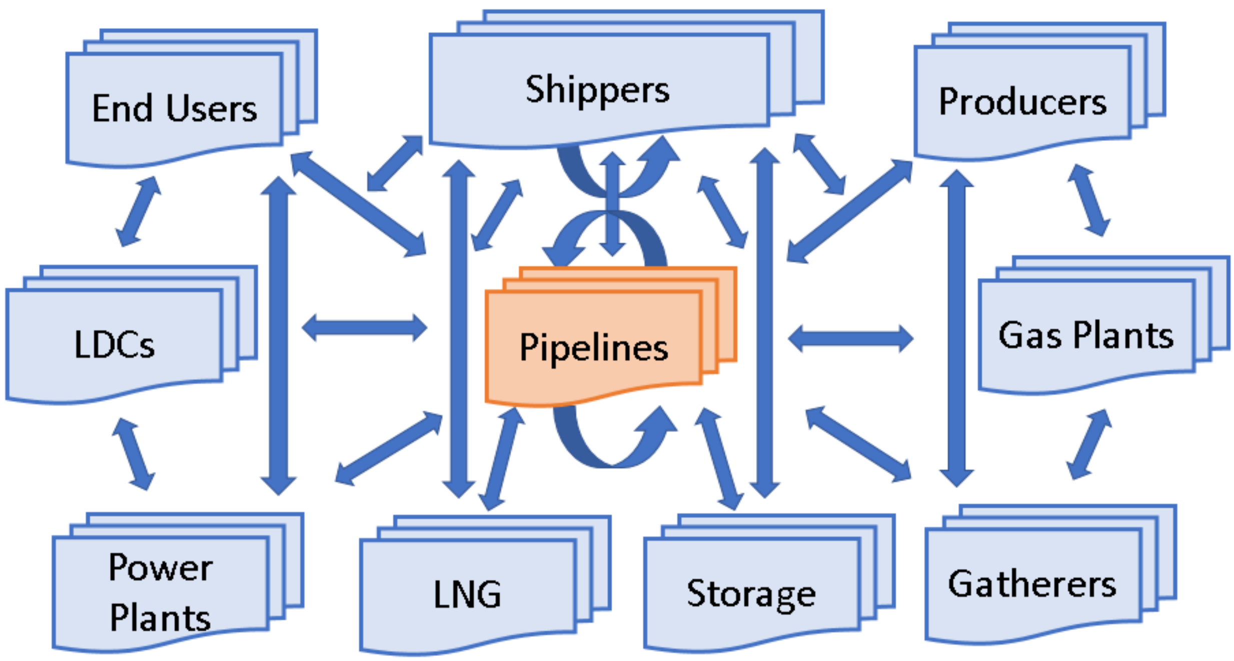


Figure 5. Complex communications within the natural gas transmission industry.

The key terms used to describe the scheduling procedure are

- **Nomination** – a procedure in which a shipper requests that a pipeline will schedule a contract for transportation of gas between two locations on a pipeline or a contract to make injections or withdrawals from a storage facility
- **Confirmation** – a procedure in which an upstream party and a downstream party establish an agreement about the quantity of gas that will flow at a location, at which one of the parties operates custody transfer
- **Scheduling** – a procedure in which the nominated or confirmed quantities are compared with the transportation capacity available within the pipeline system to determine which quantities will be able to flow through the system and interconnection points. The procedure is internal to the pipeline and incorporates automated and manual processes for allocation of system capacity. The procedure

may occur before or after the confirmation process or multiple times during the evaluation window as needed.

- **Balancing –** a procedure in which any reductions in nominated or confirmed quantities are applied as needed to balance transactions on the pipeline system. These quantities typically need to be re-confirmed.
- **Scheduled quantity** – the final approved flow quantity that results from the nomination by a shipper and evaluation by the pipeline during the confirmation and scheduling processes
- **Electronic bulletin board (EBB)** – the standard platform for exchange of information on the customer activities website of the pipeline. The data are communicated over the internet using the NAESB electronic delivery mechanism standard.

The processes of nomination, scheduling, balancing, and confirmation are iterative and depend on the pipeline company and system, and may be performed multiple times between the nomination and confirmation deadlines to maximize utilization of pipeline capacity while minimizing imbalances between shipper schedules. Many of the variables in the scheduling process require manual intervention and are problematic to automate. For example, there may be a need for no-notice capacity to support expected usage of purchased services, or non-ratable flexibility made available either to support purchased services or on a best efforts basis. Changes to the schedule such as these are often called upon by electricity generator activity. There is an interdependence between the performance of receipt and delivery locations, line pack and storage levels, demand and supply, gas quality fluctuation, backhaul and displacement reliability, and maintenance that may require redirection of nominations through outer segments of the pipeline. Furthermore, weather may impact supply and demand as well as compressor efficiencies and thus capacity. Physical assistance may be agreed upon by interconnecting parties, and the order in which reductions are applied may vary with respect to location, timing, and balancing. Significant effort goes into identifying opportunities for managing imbalances.

Additional factors make automation problematic, such as the heterogeneity among pipelines of physical structure, throughput capacity, tariffs, and services approved by FERC. Pipelines may also use different communication standards, such as a combination of proprietary and third-party EBBs. Even though significant effort by experienced humans to perform analysis is needed to factor in variables outside of submitted nominations, the costs of automation may not be supported by the benefits. For instance, the level of activity may be low, there may be a lack of qualified human expertise and system resources to develop and maintain the automation system, and finally, many processes that can be automated have already been automated. Automation would also be problematic for many financial transactions, and thus could restrict or eliminate significant customer service activities. Thus, significant effort would be needed to evaluate what modifications to the current nomination timeline, interfaces, and communications would be needed to implement any additional automation of the current scheduling procedure. The current priority is placed on the most efficient utilization of the U.S. pipeline network, and current structures that support this requirement can form the foundation of the future architecture for coordination. In particular, any changes to the scheduling process should account for operational aspects of all parties, including the pipeline, as well as physics of gas flow that limit the rate at which the flow and line pack distribution in the system can be altered.

2.5.3 Human Factors and Decision Processes in Pipeline Operations

Pipeline system control operations are often conducted with limited predictive information and significant reliance on the training and historical experience of operators. Such decision-making is especially challenging to coordinate between the gas and electric industry sectors[270-276]. In actual system operations, all control points have automatic systems that maintain operating set points. For example, a regulator may adjust through flow to follow a given upstream pressure, or a centrifugal gas compressor station may adjust turbine power to follow a given downstream pressure. These systems were designed for efficient operation under steady flow conditions. When flows vary in time, gas controllers must adjust the operating set points in real time in reaction to changes in system conditions as they are observed. When the system is observed to be approaching problematic conditions, such as dangerously low pressures, certain emergency actions may be taken. The most commonly used such action is the OFO, which requires customers to adhere to strictly specified offtakes. Any adjustments to control set points must account for all system limitations and constraints, which requires substantial operator training and experience. Transient hydraulic analysis must, therefore, account for the human factors of system operations. Specifically, planning engineers must consider the likely actions of gas control operators in reaction to changes in conditions, and recognize situations in which an OFO may be issued.

The observations available to the gas control operator include pressure, flow, and temperature measurements throughout the system. Consumption of natural gas generally follows ambient temperature, so operators have traditionally forecasted load based on the weather. As electric generator gas loads have grown, such forecasting has become less informative because generators are activated according to the economic day-ahead market clearing practices of ISOs. Recently, the removal of regulatory barriers to operational coordination has permitted pipeline operators to receive predictive information about when and where gas-fired generators are activated. Nevertheless, the flow profiles of offtakes by EG customers can be highly uncertain, and information given in "burn sheets" may be insufficient or may become available only after key operational decisions have been made.

Even when full EG gas offtake schedules are available in advance, there is no software tool that can compute time-dependent adjustments to the many system set points for the upcoming day based on known flow profiles. Thus, gas controllers must depend on their training, experience, and detailed knowledge of the specific system, including historical and seasonal trends, to maintain reliable operations. Further, there are many human factors involved in the process of market clearing, flow scheduling, and gas control, which are difficult to model. These decision processes vary by region and by company, and may be proprietary.

In general, the market and physical operations of natural gas transmission and electric power generation are highly complex. Because data standards for inter-sector interaction are lacking, there is high reliance on human communication at the interface. The hydraulic analysis for capacity planning must, therefore, be conservative to account for uncertainty in human behavior between decision cycles. The possibility of maintenance outages or unplanned contingencies further justify a conservative approach to evaluating capacity.

2.5.4 Analytics Technology and Capacity Analysis

Numerous software applications exist for analysis of pipeline transients such as those caused by intra-day changes in loads[171]. These can be used to assess load capabilities of a pipeline system under various conditions. The mathematical and computational foundations for such software were laid over four decades ago[221,212], with numerous subsequent investigations[113-131,133-149,151-161,203-216]. Such software accurately models complex, integrated multi-pressure level systems and provides its users with information regarding predictions of pressures, flows, valve positions, pipe diameters, compressor powers and speeds, and storage field utilization factors. This process is called hydraulic modeling.

The primary capability of commercial transient analysis software is to predict how the pipeline system will behave under given conditions. The inputs to the analysis are offtakes (load) throughout the system and operating protocols of the control points described above. The output of the software is a simulation of what, mathematically, is an initial value problem. From a starting condition, the state of the system is evolved forward in time according to well-defined rules that represent physics and engineering operations.

Commercially available pipeline transient analysis software can efficiently simulate highly complex pipeline operations, ***but it cannot determine how the system should be optimally operated***. It cannot give the user protocols for compressor and regulator operation that maximize system throughput, or determine economically optimal intra-day flow allocation give system capacity. The development of a fielded technology with such capability remains a challenge for the gas pipeline industry[283-285]. Hydraulic modeling is therefore used primarily to evaluate pipeline capacity. Transient analysis is used to quantify pipeline flows and pressures under time-varying boundary conditions (i.e., consumer offtakes). Such analysis can be used to estimate the maximum utilization of a pipeline system, however, aspects of flow control operations must be accounted for when estimating capacity given varying flows and actual operating conditions. The analysis must specifically account for how gas control engineers operate the system with the available tools and information. Accounting for the numerous decision processes, uncertainties, and human factors involved is a labor-intensive and time consuming process that cannot be performed using current technology for real-time operations. An engineer must go through an iterative procedure to approximate the effects of such factors, as described below.

The software tools available to capacity planning engineers do not provide a solution to controlling transient flows through a pipeline system. Rather, these tools describe what will happen if a given protocol is applied under specified offtake and supply profiles. Capacity planning departments at pipeline companies use an approach called ***iteration*** to evaluate maximum system utilization under a given set of conditions. Iteration involves simulating the system until constraints are encountered, then returning to a point where actions can be determined that prevent constraint violation. For example, if a line pressure is seen to hit a MINOP, the engineer may rewind the simulation by an hour and modify a compressor station set point that will maintain the pressure. The process can be summarized as follows:

1. An initial steady flow state for the simulated system is chosen (at the level of nighttime flows).
2. From the initial state, the simulated system is transitioned to the initial line-pack configuration expected at the beginning of the day by adjusting flows and settings of compressors and regulators.
3. As the simulation proceeds through the 24-hour gas day, whenever situations are encountered for which gas control would take emergency action, such as a curtailment or an OFO, the simulation is returned to an earlier time and a preventative action is programmed in the simulation. Such preventative action would be adjustment of compressor or regulator settings.
4. The steps are repeated until the simulation has gone through the 24-hour operating day, and the procedure is then concluded.

In actual operations, the gas control department of a pipeline company will take action well before the system moves into a state that requires emergency action. When pressures are seen to drop precipitously because of high offtakes in a part of the system, the operator does not know whether the high offtake will end soon, thus keeping pressure above the MINOP. The operator assumes that the pressure will continue to drop unless action is taken. The operator does not have the opportunity to reverse reality to make adjustments, as is done by a capacity planning engineer in the simulation during the iteration procedure.

Because the gas control department has limited information on which to act predictively, actions taken in the field are primarily reactive to deviations from the expected schedule. In contrast, capacity planners running simulations have predictive information (flow profiles used in the simulation are known). Also, they have the option of returning to previous times and adjusting a simulation. The process of iteration is a reasonable emulation of the actions that the gas control department takes to operate the system; therefore, the procedure leads to a reasonable estimate of maximum system utilization.

2.5.5 Calibration to Actual Conditions (Design Day)

Simulations performed for transient analysis can provide estimates of theoretical optimal performance of a pipeline system under certain conditions. Such analyses are done by capacity planning departments to develop a risk assessment, e.g., to quantify the likelihood that the system may not be able to deliver required load under extreme conditions. It is necessary to understand that these results incorporate many uncertainties in model and case study parameters, as well as human factors and decision processes. When operators in the gas control department monitor the system, they rely on their training and experience to make real-time decisions about control actions and balancing needs. Furthermore, significant uncertainty in flow profiles can exist, and the sensitivity of the system performance to variations is substantial. Even minor deviations in the timing and volume of forecasted offtakes can lead to a large discrepancy between predicted and observed system flows and pressures.

A solution obtained using the iteration procedure described above is a conservative estimate of maximum capacity under a given scenario, and may be lower than the theoretical optimal system performance. It is not intuitive to produce control protocols corresponding to the maximal system utilization because of the time-dependent complexity and the many control points. Producing a reasonable solution using this procedure requires substantial time and experience using pipeline transient simulation software. However, a conservative solution is warranted because of the significant uncertainty, human factors, and lack of predictive information (particularly with regard to EG gas offtakes) that characterize actual operations, as discussed above. Furthermore, additional simulations may be required to assess the impacts of unplanned events that cause outages or reductions in capacity or control of the system.

Finally, the very significant consequences of system depressurization require conservative analysis. If distribution system pressure dropped below the critical levels needed to service residential customers, the result would be catastrophic because of the time and resources required to re-light all the affected appliances[273-274]. To ensure that network modeling being used by gas companies in the United States and internationally is effective as a flow assurance measure against catastrophic system events, gas company personnel seek to identify specific scenarios for the gas company's system that represents the "worst case" or "perfect storm". These scenarios represent what the company and the public it serves would expect to be a reasonable set of possible events and situations from past historical events and data, future weather forecasts, as well as gas supply and customer load potential swings and trends, i.e., EG gas offtakes. This approach is akin to the 100-year flood planning and similar exercises that ensure measures are in place to prevent and/or mitigate a catastrophic event in other parts of the community.

