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INTERDISCIPLINARY OPERATION OF NATURAL GAS AND ELECTRIC POWER SYSTEMS

BACKGROUND

Environmental and economic factors play ever increasing roles in energy production, transportation, and consumption. The development of sustainable, affordable, and clean sources of energy is generally considered a prerequisite for today's economic strength and will benefit tomorrow's society. Under the impetus of competition in the energy industry, the unbundling of the electricity sector has introduced new technologies for the generation and the delivery of electricity, which signify less pollutant, highly efficient, and less costly ways of supplying the electricity. Such technologies would highlight the applications of gas-fired combined cycle plants and renewable sources of energy.

In recent years, a new trend in power generation has emerged as combined cycle gas turbine units (CCGTs) have been introduced to power systems and installed in increasing numbers throughout the world. CCGTs demonstrate their advantages based on four principles (1–3). First, gas-fired generating units have lower environmental impacts. NOx, CO_2, and SO_2 emissions from a CCGT could be reduced to be significantly less than those of other types of thermal plants. Second, CCGTs demonstrate higher economic competitiveness over fossil units. CCGTs integrate two thermal cycles for improving the total energy conversion efficiency. Third, CCGTs can be instrumental in hedging rapid fluctuations in electricity and fuel markets because of their fast ramping and quick start capabilities. Fourth, CCGTs have relatively lower investment costs and require shorter installation periods. Natural gas has been the primary choice for expanding the fossil fuel power generation. This trend is expected to continue over the next several years by increasing the proportion of natural gas power generation in the electricity industry.

Besides natural gas-fired power generation, renewable sources of energy such as wind and solar have become more common in electric power systems. In particular, wind energy in the United States is projected to represent 20% of consumption by 2030 (4). The large-scale integration of volatile and intermittent renewable units into power systems would require additional reserves and a fast response generating capacity, whereas the installed coal and nuclear units would continue to supply the base load. Natural gas-fired generating units including CCGTs, single gas-turbine units, and fuel-switching units have a remarkably fast response performance. Thereby, the natural gas-fired generation units will continue to play an indispensable role in power systems with volatile renewable power generation units.

According to the published data in the United States by the Energy Information Administration (EIA) (5), natural gas-fired units generated 496,058 Gigawatt hours in 1995. The number increased to 920,378 Gigawatt hours in 2009 accounting for 23.3% of the total U.S. electricity consumption. In certain U.S. regions (i.e., New England, New York, Texas, Florida, California-Arizona-Southern Nevada, and Alaska), the dependency on natural gas is much higher. For instance, the gas-fired generating units in ERCOT and Florida exceed 60% and 51% (6) of the total capacity. ISO New England installed 11,705 MW gas-fired units prior to 2008 that accounted for 38% of its total installed generation capacity (7). From the natural gas sector's view, power plants are considered the fastest growing customer in the United States. In 2008, the natural gas used for the electric power generation account for almost one third of the total consumptions as shown in Table 1 (5). Q2

Table 1. U.S. Natural Gas Consumption in 2004–2009 (Trillion Cubic Feet)

Consumption Sector	2004	2005	2006	2007	2008	2009
Residential and commercial	8.00	7.83	7.20	7.74	8.04	7.90
Industrial	7.24	6.60	6.51	6.65	6.66	6.17
Electric power	5.46	5.87	6.22	6.84	6.67	6.87
Lease and plant fuel	1.10	1.11	1.14	1.23	1.22	1.28
Pipeline use	0.57	0.58	0.58	0.62	0.65	0.60
Vehicle use	0.02	0.02	0.02	0.02	0.03	0.03
Total consumption	22.39	22.01	21.68	23.10	23.27	22.84

Around the world, natural gas-fired power plants represent a comparatively rapidly increasing capacity. Especially in Europe and South America, natural gas-fired power plants accounted for half of the newly installed capacity from 1990 to 2004 (8). In 2005, more than 26% of the total gas consumed in South American countries was used to generate electricity. More than 90% of the natural gas supply is delivered to power plants in Argentina, Brazil, Chile, Colombia, and Venezuela (9).

It is evident that the electric power sector relies highly on the natural gas supply to maintain its reliability and to pursue economic operations. In addition, the natural gas system supplies an increasing level of demand in electric power systems.

ELECTRIC POWER AND NATURAL GAS SYSTEMS

Coupled Infrastructures

Electric power and natural gas infrastructures have common features but also pose significant differences. Both energy infrastructures can be divided into four major sectors including supply, transmission, distribution, and consumption. Table 2 lists components of different sectors in each system and shows their corresponding relationships.

Power plants produce electricity by converting different primary sources of energy into electric power. In natural gas systems, gas wells are the main suppliers, which are commonly located at remote sites that are far from load centers. After processing, the natural gas is injected into the pipeline network. Unlike electricity, natural gas can be stored in large ungrounded storage facilities or metal tanks as liquid state. During the peak demand hours, the gas storage located near loads and liquefied natural gas (LNG) can supplement suppliers in the natural gas system.

The transportation network can be classified into transmission and distribution sectors according to their pressure level and voltage level, respectively. The transmission

Table 2. Structures of Electric Power and Natural Gas Systems

Sectors	Natural Gas System	Electric Power System
Supply	Gas wells, storages and LNG injection terminal	Power plants (coal, natural gas, nuclear, and renewable)
Transmission	Higher pressure network (interstate pipelines, compressors, valves)	Higher voltage network (transmission lines, underground cables, transformers, and breakers)
Distribution	Lower pressure network (intrastate pipelines, regulators, and valves)	Lower voltage network (transmission lines, underground cables, transformers, and breakers)
Consumption	Large and small consumers	Large and small consumers

network delivers bulk energy into regional demands or large customers. The distribution part mostly owned by the utility links small customers to junctions of the transmission network. In electric power systems, a network consists of transmission lines, cables, breakers, transformers, and so on, whereas a natural gas network is represented by pipelines, valves, and compressors. The network components can be modeled as either distributed or lumped parameters.

The load sectors in both electric power and natural gas systems include large and small customers. Most residential and commercial customers are supplied by distribution networks. Industrial customers are usually large, which are linked directly to transmission networks.

