

Integrated Coordination Scheduling Framework of Electricity-Natural Gas Systems Considering Electricity Transmission $N-1$ Contingencies and Gas Dynamics

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Abstract—This paper discusses a security-constrained integrated coordination scheduling framework for an integrated electricity-natural gas system (IEGS), in which both tight interdependence between electricity and natural gas transmission networks and their distinct dynamic characteristics at different timescales are fully considered. The proposed framework includes two linear programming (LP) models. The first one focuses on hourly-based steady-state coordinated economic scheduling on power outputs of electricity generators and mass flow rates of natural gas sources while considering electricity transmission $N-1$ contingencies. **Using the steady-state mass flow rate solutions of gas sources as the initial value**, the second one studies second-based slow gas dynamics and optimizes pressures of gas sources to ensure that inlet gas pressure of gas-fired generator is within the required pressure range at any time between two consecutive steady-state scheduling. The proposed integrated scheduling framework is validated via an IEGS, consisting of an IEEE 24-bus electricity network and a 15-node 14-pipeline natural gas network coupled by gas-fired generators. Numerical results illustrate effectiveness of the proposed framework in coordinating electricity and natural gas systems as well as achieving economical and reliable operation of IEGS.

Index Terms—Gas dynamics, integrated electricity-natural gas system, $N-1$ contingency, optimization, scheduling

NOMENCLATURE

Indices and Sets:

b	Index of electric buses
i, j	Index of coal-fired or gas-fired generators
k	Index of electricity transmission $N-1$ contingency events
l	Index of electricity transmission lines
m, n	Index of gas nodes in natural gas network
s	Index of gas nodes with gas sources
t	Time index of second-based optimization of gas source pressures considering slow gas dynamics
CG	Set of coal-fired electric generators
CE	Set of electricity transmission $N-1$ contingency events
EB	Set of electric buses
ED	Set of electricity demand nodes
EL	Set of electric transmission lines
GD	Set of generation gas demand nodes
GG	Set of gas-fired electric generators
NGD	Set of non-generation gas demand nodes
T	Time index of hourly-based scheduling considering electricity transmission $N-1$ contingencies

Parameters:

α	Energy conversion coefficient of a gas-fired generator
β	Cost coefficient of a coal-fired generator
c_{GAS}	Cost coefficient of natural gas mass flow rate
d	Diameter of a natural gas pipeline (m)
r	Indicator of service status for an electricity transmission line (0: not in service; 1: in service)
x	Reactance of an electricity transmission line (p.u.)
A	Cross-sectional area of a natural gas pipeline (m ²)
L	Length of a natural gas pipeline (m)
$Pload$	Electricity demand (MW)

R^+	Maximum ramp up rate of an electricity generator (MW/h)
R^-	Maximum ramp down rate of an electricity generator (MW/h)
R^{SD}	Maximum shutdown ramp rate of an electricity generator (MW/h)
R^{SU}	Maximum startup ramp rate of an electricity generator (MW/h)
TD	Minimum down time of an electricity generator (h)
TU	Minimum up time of an electricity generator (h)

Superscripts and Subscripts:

P	Electricity production
SU	Startup of an electricity generator
SD	Shutdown of an electricity generator

Variables:

θ	Voltage angle of an electric bus (p.u.)
π	Gas pressure at a gas node (bar)
ρ	Density of natural gas (kg/m ³)
I	Binary unit commitment variable for an electricity generator (0: offline/down, 1: online/operational)
M	Natural gas mass flow rate (kg/s)
P	Electric active power generation (MW)
Pf	Power flow through an electricity transmission line (MW)
SD	Binary shutdown variable for an electricity generator (1: shutdown, 0: otherwise)
SU	Binary startup variable for an electricity generator (1: startup, 0: otherwise)

I. INTRODUCTION

NATURAL gas has become an important and promising alternative fuel for power systems, as compared to traditional fossil fuels such as coal or oil, owing to low pollutant emission, high energy conversion efficiency, and technology improvements of gas turbines. Indeed, **the total installed capacity of natural gas generators has been** continually increasing since the 1980s, which accounts for over 70% of total installed generation capacity in Qatar and Malaysia, about 40%-60% in Holland and Argentina, and about 20%-40% in Britain, Japan, and Italy now [1]-[2].