Industry standard practices for gas companies include planning for a ***design day***. A design day is the annual day or days that represent the "worst case" for the system from the standpoint of loads, flows, demands, weather, and other factors[277]. These factors have and/or can be expected to adversely affect the reliability of the gas system. Consequences such as curtailments, low pressure events, and worst case-outages are possible. Outages are the worst case because of customer interruptions and the amount of time and resources involved in re-lighting gas appliances for core residential and commercial customers.

Gas pipeline companies work to avoid system outages all costs. System curtailments for customers without firm contracts for capacity, which include most gas-fired power plants, are the means to protect the reliability of natural gas supply to firm contract holders, which are typically LDCs. Design day analysis includes running sensitivity analysis around the initial design day to see the effect of other potential factors, i.e., cold/hot weather over an extended period of days, parts of the system down for maintenance, third-party damage events, or some known potential issues that could affect the system. Running multiple probabilistic studies on the myriad of factors that "could go wrong" is not practical nor suggested because the value from these studies is limited to the real world effects of what can be done to avoid the perceived issue. Unless all of the probable factors are modeled in most or all combinations, which is statistically inefficient and in some ways not possible, one cannot accurately predict the exact combination of conditions that will "trip the system". Therefore, the industry standard practice is to perform sensitivity studies around the design day base case that are practical and closest to what has previously occurred or what is expected to happen. When new events occur, the design base case can be adjusted to see the impact of these new factors on the gas system from a modeling standpoint and required changes to the operations of the gas system infrastructure or system improvements (projects) can be inferred.

2.6 Power System Issues with Gas Pipeline Operations

Many regional markets currently use natural gas as a primary fuel. For example, 44% (13,650 MW) of total generation capacity in New England uses natural gas. However, the vast majority of this capacity relies on interruptible non-firm gas contracts to obtain their fuel supply. As a result, the availability of natural gas for power generation has a significant impact on grid reliability. When there is enough pipeline capacity to serve the region's power generation demand, such as during the summer when heating demand is low, generators have little trouble obtaining gas. During the winter, however, when the pipelines serving the region are often operating at full capacity just to meet heating demand, generators have experienced challenges obtaining gas[43]. For instance, the lack of fuel diversity on the New England electric system is exacerbated by the fact that natural gas is a "just-in-time" resource. As a result, New England generators have migrated away from on-site fuel storage in the form of coal and oil, where disruptions in fuel delivery chains were able to be coordinated over days and weeks. Now these generators are dependent on just-in-time fuel delivery from the gas pipelines, and any interruptions in this supply chain have an immediate impact on the operation of the power system. Specific issues that have contributed to these challenges are described below.

2.6.1 Non-firm Contracts

Many of the electric reliability issues related to gas dependence in New England originate from the fact that most gas-fired generators do not procure firm priority rights to pipeline capacity, and thus operate with an interruptible fuel source. Most generators also do not have the ability to switch to an on-site fuel supply. This means that when conditions become constrained on the gas pipelines these interruptible generator customers may not be able to schedule fuel or use the fuel delivery system to operate in accordance with their operating characteristics. Such fuel delivery interruptions or limitations generally happen on short notice and give system operators little time to respond.

2.6.2 Pipeline Limitations

While pipeline usage is often at or near capacity during the winter months, pipeline operators will not expand pipeline capacity without signed contracts from firm customers. In addition, FERC, which must approve pipeline projects, bases its decision on whether a pipeline project is in the public convenience and necessity in large part on the existence of firm contractual commitments. As a result, to the extent that projected growth stems from the need to service gas-fired generation, pipelines will not expand to accommodate this growth unless the electric industry begins to sign firm fuel supply contracts.

2.6.3 Generator Schedule Mismatch with Fuel Nominations

Occasionally, gas-fired generators use more natural gas than scheduled for the operating day. The impact of this practice on natural gas pipelines depends on the operating at the time. Sometimes, the impact is minimal because the pipelines have sufficient capacity to deliver the gas and time to recover from the over-draw before the next operating day. However, during periods of pipeline maintenance, outages, or high system demand, the pipelines may have limited ability to serve this additional demand. During these times, the pipeline operators may need to exercise their rights under their tariffs and will use flow control and valve shutoffs when generators place the pipeline system at risk by overdrawing gas to meet their generation obligations.

In addition, as previously discussed, generators use gas in a different pattern than is ideal for pipeline operators. Pipeline operators determine their ability to deliver gas based on a customer utilizing 1/24th of its daily nomination in each hour during the gas day. However, peaking units are often committed by an ISO to meet peak loads during the afternoon. As a result, such units may schedule gas for the entire gas day, but will burn their total allotted volume during only a few hours in the afternoon. While some pipeline operators may be able accommodate these differences between scheduled and actual usage if their pipelines have time to recover gas pressure, the pipelines in the Northeastern United States have not been designed to handle these imbalances. The sudden ramps and shut-offs can cause pipeline pressures to vary significantly from hour to hour, thereby jeopardizing reliability to all other customers withdrawing gas from the pipeline. ***These challenges will become greater as more wind resources are connected to the electric system and gas generators are increasingly called on to balance the increasingly volatile system.***

2.6.4 Timing Differences between Gas & Electric Systems

As described above, generators are often not consuming gas as expected by the pipeline operators throughout the operating day. In part, this is because of differences in timing between the gas and electric systems. The gas industry operates on a different schedule from that of the electric system, which was described in detail in the previous section. The purchase of gas is generally through brokered markets (i.e., Intercontinental Exchange) for the next gas day. The gas market is most liquid between 8:00 a.m. and 9:00 a.m. the day prior to the electric operating day. It is during this trading period that prices for the next gas delivery day become known and can be used to formulate offer prices by generators for the DAM.

Next, a generator must nominate pipeline capacity to transport the natural gas from one specified location to another over the gas day. Submitted nominations are confirmed and scheduled by the pipeline operators based on service priority, available pipeline capacity, and the pipeline's ability to maintain pressure requirements along the designated contract path. Natural gas transport is nominated and scheduled on a one-day advance basis, using a 24-hour gas day from 10:00 a.m. to 9:59 a.m. Eastern Standard Time. Nomination cycles fall into three categories: Timely, Evening, and Intraday. Timely and Evening nominations are for deliveries on the following gas day, while intraday nominations are for deliveries in the same gas day. The timing of each nomination cycle is detailed in Table 1.

Timely nominations give customers the most assurance that they will receive their nominated amounts of pipeline capacity during the next gas day, as long as they do not exceed their scheduled contract quantities. Under industry standards, firm customers that do not nominate their full entitlements during the Timely nominations cycle free up additional capacity for other customers that have a lower pipeline service priority.

During the evening nomination cycle "bumping" can occur. Bumping is the process by which a customer with a higher priority can force its nomination to take precedence over that of a customer with a lower priority. As the gas day progresses, the three remaining gas scheduling periods, Intraday 1, Intraday 2, and Intraday 3 become windows of last resort for nominating additional fuel. Furthermore, gas trading typically does not take place over weekends and holidays, meaning generators must plan several days in advance during these times.

For each electric operating day, gas-fired generators must also manage fuel procurement and scheduling that spans two gas operating days. For hours ending 11:00 a.m. through midnight, generators can purchase and nominate their gas during the previous day's Timely Nomination Cycle based on the DAM results. For hours ending 1:00 a.m. through 10:00 a.m., they must rely on the sum of the Timely Nomination Cycle from 2 days prior, plus the intraday nomination cycles from the previous gas day to schedule their gas. During the Intraday nomination cycles, there is high risk of not being able to schedule gas, or being forced to pay high premiums. If such intraday gas cannot be scheduled, that leaves the early hours of the next morning dependent on nominations made 2 days prior. In effect, gas nominated for those periods is based on *very* stale information if gas from intraday nominations cannot be purchased due to supply limitations or other reasons.

2.6.5 Gas Supply Disruption and Pipeline Maintenance

Often pipelines are able to operate with a temporary supply disruption if gas pressure is maintained within acceptable limits. However, a major failure to an interstate gas pipeline could result in the loss of electric generating capacity that exceeds system operating reserves available to compensate for these losses. For example, a single major pipeline currently supports approximately 10,000 MW of generation capacity in New England. A major supply disruption to this pipeline would likely result in the need for emergency procedures to maintain reliable operation of the power system. Occasionally, gas-fired generators become unavailable to enable pipeline inspections and maintenance. Normally, pipeline outages occur during the pipelines' off-peak season (summer), which coincides with the peak season on the electric system. While pipeline maintenance outages are expected, issues have arisen both due to pipeline operators providing short notice of such outages and the timing of such outages during periods of high electric system demand.

2.7 Possible Gas-Electric Coordination Solutions

There are several promising directions for overcoming the hurdles posed by issues described above. These can be categorized as improvements in communication, market structures, and technological advancement in transient optimization and uncertainty management.

2.7.1 Communication Improvements

First and foremost, the most straightforward and immediate improvements follow from communication between operators of transmission systems for the two sectors. Following FERC Order 787, day-ahead planned schedules for gas-fired generator operation (burn sheets) are already usually available from ISOs.[46] However, because the use of generating reserves is decided in real time, the actual schedules of gas-fired generators are uncertain.

However, statistics could be computed on a per-generator basis to quantify the deviation from the planned schedule as a function of time throughout the day. In addition, because the production of 10 minute non-spinning contingency reserves must be replaced within 90 minutes, such generators are only operated at times of peak stress[55]. Thus, given the locations on the pipeline of such generators, the pipeline operator can know where additional line pack could be maintained to mitigate the effect of sudden additional gas loads. Thus, two types of information that pipeline operators should seek from ISOs are

- Day-ahead gas-fired generator schedules
- Locations and usage statistics for gas-fired generators used as 10-minute non-spinning reserves

An RAA report from the ISO ***can indicate which power plants are likely to alter the volume of their gas takes during the current operational day*****.** The total power system load forecast, given by the ED schedule, ***can indicate the times when this unscheduled operation is most likely to occur.*** A history of reserve activation in the real-time market of an ISO ***can indicate the likelihood of a gas-fired generator deviating from its scheduled day-ahead gas takes*****.** If such information is only shared with managers responsible for operations, the market participants would not be affected[44]. However, for any information to be effectively utilized, the participants must agree to the types of information to be shared, and which actors are permitted to obtain and use it.

2.7.2 Market Improvements

Wholesale electricity markets are often cleared by solving a series of optimization problems that minimize the cost of production while taking into account the physical process of delivering energy between production and consumption locations. This process takes advantage of optimization technology to account for physical limitations of the power grid in both space and time using so-called LMPs for electricity[54-46].

In contrast, the natural gas market is based on bilateral transactions between traders who seek to balance supply and demand[251,255]. This mechanism can be slow to respond to contingencies, and is imperfect for ordinary day-to-day operations, particularly with respect to coordination with wholesale electricity markets[35,260].

One possible direction for improvement is to formulate an optimization problem that either a pipeline company, or an independent non-profit entity, similar to an ISO, could use to clear the day-ahead natural gas market given bids from producers and suppliers[78,264]. When consumption by non-firm contract holders is an optimization variable based on a cost curve (e.g., related to the heat-rate of a gas-fired generator and the LMP for electricity), a locational trade value (LTV) for gas could be computed[248,252,278]. This would allow the price of gas throughout a pipeline system to be computed based on the physical ability to deliver it from suppliers. A principled, physics-based balance of electricity and gas prices would mitigate the interdependence issues described above[35]. It is recognized that this is a very ambitious suggestion, but one that merits technical investigation because of the potential size of the payoff. Implementation would require a formal cross-industry project at least as large as the one that led to FERC orders 787 and 809.

2.7.3 Advancing Transient Optimization

In the context of the current FERC natural gas market scheme with more frequent nominations, transient pipeline optimization has high potential as an enabling tool[186]. In the control room, and in conjunction with a state finding tool, it can help pipeline operators know how to best operate their stations in a predictive manner, and reposition line pack as the variable loads unfold across the system during the day. As a planning tool, it can be invoked using generic starting states so that transient system characteristics can be examined over multi-day scenarios to determine, for example, the actual system capacity as opposed to steady state approximations. Hence objectives such as capacity validation and/or maximization are typical choices for planning, as are fuel cost minimization and the achievement of regional linepack targets at specified times.

For a day-ahead market-clearing scheme that is coupled with predictive grid-load information, transient optimization becomes even more attractive[187]. Because of the slow speed of gas flow relative to electricity flow, day-ahead market-clearing computation for natural gas would need to take transient flows into account. This is challenging because of the high nonlinearity and complexity of the resulting optimization problem. It would require more advances in gas pipeline modeling and optimization technology, and specifically the advancement of transient optimization into use in the field. To take full advantage of communicated information, and to make possible a principled market clearing mechanism, reliable and fast methods for transient optimization are required.

Transient optimization is thus a key enabling step for effective gas-electric coordination. If it is made robust, fast, and practical for large systems, this approach can help companies estimate available capacities more accurately before each nomination cycle begins. In the event of tighter coordination with the electric industry, other objective functions will certainly be formulated. Several approaches to transient optimization have been proposed. Some examples of different approaches to transient optimization can be found[80-85,132,188,159-165,283-285]. Explicit inclusion of load uncertainty has also been considered[183]. Inclusion of discrete variables is also an active topic of research. Despite these advances, challenges remain in areas such as computational runtime, problem scaling, and multiple local solutions. Solving a formulation coupled with electrical grid components will enhance these challenges. Because of the diversity and importance of transient optimization applications, the development of a wide variety of competing and complementary approaches is crucial.

3.0 Power Grid Information use in Pipeline Operations

The recent increase in the use of natural gas as a fuel for electricity production has greatly strengthened the interdependence between the electric power and natural gas industries[36-53,184,185]. The resulting intra-day fluctuations in pipeline loads caused by intermittent or unexpected gas-fired electric power plant operations have become particularly problematic. To mitigate this issue, regulatory changes have been initiated to lower the barriers on communication between operators of power grids and gas pipelines, as described above. In order to leverage these changes, some types of intra-day operational information can be obtained and used by pipeline managers from power grid operators in order to forecast time-varying pipeline loads and characterize uncertainty of these loads in space and time. Emerging control technologies could also be developed by the pipeline simulation and controls industry to provide tools for pipeline operators to more effectively use such information to mitigate intra-day gas-electricity interdependence issues. Specifically, new techniques for using transient optimization could be applied to find feasible compressor operation schedules, which are resilient under uncertainty, given such power system data. Bringing these methods into practice can enable gas pipelines to reduce the risk of service interruptions caused by intermittent power plant activity. Additionally, pipelines will be able to more reliably service power plants that use their gas nominations during only part of the day, or that may start up or shut down with little warning.