Natural gas-fired power plants are linkages between the two infrastructures as shown in Fig. 1. They belong to the load sector in the natural gas system while representing suppliers in the electric power system.

Competitive Market and Restructured Environment

Electric power systems are rapidly becoming market driven. In a competitive electricity market, the traditional vertically integrated monopolies are restructured into generation, transmission, and distribution entities as shown in Fig. 2, and competition is introduced through open access. The introduction of restructuring is to reduce energy charges through competition, provide customers with more choices by creating open access, price different levels of service reliability for customers, and create more business opportunities for new products and services. However, restructuring is not synonymous with deregulation. The self-interested entities including generation companies (GENCOs), transmission companies (TRANSCOs), and distribution companies (DISCOs) constitute optimal strategies to maximize their profits by performing price-based unit commitment and scheduled maintenance outage planning based on forecasted market prices of energy and ancillary services.

An independent system operator (ISO) coordinates market participants for supplying the real-time load demand and satisfying limited fuel and other resource constraints, environmental constraints, and transmission security requirements (10, 11).

In competitive electricity markets, customers expect a least-cost and high-quality supply of electric energy that requires the solution of security-constrained unit commitments and other sophisticated techniques executed by the ISO (such as the PJM ISO or the New York ISO) to minimize the system operation cost and enhance the power systems reliability.

In general, the electricity energy market operated by ISO includes a day-ahead market (DAM) and a real-time market (RTM) as well as bilateral contracts arranged independent of RTM and DAM. The DAM is an hourly forward market for scheduling electricity demands and resources. To ensure the reliability of power systems, the production

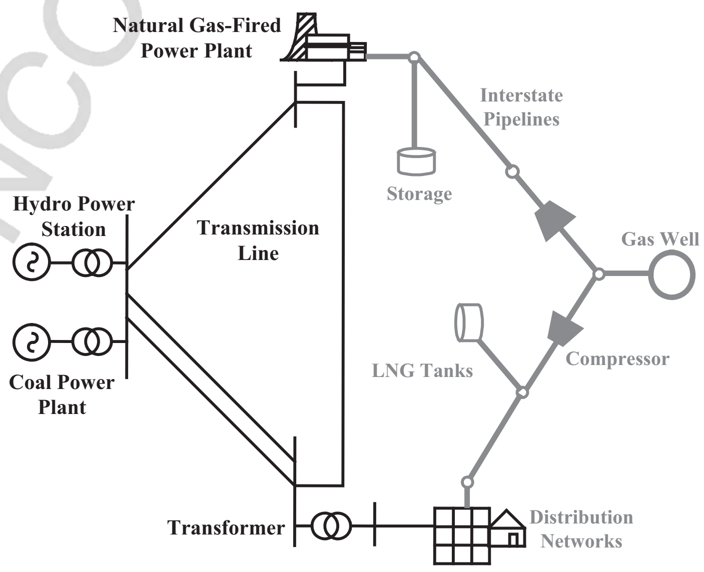

Figure 1. Coupled electricity and natural gas infrastructures.

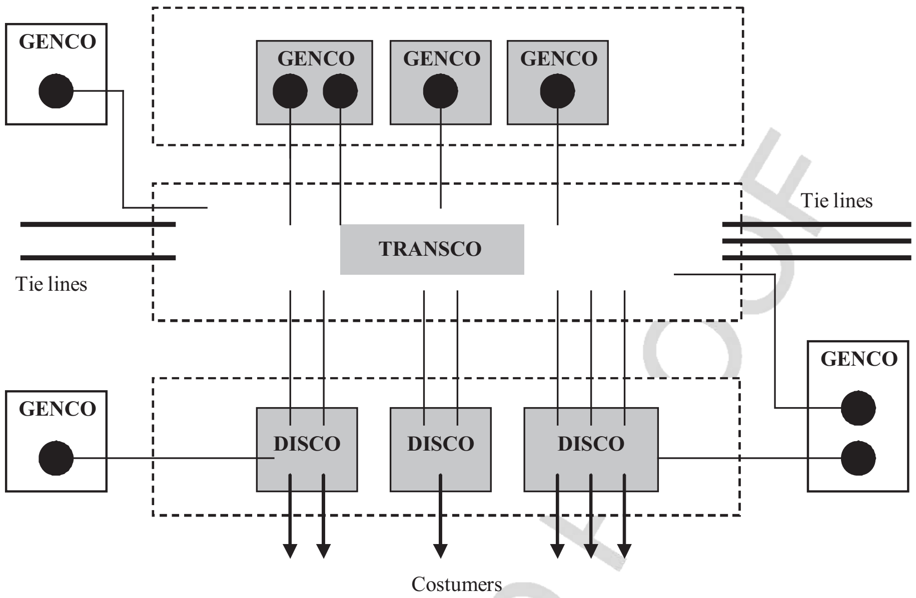

Figure 2. Restructured electric power systems.

and consumption of electric power would have to be balanced in real time. The RTM is designed to compensate differences between the day-ahead scheduled electricity and the actual real-time load requirements.

In the reserve market (ancillary service market), reserve products are cleared and procured through a system-wide or zonal-based auction to prevent the loss of system reliability from contingencies. Besides, certain ISOs operate a forward capacity market for long-term reliability and a financial transmission right market to deal with transmission congestion.

Market participants either pay or are paid the real-time locational marginal price (LMP). LMP is a price incentive for capturing the impact on operating cost of locational variations in supply, demand, and transmission limits at related bus in power systems (11).

Under the Natural Gas Wellhead Decontrol Act of 1989, the natural gas supply is a deregulated business that allows the market to determine the price of natural gas at the wellhead. The electricity and natural gas markets are remarkably different. The electricity market has hourly and real-time pricing in DAM and RTM. In contrast, the natural gas market is based on daily pricing of its commodity with nominations for transportation.

Natural gas transmission sectors are regulated by two entities. Interstate gas pipelines are regulated by the Federal Energy Regulatory Commission (FERC), whereas intrastate pipelines are regulated by State Public Utility Commissions. In 1985 and 1987, respectively, the U.S. FERC issued "Open Access Orders" 436 and 500 that took the first step toward allowing pipeline customers the choice in the purchase of natural gas and only transportation services. The interstate pipelines were regulated to offer nondiscriminatory services to all transportation requests. The transportation service gradually became the primary function and business of interstate pipelines. The FERC Order No. 636 took further steps toward unbundling of transportation and sales so that all pipeline customers could select their gas sales, transportation, and storage services from any provider in any quantity. A variety of gas purchase and transportation patterns appeared during market evolutions.