Consequently, natural gas network plays an increasingly significant role in the power system, and the growing reliance of the electricity grid on the natural gas network brings new challenges on **the secure operation of such an integrated electricity-natural gas system (IEGS)** [2]. Indeed, in traditional security-constrained optimal operation of the electricity grid, **fossil and/or oil fuel supplies** to generation units are considered sufficient; however, in the IEGS, the availability and adequacy of just-in-time natural gas delivery is critical to ensure power system reliability [3]-[5]. To this end, coordinated security-constrained scheduling problem while considering interdependence of the two systems is in urgent need for the reliable and economic operation of the IEGS.

In recent years, some studies on the interdependence and coordinated scheduling strategy of the IEGS have been carried out. A coordinated operation strategy for the short-term scheduling of IEGS was introduced in [6] while considering demand response and wind uncertainty. A coordinated stochastic model was proposed in [7] to study the interdependence of IEGS and analyze the impact of random contingencies on power system operations. A short-term robust operation model of IEGS was proposed in [8], in which the electricity generation and natural gas allocation

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were co-optimized, while providing robust feasible controls over a range of possible contingency scenarios. A robust scheduling model for the wind-integrated IEGS was developed in [9], with the considerations of both gas pipeline and power transmission $N-1$ contingencies. A security-constrained economic dispatching for IEGS was introduced in [10], in which economic supplies for both natural gas and electricity systems were dispatched simultaneously due to their firm interconnections. A security-constrained optimal power flow and natural gas flow model was formulated in [11], in which a contingency analysis for natural gas system was developed via linear sensitivity factors. It is noteworthy that above existing researches on the security-constrained coordinated scheduling for IEGS only consider steady-state network constraints of the natural gas network, while neglecting distinct time constants of the electricity and natural gas systems. Thus, they may result in suboptimal or even infeasible coordinated scheduling of the IEGS.

Indeed, the significant difference in response speed between electricity and gas energy infrastructures, varying from millisecond to hours [5], imposes great challenges in exploring their interdependency. On one hand, time dynamic of electricity power is negligible since transiting from one steady state to another can be accomplished at the speed of light, i.e. a new electricity steady-state can be reached almost instantaneously from a previous one [12]. On the other hand, the change in steady-state operation of the electricity system may be propagated to the gas network [13]-[14] through coupling components, such as gas-fired generators, which would cause slow dynamic changes of mass flow rates and pressures within gas pipelines. Consequently, dynamic models of the natural gas network is needed to simulate transient flow characteristics once a new electricity steady-state arises, and dynamics of different time-scales for the gas and electricity networks need be considered properly.

Recently, the impacts of gas dynamics, such as linepack, on the short-term operation has attracted widespread attention. The linepack is defined as the total mass of gas contained in gas pipelines, resulted from the compressibility of natural gas as the energy transmission media. Indeed, different from the electricity transmission network, pipelines of the gas network not only deliver gas, but also play the role of storage due to the compressibility and storability of gas. In this paper, when gas supply and demand mismatch happens, the gas demand could be potentially satisfied by consuming linepack. A coordinated scheduling model of IEGS with transient-state formulation of the natural gas network was proposed [5]. The transient gas flow and steady-state power flow were adopted in [15] to formulate dynamic optimal energy flow of IEGS. By analyzing both steady-state and transient gas flows, a methodology was proposed in [16] to quantify flexibility of the gas network brought to the power system. A mixed-integer linear programming (MILP) formulation of IEGS was developed in [17] while taking into account gas traveling velocity and adequacy of gas for assuring power system reliability. In fact, as gas dynamics are quite complex and usually described by partial differential equations, various simplifications and approximations have been applied to analyze gas dynamics, attempting to solve the coordinated gas and power networks via more efficient linear models [18-20].

To the best of the authors' knowledge, very limited publications present solutions to the security-constrained scheduling of IEGS with $N-1$ contingencies of the electricity network, while also integrating dynamic model based gas transmission scheduling to ensure adequate gas supply to gas-fired generators.