3.1 Status Quo of Gas-Electric Communication

Extensive gas-fired power plant construction, as well as subsequent utilization of these plants to serve peak electric loads and provide generating reserves, has caused electric power grids to increasingly depend on greater and more reliable gas supplies. Such gas-fired generation can be intermittent, which causes large and sudden variations in takes from high pressure gas pipelines. These conditions lead to gas price fluctuations, line pressure drops, OFOs, and increased operating expenses for both industry sectors. Because natural gas is now the largest fuel source used for electric power production in many regions of North America, interest in coordinating the operations of these systems has grown. However, natural gas pipelines and power grids operate on very different spatial and temporal scales, and this makes the coordination of market clearing procedures and physical infrastructure operations difficult.

While gas is purchased using nominations for steady takes over 12 to 24 hour intervals, power system operators often require gas-fired generators to commit to production schedules in which their nomination is burned over only part of the contract period. Furthermore, this schedule may change unexpectedly because of real-time re-dispatch and reserve generator activation. Thus, pipelines must use line pack and storage to balance supply rates with variable and uncertain delivery volumes. In light of this, pipeline system managers would benefit greatly from information about upcoming or possible changes in gas takes. Adapting pipeline operations to maximize efficiency and security under these new conditions requires simulation and optimization methods that accurately account for transient flows. It is well-understood that transient optimization methods for managing time-varying flows throughout intercontinental pipeline systems require a predictive element to be effective, because changes in one pipeline zone may take many hours to be felt in a different, distant zone. Specifically, information about the volume, timing, and uncertainty of variable and intermittent gas takes is necessary. These variations are currently caused primarily by the commitment and re-dispatch of gas-fired generators.

Recently, the regulatory changes described above have lowered barriers to coordination between pipelines and power grid operators. The information required to implement model-predictive optimization and manage uncertainty in intra-day pipeline operations can now be shared and utilized. Operators of public energy utilities and gas pipelines are now authorized, and explicitly encouraged, to share non-public, operational information in order to promote reliable service or operational planning on either the public utility's or pipeline's system. The regulatory efforts to foster inter-sector communication do not, however, provide direction on the types of information to be shared, or what should be done with what is communicated. The freedom to determine the appropriate coordination mechanisms and design new operating paradigms that incorporate shared information was left up to industry stakeholders.

Several types of information can currently be obtained from power grid operators, and can be used to characterize the timing and uncertainty in intra-day withdrawals by gas-fired generators from servicing pipelines. Certain information that would be very useful to pipeline managers is problematic for power grid operators to provide. This information is summarized below, and is intended to serve as a basis for the subsequent description of computational methods and pipeline operating paradigms that would take advantage of operational data communicated by power systems to improve pipeline operations in terms of day-to-day efficiency and security in extreme conditions.

In addition, recent developments in the area of transient optimization and uncertainty management for pipeline operations are reviewed here. New efficient computational methods have recently been developed that could be implemented in procedures for intra-day operation of gas pipeline systems[80-85]. These methods would anticipate the effects of transient flows and uncertainties in flow volume based on the times and locations where they are likely to occur, based on data provided by power systems and other customers. Alternatively, such methods could be used within a market-based mechanism to actually determine feasible flows that optimally utilize available pipeline capacity[248,252,278]. New physical and mathematical models and recent advances in optimization algorithms have enabled the timely computation of solutions for large-scale pipeline systems in time to plan for intra-day operations. In particular, planned gas take schedules subject to uncertainty in discrete changes in timing caused by gas-fired power plant commitment schedules, and to variation in volume caused by real-time re-dispatch, can be used as optimization parameters. These methods can enable natural gas systems to inter-operate with electric power systems on the time-scale of intra-day changes in generator activity.

3.2 Power System Data of Interest

Electric power systems in the United States are managed by ISOs or RTOs, which are non-profit corporations. Each such authority is responsible for operating high-voltage electric power transmission systems for a region consisting of one or more states, where it also administers the wholesale electricity markets, and manages the power system planning process. An ISO clears the day-ahead market for power systems by solving optimization problems that account for time-dependent constraints on generator flexibility and reserve requirements mandated by the NERC guidelines. Additional optimization problems are solved in real time to ensure that electric power production is balanced with loads, while power flows do not exceed thermal limits on any active lines, and grid stability is secure in the event of line and generator outages. Thus, a forecast of the gas takes by gas-fired generators dispatched by an ISO can be inferred from the day-ahead schedule, and the uncertainty in that forecast is determined by the use of gas-fired generators for reserve allocation and the variation in real time re-dispatch.

3.2.1 Day-Ahead Commitment Schedules

The Day-Ahead Market (DAM) is cleared by an ISO one day prior to the operating day. In addition to pricing, the DAM clearing results provide a base unit commitment (UC) schedule for the operating day that includes hourly dispatch levels for each committed resource. The market is cleared by first solving the UC optimization problem, which is a mixed-integer program that determines when generators must be available for dispatch. The results of the UC optimization problem are then used as inputs to the ED optimization problem, which determines the electricity production level for each committed resource. The inputs to the UC problem are offers representing a generator’s costs of operation, which include no-load costs, start-up costs, and incremental energy costs. In the ED problem, only a generator’s incremental energy offers are considered. These costs are provided by all large electric power generators on the system managed by the ISO. *The UC and ED schedules for a gas-fired power plant, as obtained from an ISO that manages that* *plant's production, provide a baseline forecast for when that generator will be activated and how much gas it will burn throughout the following operating day.*

3.2.2 Day-Ahead Reserve Allocation

All bulk power systems need reserve capacity to be able to respond to contingencies, such as those caused by unexpected outages or changes in load. Operating reserves are the unloaded capacity of generating resources, either online or offline, which can deliver electric energy within 10 or 30 minutes. Each ISO maintains a minimum level of reserves to be in compliance with NERC guidelines. These requirements are designed to protect the system from the impacts associated with the loss of generation or transmission equipment. For example, an ISO may be required to maintain a sufficient amount of reserves to be able to recover from the loss of the largest single system contingency within 10 minutes. This requirement is referred to as the total 10-minute reserve requirement. Reserves must also be available within 30 minutes to meet 50% of the second-largest system contingency. Adding this to the total 10-minute reserve requirement comprises the total system reserve requirement.

In addition, an ISO is required to meet contingency response criteria, which are designed to ensure adequate response in the case of a large single source supply loss. Such contingency response allows the system operators to quickly restore system reserve margins and position the system for a second large single source supply loss. An ISO may be required to restore ten-minute reserves within 90 minutes of recovering from a contingency or falling below the ten-minute reserve requirement. Reserves are allocated as part of the Reserve Adequacy Assessment (RAA) procedure, which involves an additional optimization problem that is solved after the UC and ED solutions are obtained, prior to the operating day. Because gas-fired generators are used both as operating reserves and offline contingency reserves, the result of the RAA process can indicate whether a gas-fired generator is likely to follow its UC and ED schedules.

3.2.3 The Real-Time Market

During the operating day, an ISO re-dispatches all generating units every 5-15 minutes through the Real-time Market (RTM), or spot market, to meet energy demand, reserves, and regulation requirements[54-56]. All units committed in the DAM, RAA process, and in the Real-time Unit Commitment process are included in the RTM dispatch. In addition, intraday reoffers allow generators not committed in the DAM or RAA process to self-schedule as price-takers in the RTM. The Real-Time Unit Commitment process runs every 15 minutes and commits additional qualified fast-start resources as needed throughout the operating day. Qualified fast-start resources are generating units that can start-up within 30 minutes and meet several other operating requirements. One of the objectives of providing generators the ability to update their offers intraday is to allow them to reflect the real-time cost of fuel in their offers.

3.2.4 Gas Flow Uncertainty from Power System Data

FERC order 787 has permitted and indeed encouraged power grid and gas pipeline operators to exchange non-public operational information in order to coordinate their operations[46]. In this setting, ISOs have substantial interest in sharing the results of their UC and ED schedules, RAA evaluations, parameters used in the RTM in order to ensure the security of their operations. A review is provided of how these types of data can quantify uncertainties in gas pipeline flows.

Reserve Adequacy Assessment: Operating Reserves. When gas-fired generators are used as online operating reserves, they will be committed according to their UC schedule, and burn at least their no-load take. Their production level may be shifted away from the ED schedule in order to satisfy real-time operating requirements. *Thus, the RAA can indicate which gas-fired power plants are likely to alter the volume of their gas takes.*

Reserve Adequacy Assessment: Offline Reserves. When a gas-fired generator is held as an offline contingency reserve, its UC schedule will not commit it at all for the day-ahead market, and thus its burn sheet will schedule zero gas takes from the pipeline. This can be particularly problematic, because pipeline operators may therefore expect no consumption at all from the plant. It is important to understand that offline reserves are used at times of peak load, but otherwise unlikely contingencies. *Thus, the RAA can indicate which gas-fired power plants may take gas when not scheduled. The total power system load forecast, given by the ED schedule, indicates the times when this unscheduled operation is most likely to occur.*

Real-Time Market Information. Real-time market operations of power grids can be most problematic for pipeline managers, because it may not be possible to adjust line pack in time to react to the resulting flow changes. In addition, there is no direct distinction in the day-ahead market between regular, scheduled generators and reserves – this distinction only appears in the RTM. A generator that is scheduled to come online at a given time is used as a reserve resource until then, and could therefore be activated early. If a reserve resource must be activated, the choice of which generator is chosen to compensate for increased load depends on many factors, including the real-time marginal energy price, how long each generator has been on- or offline, and the distribution of loads throughout the power grid. Thus, a straightforward prioritization of generators that are held ready as contingency reserves cannot be made directly. *A history of reserve activation in the real-time market of an ISO quantifies the likelihood of a gas-fired generator deviating from its scheduled day-ahead gas takes.*

3.3 Transient Optimization Concept

An ISO can provide UC and ED schedules for major gas-fired power plants on its system, although this is non-public information, and ISOs today have no obligation to share it. These schedules provide a baseline forecast for when that generator will be activated and how much gas it will burn as a function of time during the following day. This information could be used to form baseline boundary conditions for transient optimization of gas pipelines that service power plants on the system managed by an ISO. In order to make transient optimization a regular component of pipeline operations, it must be made robust, fast, and practical for large systems. This would enable economic compressor station operation, while meeting minimum pressure requirements given time-varying gas takes by customers. Pipeline companies would better quantify available capacities and more effectively reposition line pack for the following day.

A variety of transient optimization approaches have been proposed in the literature for creating operational plans that satisfy dynamically changing loads while keeping operation within stated system constraints and equipment limitations[80-85,132,188,159-165,283-285]. In contrast to steady state optimization[191-196], transient approaches are intended for cases with time dependent (and possibly unbalanced) loads and supplies, and that are actively packing and drafting throughout the planning period. A useful way of viewing these approaches is as methods to provide time-dependent schedules for compressor discharge pressures, and offtake profiles if these are also optimized, not just by reacting to current conditions, but by looking ahead and actually repositioning line-pack (mass of gas in the system) to optimal locations in advance of expected upcoming load fluctuations. In addition to finding feasible operational plans under challenging circumstances, these techniques can be tasked with objectives such as minimizing operational costs, achieving user specified line-pack targets in critical regions, or determining maximum possible time-integrated deliveries.

Transient optimization problems can be computationally intensive, ill conditioned, prone to multiple local solutions, and dependent on accurate timely information. Solutions must nevertheless be computed rapidly enough to support real-time decision-making. The human interfaces and work flow must be in a form that makes it easier for operators and marketers to make decisions, rather than being an extra complication. In some instances continuous optimization formulations suffice, while in others explicit treatment of discrete variables is advantageous. Formulations that deal with uncertain upcoming conditions are also very important. Regardless of all these factors, transient optimization tools are clearly needed for pipelines to most effectively deal with the difficulties of interacting with grid power loads. Because of the difficulty, diversity, and importance of these problems, the development of a wide variety of competing and complementary approaches is very welcome.

One category of existing transient optimization techniques is based on repeated executions of high-fidelity simulations[132,162,283-285]. This guarantees physically very accurate results, and adjoint-based gradients for use in optimization codes can be obtained at little extra computational expense beyond the cost of the simulation. Individual simulations can be performed rapidly by exploiting sparsity and parallel computation. On the other hand, higher order derivatives and Jacobians of the active constraints, both of which would accelerate convergence and aid robustness, are difficult to obtain without increased computational expense. These approaches can be called *"simulation-based"*.

Another set of techniques starts with an optimal control formulation that includes a cost objective and all equality and inequality constraints on state variables, just as in simulation-based approaches. Then algebraic approximations of partial differential equations describing the physical behavior of the system are incorporated directly as constraints within the optimization problem, rather than as independent simulations. Model reduction may be used to simplify the complexity of the partial differential equations (PDE) representation in space. This continuous optimization problem, where the variables are functions of time, is then discretized using approximations (such as finite differences) of the functions evaluated at time- and space- collocation points. This results in a nonlinear program (NLP) with purely algebraic objective and constraint functions. Although this type of formulation may become very large-scale, it can be solved by taking advantage of special structure[79,80,161], or by recently developed general optimization tools for problems with sparse constraints[84,85,159]. One significant advantage of such *"discretize-then-optimize"* approaches is the ability to quickly evaluate the Jacobian of the constraints for the entire optimization period. For computational tractability, the dynamic constraints that represent flow physics may need to be discretized on a coarser grid than in a simulation-based approach, potentially reducing accuracy. However, the implicit solution of the problem over the entire optimization period provides an upper bound on error in this representation, and it has been proven that the approximation converges asymptotically as grid mesh is made finer. Transient pipeline optimization methods using the "discretize-then-optimize" methodology show promise, and with further work could be developed into tools for day-ahead or moving horizon flow and compressor operation scheduling. By using appropriate model reductions and optimization formulations, the computation could be simplified to where it can produce timely results on a commodity computing platform using general optimization solvers even for large pipelines.

3.3.1 Control System Modeling of Pipeline Systems

This section contains a brief description of a modeling approach for representing large-scale, system-wide effects throughout a regional or continental scale pipeline system, and thus use numerous simplifying assumptions. Several assumptions are applied, starting with isothermal flow through a horizontal pipeline with a standard equation of state, such as Peng-Robinson[175] or CNGA[176], that relates pressure to density given constant and uniform gas composition and temperature. It is also standard to assume that flow changes are sufficiently slow so as not to excite waves or shocks, so that relatively coarse discretizations in both space and time may be used. The important parameters for a pipe are length, diameter, and the Colebrook-White friction factor. System-wide parameters for gas composition and temperature (which may be provided by subsystem for large-scale systems) must be specified as well. The dynamics of gas flow within the pipe can then be modeled using the isothermal Euler equations in one dimension, with the inertia and gravity terms omitted[113,115,140,148].