Different classes of gas transportation services are defined by (7) the following:

No-Notice: The customer can use gas whether nominated or not on a daily basis up to its firm entitlement without incurring any balancing or scheduling penalties.

Primary Firm: The customer should have no interruptions (except for force majeure) but is responsible for paying the penalties for using more gas than their nominated amount. This service can bump interruptible customers.

Secondary Firm: Similar to primary firm except the customer nominates at a location other than the primary point that was specified in their contract or nominates at a value that was greater than what they were entitled to at specific points.

Interruptible: The customer can be interrupted with little notice and can be bumped by higher priority services.

With unbundling environment and competition, however, the natural gas transmission sectors are no longer responsible for assuring sufficient supplies on interstate pipeline for noncore interruptible customers such as electric generators. These customers will have to acquire interstate pipeline capacity, whereas locational gas distribution companies (LDCs) or utilities are responsible for assuring that the intrastate gas system is adequate to draw the flow from the interstate pipelines.

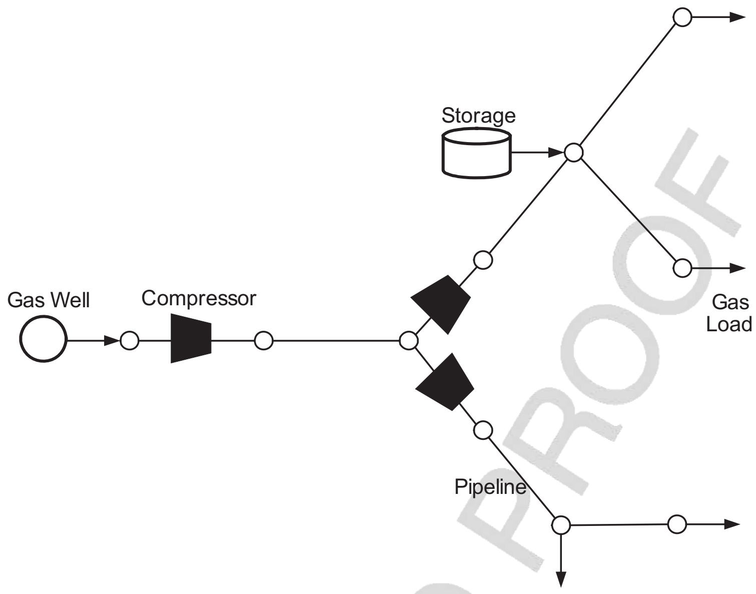

Figure 3. Natural gas transmission system.

Natural gas sectors usually run an optimization program to make a short-term or long-term schedule for natural gas system operation. The objective function is usually to minimize energy consumed cost of compressors, gas allocation cost, or maximize their revenues while satisfying premium of network constraints and pressure requirements of receiving points.

Short-Term Operation Scheduling of Electric Power and Natural Gas Systems

In the past, electric power systems and natural gas systems were usually scheduled independently. The scheduling models in mathematics are optimization problems.

Q3 The objective of electric power system scheduling problem called security-constrained unit commitment (SCUC) is to minimize the operating cost of power systems (12). SCUC refers to the strategic choice for determining the on/off status and dispatch of available generators with the minimum cost for all available generators while preserving the network security and satisfying the load demand forecasted by an ISO. Considering individual characteristics of each generator, additional constraints include minimum on/off time, ramping up/down constraints, minimum/maximum generation limits, and fuel and emission constraints (11). Electric power system network can be modeled as alternating current (AC) power flow constraints (nonlinear) or direct current power flow constraints (linear). Apparently, the AC power flow model is more accurate but requires more computational resources to solve it. SCUC has transmission network constraints and hold L-shaped structure. Once the dispatch of power generation is determined, the network constraints become uncoupled among different hours. For large-scale applications, the network security check is usually separated from the economic resource dispatch by either the Benders decomposition or the sensitivity analysis (i.e., power transfer distribution factor [PTDF]) (13, 14).

The gas allocation is to commit and schedule natural gas resources while satisfying gas transmission constraints (15). The objective function of gas allocation problem is to minimize the sum of energy consumption of the compressors or the operating cost of the natural gas system. The natural gas transmission system can be represented by its steady-state and dynamic characteristics (16, 17).

Figure 3 depicts the natural gas transmission system from producers to end users that is comprised of natural gas wells, transmission and distribution pipelines, storage facilities, and compressors. These components are categorized into nodes and branches. The steady-state mathematical model of the natural gas transmission system comprised of a group of nonlinear algebraic equations (15, 18, 19). As state variables, gas pressure is associated with each node, whereas the natural gas flow rate is associated with each branch. A steady-state mathematical model of a natural gas transmission system is based on the nodal balance approach that indicates that the natural gas flow injected in a node is equal to the natural gas flowing out of the node. In other words, the natural gas flow mismatch at a node is equal to zero.

It is of paramount necessity to incorporate the natural gas transmission system model into the operation planning and optimization of electric power systems. In the last decade, References 14 and 20–25 proposed several state of the art strategies to model the two systems together. However all of them focus on steady-state formulations for both electric power and natural gas transmission systems. They neglect significant distinctness on travelling speeds of natural gas flow and power flow as well as line-pack capacities of interstate pipelines. Line pack relates to the amount of additional gas that is stored in a pipeline as a result of maintaining above-normal pressure in the pipeline (26, 27). By analogy with the important function of reserve in power systems, line pack is essential for a pipeline to handle large swing in gas load such as ramp up of gas-fired units during peak hours or called reserve of gas-fired units to react contingencies in power systems. It is well recognized that natural gas flow in high-pressure interstate pipelines is governed by some dynamic laws based on distributed parameters in short-term periods such as several hours.