In order to bridge the gap, this paper develops a general linear programming (LP) based coordinated optimal scheduling framework for IEGS, in which economic steady-state operations in terms of power outputs of electricity generators and mass flow rates at gas source nodes are scheduled at an hourly-basis, while considering supply and demand balance of electricity and gas energy as well as electricity transmission $N-1$ contingencies. Moreover, in the natural gas network, in addition to mass flow rates of gas sources, gas pressures at gas source nodes are also optimized in a second-basis to maintain required outlet pressure ranges at gas load nodes, in which gas dynamics is represented by Wendroff difference approximation. That is, the optimal gas source pressure scheduling problem covers the time period between two consecutive steady-state schedules, to accurately describe slow gas transient characteristics.

The major contributions of this work are twofold:

- (i) Considering the inertia of gas transmission network, dynamic model of the gas transmission system, together with $N-1$ electricity transmission contingency, is included in the security-constrained scheduling of IEGS, aiming at guaranteeing the adequacy of gas supply when $N-1$ transmission contingency occurs. Indeed, in the IEGS, the change in states of the electricity network will propagate to the gas network through coupling components. However, due to the inertia of gas transmission, the induced state evolution process in the gas network could last for a non-ignorable longer time period. Thus, dynamic model of the gas transmission system can accurately describe the transition process when the electricity transmission $N-1$ contingency occurs.
- (ii) Minimizing pressures at gas source nodes is considered via an LP problem in the second optimization stage of the IEGS security-constrained scheduling framework with $N-1$ electricity transmission contingency, which would derive optimal linepack to ensure the required inlet pressures of gas-fired generators at terminal nodes of pipelines. Indeed, as natural gas flow through a gas pipeline is driven by the pressure difference between two adjacent nodes, a same mass flow rate could correspond to various pairs of gas source pressures as long as the relationship between mass flow rate and the squared pressure drop is satisfied. Thus, this LP problem calculates optimal pressures of source nodes at second timescale, while satisfying pressure constraints of non-generation and gas-fired generators nodes.

The remaining paper is organized as follows. The integrated coordination scheduling framework of IEGS considering $N-1$ contingencies of the electricity network and gas dynamics is presented in Section II. Section III describes detailed formulations of the hourly-based optimal steady-state economic scheduling and the second-based optimal gas pressure scheduling while considering slow gas dynamics between two consecutive steady-state points. Simulation results and discussions are given in Section IV, and the conclusions are drawn in Section V.

II. INTEGRATED COORDINATION SCHEDULING FRAMEWORK CONSIDERING TRANSMISSION $N-1$ CONTINGENCIES AND GAS DYNAMICS

When an $N-1$ contingency in the electricity transmission network occurs, the transition process in the electricity system can be finished instantaneously, i.e., time duration of the transition process can be neglected. However, due to large inertia of the gas transmission network, the relatively long transition process should be considered to describe how the gas system gradually evolves from one state to another, induced by electricity transmission $N-1$ contingency. To this end, a second-based scheduling is necessary for analyzing and optimizing transition process of the gas network. Therefore, in order to investigate the integrated coordination scheduling in IEGS with electricity transmission $N-1$ contingency, the two-timescale scheduling framework including hourly and second timescales is proposed to solve the problem.

The proposed integrated coordination scheduling framework for IEGS while considering electricity transmission $N-1$ contingencies and gas dynamics is depicted in Fig. 1, which includes two optimization models at hourly and second resolutions. Specifically, the upper section of Fig. 1 describes the coordinated scheduling optimization model of IEGS considering electricity transmission $N-1$ contingencies, through which the optimal steady-state operating points, including power outputs of electric generators and mass flow rates of gas sources, are derived. The objective of this hourly-based steady-state coordinated scheduling optimization model is to minimize the total operation costs, while considering unit commitment constraints, electricity network security constraints with electricity transmission $N-1$ contingencies, and natural gas mass flow rates constraints.

The steady-state solutions of gas source mass flow rates acquired from the hourly-based model of Fig. 1 are inputs to the second-based model of Fig. 1, acting as initial values at the beginning of the hour. The second-based model further optimizes gas source pressures for the time period between two consecutive steady-state schedules, with the consideration of the slow gas transient characteristics. In the natural gas network, pressure is also an important variable besides mass flow rate. Indeed, natural gas flow through a gas pipeline is driven by the pressure difference between two adjacent nodes, while a same mass flow rate could correspond to various pairs of gas source pressures as long as the relationship between mass flow rate and the squared pressure drop is satisfied. Moreover, gas pressure loss occurs along the pipeline, while certain gas loads, especially gas-fired generators, require a certain gas pressure range to sustain their normal operations. Thus, gas source pressure optimization also plays a critical role in the IEGS operation, including maintaining desired outlet pressures and gas flow characteristics. Consequently, after gas mass flow rates are optimized via the steady-state security-constrained coordination scheduling to guarantee the optimal operation of gas-fired generators, another scheduling is implemented to ensure that inlet pressures of gas-fired generators at terminal nodes of pipelines are within required pressure ranges. Specifically, in optimizing gas source pressures, gas transmission dynamics are considered to ensure that gas-fired generators can be supplied with adequate natural gas and

under required operational pressures at any time between two consecutive IEGS steady-state schedules.