For simplicity, compressor stations and regulator elements are modeled as two-ended flow devices that can enforce given time-dependent pressures on a specified side, such as the discharge for a compressor. Theoretical power for compressors is computed proportionally to a simple function of volumetric flow rate

ϕ and compression ratio α, given by $|\phi(t)|(max\{\alpha(t),1\}^m-1)$, where $m=(\gamma-1)/\gamma$, and γ is the heat capacity factor of the gas[176]. A multiple of this function is used as a surrogate for cost of compression when defining an operational cost optimization objective function. Compressor station fuel is not removed from the pipeline flow, because it is straightforward to compute that a modern compressor working at full power will remove less than 0.01% of the through flow to power itself[176].

In order to model its intra-day dynamics, a large-scale pipeline system can be modeled as a collection of pipes, compressors, and regulators that are connected at nodes[85,117]. This collection of elements connected at nodes is considered as a directed graph $G=(V,E)$, where each segment $e=(i,j)\in E$ is an edge that connects two nodes i and j in the set of nodes V. The instantaneous state within an edge is characterized by the pressure p_{ij} and flow ϕ_{ij}, which for pipes are functions of both time on an interval [0, T] and space on an interval [0, L_e], where T is the optimization horizon and L_e is the length of pipe segment e. The positive flow direction on each pipe can be assigned arbitrarily. Then, conditions specified for the relation between pressure and flow at the boundaries of a pipe segment to the conditions at a node.

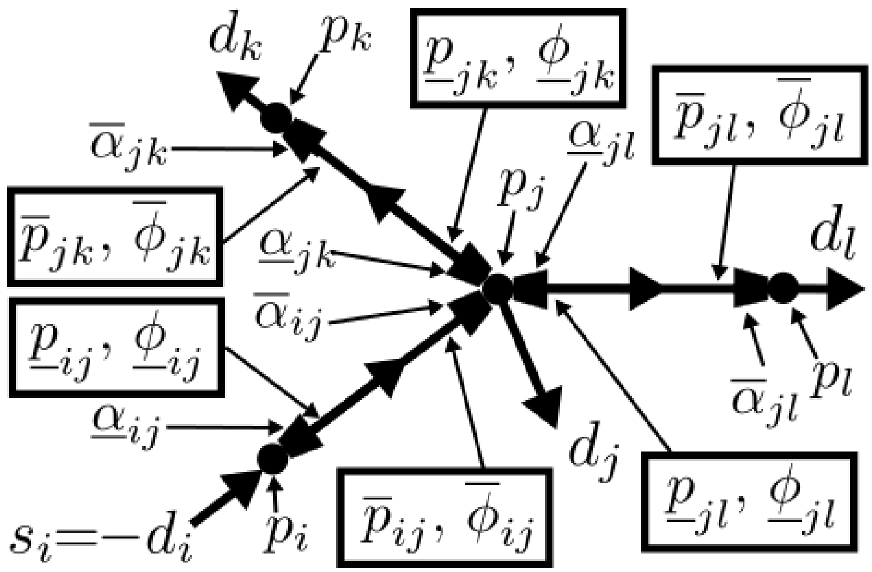


Figure 6. Diagram of nodal control system modeling for large-scale gas transmission pipelines. Given a directed graph that represents the pipeline network, $\underline{p}_{ij}$ and $\overline{p}_{ij}$ represent pressures at the sending and receiving ends of each pipe, while $\underline{\phi}_{ij}$ and $\overline{\phi}_{ij}$ represent mass flux at the sending and receiving ends of each pipe. The quantities $\underline{\alpha}_{ij}$ and $\overline{\alpha}_{ij}$ represent pressure boost ratios of compressors that are, without loss of generality, located at every interface between a node and a pipe. Thus, nodal pressures p_i and p_j are related to pipe endpoint pressures $\underline{p}_{ij}$ and $\overline{p}_{ij}$ according to $\underline{p}_{ij}=\underline{\alpha}_{ij}p_i$ and $\overline{p}_{ij}=\overline{\alpha}_{ij}p_j$. The withdrawal from the network at a node j is denoted by d_j, which is constructed from pre-existing contracts $\overline{q}_j(t)$ and secondary supply and demand profiles $\hat{s}_j(t)$ and $\hat{d}_j(t)$, or the supply injected at a node i is denoted by s_j.

Each node must be classified as either a specified pressure node $j\in V_S$, where a pressure profile s_j in time is specified and flow is a free variable, or a specified flow node $j\in V_D$, where the time-dependent flow d_j entering or leaving the network is specified and pressure is free. At least one specified pressure node must be included so that there is a degree of freedom in flow for well-posed-ness of the boundary value problem. This will typically be a large source point, such as a supply interconnection or storage unit. There, the pressure is specified as a boundary condition. Each node must follow the Kirchhoff-Neumann boundary condition, which enforces flow balance through the node. This stipulates that the sum of incoming flows is equal to the sum of outgoing flows plus any consumption d_j at that node. Each specified flow node $j \in V_D$ is also assigned an internal nodal pressure, p_j which serves as an auxiliary variable. A compressor can boost the pressure difference between pipe segments attached at its inlet and outlet nodes. This induces extra compatibility equations into the description of the coupled system of differential equations. A representation of this network modeling approach is illustrated in Figure 6.

3.3.2 Optimal Control Problem for Efficient Compressor Operation

Given this basis, a class of PDE-constrained optimal control problems (OCPs) can be formulated for gas pipeline networks, for which the edge dynamics and nodal conditions described above form the dynamic constraints. The set compression profiles $\alpha(t)$ of compressors in the system are the control functions, and the time-varying consumption flows at specified flow nodes $j \in V_D$ are parameter functions. Inequality constraints must be provided to bound the pressure between MAOP and MINOP at each node. Compressor stations are in reality subject to complex operational limitations, so a limit on the pressure boost ratio (typically on the order of 1.4) is required, as well as a bound on the compressor power, in order to approximate station constraints. In principle, more complex engineering constraints can be included. For simplicity, terminal conditions on the state and control variables are typically chosen to be time-periodic. Alternatively, one could specify initial and terminal conditions (e.g., steady state flows associated with different compression ratios) and require total system mass balance over the optimization period. The objective of the optimization in the majority of academic research studies is a time integral of the theoretical power expended by compressors over a 24-hour optimization period. Crucially, because topological changes (such as opening/closing of valves) are typically not made in intra-day operations, it is often assumed that no discrete changes to the network topology occur during the optimization period. Thus, no discrete variables, such as binary on/off switches, need to be included in the intra-day formulation. In order to solve an OCP problem, the problem must be discretized in both space and time.

3.3.3 Discretization of the Optimal Control Problem

The first step to discretizing dynamic constraints for optimization is to choose a set of collocation points in time and space. The pressure and flow at those points are used as optimization variables, in addition to compression ratios. One way to view spatial discretization of the pipeline network is as the addition of nodes to split long pipes into short segments. This can be considered a "refinement" of the network. The maximum length required for these short segments depends on the time-scale of pressure changes, and the method for approximating the derivatives in the dynamic equations. A straightforward approximation for the partial derivatives is obtained using finite differences. However, this is a first-order approximation, which requires a fine grid. In the case of relatively slowly varying flows that do not cause waves or shocks, the dynamics on a pipeline segment can be approximated using a lumped element approach. This involves integrating the PDE equations for the dynamics along the length of a pipe segment, evaluating integrals of spatial gradients directly as differences of endpoint conditions, and approximating the other terms using the trapezoidal rule approximation. The lumped element approximation eliminates partial derivatives in space, so that only time-derivatives remain[84,85,159]. These can then be approximated using a finite difference discretization or a spectral approximation in time.

3.3.4 Implementation of the Optimization and Example

The OCP in continuous space-time variables is approximated to an NLP defined by purely algebraic expressions using continuous variables. The objective function and the constraints can then be provided to a generic large-scale solver for continuous problems. Using lumped element approximation in space and trapezoidal steps in time yields a problem of minimal size where each constraint in the NLP only involves a few variables. Recent advances in optimization methods have enabled rapid solution of such NLPs. For example, IPOPT is a freely available line-search filter interior-point method solver that takes advantage of sparse linear algebra routines for matrix operations done in each iteration step[232,233]. Crucially, because the objective function and dynamic constraints of the OCP are given as algebraic expressions in the NLP, gradients of both the objective and all individual constraints can be obtained analytically. That is, an analytic constraint Jacobian is available for use during optimization. If the constraints are formulated in an optimization language such as AMPL or Julia/JuMP[286], automatic differentiation can be used to compute these derivatives, which greatly reduces the labor of setting up a detailed model and including additional physical effects, such as those related to temperature and gravity effects.

As an example, a benchmark test case investigated in a preliminary study[85] is shown in Figure 7. Given a system model with expected flow profiles for the loads over the 24-hour optimization horizon, a model-predictive optimal control algorithm will compute compressor controls over that horizon such that the pressures throughout the system are maintained within a feasible region (e.g., between 500 and 800 psi). Note that in this example, the flow profiles are given as known time-dependent parameters to the optimization. Thus, it is an application of the traditional transient pipeline optimization paradigm, which is reactive to the behavior of consumers. The subsequent section contains a formulation of a new transient pipeline optimization problem with an economic foundation, where the flow profiles will be determined to develop economically optimal resource allocation that maximizes pipeline capacity utilization while delivering gas flows to customers (such as gas-fired electric generators) that satisfy the greatest societal need. Crucially, feasible and secure operation of the pipeline system is enforced.

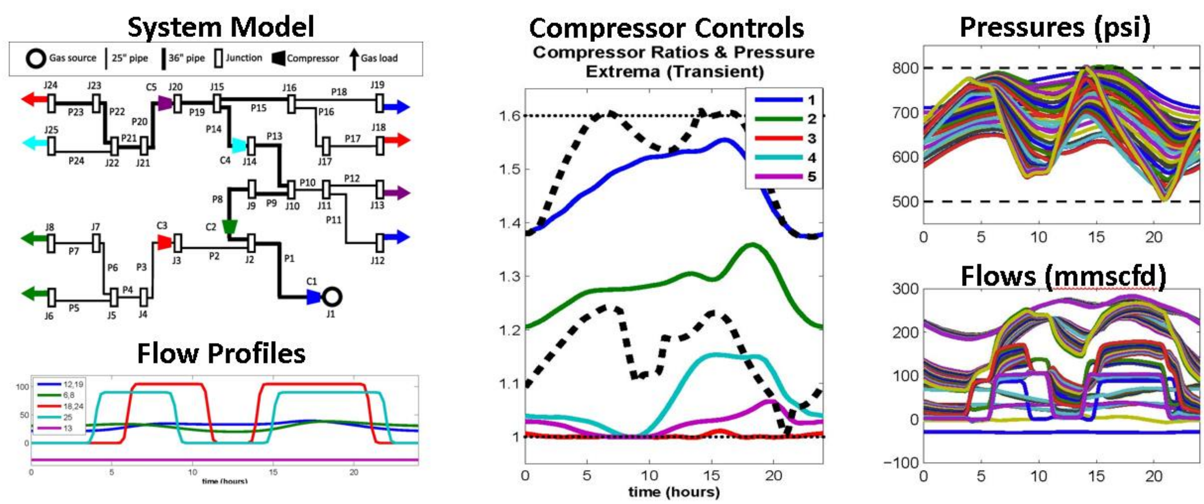


Figure 7. Example of transient pipeline optimal control solution. Left: System model and expected flow profiles (corresponding by color to arrows in the diagram); Center: compression (pressure boost) ratios computed by optimal control algorithm (solid – corresponding by color to compressors in the diagram); Right: Pressures and flows throughout the system resulting from application of the computed controls. Note that pressures are within the feasible region between 500 to 800 psi.

3.4 Managing Uncertainty in Pipeline Loads

Recently, theoretical results have been established for dynamic natural gas flows on pipeline networks described by PDEs coupled at the boundaries in a network structure. Specifically, conditions have been established under which pressure anywhere in the network can only increase monotonically when more gas is injected anywhere in the system.[179-181] Conversely, the pressure can only decrease if more gas is withdrawn from the system.

This monotonicity property, while intuitive for a single pipe, is not as clear in the case of a system with loops, or for a system subject to complex, time-varying gas withdrawals and compressor behavior. But crucially, it forms the theoretical foundation for computation of control plans that are robust with respect to a certain amount of uncertainty in the upcoming loads. The result was shown to hold for complex networks with arbitrary time-varying dynamics, given certain conditions on compressor operation.[181]

The derivation examines the propagation of monotone order properties in the following sense. Suppose that two initial states $p_1(0)$ and $p_2(0)$ are given for a pipeline system, where $p_1(0) \leq p_2(0)$, i.e. the pressure in the state $p_1(0)$ is lower than that of state $p_2(0)$ pointwise everywhere in the network. Note that these states also depend on location in the pipe and the network. Next, suppose that the system could be subject to two sets of gas injection profiles, $q_1(t)$ and $q_2(t)$, with $q_1(t) \leq q_2(t)$, i.e., an injection at any point in the network is greater for $q_2(t)$ than for $q_1(t)$ (or any withdrawal for $q_1(t)$ is greater than for $q_2(t)$) for all times $t \geq 0$. Then the monotonicity theorem states that $p_1(t) \leq p_2(t)$ for all $t \geq 0$.

Suppose then that the same system, starting from a unique initial state $p(0)$, may be subject to an injection profile $q(t)$ that is uncertain, but that is constrained by $q_1(t) \leq q(t) \leq q_2(t)$. Furthermore, suppose that one desires to find a protocol for operating the compressors on the system so that the pressure $p(t)$ will remain within the required bounds, $p_{min} \leq p(t) \leq p_{max}$, for any possible $q(t)$ within this class of functions. This sort of optimization requires finding a solution that works for an infinitely large collection of possible scenarios. The OCP to be solved then becomes a "*robust OCP*", where the solutions must be robust to a continuum of uncertainty in the parameters, which in this example are gas injections.

As a consequence of the monotonicity theorem, it is possible to reformulate the semi-infinite constrained transient optimization with uncertainty in withdrawals by enforcing feasibility only for the extreme scenarios. As long as the compressor set point profile solution satisfies the constraints for the two extremal cases $q_1(t)$ and $q_2(t)$, then feasibility will also be guaranteed for all injection functions $q(t)$ that are bounded by $q_1(t)$ and $q_2(t)$. Therefore, one only needs to obtain a solution for compressor operation such that $p_{min} \leq p_1(t) \leq p_{max}$ and $p_{min} \leq p_2(t) \leq p_{max}$, (meant pointwise), where $p_1(t)$ and $p_2(t)$ are the system-wide pressure profiles that correspond to $q_1(t)$ and $q_2(t)$, respectively. The optimization objective may be evaluated for either $p_1(t)$ or $p_2(t)$, or for the pressure profile $p_{nom}(t)$ corresponding to a nominal injection profile $q_{nom}(t)$. Thus, an optimization problem can be made robust to time-varying uncertainty by only doubling the number of constraints (or tripling, if a nominal profile is used in the objective). It is evident that the monotonicity property is powerful for enabling tractable optimization formulations.