Energy infrastructure dynamics vary from milliseconds to a couple of hours, which indicates the fact that the transportation of energy via different infrastructures happen over different time frames. It is well known that electrical energy travels via the current electrical transmission systems almost instantaneously and cannot be stored in large amount. Once power injection and load on each bus is given, power flows in transmission system satisfy steady-state algebraic equations and are independent from hour to hour. Therefore, in the operation planning stage, traditional security-constrained unit commitment (SCUC) and security-constrained economic dispatch commonly ignore electrical transient process of electricity infrastructure and instead focus on steady-state analysis (11–13).

Unlike the instantaneous delivery of energy over electric power systems, the natural gas flow traveling via pipeline represents much slower phenomenon. When the gas load or gas supply changes, natural gas transmission system will take more time to respond to disturbances. In particular, the dynamics for high-pressure interstate pipelines are much slower, and a large amount of gas stored in the pipelines cannot be neglected. In this case, steady-state assumption and corresponding algebraic Weymouth equation of pipeline might be inappropriate and inaccurate for numerical simulation of unsteady gas flows. Rigorous gas flow simulation requires pipeline distributed parameters and the transient state model.

Natural gas flows through pipelines, driven by pressures, are dependent on factors such as the length and the diameter of pipelines, operating temperatures, composition of natural gas, altitude change over the transmission path, roughness of pipelines, and boundary conditions. The transient-state natural gas flow through a gas pipeline is usually described as a one-dimensional dynamic alongside the axis of natural gas pipeline. Dynamic simulation requires the use of distributed parameters and the consideration of time-varying state variables. A set of partial differential equations is obtained by applying laws regarding conservation of mass, momentum, and conservation of energy (28–39).

There are many methods to solve the partial differential equations (PDEs). Analytical methods can provide a continuous solution by compact mathematic expression if the region and boundary values of dependent variables are defined. Compared with analytical methods, numerical methods are more popular for engineering computation of gas pipeline dynamics. They are used to evaluate the dependent variables at discrete points in a spanning region of time and space as shown in Fig. 4.

People usually adopt the finite-difference numerical method to approximate PDE and by replacing derivative expressions in space and time with equivalent difference quotients. Generally, implicit methods have better

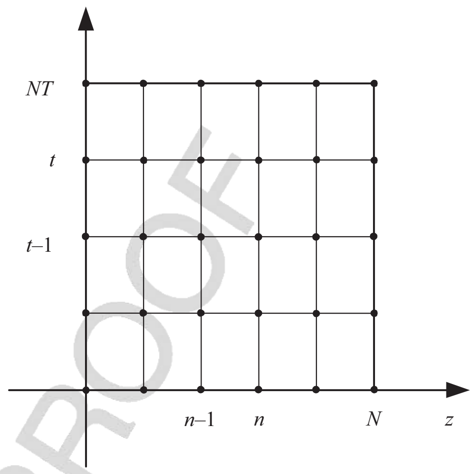

Figure 4. Grid points in the finite-difference scheme.

numerical stability than explicit methods because explicit methods calculate dependent variables at a later time from those at the current time, whereas implicit methods find a solution by solving an equation involving dependent variables in both the current and the future times. PDEs are finally transformed into a set of algebraic equations.

ELECTRICITY/NATURAL GAS INTERDEPENDENCIES

Natural gas-fired power plants erect a bridge between the electric power system and the natural gas system. The reliability assessment report (26) put forward in 2002 the interdependency of electricity and natural gas. In Shahidehpour et al. (31), the security of interdependent gas and electricity infrastructures were addressed. Rubio et al. (8) surveyed the interdependency of electricity and gas systems in South American and analyzed the latest research and development on this topic. ISO New England (7) introduced a case study on the interactions of electricity market and natural gas market in New England. The interdependent relationship between the two systems is examined and described as follows.

Market

The natural gas price fluctuation profile in gas markets is a key driver of electricity price movements in electricity markets. Natural gas-fired units usually serve intermediate and peak electricity demands, so a gas price hike could increase their marginal cost of generating electricity. In a competitive environment, the gas price will affect directly a GENCO's bidding strategies which is one of key factors in market clearing.

Another important price factor in the electricity markets is natural gas supply disruptions during critical gas operating hours or seasons. Gas LDCs traditionally sign a no-notice or firm transportation service contracts to guarantee the supply of their core customers. In some regions during the winter, LDCs buy almost the entire capacity of pipelines to supply the space heating demands of residual and commercial customers. However, most gas-fired generators do not use firm transportation contracts for economic reasons because the expected price in electricity markets is relatively low. Interruptible natural gas transportation contracts could lead to bumps or delays of ongoing natural gas supply and the disruption of electricity generation by gas-fired units. To balance electricity generation and demands, the electric market would need to switch from gas-fired units to less efficient units that use other types of fuel such as coal and oil, which would translate into higher market prices for electricity.

The gas-fired units participate in both the electricity market and the natural gas market. On the one hand, GENCOs can seek to arbitrage the price difference between electric and gas markets in real time at particular locations. When the market implies higher natural gas prices and lower electricity prices, the power generator could buy electricity, rather than producing it, and sell natural gas to the spot market (7, 32). On the other hand, the risk management for gas-fired units is likely more complicated than those units with other types of fuel because gas-fired units face a gas consumption balancing issue in the real-time generation, gas nomination in dynamic forward natural gas market, and gas transportation via pipelines. Owners or operators of gas-fired generation units must constantly deal with hourly, daily, weekly, or monthly imbalance resolutions. In the winter, uncertainty threat of gas supply in gas markets and gas transportation may impact the market participants' profit and behavior when they play in DAM, RTM, and reserve markets.

A stochastic optimization model for electric utility was proposed in Reference 32. The model maximizes utility benefits by considering the financial risks associated with the gas supply portfolio of electricity utility. The impact of natural gas transmission system on power markets was discussed by Morais and Lima (24).

Operation

Gas fuel adequacy and availability will directly affect a generation unit's commitment, dispatch, and generation cost. Gas adequacy has two components, supply (gas well and storage) and the infrastructure to transport it. Thus, the natural gas transmission congestion or the gas well maximum output can impact the schedule and the operating status of power systems.