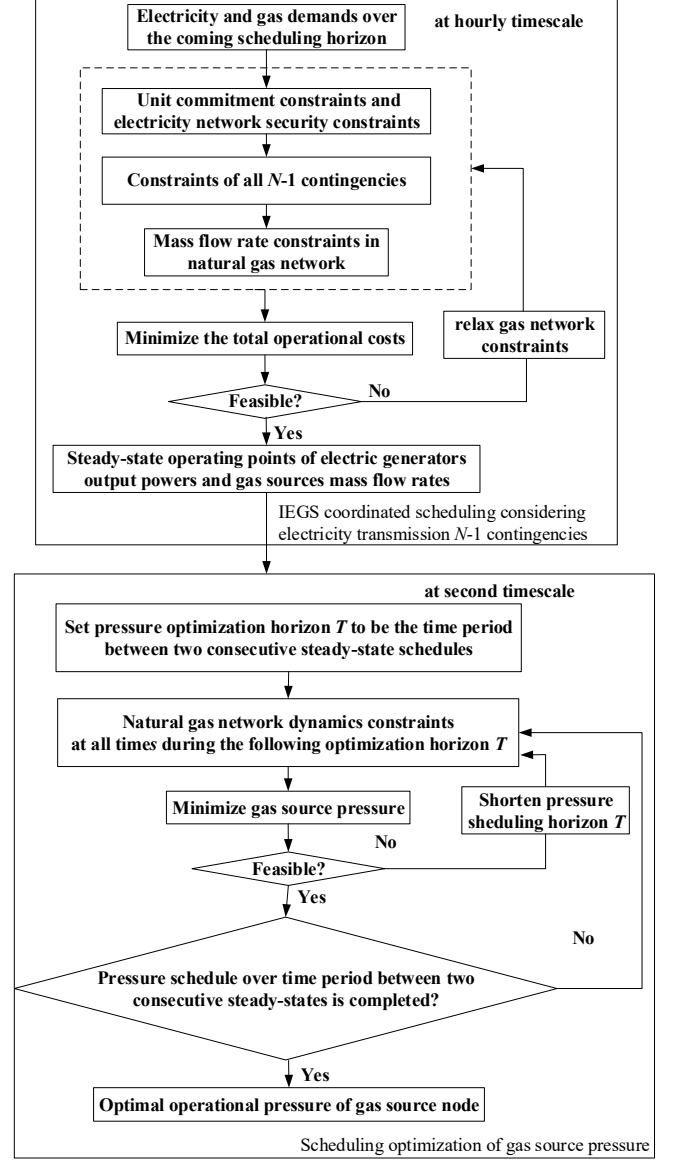


Fig. 1. Flowchart of the proposed integrated coordination scheduling framework.

Linepack storage in gas network infrastructure can provide major flexibility and reliability to the natural gas system. Thus, gas source pressures can be raised to increase the linkpack, which can be used later to supply the desired mass flow rate within the required pressure range of load nodes even when the supply/demand balance of mass flow rates cannot be achieved. Consequently, if the coordinated scheduling optimization is infeasible due to limited gas sources mass flow rates, natural gas mass flow rates constraints are relaxed to derive the steady-state points of the electricity system. As a result, it is possible that the gas source pressure optimization is infeasible because of the violation on gas source pressure limits. If this happens, we could shorten the scheduling horizon of the gas source pressure optimization problem to make it feasible, and repeat it multiple times to over the entire time period between two consecutive steady-state schedules.