Further, for gas pipeline systems, discharge pressure of compressors may be used as optimization variables. As long as (1) pressure is greater at one end of a pipe than the other, and (2) boundary conditions do not change quickly enough to excite shocks or waves that overcome dissipative friction effects, then pressure will decrease uniformly in the direction of flow along the pipe. Thus, if compressor and regulator discharge pressures remain below the MAOP under such conditions, pressures downstream also remain below the MAOP. Next, by the monotone ordering property, pressure can only decrease with increasing gas consumption. Suppose the compressor discharge pressure profiles are below the MAOP, and also guarantee that minimum pressures are maintained given the maximum possible gas consumption. Then these discharge pressure profiles will keep the system pressure feasible for all gas consumptions that are less than the maximum, pointwise.

Observe, however, that this formulation is a very conservative method for managing uncertainty. For instance, suppose that some uncertainty exists in the timing of operation of gas-fired generators that are supplied by a pipeline system. To compensate for uncertainty in volume, it is sufficient to perform a single transient optimization using the load profiles corresponding to maximum probable usage over all consumers, including power plants. However, if the uncertainty is a question of timing of activation, about which no information is known, then the minimum and maximum profiles are zero and maximum output, respectively. In this case, a suitable compression profile that is feasible for all possible scenarios may not exist. Because of such issues, understanding how to best utilize the monotonicity property is a subject of ongoing research.

Interval optimization of this sort is a very powerful additional tool for dealing with uncertainty, but as presented it does not explicitly take advantage of *recourse*. Loads that are uncertain at the time when the planning software is run will eventually reveal themselves. For example, a load may come online earlier than nominally planned or at a different location, and even if these events were only possibilities earlier in the day, once they occur they will be known to the operator. When this happens operators will not continue with the nominal plan no matter how robust, but will exercise recourse – the ability to choose among alternate plans, each tailored to a different possible load pattern. A methodology for recourse planning under load uncertainty in space and time has been proposed[284], where time is separated into a *preparation period* and a *recourse period*. A collection of possible upcoming load scenarios (perhaps with extreme differences) are selected by the user based on his knowledge of the day's possibilities. The method computes a *single operational plan* for the preparation period and a *collection of contingency plans* for the recourse period. The operator will decide which contingency plan to use based on what actually happens with loads.

This approach can be referred to as *multi-scenario optimization with explicit recourse*. An optimal pack management plan during the preparation phase is selected based on the criteria that it will lead to a good starting state for *any* of the contingency plans, and the contingency plans are selected on the criteria that they work well during the recourse period starting from that state, each with a particular possible load pattern. The key point is that both the setup and all contingency plans are computed together as one seamless coupled mathematical problem. Looking at the preparation period, an optimal preparation plan computed in this way can be quite different from a plan computed using interval optimization. Moreover, it is less likely to return infeasible or over-conservative plans when load uncertainty is large. However, recourse approaches developed to date provide no theoretical reasons to expect that the solutions obtained will be robust with respect to load scenarios *in between* the base scenarios selected during problem setup. Nor does it guard against potential extreme runtimes if the number of load scenarios grows in a combinatorial manner. In that sense, interval optimization and multi-scenario optimization with explicit recourse are complementary and can be used to develop uncertainty management methodologies that combine interval and recourse approaches.

4.0 Intra-Day Economic Optimization for Gas Pipelines

As dependence of the bulk electric power system on gas-fired generation grows, more economically efficient coordination between the wholesale natural gas and electricity markets is increasingly important. There exists a critical need for new tools and architectures to achieve more efficient and reliable operation of both markets by providing participants more accurate price signals on which to base their investment and operating decisions.

Today's Electricity energy prices are consistent with the physical flow of electric energy in the power grid because of the economic optimization of power system operation in organized electricity markets administered by RTOs. A similar optimization approach that accounts for physical and engineering factors of pipeline hydraulics and compressor station operations would lead to location- and time-dependent intra-day prices of natural gas consistent with pipeline engineering factors, operations, and the physics of gas flow[187,248,278]. More economically efficient gas-electric coordination could be envisioned as the timely exchange of both physical and pricing data between participants in each market, with price formation in both markets being fully consistent with the physics of energy flow. Physical data would be intra-day (e.g., hourly) gas schedules (burn and delivery) and pricing data would be bids and offers reflecting willingness to pay and to accept. The following description of economic concepts related to this exchange leads to a formulation for an intra-day pipeline market clearing problem whose solution provides a flow schedule and hourly pricing, while ensuring that pipeline hydraulic limitations, compressor station constraints, operational factors, and pre-existing shipping contracts are satisfied.

4.1 Motivation for Market-Based Gas-Electric Architecture

The growing reliance of the bulk electric power system on gas-fired generation has made organized coordination between the wholesale natural gas and electricity markets an increasingly pressing need. Replacement of coal fired and nuclear plants with gas-fired generating capacity significantly increases the amount of natural gas used as fuel for power generation. In parallel, the variability of electric generation from wind and solar increases the variability of pipeline deliveries to gas-fired generators used to balance the electric grid. The resulting intra-day and even sub-hourly swings in demand for natural gas as a fuel for electric generation create new challenges for pipeline operators, and may pose reliability risks for both gas pipelines and electric systems.

The need to better coordinate the two sectors to mitigate these risks is well recognized, and as described above, is reflected in the recent orders 787 and 809 by the FERC, which regulates access to pipeline capacity[46,266-268]. Coordination mechanisms proposed to date are based on widening the scope of operational information exchanged by the two sectors and on adjusting the timing of when these exchanges occur. While these measures are helpful, a truly efficient coordination should be based on timely exchange of both physical and pricing data with price formation in both markets being fully consistent with the physics of energy flow. Electricity prices consistent with the physical flow of electric energy in the power grid are the outcome of economic optimization of power system operation in organized electricity markets administered by RTOs. A similar optimization approach that accounts for physical and engineering factors of pipeline hydraulics and compressor station operations would lead to location- and time-dependent economic value of natural gas consistent with the physics of gas flow[187,248,278].

Our goal is to formulate and solve a transient pipeline optimization problem that maximizes total market surplus over supply and offtake schedules. Market surplus in this context is defined as the sum of the producer/supplier surplus and consumer/buyer surplus. Producer surplus is derived whenever the price the producer receives exceeds the value they are willing to accept for the goods they sell. Similarly, consumer surplus is derived whenever the price the consumer ends up paying for good is below the value they are prepared to pay. Market surplus is the sum of individual surpluses over all consumers/buyers and producers/sellers participating in the market. The appropriate transient optimization solution dynamically allocates pipeline capacity among transactions between suppliers and consumers based on the economic value of these transactions. Compressor operations and line pack are optimized in conjunction with the selection of location-dependent offers to sell, and bids to buy, natural gas. Location-based (nodal) prices of natural gas are computed as dual variables corresponding to the nodal flow balance constraints in the optimal solution, and reflect the time- and location-dependent economic value of gas in the network.

An economically efficient gas-electric coordination architecture is then envisioned as the timely exchange of both physical and pricing data between participants in each market, with price formation in both markets being fully consistent with the physics of energy flow. Physical data would be intra-day (e.g., hourly) gas schedules (burn and delivery) and pricing data would be bids and offers reflecting willingness to pay and to accept. Location-based gas prices would be obtained using optimization of transient pipeline flow models. Inputs to the pipeline optimization problem include prices that power plants are willing to pay for gas, as derived from nodal electricity prices that are produced by power system optimization.

A pricing concept can be defined in terms of LTVs for natural gas that are obtained using the single-price two-sided auction mechanism while accounting for the physics of natural gas flows and engineering factors of pipeline networks. There have been proposals for such valuation mechanisms using models with linearized gas flow equations[248,249,264]. New methods have recently been proposed that use accurate nonlinear dynamic pipeline equations and thus retain the impact of non-linearities on LTV formation[187]. A modeling approach developed for large-scale control system modeling of gas pipelines, where constraints on flow and energy usage by compressors are accurately described, can be used in an optimization formulation that maximizes market surplus and provides physically and economically meaningful LTVs. While marginal pricing and economic spot markets for gas have been studied[249-259], LTVs that provide price signals reflecting the physical ability to transport gas through a pipeline system remain a subject of ongoing research. The following section contains a preliminary engineering economic analysis of LTV basis differentials created through the proposed market mechanism. Properties of the mechanism are also described, including revenue adequacy for the market administrator, which have been shown in the case of power systems to make practical implementation possible.

4.2 Gas Pipeline Market Structures: Status Quo and Outlook

Significant and rapid growth in the use of natural gas for power generation in the United States is greatly increasing demand for transportation of gas through large-scale interstate pipelines[257,258]. Among other factors this is being driven by environmental regulations, the transition to cleaner electric power sources, the abundance of inexpensive natural gas, and improvements in gas turbine efficiency[105-109]. Coal-fired and nuclear power plants therefore continue to be replaced primarily by gas-fired generating units throughout the United States[4]. Because power production by gas turbines can be ramped up and down easily, gas-fired generators are widely used to compensate for fluctuations caused by variable and non-dispatched sources including wind and solar[5,110]. Increased reliance on gas-fired generation is transferring the demand for electric energy onto natural gas pipeline infrastructure[6]. Moreover, that demand is increasingly variable by hour within the day.

Market structures for interstate pipeline transportation services in the United States are at present constrained within a regulatory framework that was not designed to support market responsive price formation[250]. Access to pipeline capacity is provided at rates regulated by the FERC. Holders of firm physical rights are allowed to sell unneeded capacity on a daily basis through a release mechanism. Released capacity is bundled with gas supply and traded bilaterally in a locational spot market for natural gas. Trading platforms such as the Intercontinental Exchange (ICE) serve as major vehicles for price formation. Reported price indices for several dozen locations in North America change daily with Friday prices prevailing over the weekend. These daily prices do not reflect intra-day demand variations. Historically, intra-day demand variations were primarily caused by changes in residential and commercial loads. These changes are typically weather driven, predictable, and reasonably well managed by pipeline operators. In contrast, significant intra-day and even sub-hourly swings in demand for natural gas as a fuel for electric generation create new challenges for pipeline operators, and pose reliability risks for gas pipelines and electric systems. Better coordination is needed between the two sectors to mitigate these risks[4,39]. The impacts of regulatory changes on coordinating operations of gas pipeline and electric power grids were recently examined[185].

Coordination mechanisms proposed to date are based on widening the scope of operational information exchanged by the two sectors and on adjusting the timing of when these exchanges occur. In addition to such changes, new economic tools are needed for gas-electric coordination that provides financial incentives for market participants to change behavior in a way that would result in more efficient and reliable operation of both infrastructures. Intra-day locational prices of natural gas that are consistent with the physics and engineering constraints of pipeline operation could provide such a tool. However, this complexity is highly challenging to account for in physical operation, and current approaches can only roughly estimate capacities for intra-day market clearing[253]. Even today, price formation on the natural gas spot market is based on bilateral trading[255,256], and pricing of capacities relies on statistical analysis of historical data[259].

In the electric power industry, it is standard to use optimization to price electric energy based on the physical ability of the electric network to deliver it from producers to consumers[54-57]. In contrast, with the exception of a market in the Australian province of Victoria[248,264], the use of physics-based optimization to clear natural gas markets remains a topic of research. Developing locational pricing mechanisms for natural gas is challenging because of complex physical and engineering factors of pipeline hydraulic modeling and optimization[59,176]. Thus, in addition to the different physical and operational aspects of gas pipelines and electric power grids, there is also a disparity in market mechanisms that complicates attempts to bridge the gap in coordination between these sectors[39,64].

Auction-based pricing mechanisms for pipeline capacity that are similar to what is used in wholesale electricity markets have been of interest for nearly 30 years, and were explored in a 1987 FERC report[270]. In that report, a linear programming model for auctioning pipeline transportation rights was proposed, with primary auctions to be conducted as often as daily. More frequent secondary auctions for re-selling of capacity rights were envisioned as well. Many of the ideas in the 1987 proposal remain relevant and deserve to be re-examined in light of noted trends in the natural gas industry, improved optimization techniques[80-85,132,188,159-165,283-285], engineering economic formulations[248-264,278], and the significant experience gained through successful implementation of auction-based market mechanisms over the past two decades in the power industry worldwide.

4.3 Gas Market Clearing by Intra-Day Optimization

This section contains a brief review of transient pipeline optimization from the point of view of engineering economics, an approach to simplified pipeline modeling for the purpose of transient optimization of large-scale systems, and an explanation of the optimization formulation suggested for use as a market mechanism including mathematical nomenclature and formulation.

4.3.1 Transient Optimization Overview

Many transient optimization approaches have been proposed for creating operational plans that satisfy expected dynamically changing loads while keeping operation within contractual and operating constraints and equipment limitations[80-85,132,188,159-165,283-285]. The majority of previously developed methods aim to provide time-dependent schedules for compressor discharge pressures by looking ahead and repositioning line pack to optimal locations in advance of expected upcoming load fluctuations. In addition to finding feasible operational plans under challenging circumstances, these techniques can be tasked with objectives such as minimizing operational costs, achieving user specified line pack targets in critical regions, or determining maximum possible time-integrated deliveries. Transient optimization problems are typically computationally intensive yet depend on accurate and timely information. Solutions must also be computed rapidly enough to support real-time decision-making, while human interfaces and work flow must aid operators and marketers in that decision making. Timely solutions are complicated by the nature of pipeline control engineering, which includes continuous and discrete control variables, and which are highly challenging to optimize under dynamic conditions[59,171,176]. Nevertheless, development of transient optimization tools is needed for pipelines to effectively deal with the difficulties of interacting with electric transmission systems. Continuous optimization formulations that do not explicitly treat discrete variables have been suggested as an acceptable approximation for intra-day optimization of large (e.g., continental) scale transmission pipeline systems. Indeed, a validation of such simplified modeling for transients in large-scale pipelines has been successfully performed as part of a recent study on the feasibility of intra-day economic pipeline optimization[187].