In natural gas operating center, gas-fired units with interruptible transportation contract are usually treated as the top curtailment candidate. Once the congestion has occurred in natural gas transmission systems or the gas well has reached its maximum output, the natural gas drawn by gas-fired units with non-firm transportation contracts are expected to be limited or bumped. Moreover, operating new gas turbine units or CCGT usually depends on high gas pressure based on their specific design, so electric generators are more susceptible to the pressure drops in their delivery point than other gas load. Even gas delivery service priority of gas-fired units is same as other gas loads, weaker bearing ability of pressure drops make gas curtailment of gas-fired units more possibly happened.

From another point of view, the scheduling of natural gas transmission systems will be based on the unit commitment and the dispatch of gas-fired units in electric power systems. Gas-fired units usually serve intermediate or peak electrical loads, which would lead to fluctuating gas consumptions. The natural gas system would have to schedule compressors, line-pack resources as well as gas wells in advance to satisfy the constraints on gas-fired units and other gas loads within a reasonable pressure range.

It is inevitable that forced outages occur in both power and natural gas systems. In contingency cases, potential interactions between the two systems are expected to be strengthened. The two scenarios to be considered are as follows:

1. Contingencies in power systems. The direct loss of a gas-fired generating unit would result in a step change in gas demand, whereas the power system frequency would drop. Then, the other power system units will be rescheduled to pick up the lost power. The loss of non–gas-fired units or transmission lines will also call on reserves to maintain the security and to balance the power in real time. Lines pack resource in a pipeline is crucial to deal with large swings in gas demand. To ensure the integrity of gas pipelines in winter, some pipelines will not allow gas-fired units to come online to absorb their curtail line pack resource unless their fuel nomination has been confirmed. This, in effect, turns these quick start gas-fired units into the ones with longer response times and can prevent them from providing quick spinning and operating reserves to power systems.
2. Contingencies in natural gas systems. Because of the proliferation of new gas-fired units supplied by a common source or regional gas pipelines, the sudden loss of a gas supply, compressor or pipeline may cause the loss of several gas-fired generators. This case may be beyond the traditional N-1 planning standards and could seriously jeopardize the security of power systems. The electrical load shedding may possibly happen to balance the real-time demand and maintain the security of power system. When a contingency occurs, certain gas units can switch quickly to burn and others without dual-fuel capacities must be taken off the online to switch burners.

In An et al. (22) and Unsihuay et al. (20), a nonlinear continuous optimization model was proposed by merging the traditional optimal power flow and the natural gas optimal flow. However, the model is based on a single-hour horizon. The objective function of An et al. (22) is to maximize the social welfare. The case studies show the difference between the independent model for the two systems and the proposed integrated model. Mello and Ohishi (33) and Munoz et al. (34) present the two-phase integrated models to calculate the maximum generation output of an electric power plant subject to natural gas system constraints. Active and passive arcs represented as linear equations are used to represent natural gas pipelines and compressors.

The short-term scheduling of hydrothermal power systems with linear gas transmission constraints was considered by Unsihuay et al. (21) where the problem is formulated as a multistage scheduling in which the objective function is to minimize the total operating cost to meet electricity demand forecasts. The heat-rate curve of gas-fired units is based on a proportional function. The unit commitment problem was decomposed into subproblems for each unit by relaxing the electricity load balance and reserve constraints. Linear natural gas transmission constraints with a pipeline loss factor are modeled into subproblems for gas-fired units. In Li et al. (35), a SCUC model with hourly and daily natural gas usage limits, instead of gas network constraints, are proposed. The detailed mixed-integer programming formulation of combined-cycle gas units and fuel switching units are incorporated into the unit commitment (UC) model. Shahidehpour et al. (31) also gave a SCUC model with relatively simple gas network considerations. The piecewise linear approximation of nonlinear gas flow pressure is modeled in the UC problem (25). Geidl and Anderson (36) introduced a general optimization approach for power dispatch that included multiple energy carriers such as electricity, natural gas, and district heating. Additionally, the optimality conditions for the multiple energy carrier dispatch were derived for a simplified natural gas transmission system. Padberg and Haubrich (37) considered the optimization of the natural gas portfolio by a stochastic model.

The natural gas transmission network in some existing models is considered as a linear system or simplified nonlinear equations. In power systems, simplified linear power flow equations are applicable because branch flows are approximated as a linear function of the voltage angel difference between two linked buses. However, the simplified natural gas flow model lacks a similar theoretical support. In addition, unlike power systems, the storage facilities in natural gas systems cannot be ignored. Thus, the exact nonlinear steady-state model of natural gas system should be adopted, which may introduce more difficulties in the solution of the integrated model. Because natural gas flows travel slowly and some of interstate pipelines have line pack capacity, the steady-state flow assumption may lead to inaccurate results. Rigorously, in a short-
Q4 term integrated operation model, it is required to consider pipeline distributed parameters and a transient model (38, 39).

Midterm and Long-Term Planning

Midterm and long-term integrated models require stochastic representations and appropriate simplifications based on the short-term model. The midterm and long-term economics and reliability of natural gas and power system are impacted by the installation of new resources, transportation network expansions, long-term load profile, and maintenance. The addition of new component will impact the natural gas supply system. For instance, a new interstate pipeline could alleviate the burden on existing pipelines. In such cases, the curtailment of natural gas supply to power generation units may be diminished and the reliability of power system could be enhanced, even if gas-fired units still hold interruptible contracts that are subordinate to residual and commercial gas loads. On the contrary, the maintenance of a compressor may reduce the natural gas transportation capacity and result in a lower reliability of power system if the supply to gas-fired units is interrupted.

In addition, the planning of additional gas-fired power plants in electric power systems would require an adequate supply of natural gas. In general, the pipeline expansion, which is in response to the load growth, is regulated by FERC. FERC will generally not authorize new pipelines or facilities to improve the existing capacity unless customers are already obliged to such expansions. Thus, in an optimal situation, the gas-fired power plant planning should be bundled with the gas pipeline expansion planning.