Fig. 2 further shows the rolling based implementation of the proposed integrated coordination scheduling framework for IEGS. That is, the coordinated scheduling optimization

model with $N-1$ contingencies aims to derive hourly operating points for power outputs of electricity generators and mass flow rates at gas source nodes over the next NT hours, and the optimal scheduling of gas source pressures is further used to determine pressures at gas source nodes for every second of the next 1h. After both of them are executed, the integrated coordination scheduling framework is shifted forward by 1 hour.

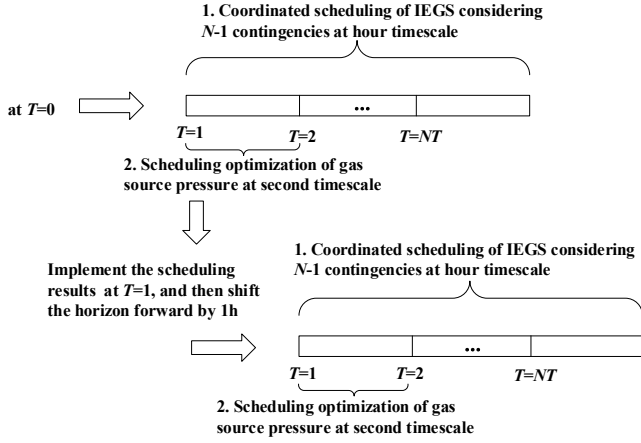


Fig. 2. Rolling based implementation of the proposed integrated coordination scheduling framework.

III. FORMULATION OF THE INTEGRATED COORDINATION SCHEDULING FRAMEWORK CONSIDERING TRANSMISSION $N-1$ CONTINGENCIES AND GAS DYNAMIC

In this paper, the electricity and gas sub-systems are considered to be coupled via gas-fired generators to constitute an IEGS. That is, electricity demands in the IEGS are satisfied by gas-fired generators and coal-fired generators through the power network, while non-generation and generation gas demands are satisfied by gas sources through the gas network.

A. Hourly-Based Coordinated Scheduling of IEGS Considering Electricity Transmission $N-1$ Contingencies

For an IEGS, the proposed hourly-based security-constrained coordinated scheduling is implemented over a NT -hour time horizon to minimize total system operation costs while satisfying **operation constraints** and electricity transmission $N-1$ contingencies. The objective is described in (1), including production costs, startup costs, and shutdown costs of coal-fired generators as well as natural gas production costs from gas source nodes.

$$\begin{aligned} \min c_{\text{GAS}} \sum_{T=1}^{NT} \sum_s M_s(T) &+ \sum_{T=1}^{NT} \sum_{i \in CG} \beta_i^P P_i(T) \\ &+ \sum_{T=1}^{NT} \sum_{i \in CG} \beta_i^{\text{SU}} \text{SU}_i(T) + \sum_{T=1}^{NT} \sum_{i \in CG} \beta_i^{\text{SD}} \text{SD}_i(T) \end{aligned} \quad (1)$$

Operation constraints are discussed as follows.

1) Unit Commitment Constraints

Minimum and maximum operating levels of coal-fired and gas-fired generators are presented as in (2).

$$I_i(T)P_i^{\min} \leq P_i(T) \leq I_i(T)P_i^{\max}, i \in CG \cup \dots \quad (2)$$

Minimum up and down time constraints are imposed as in (3) and (4).

$$\sum_{\tau=\max\{1, T-TU_i+1\}}^T \text{SU}_i(\tau) \leq I_i(T), i \in CG \cup \dots \quad (3)$$

$$\sum_{\tau=\max\{1, T-TD_i+1\}}^T \text{SD}_i(\tau) \leq 1 - I_i(T), i \in CG \cup \dots \quad (4)$$

Ramping constraints are given in (5) and (6), including startup and shutdown ramp rates that might be different from ramp up/down rates.

$$P_i(T) - P_i(T-1) \leq R_i^+ I_i(T-1) + R_i^{\text{SU}} \text{SU}_i(T), \quad i \in CG \cup \dots \quad (5)$$

$$P_i(T-1) - P_i(T) \leq R_i^- I_i(T) + R_i^{\text{SD}} \text{SD}_i(T), \quad i \in CG \cup \dots \quad (6)$$

The logic constraints among binary unit commitment variables, startup variables, and shutdown variables are modeled as in (7) and (8).