Formulations that employ recourse to account for uncertain upcoming system loads have been developed[284], and provide an important capability. However, as with most previously proposed transient optimization concepts, the actual intra-day load profiles are considered as parameters, which are possibly uncertain, rather than optimization variables. The major obstacle to fielding such approaches is the use of predictions for load profiles, so that there is no guarantee that the expected conditions will actually take place. In contrast, the paradigm presented here proposes an organized mechanism for shippers and operators of a pipeline system to make optimal decisions about what the upcoming system loads should be. If implemented, such a decision-making system would eliminate substantial uncertainty for all parties involved in pipeline system operations. This transient pipeline optimization paradigm could, with further development, enable day-ahead or rolling horizon flow scheduling and compressor operation optimization based on an economic market concept. The computation can be rapid enough to produce timely results on a commodity computing platform using general optimization solvers even for large pipelines[159,232,233]. A fielded system would be able to utilize high performance computing, as done in power systems operations.

4.3.2 Economic Optimal Control of Intra-Day Pipeline Operations

Using the simplified pipeline network modeling for transient optimization of large-scale pipelines described above, and following recent modeling and computational work[85,187], an OCP subject to PDE constraints is formulated for gas pipeline networks, for which the edge dynamics and nodal conditions described above form the dynamic constraints. The formulation is given in Figure 8, and the nomenclature is described in Figure 9. The aim is to maximize an economic objective function in the form of the market surplus, which is evaluated in total over the optimization horizon *[0,T]*, which may be a 24-hour day or longer. At each point in time, market surplus is the difference between the economic value consumers (buyers) are placing on (willing to pay for) gas purchases $\hat{d}_j(t)$ at nodes *j* minus the value of gas which producers (sellers) are placing on (willing to accept for) gas sales $\hat{s}_j(t)$ at nodes j. The inputs to the problem consist of the bid and offer prices $c_j^d(t)$ and $c_j^s(t)$, respectively that buyers or sellers at a node *j* are willing to pay or accept at time *t* within the optimization horizon $[0,T]$. In addition to price bids, quantity bids are also supplied in the form of pre-existing contracts $\overline{q}_j(t)$, minimum and maximum offtake curves $d_j^{min}(t)$ and $d_j^{max}(t)$ of buyers, and minimum and maximum supply curves $s_j^{min}(t)$ and $s_j^{max}(t)$ of suppliers.

The economic objective is maximized subject to a collection of constraints that describe pipeline system operation, and where the control variables include compression ratios $\underline{\alpha}_{ij}(t)$ of gas compressors or compression ratios in the system. The PDE dynamics for gas flow on each pipe *(i,j)* are enforced, as well as flow balance at each node *j* and pressure changes caused by compression. Inequality constraints include minimum and maximum limits on pressure on each pipe, maximum power limits of each compressor, and maximum and minimum withdrawals or injections for off-takers and suppliers. For simplicity, terminal conditions on the state and control variables are chosen to be time-periodic. Alternative initial and terminal conditions such as mass balance over the optimization period on certain subsystems could be included.

Crucially, one may assume that no discrete changes to the network topology occur during the optimization period, as these are not typically made in intra-day operations but rather seasonally or for scheduled maintenance. Thus, no discrete variables, such as binary on/off switches, are included in the formulation given here. While compressor stations are in reality subject to complex operational limitations, it is understood that in principle, nonlinear station constraints can be included in a computationally tractable manner as long as the modeling does not include on/off variables. For instance, a large compressor station with multiple (e.g., a dozen or more) units that receive flow from a common feeder and deliver flow to a common header can be modeled as a single theoretical boost ratio for the purpose of optimization. Modern compressor stations often have control systems that can be set to track a set point or reference signal for discharge pressure or horsepower. The management of individual compressor units within a compressor station is typically automated, so that engineering models developed for gas-electric coordination mechanisms may focus on the large-scale system effects of control actions while supposing that subsystems can be taken care of at a local level. This approach to simplification of transmission pipeline planning models for transient analysis has been successfully validated by comparison of the simulation approach to real time-series of physical pipeline data in a recent study[187]. The optimal control formulation for the two-sided auction market and the mathematical nomenclature are given in Figures 8 and 9.

$$
\begin{array}{lrll}
\max & \text{Market Surplus:} & \displaystyle\sum_{j\in\mathcal{V}}\int_0^T c_j^d(t)\hat{d}_j(t)\mathrm{d}t-\sum_{j\in\mathcal{V}}\int_0^T c_j^s(t)\hat{s}_j(t)\mathrm{d}t & \\
\text{s.t.} & \text{Mass conservation:} & \partial_t\rho_{ij}+\partial_x\phi_{ij}=0, & \forall(i,j)\in\mathcal{E}, \\
 & \text{Momentum conservation:} & \partial_t\phi_{ij}+\partial_x p_{ij}=-Z(p_{ij})RT_w\dfrac{f_{ij}}{2D_{ij}}\dfrac{\phi|\phi|}{p}, & \forall(i,j)\in\mathcal{E}, \\
 & \text{Equation of State:} & p_{ij}=Z(p_{ij})RT_w\rho_{ij}, & \forall(i,j)\in\mathcal{E}, \\
 & \text{Nodal flow balance:} & \displaystyle\sum_{k\in\partial_-j}A_{jk}\underline{\phi}_{jk}(t)-\sum_{i\in\partial_+j}A_{ij}\overline{\phi}_{ij}(t)-\bar{q}_j(t) & \\
 & & \quad-(\hat{s}_j(t)-\hat{d}_j(t))=0, & \forall j\in\mathcal{V}, \\
 & \text{Compressor boost:} & \underline{p}_{ij}(t)=\underline{\alpha}_{ij}(t)p_i(t), & \forall(i,j)\in\mathcal{E}, \\
 & & \overline{p}_{ij}(t)=\overline{\alpha}_{ij}(t)p_j(t), & \forall(i,j)\in\mathcal{E}, \\
 & \text{Pressure limits:} & p_{ij}^{\min}\le p_{ij}(t,0)\le p_{ij}^{\max}, & \forall(i,j)\in\mathcal{E}, \\
 & & p_{ij}^{\min}\le p_{ij}(t,L_{ij})\le p_{ij}^{\max}, & \forall(i,j)\in\mathcal{E}, \\
 & \text{Boost upper limits:} & \underline{\varepsilon}_{ij}|\underline{\phi}_{ij}(t)|\Big((\underline{\alpha}_{ij}(t))^h-1\Big)\le\underline{E}_{ij}^{\max}, & \forall(i,j)\in\mathcal{E}, \\
 & & \overline{\varepsilon}_{ij}|\overline{\phi}_{ij}(t)|\Big((\overline{\alpha}_{ij}(t))^h-1\Big)\le\overline{E}_{ij}^{\max}, & \forall(i,j)\in\mathcal{E}, \\
 & \text{Boost lower limits:} & \underline{\alpha}_{ij}(t)\ge 1,\quad\overline{\alpha}_{ij}(t)\ge 1 & \forall(i,j)\in\mathcal{E}, \\
 & \text{Supply limits:} & s_j^{\min}(t)\le s_j(t)\le s_j^{\max}(t) & \forall j\in\mathcal{V}, \\
 & \text{Demand limits:} & d_j^{\min}(t)\le d_j(t)\le d_j^{\max}(t) & \forall j\in\mathcal{V},
\end{array}
$$

Figure 8. Optimal control formulation for two-sided pipeline auction market. The objective is to maximize the market surplus for the pipeline system, subject to flow physics, mass flow balance at nodes, and actions of gas compressors – constraints that specify the dynamics of the system. In addition, the problem must include inequality constraints that reflect operational limitations of the system – these include minimum and maximum limits on pressure (which are enforced on each pipe), maximum power limits on compressor stations, and a requirement that compression ratios are positive (to reflect compressor bypass in the case when no pressure boost is needed or flow is in the opposite direction of compressor orientation). Minimum and maximum constraints on supply and demand at each node are generated based on physical injection or offtake capabilities as well as the financial positions of shippers bidding into the market at that location. Additional constraints that require the total mass (and thus energy) in the system to return to the initial value at the end of the optimization interval may be added. Time-periodicity of the solution may be enforced[187], i.e., the entire system state (all flows and pressures) at the time T is equal to that at time 0.

4.4 Locational Pricing

The concept of locational pricing is now in widespread use throughout the world in organized wholesale electricity markets. Recent studies have examined the extension of this concept to natural gas pipeline networks.

$\mathcal{V}$	set of nodes (j)
$\mathcal{E}$	set of pipes (i,j) for i and j in $\mathcal{V}$
T	optimization time length; optimization interval is $[0,T]$
R	gas constant (depends on gas gravity)
T_w	working temperature (assumed constant throughout the system)
$Z(\cdot)$	gas compressibility as function of pressure (working temperature)
f_{ij}	Colebrook-White friction factor on pipe (i,j)
D_{ij}	inner diameter of pipe (i,j)
A_{ij}	cross-sectional area of pipe (i,j)
L_{ij}	length of pipe (i,j)
$c_j^d(t)$	demand bid at node j at time t
$c_j^s(t)$	supply offer at node j at time t
$\hat{d}_j(t)$	variable demand at node j at time t
$\hat{s}_j(t)$	variable supply at node j at time t
$\rho_{ij}(t,x)$	density on pipe (i,j) at time t and location x
$\phi_{ij}(t,x)$	mass flux on pipe (i,j) at time t and location x
$p_{ij}(t,x)$	pressure on pipe (i,j) at time t and location x
$p_i(t)$	pressure at node j at time t
$\underline{p}_{ij}(t)$, $\overline{p}_{ij}(t)$	pressure at start and end of pipe (i,j)
$\underline{\phi}_{ij}(t)$, $\overline{\phi}_{ij}(t)$	mass flux at start and end of pipe (i,j)
$p_{ij}^{\min}$, $p_{ij}^{\max}$	minimum and maximum pressure on pipe (i,j)
$\underline{\varepsilon}_{ij}$, $\overline{\varepsilon}_{ij}$	compressor energy usage factor of compressors at start and end of pipe (i,j)
$\underline{\alpha}_{ij}$, $\overline{\alpha}_{ij}$	boost ratios of compressors at start and end of pipe (i,j)
h	compressor energy function exponent (depends on gas specific heat capacity ratio)
$\underline{E}_{ij}^{\max}$, $\overline{E}_{ij}^{\max}$	maximum energy (horsepower) of compressors at start and end of pipe (i,j)
$s_j^{\min}(t)$, $s_j^{\max}(t)$	minimum and maximum supply from node j at time t
$d_j^{\min}(t)$, $d_j^{\max}(t)$	minimum and maximum demand at node j at time t

Figure 9. Mathematical nomenclature for optimal control formulation in Figure 8

4.4.1 Locational Marginal Pricing of Electricity

The LMPs for electricity emerged in the United States in late 1990s to early 2000s with the formation of organized electricity markets such as PJM Interconnection[55] and the ISOs of New York, New England[56], and California, followed later by Midcontinent ISO, Southwest Power Pool and ERCOT. In these systems, LMPs are defined for thousands of electric network nodes (busses) and are used to price electricity sales and purchases on a locational basis[54]. Most electricity markets use a two-settlement system in which electricity is first traded in the day-ahead and then in the RTMs. Transactions cleared in the DAM are represented by hourly power injection and withdrawal schedules and corresponding hourly day-ahead LMPs defining economic values of these schedules that are location-specific and changing hourly. Outcomes of the DAM are financially binding. Transactions cleared in the RTM are typically represented by schedules and LMPs determined in real time (i.e., changing every 5 minutes). Real-time LMPs are determined *ex post* consistently with actual economic dispatch of the electric system and are used to price deviations between actual electricity injections and withdrawals and schedules cleared in the DAM.

Economically, LMPs reflect the incremental cost to the system of serving an infinitesimal incremental demand imposed at a specific location (node) in the network at a specific point in time. In the absence of binding transmission constraints (and ignoring marginal transmission losses), LMPs at all nodes are identical and equal to the short-run operating and fuel cost of the marginal generating resource. Each binding transmission constraint adds one additional marginal resource such that the total number of marginal resources equals number of simultaneously binding constraints plus one. This is because serving an incremental load at a given node becomes a balancing act of maintaining power flow through each binding constraint equal to that constraint limit. As result, at each location, the electric LMP equals a linear combination of short-run operating and fuel costs of marginal resources specific to that location.

While serving to price transactions between electricity market participants, electric LMPs can provide information that is critical for the market-based coordination of gas and electric networks. For a gas-fired generating unit, electric LMPs effectively determine a ceiling on the price that unit will be willing to pay for natural gas. Indeed, to avoid operating at a loss, a generator would be willing to pay for fuel at most

$$C_{\max} = (LMP - VOM) / \ H + R$$

where $C_{\max}$ is the gas price ceiling, LMP is the electric LMP at the generator's node, *VOM* is the non-fuel variable operating and maintenance costs of generator, and H is the generator's heat rate. The term R reflects an additional risk premium generators would factor into their willingness to pay for gas to avoid excess charges they may face in the real-time electricity market and potentially high non-performance penalties during scarcity events.

4.4.2 Locational Pricing of Natural Gas

Combined with electric LMPs, locational pricing of natural gas may become another critical economic tool for the efficient coordination of gas and electric network operation. To avoid confusion of electric LMPs and with spot prices for natural gas already in place, the term LTV has been suggested for locational pricing of natural gas. In a similar manner to the information provided by electric LMPs, LTVs would reflect the incremental cost to a natural gas supply system of serving an infinitesimal incremental demand for natural gas imposed at a specific location (node) in the network at a specific point in time. Another important similarity between electric LMPs and gas LTVs is their consistency with the physical operation of the respective network. That property contrasts LTVs from daily cleared regional gas prices. Daily prices reflect anticipated constraints in the gas transportation network based on the previously *allocated* pipeline capacity determined in daily throughput quantities. Locational difference in such daily prices known as *basis differentials* are driven by the expectation that the demand for throughput capacity needed to move gas from one location to another will exceed the total allocated capacity limit and that capacity therefore needs to be rationed. Thus, the basis differential is effectively related to the allocated limit of the maximum daily throughput of a pipeline or its segment.

This representation of pipeline transportation capacity, and the pricing scheme associated with it, over-simplify the capabilities of the pipeline network and assume away non-linear relationships between gas flows, pressure and compressor horsepower limitations. It has been demonstrated that even for a single pipe, basis differentials may not be directly attributable to constrained throughput because the static capacity allocation mechanism does not capture the transient nature of the mechanics of gas movement within the pipeline network[187]. In contrast, LTVs accurately capture the physics of pipeline flow in both space and time. They reflect the noted non-linear relationships between gas flows, pressure, the capabilities of compressor stations, transient phenomena.