The long-term integrated planning is analyzed by Hecq et al. (23) and Unsihuay et al. (40) as decisions are highly interdependent in natural gas and power transmission systems. These approaches are based on a multiperiod deterministic optimization in which the objective function is to minimize the gas-electricity investment and operating costs. However, gas prices are stated as deterministic input parameters, whereas in the practice, they exhibit a stochastic nature and would depend on the gas pipeline expansion decisions. For a long-term model, Gil et al. (41) proposed multiperiod generalized network flow model of the U.S integrated energy system with natural gas, coal, and power infrastructures. Quelhas et al. (42, 43) further developed this model by proposing nodal prices in an integrated energy system. The application focused on long-term macroscopic analyses for the national economic and large-scale disruptions and is based on virtual infrastructure topology and linear network flows. Wu and Shahidehpour et al. (44) and Sahin et al. (45) presented a methodology that modeled the natural gas supply, demand, and transmission network in the stochastic hydrothermal scheduling. The objective function is to minimize the expectation of operating cost for a several-year horizon.

COORDINATED SCHEDULING OF ELECTRIC POWER AND NATURAL GAS SYSTEMS

Security Constrained Electric Power System Scheduling with Natural Gas Transmission Constraints

Different coordination schemes between natural gas and electric power sectors may bring about different objective functions and model structures. For instance, electric power and natural gas systems can be modeled as an integrated system to pursue their overall benefits. Also, two systems can be considered individually with respective contracts and constraints. An iterative coordination and communications is executed until they obtain respective feasible solutions acceptable by both systems. For diversity, subsequent research on different coordination schemes would be needed. The integrated model is frequently a mixed-integer nonlinear programming problem with large-scale complex transmission network constraints. It is hard to solve the entire system as one piece. Optimization techniques applied to the operation and planning of a single energy carrier system have been well developed. It is convenient to use decomposition techniques to separate the integrated model into several subproblems that can be handled more easily.

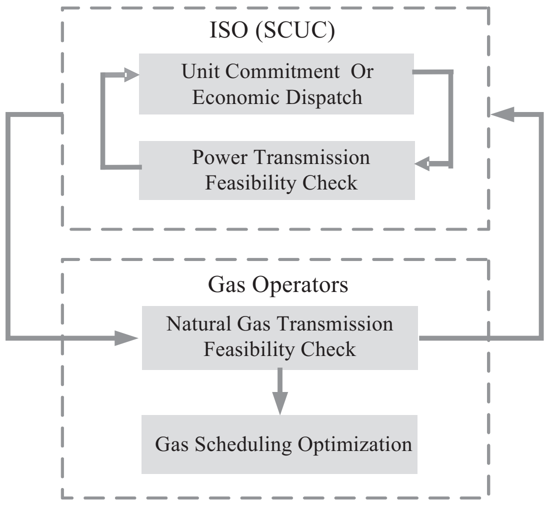

Figure 5. Coordination scheme of electric power and natural gas systems.

Liu et al. (14, 39) concentrated on the development of a methodology for the coordinated scheduling of interdependent power system with natural gas transmission constraints. The interstate natural gas pipelines are described by a set of PDEs (46) or steady-state Weymouth equations. An implicit finite-difference method will be adopted to approximate PDEs into algebraic difference equations. As a result, the natural gas flow model will be coupled not only in space but also in time.

The coordination scheme between gas system operators and ISO of power systems is shown in Fig. 5.

The electric power systems, with the gas-fired units, can be viewed as the demand side of the natural gas transmission system. The electric power sectors have upper level pulling power to determine the amount of natural gas consumption. Under this assumption, the natural gas transmission operators have to respect the transportation contracts if their physical gas infrastructures can afford them. Mathematically, the proposed scheduling coordination problem can be described by a bilevel programming formulation as follows:

$$\underset{\boldsymbol{x}}{\text{Min}}\ EC(\boldsymbol{x}) \tag{1}$$

$$s.t. \quad \boldsymbol{EU}(\boldsymbol{x}) \leq 0 \tag{2}$$

$$\boldsymbol{EN}(\boldsymbol{x}) \leq 0 \tag{3}$$

$$\boldsymbol{e}(\boldsymbol{x}_c) - \boldsymbol{g}(\boldsymbol{y}_c) = 0 \tag{4}$$

$$\underset{\boldsymbol{y}}{\text{Min}}\ GC(\boldsymbol{y}) \tag{5}$$

$$s.t. \quad \boldsymbol{GN}(\boldsymbol{y}) \leq 0 \tag{6}$$

where $\boldsymbol{x}$ and $\boldsymbol{y}$ represent state and decision variables in power system and gas system optimization, respectively. $\boldsymbol{x}_c$ is subvector of $\boldsymbol{x}$ for representing natural gas consumptions by power plants. Equations 2, 3, 6 and 4 denote unit commitment constraints, power transmission network constraints, transient natural gas transmission constraints and electricity-natural gas coupling constraints respectively. The lower level problem in Equations 5 and 6 represents gas scheduling optimization problem, which is a constraint embedded into the upper level optimization problem for generation scheduling.

By ignoring Equation 5, bilevel programming problem will be transferred into Equation 7. Obviously, LB provides a lower bound for primal problem (Equations 1–6).

$$\text{LB} = EC(\boldsymbol{x}^*, \boldsymbol{y}^{\#}) = \underset{\boldsymbol{x}}{\text{Min}} \left\{ EC(\boldsymbol{x}) | \text{ Equations 2, 3, 4, and 6} \right\} \tag{7}$$

It is noted that $\boldsymbol{x}_c$ are not part of the decision variables in the lower level problem. Based on fixed $\boldsymbol{x}_c^*$ from Equation 7, we can solve Equation 8 and obtain an optimal solution $\boldsymbol{y}^*$. Because $(\boldsymbol{x}^*, \boldsymbol{y}^*)$ is a feasible solution of the bilevel optimization problem (Equations 1–6), $EC(\boldsymbol{x}^*, \boldsymbol{y}^*)$ is an upper bound for Equations 1–6.

$$\boldsymbol{y}^* = \text{Arg}\ \underset{\boldsymbol{y}}{\min} \left\{ GC(\boldsymbol{y}) | \text{ Equation 6} \right\} \tag{8}$$

$$\text{UB} = EC(\boldsymbol{x}^*, \boldsymbol{y}^*) = EC(\boldsymbol{x}^*, \boldsymbol{y}^{\#}) = LB \tag{9}$$

$(\boldsymbol{x}^*, \boldsymbol{y}^*)$ is an optimal solution for the original bilevel programming problem (Equations 1–6).