$$0 \leq \text{SU}_i(T) + \text{SD}_i(T) \leq 1, i \in CG \cup \dots \quad (7)$$

$$I_i(T) - I_i(T-1) = \text{SU}_i(T) - \text{SD}_i(T), \quad i \in CG \cup \dots \quad (8)$$

2) Electricity Network Security Constraints

The supply and demand balance of electricity power is described as follows:

$$\sum_{b \in ED} P_{\text{load}_b}(T) = \sum_{i \in CG \cup} P_i(T), T = 1, \dots \quad (9)$$

Binary parameter r_l^k is introduced to describe status of transmission line l in an electricity transmission $N-1$ contingency k . That is, $r_l^k = 0$ represents the outage of transmission line l , and $r_l^k = 1$ indicates its normal operation state. For $N-1$ contingency k in which the k -th transmission line fails, the parameters are defined as

$$r_l^k = 0, \text{ if } l = k \text{ and } r_l^k = 1, \text{ otherwise, } l \in EL, k \in CE \quad (10)$$

DC power flow $Pf_l^k(T)$ through transmission line l in an electricity transmission $N-1$ contingency k is modeled as in (11)-(12).

$$Pf_l^k(T) - \frac{\Delta\theta_l^k(T)}{x_l} - (1 - r_l^k) \cdot ML \leq 0, \quad l \in EL, k \in CE, T = 1, \dots \quad (11)$$

$$Pf_l^k(T) - \frac{\Delta\theta_l^k(T)}{x_l} + (1 - r_l^k) \cdot ML \geq 0, \quad l \in EL, k \in CE, T = 1, \dots \quad (12)$$

In (11)-(12), ML is the “big M” value. When $r_l^k = 1$, (11) and (12) degrade to an equality constraint, i.e. traditional power flow constraint through line; when $r_l^k = 0$, the value of ML is chosen large enough to ensure that (11) and (12) are satisfied regardless of difference of the two bus angles $\Delta\theta_l^k(T)$.

Power flow through transmission line l is subject to the thermal limits of transmission capacity.

$$-r_l \cdot Pf_l^{\max} \leq Pf_l^k(T) \leq r_l \cdot Pf_l^{\max}, \quad l \in EL, k \in CE, T = 1, \dots \quad (13)$$

Voltage phase angles of electricity nodes are also constrained by their upper and lower limits.

$$\theta_{\min} \leq \theta_b^k(T) \leq \theta_{\max}, b \in EB, k \in CE, T = 1, \dots \quad (14)$$

3) Gas Supply-Demand Balance and Mass Flow Rate Limits

Natural gas-fired generators couple the two interdependent systems. Natural gas consumption of a gas-fired generator is represented as in (15), **including gas consumptions for startup, shutdown, and electricity production operations, where α_j^p , α_j^{su} , and α_j^{sd} are constant energy conversion coefficients.**

$$M_j(T) = \alpha_j^p P_j(T) + \alpha_j^{su} S U_j(T) + \alpha_j^{sd} S D_j(T), T = 1, \dots \quad (15)$$

Supply and demand balance of gas mass flow rate at steady state is considered as follows:

$$\sum_{n \in NGD} M_n(T) + \sum_{j \in GG} M_j(T) = \sum_s M_s(T), T = 1, \dots \quad (16)$$

Mass flow rate at each gas source is constrained by its upper limit:

$$0 \leq M_s(T) \leq M_s^{\max}, T = 1, \dots \quad (17)$$

In summary, the security-constrained coordinated scheduling of IEGS considering electricity transmission $N-1$ contingencies is formulated as an MILP problem, including objective (1) and constraints (2)-(17). By solving the MILP problem, the steady-state operation points of electricity generators as well as mass flow rates of natural gas sources are optimized.

B. Second-based Optimal Scheduling Model of Gas Source Pressures Considering Gas Dynamics

The above IEG coordinated scheduling model with electricity transmission $N-1$ contingencies optimizes gas mass flow rates required for the operation of gas-fired generators. In this section, based on the calculated gas mass flow rates, gas source pressures are further optimized to ensure that inlet pressures of gas-fired generators at terminal nodes of pipelines are within the required pressure range.

In the natural gas network, travelling time of gas mass from source nodes to load nodes is not negligible, and a much longer response time is needed to reach a new steady state. **Indeed, when gas supply-demand mismatch arises due to the scheduled higher power outputs of gas-fired generators, the corresponding gas network operation status is not a steady-state, and a gas dynamic model is needed.**

In order to represent dynamic characteristics of the gas network more practically after a new steady-state electricity transmission is reached, the basic principles of the fluid dynamics is used to describe gas transmission within pipelines.