Following a recent preliminary study focusing on steady-state flow[34], two types of constraints could cause the difference in LTVs at the two ends of a pipe: a pressure constraint and compression constraint. The first type occurs if the pressure in the pipe reaches the MAOP level, and the second when a compressor operates at maximum horsepower limit or maximum compression ratio. Analysis of these conditions further indicates that for the LTVs to differ, the pipe must be simultaneously constrained both at the sending and at the receiving end. At the receiving end, the pressure must fall to the low limit. At the sending end, either the maximum pressure or the maximum compression constraint must be binding. The pressure congestion would uniquely define the constrained pipe flow by

$$\phi_{\max} = \frac{\sqrt{p_{\max}^2 - p_{\min}^2}}{\sqrt{\beta}}.$$

where, $p_{\max}$ represents MAOP, $p_{\min}$ is the minimum pressure requirement at the receiving end of the pipe, and β is the constant that depends on pipe diameter and friction factor and which reflects resistive losses. However, when the sending end of the pipe is constrained due to the compression limitation, the pipe flow is not uniquely determined and may vary depending on the compression ratio α according to

$$\phi = \frac{E^{\max}}{\varepsilon(\alpha^h + 1)},$$

where $E^{\max}$ and ε are the compressor's horsepower limit and energy utilization factor, respectively, and α is the compression ratio. The latter is dependent on the suction pressure at the compressor. Therefore, although the pipe is constrained, and its throughput may be different from the predetermined allocated capacity, it could be below it or exceed it.

An analysis of LTVs in the dynamic case leads to several important observations[187].

1. Economic congestion (or congestion-based LTV differentials) in the pipeline is not necessarily driven by limitations on the pipeline *throughput*.
2. In a pipeline system with sufficient line pack potential, economic congestion is non-monotonic with respect to demand: LTV differentials can occur at intermediate load levels but may disappear at high and low demand levels.
3. LTV differentials may be essentially a transient phenomenon associated with LTVs migrating between higher and lower levels but at a different pace depending on the location.
4. Using LTVs as a pricing mechanism instead of, or in addition to, regional daily prices might have significant financial implications for market participants. For example, if paid according to LTVs, gas suppliers may enjoy high gas prices at the time of high demand due to the observed convergence of LTVs, whereas daily prices based on linear capacity allocation would tend to reduce payments to producers located *upstream* of such a capacity constraint. Similarly, consumers who pay according to LTVs may enjoy lower payments for the part of the day with lower demand and during the price transitions between lower and higher levels, whereas daily prices based on linear capacity allocation would tend to increase payment by all consumers located *downstream* of such a capacity constraint.
5. Under the dynamic LTVs, precise hour-by-hour coordination in price and supply/demand scheduling is important as it has major financial implications for market participants. It is therefore essential that prices and physical schedules are developed through a formalized mechanism that guarantees that developed schedules are feasible and binding, and that LTVs formed through this mechanism are consistent with engineering limitations, pipeline operations, and the physics of gas flows.

4.5 Computational Methodology and Example

Substantial research and development has been done on computational methods for transient optimization of gas pipeline systems, resulting in two general classes of methods, as described above. As outlined above, one set of existing *"simulation-based"* methods relies on repeated executions of high-fidelity simulations[123,124,148,162,283-285]. Such methods accommodate highly detailed models that yield solutions of accurate physical feasibility, and adjoint-based gradients for use in optimization codes can be obtained at little extra computational cost. While these methods allow exploitation of sparsity and parallelization, higher order derivatives and Jacobians of the active constraints, both of which would accelerate convergence and aid robustness, are computationally costly.

Alternatively, *"discretize-then-optimize"* approaches allow rapid evaluation of constraint Jacobians for the entire optimization period. Starting with an optimal control formulation that includes a cost objective and all equality and inequality constraints on state variables, algebraic approximations of PDEs describing the physical behavior of the system are incorporated directly as constraints within the optimization problem, rather than as independent simulations. Model reduction may be used to simplify the complexity of PDE representation in space. The problem is discretized in time using approximations (such as finite differences) of the functions evaluated at time- and space- collocation points. This results in an NLP with purely algebraic objective and constraint functions. Although this type of formulation may become very large-scale, it can be solved by taking advantage of special structure[79,80], or by recently developed general optimization tools for problems with sparse constraints[85,159]. While entire problem must be discretized on a coarser grid than in a simulation-based approach for computational tractability, thus potentially reducing accuracy, the induced error remains local and can be shown to be acceptable.

A promising approach that has proven effective in recent computational studies utilizes the *"discretize-then-optimize"* approach[85,179], in which a large-scale NLP is produced and solved using the IPOPT interior point solver[233]. The results of the optimization can be used to produce an initial value problem that can then be solved using numerical methods designed for pipeline simulation based on the reduced modeling approach. The same initial value problem can also be solved using a commercial simulation engine for the purpose of solution verification.

The desired LTVs are sensitivities of the objective function of the optimal control problem in Figure 8 to changes in flows to customers. It is important to examine the theoretical and computational aspects of LTV computation. Because the maximum market surplus based pipeline optimization problem is nonlinear and nonconvex, no guarantee is given on whether an interior point optimization method reaches a global solution. Thus, it is important to investigate the optimality gap and determine whether the solutions obtained are indeed global, and thus to verify whether the dual variables provide the desired Lagrange multipliers and thus the correct values of LTVs for the pricing mechanism.

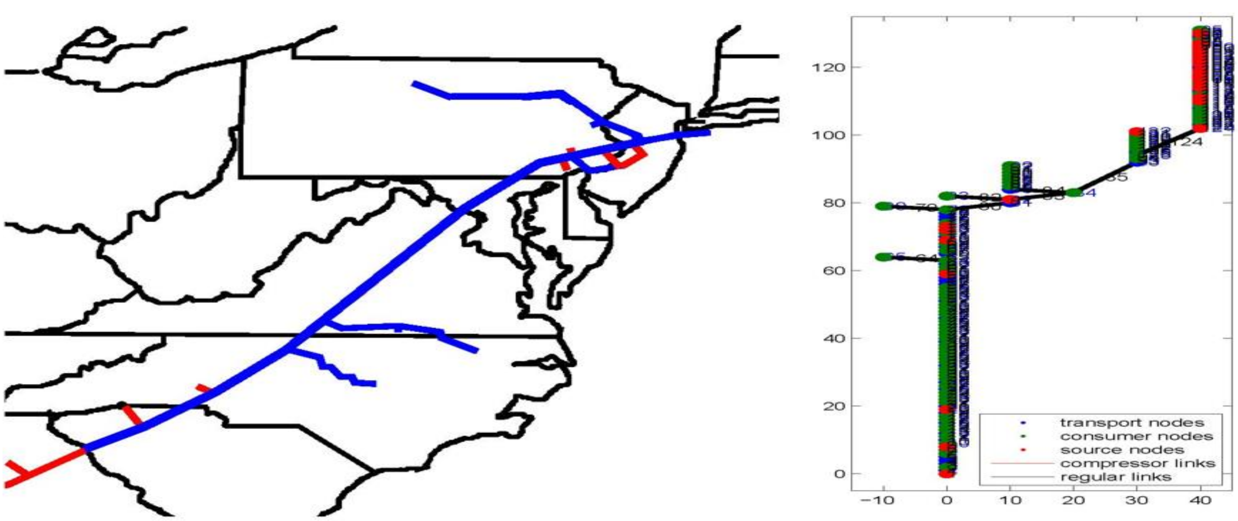


Figure 10. Left: Illustration of East Coast zones of a major U.S. pipeline with 1664 miles; Right: Topological schematic of the pipeline with 132 nodes, 131 pipes, and 31 compressors.

The application of the *"discretize-then-optimize"* approach to solve the transient pipeline optimization problem described in Figure 8 is illustrated on an example a case study using a model that approximates a real system that was first examined in a study on optimizing compressor efficiency[84]. The inputs to the optimization are firm gas withdrawals, as well as maximum offtakes and bid prices by flexible electric generation customers, which are shown in Figure 11.

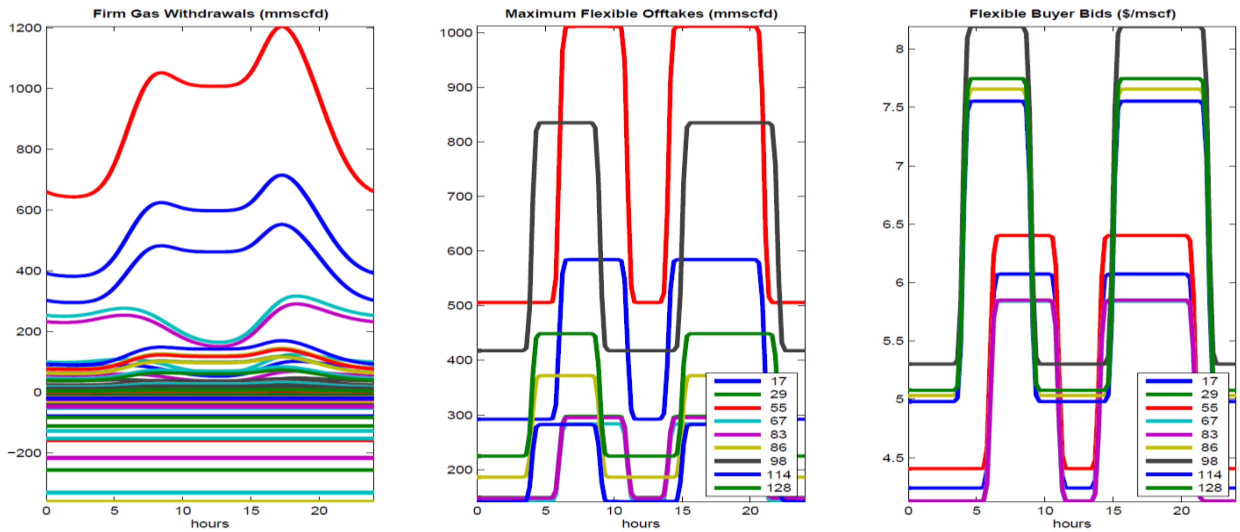


Figure 11. Physical and market inputs to transient pipeline optimization problem. Left: Predicted gas load profiles of firm customers (mmscfd); Center: maximum withdrawal bids (mmscfd) of flexible EG customers; Right: Intra-day market bids ($/mscf) of flexible electric generation customers, compared to supply offered at southern terminal at $1.61.

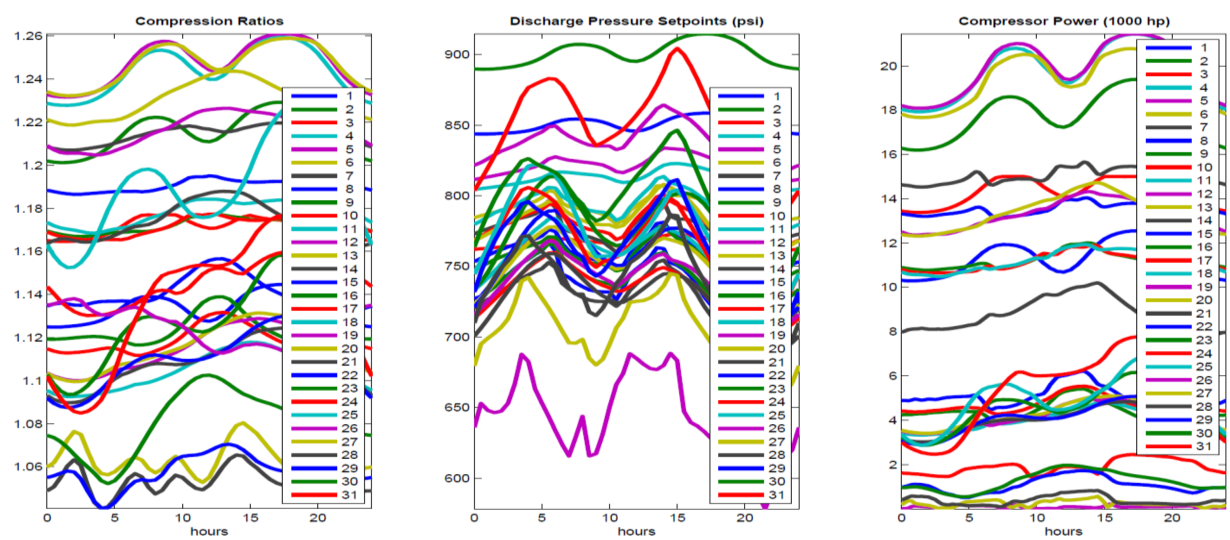


Figure 12. Compressor control solution from transient pipeline optimization example. Left: compression ratios; Center: discharge pressures (psia) of compressors; Right: compressor power (horsepower). The discharge pressure is the typical control used to decouple the dynamics of pipeline subsystems by creating pressure separation points.

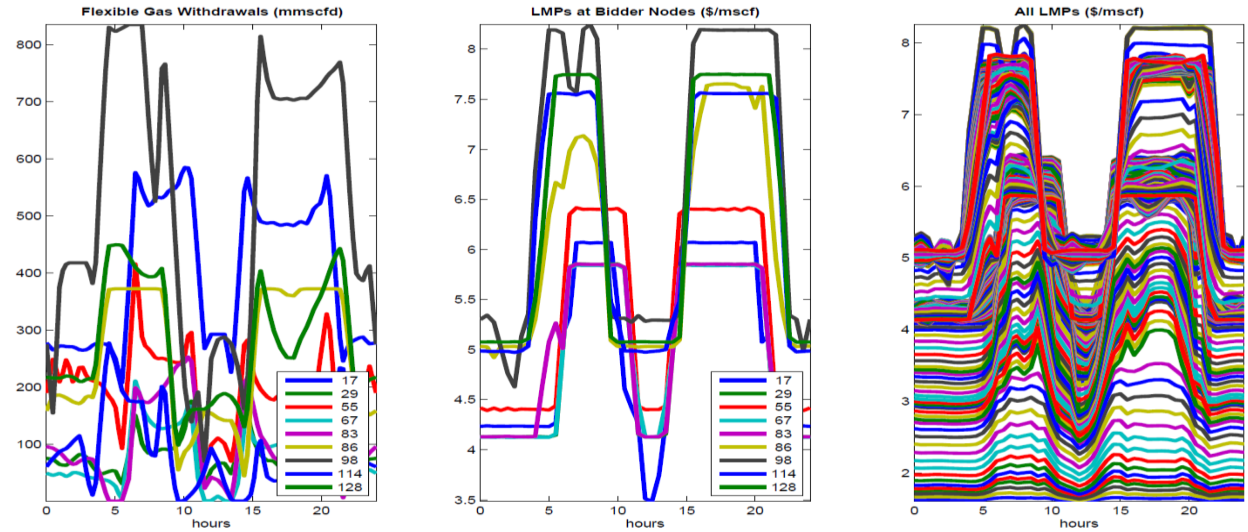


Figure 13. Physical and market outputs from transient pipeline optimization solution. Left: offtakes at market participant nodes with flexible EG customers; Center: locational trade value (LTV) for flexible EG customers; Right: LTVs throughout the entire system as functions of time. Observe that capacity constraints create price separation.