Generalized L-shaped decomposition (row generation) (47, 48) is applied to decompose the optimization problem (Equation 7) into UC master problem (Equation 10), power transmission network constraints (Equation 3) check subproblem and gas transmission network constraints (Equation 6) check subproblem.

$$\underset{\boldsymbol{x}}{\text{Min}} \left\{ EC(\boldsymbol{x}) | \text{ Equations 2 and 4} \right\} \tag{10}$$

It should be noted that the above conclusion can be obtained only under the fact that natural gas transmission operator cannot shed gas loads requested from power plants just for the purpose of reducing the compressors' cost. Gas loads can only be bumped by other gas loads with higher transportation priority when there is congestion. However, if $\boldsymbol{x}_c$ is also a decision variable of lower level optimization problem, then the primal bilevel optimization problem will be more complicated and can be solved by employing Kuhn–Tucker conditions of the lower level problem. This will be a topic for future research.

Figure 6 depicts the flowchart for coordinating the electricity and natural gas infrastructure scheduling. The whole process can be divided into two parts: the ISO part and the gas system operator part.

The ISO or the utility operator would execute the unit commitment to determine the UC schedule and hourly dispatch that would satisfy the forecasted electric load. If generation facilities cannot provide enough power to match electricity demands, then a load shedding scheme will be employed. Based on the UC and dispatch solutions, the ISO conducts the security analysis for network constraints. The power transmission check mitigates transmission violations and iterates with the UC via PTDFs or Benders cuts (11, 13, 49). If no violation occurs in the power transmission network, then the ISO can determine the natural gas amount consumed by gas-fired units and submit the gas demands to the gas system operator.

Meanwhile, natural gas transmission system operators collect the information on requested gas demands, gas contracts, gas transmission parameters, initial pressures, and

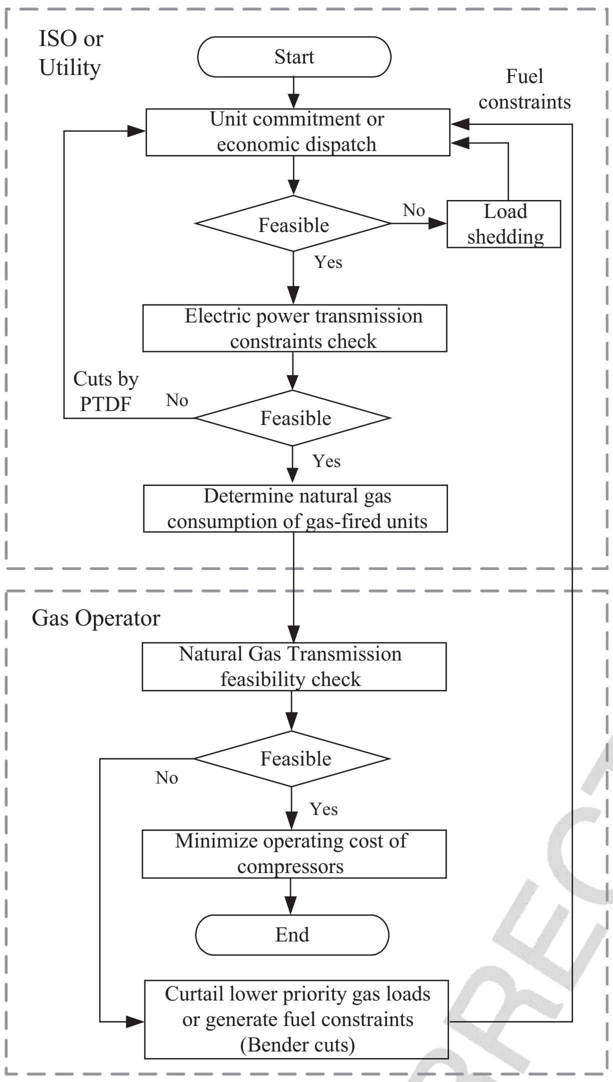

Figure 6. Flowchart of coordination schemes between ISO and gas operator.

planned outage of gas pipelines. The gas feasibility check problem will examine the feasibility of the gas transmission system for serving expected gas loads. If the outcome of the gas transmission check is infeasible, then gas fuel constraints using cutting-plane method for gas-fired power plants will be formed and fed back to the ISO for rescheduling. The iterative process between SCUC and the gas transmission feasibility check will continue until the feasibility of transient gas transmission flow is obtained. It is noted that the gas flow obtained during the feasibility check is not necessarily the optimal result for gas transmission network operation on the next day. The gas transient flow feasibility check only verifies whether enough line pack resources and transportation capacities exist to support the ISO's committed gas-fired units. If the gas transmission feasibility check is feasible, then the solution of SCUC will be firmed and the gas transmission system operator will continue to schedule compressors, storages, and line pack resources by minimizing the operating cost of compressors.

Least Social Cost of Coordinated Scheduling of Electric Power and Natural Gas Systems

The previous model considered the viewpoints of the ISO and vertically integrated utility operators. Furthermore, the operating costs of compressors, natural gas wells, and residual gas load models were not considered directly in the objective function.

A coordinated scheduling model from a joint operator's viewpoint is presented in this section. The coordination model is a mixed-integer nonlinear optimization problem in which the objective function will minimize the social cost of electric power and natural gas systems. Furthermore, our coordination model does not lay any particular emphasis or preference on either natural gas or electric power system. The outline of the coordination model is described as the following optimization problem.

Max social welfare or Min social cost
s.t.

- Power balance and reserve requirements
- Individual generator constraints (including min on/off time, min/max generation capacity, startup/shutdown characteristics, ramp rate limits, etc.)
- Power transmission constraints
- Gas source limits and gas storage constraints
- Natural gas network constraints
- Electricity-gas coupling constraints

$$\min_{x,y} EC(\boldsymbol{x}) + GC(\boldsymbol{y}) \tag{11}$$

$$s.t. \qquad \boldsymbol{EU}(\boldsymbol{x}) \le 0 \tag{12}$$

$$\boldsymbol{EN}(\boldsymbol{x}) \le 0 \tag{13}$$

$$\boldsymbol{e}(\boldsymbol{x}_c) - \boldsymbol{g}(\boldsymbol{y}_c) = 0 \tag{14}$$

$$\boldsymbol{GN}(\boldsymbol{y}) \le 0 \tag{15}$$

The joint operator is an independent organization that could operate outside the traditional jurisdictions of gas and electric power operators and would pursue the overall interest of coordinated energy systems. Natural gas resources will be allocated optimally either to supply gas loads or to gas-fired generating units. The two systems have a decomposable structure and people can consider the Lagrangian relaxation (LR) method as the decomposition strategy of the coordination problem.