The solution of the problem is shown in Figures 12 and 13, and given as compressor controls, physical flows to market participants, and LTVs for gas throughout the network. The key results of the optimization example can be explained as follows. The maximum (desired) withdrawals by flexible electric generation customers and corresponding prices, given as hourly values (shown at center and at right in Figure 11) define a price/quantity bid by buyers into the market. The withdrawal profiles allocated to these customers, as well as LTVs at nodes where they are located (shown in Figure 13) are outputs of the optimization. The important outcome is the time-dependent LTVs throughout the network, which are illustrated at right in Figure 13. These can be used by other customers who did not participate in the intra-day market to determine the impact of intra-day electric generation activity on the existing gas market for baseline daily nominations.

4.6 Market-Based Gas-Electric Coordination

Recent studies have led to a vision for LTVs to become instrumental in improving coordination of gas and electric systems[179,184]. Conceptually, a coordination mechanism could be based on an iterative direct exchange of electric LMPs and gas LTVs between the corresponding market clearing mechanisms for wholesale electricity and gas. Gas-fired generating units would use hourly LTVs at precise locations on the gas pipeline system where they take gas as a fuel and convert these hourly LTVs into hourly and real-time offer prices they submit to their electric market operators. Once the electricity market clears based on that information, gas-fired units would receive their generation schedules and electric LMPs. Generation schedules would then be converted into gas burn sheets and electric LMPs would be used to develop gas purchase bids indicating the generators' willingness to pay for gas. That information would be submitted to the gas market operator and the iterative process repeats.

This conceptual scheme, even if it were thoroughly proven through multiple academic research studies to converge mathematically, be tractable computationally, and reflect realistic engineering operations, cannot currently be implemented because of barriers of an operational and institutional nature. Operational barriers are apparent from a side-by-side comparison of timelines of scheduling decision processes in the natural gas and electric systems as presented in Figure 14. As one can see in this timeline, there exists a highly intricate succession of decision cycles for both the electric power and natural gas clearing times. The timings of the day-ahead price formation for natural gas and power do not coincide. First, regional forward prices of natural gas emerge in bilateral trading and capacity release mechanism. These prices, although not backed up by delivery confirmation, are then used by electric generators to bid in the DAM. The DAM run by the electric system operator is a fairly complicated process, which includes not only a complex mixed integer optimization task, but also a number of post optimization verification steps assuring the feasibility of the optimization solution. Within the timing allotted to the DAM process; there is little room for any envisioned iterative processes to exchange gas and electric prices and schedules back and forth.

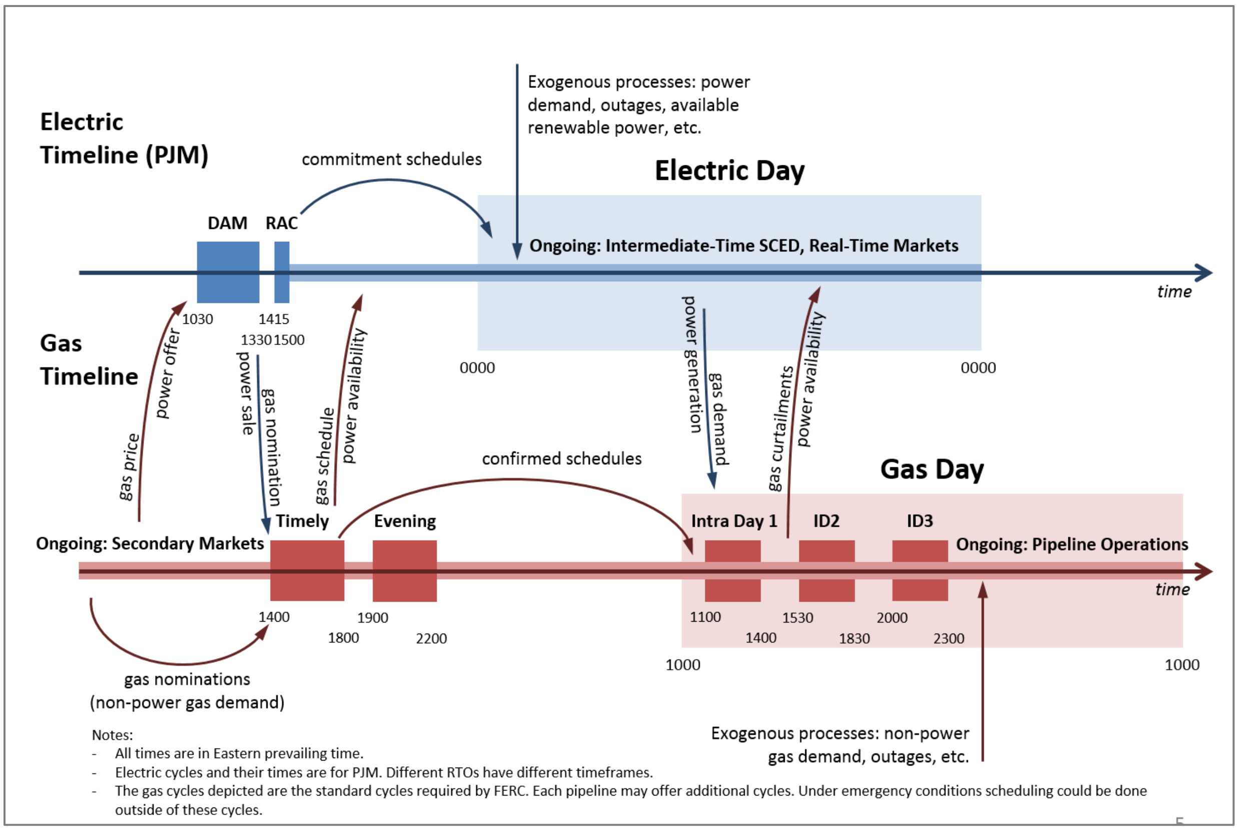


Figure 14. Description of current gas and electric decision cycles[187].

Once the DAM clears and the financially binding operational schedules for electric generators are determined, generators have just enough time to make delivery nominations with the pipeline for the next gas day. If the nominations are confirmed in the timely and evening cycles on the gas side, daily delivery quantities are essentially guaranteed. If they are not confirmed due to pipeline capacity limitations, generators will face significant financial exposure as they are obligated to deliver power but have no gas to produce it. Even if the daily delivery quantity is confirmed, generators typically need non-ratable gas deliveries that pipelines typically cannot guarantee.

Furthermore, most fast-start combined cycle generators and gas turbine peaking facilities are not committed in the DAM. Instead those units are typically scheduled through the hourly reliability updates or close to the real-time market. These "last-minute" decisions do not fit into the existing decision cycles on the gas side. An hourly natural gas balancing market would address this coordination gap by adding a clearing period after the completion of the Evening Cycle and allow market participants to trade deviations from approved schedules in the Timeline and Evening Cycles. These deviations could be traded through the formal optimization based auction-type market mechanism as described above, and would fit within the current gas and electric system decision cycles as shown in Figure 15. Such an auction could be run on an hourly basis using a rolling horizon approach, such that each hour the auction would optimize the system for multiple hours (e.g., 24 hours or even more). Such a balancing market would provide a repeated forward-looking price discovery mechanism to help the gas and electric sectors to efficiently coordinate operations.

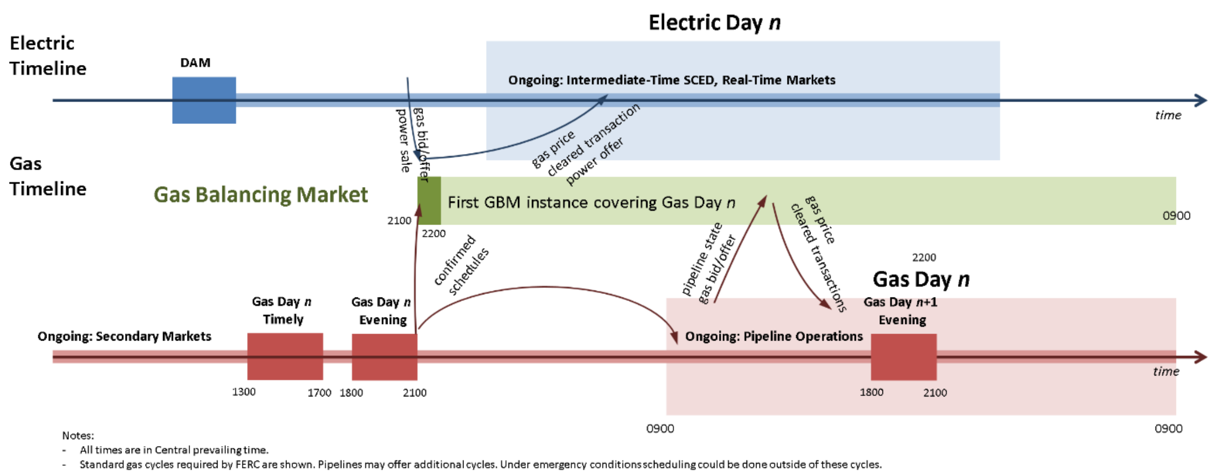


Figure 15. Future gas–electric decision cycle coordination using a gas balancing market[187].

Indeed, if the anticipated operation of the electric system produces forward looking gas burn schedules that cause operational problems on the pipeline side, a gas balancing market will reveal these operation difficulties through high LTVs at the location of gas-fired generators that are causing the problem. After receiving this information, generators would adjust upward their real-time offers to produce electricity and the electric system operator will likely re-dispatch these generators by displacing them with other resources that are either not gas constrained or even not gas fired. This coordination approach will quickly and efficiently relieve constraints on the gas side, reduce consumer prices in both the natural gas and electricity sectors and improve reliability of energy delivery.

Detailed implementation of such a mechanism is a topic of on-going research. An extensive program of research and development would be required to standardize and validate technology based on existing proof-of-concept work. In addition, its adoption by the industry will likely require a complex stakeholder process and regulatory reform. If implemented, the proposed short-term coordination mechanism will have major long-term implications for both the electric and gas industry as it will help to resolve the ongoing debate on the extent to which gas-fired generators should rely on long-term contracts for firm transportation capacity. Generating companies, especially merchant independent power producers, are not willing to enter such agreements because of a perceived high risk of such arrangements. Specifically, this risk is associated with contracting variable generation profiles that are translated into non-ratable gas use profiles. The current lack of a transparent and liquid market and associated price discovery mechanisms for non-ratable gas use profiles presents risk and uncertainty in attempting to sell under-utilized capacity on an hourly basis. The proposed gas balancing market will fill this void and help generation owners to make an informed economic decision on the level of firm transportation capacity to acquire to mitigate the financial risk associated with the volatility of two energy markets they are exposed to on the supply and demand side.

5.0 Conclusions

FERC has established a new playing field where operational coordination between the electric industry and the pipeline industry is both allowed and encouraged. The industries are also allowed and encouraged to invent and innovate using their respective domain expertise to exploit these capabilities. Information firewalls still rightfully remain for market-specific situations, but the two industry sectors are expected to find ways to improve joint operation in technical areas. Currently, “burn sheets” are one of the ways the two industries communicate, but when grid conditions change unexpectedly, they can be very unreliable. However, there is other specific information from the electric industry that can help predict which power plants are likely to alter the volume of their gas takes during the current operational day, the times when this unscheduled operation is most likely to occur, and the likelihood of a specific gas-fired generator deviating from its scheduled day-ahead gas takes. Improving coordination will require near-term actions using minimal new inter-industry communication as well as longer-term developments of new technologies based on more ambitious ideas.

Various types of intra-day non-public operational information could in principle be obtained from power grid operators and made available to pipeline managers. Such information could be used to forecast time-varying pipeline loads and characterize uncertainty of these loads in space and time. This information could help pipelines better predict which power plants are likely to deviate from their burn sheet forecast, and what forms the deviations may take, especially when formalized into an architectural framework. Various methods that could be developed by the pipeline simulation industry to more effectively use such information to mitigate intra-day gas-electricity interdependence issues were discussed as well. These types of information and organized exchanges would provide appropriate connectivity and structure for the 21st century gas-electric architecture.

A promising path towards establishing an architectural framework for gas-electric coordination involves a market-based formulation of the transient pipeline optimization problem using the economic criteria of maximization of the market surplus. Recent new methods of transient pipeline optimization[8] perform well for solving this problem and offer robust and scalable solutions. The key idea in this approach is to use modeling that captures just enough of the large-scale system-wide behavior of a large pipeline network to be both tractable and sufficiently accurate. In addition to optimizing operational decisions, the proposed methods yield economic value of natural gas in the form of LTVs. In contrast to the regional daily prices prevailing in today’s markets, LTVs are consistent with the physics of gas flow in the pipeline networks subject to essential engineering constraints. This makes LTVs an important potential instrument for improved gas-electric coordination, especially if used for intra-day coordinated scheduling of non-ratable supplies and deliveries. Preliminary illustrative analysis of LTVs reveals the shortcomings of daily prices that are disconnected from the physics of pipeline operations and indicates how market participants both on the supply and demand side could benefit from using LTVs as an intra-day pricing mechanism.

The concepts, models, computational methods, and validations described here are preliminary. Although they provide a promising path for integrating and automating markets, scheduling, and operations of gas pipelines in order to facilitate coordination with gas-fired generators and the electric power system, it is expected that numerous multi-year studies and development activities will be required to bring the methodology into the field. The physical, engineering, operational, economic, and regulatory models that form the foundation of the framework currently under development for implementation in future gas pipeline markets must be shown to adequate represent requirements and actual behavior of pipeline customers and operators. In addition to establishing new market structures, this will involve development of technological standards such as on-line methods to automatically verify feasibility of intra-day optimization solutions in comparison with commercial pipeline simulation packages. In addition, modeling approaches will require on-line verification vis-à-vis operator planning models and SCADA measurements for a real pipeline systems in real-time operation over multi-year studies.

Moreover, the gas pipeline and gas-electric interaction concepts presented here will need to be categorized and organized within an architectural framework, i.e., with an appropriate system consisting of well-defined components, behaviors, structures, connectivity, and relationships. The effort to develop the 21st century grid architecture at the gas-electric interface, currently in its initial stages and with extensive coordination with major stakeholders, will require an ongoing effort over the next decade.

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