The coupling constraints between the electric power system and the natural gas transmission system (Equation 14) is relaxed by Lagrangian multipliers and dualized into the objective function as shown in Equation 16.

$$\mathcal{L}(\boldsymbol{x}, \boldsymbol{y}, \lambda) = EC(\boldsymbol{x}) + GC(\boldsymbol{y}) + \lambda^T \boldsymbol{e}(\boldsymbol{x}_c) - \lambda^T \boldsymbol{g}(\boldsymbol{y}_c) \tag{16}$$

The LR method is divided into two phases. The first phase is to solve the dual problem.

The relaxed primal problem (Equations 11–15) is formulated in terms of minimizing the Lagrangian function subject to constraints (Equations 12, 13 and 15). $\phi(\lambda)$ in Equation 17 is defined as the Lagrangian dual function

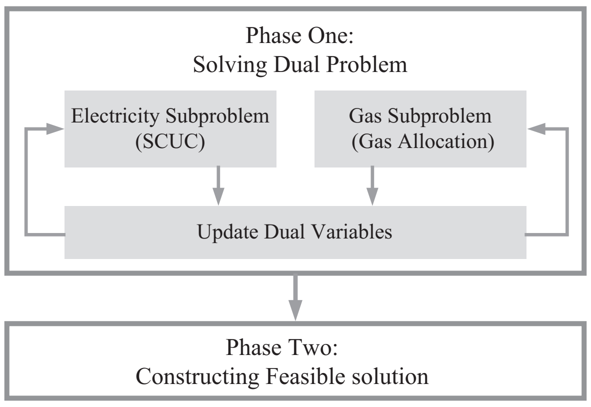

Figure 7. LR-based electricity-gas scheduling coordination.

with respect to λ.

$$\varphi(\lambda) = \operatorname*{Min}_{x,y} \left\{ \mathcal{L}(x, y, \lambda) | \text{ Equations 12, 13, and 15} \right\} \quad (17)$$

The resulting max–min problem is the following dual problem

$$\operatorname*{Max}_{\lambda} \operatorname*{Min}_{x,y} \left\{ \mathcal{L}(x, y, \lambda) | \text{ Equations 12, 13, and 15} \right\} \quad (18)$$

The difference between the optimal value of objective function of primal problem and dual problems (Equation 18) is the duality gap. In the convex case, the duality gap will be zero. In practice, most of the mathematical programming problems are nonconvex (47), such as hydrothermal coordination problem, LR-DP based unit commitment problem, and maintenance scheduling problem. The proposed gas-electricity coordination problem is also nonconvex, which is a result of the integer variables and transmission constraints.

For a given $\lambda^{(k)}$, the Lagrangian dual (Equation 17) of the primal problem is decomposed into independent SCUC and gas allocation subproblems as shown in Equations 19 and 20.

$$\operatorname*{Min}_{x} \left\{ EC(x) + \lambda^{(k)} \cdot e(x_c) | \text{ Equations 12 and 13} \right\} \quad (19)$$

$$\operatorname*{Min}_{y} \left\{ GC(y) - \lambda^{(k)} \cdot g(y_c) | \text{ Equation 15} \right\} \quad (20)$$

However, the solution of phase one may not be feasible when considering the primal problem. Thus, the phase two of the dual problem will seek a feasible solution based on the solution of phase one as shown in Fig. 7. The relaxed primal problems are decomposed into security-constrained unit commitment subproblem with the hydrocoordination (SCUC) and gas allocation subproblems, which can be solved independently but in coordination. The methodologies for SCUC and natural gas allocation problems were developed by Shahidehpour et al. (11), Wood and Wollenberg (12), and O'Neill et al. (15), which incorporate the LR framework in our proposed model to solve the mixed-integer nonlinear subproblems individually.

The LR method demonstrated a few drawbacks as follows. The nonconvex characteristics of our coordination problem with integer variables and nonlinear network constraints will create a large duality gap and make it difficult to find a good dual solution. Usually, a better dual solution with a lower degree of violation would result in a good optimal primal solution. Furthermore, the LR application in our case will cause oscillations in the solution of dual problem, which are caused by the linearity of the price function of gas wells, storage, or contracts. A similar phenomenon is recognized in the solution of hydrothermal coordination problem (50–53). In the Liu et al.'s (54) article, the augmented LR is used, which introduces penalty terms to smooth out the dual function and alleviate numerical oscillations. Here, we will not present the details of the algorithm.

The proposed model can be used by combination natural gas and electric utilities for the commitment and dispatch of power units, gas wells, compressors, and gas storage together. It can also be a theoretic foundation of forming regional joint operators to coordinate planning of coupled power and natural gas systems.

SUMMARY

The natural gas and electric power infrastructures are coupled with each other in time and space because of the increasing number of natural gas-fired power plants. To ensure more economical and secure services are provided to electricity and natural gas customers, it is envisioned that interdependent power and natural gas infrastructures need to consider an integrated approach for their operation and planning.

Discrete variables and nonlinear network formulations may bring difficulties to the solution of integrated models. In this dissertation, it has been shown that decomposition methodologies can be applied to integrated optimization problems to avoid the computational complexity when solving the proposed large-scale optimization problem with complex coupled infrastructures.

Electricity and natural gas energy are transported through infrastructures by different ways and time frames. Both steady-state and transient-state formulations of natural gas transmission system are applied in the integrated scheduling model. Compared with the steady-state model, the transient-state model can result in more accurate results especially for high-pressure interstate pipelines, but it requires longer computing time and more computing resources.

In the future, the focus would be on studying the long-term interdependency and reliability model of electricity and natural gas infrastructures on the foundation of short-term operation models.

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