The material-balance equation describes the conservation of mass in a pipeline as follows [15]:

$$\frac{\partial \rho}{\partial t} + \frac{\partial M}{A \partial x} = 0 \quad (18)$$

The momentum equation, also known as Navier-Stokes equation, describes the momentum transport in the continuum of natural gas. With proper assumptions, the equation can be simplified as in (19) [15], where **the value of friction factor λ is taken as 0.015.**

$$\frac{\partial M}{A \partial t} + \frac{\partial \rho}{\partial x} + \frac{\lambda}{2d} \frac{M^2}{\rho A^2} = 0 \quad (19)$$

Fluid dynamics (18) and (19) are partial differential equations, the solutions to which can be approximated by the Wendroff difference. Considering the relationship $\pi = c^2 \rho$ between pressure π and density ρ , where $c^2 = RTZ$ with gas constant $R=500$, temperature $T=273$ K, and

compressibility factor $Z=0.9$, constraints (18) and (19) can be reformulated as in (20) and (21), describing the dynamics of mass flow rates and pressures at two ends m and n of a pipeline mn . It can be seen that the mass flow rates and pressures of natural gas within a pipeline are spatiotemporally coupled.

$$\pi_{n,t+1} + \pi_{m,t+1} - \pi_{n,t} - \pi_{m,t} + \frac{\Delta t \cdot c^2}{L_{mn} A_{mn}} [M_{n,t+1} - M_{m,t+1} + M_{n,t} - M_{m,t}] = 0, t = 1, \dots \quad (20)$$

$$\frac{c^2}{A_{mn}} (M_{n,t+1} + M_{m,t+1} - M_{n,t} - M_{m,t}) + \frac{\Delta t}{L_{mn}} [\pi_{n,t+1} - \pi_{m,t+1} + \pi_{n,t} - \pi_{m,t}] + \frac{c^2 \lambda \Delta t \bar{\omega}_{mn}}{4d_{mn} A_{mn}} (M_{n,t+1} + M_{m,t+1} + M_{n,t} + M_{m,t}) = 0, t = 1, \dots \quad (21)$$

In (21), parameter $\bar{\omega}_{mn}$ is the average gas flow rate in m/s

$$\text{and can be calculated as } \bar{\omega}_{mn} = \frac{c^2}{2A_{mn}} \left(\frac{M_{m,t}}{\pi_{m,t}} + \frac{M_{n,t}}{\pi_{n,t}} \right).$$

In addition, at an intersection where multiple nodes $m, m+1, m+2, \dots$ are connected, a consensus gas pressure and a balanced mass flow rate should be maintained. Thus, the boundary conditions are imposed as follows:

$$\pi_{m,t} = \pi_{m+1,t} = \pi_{m+2,t} \dots, \quad \dots \quad (22)$$

$$\frac{M_{m,t}}{A_m} + \frac{M_{m+1,t}}{A_{m+1}} + \frac{M_{m+2,t}}{A_{m+2}} \dots, \quad \dots \quad (23)$$

Mass flow rates at both generation and non-generation gas load nodes are assumed to be constant during the scheduling horizon as follows:

$$M_{n,t} = M_{n,t+1}, t = 1, \dots \quad \cup \quad (24)$$

In the gas network, mass flows and pressures should meet their upper and lower limits (25)-(26). Constraint (26) also includes limits on gas inlet pressures to gas-fired generators.

$$-M_m^{\max} \leq M_{m,t} \leq M_m^{\max}, t = 1, \dots \quad (25)$$

$$\pi_m^{\min} \leq \pi_{m,t} \leq \pi_m^{\max}, t = 1, \dots \quad (26)$$

A higher gas source pressure could potentially raise the operation cost of preceding compressor. Consequently, the aim is to search for minimal gas source pressures implemented at the start of scheduling horizon, while ensuring that inlet pressures of gas-fired generators can keep within the required range during the pressure optimization period. The objective is to minimize pressures at source nodes as in (27), where parameters α_s is cost coefficient.

$$\min \sum_s \alpha_s \pi_{s,1} \quad (27)$$

In the gas source pressure optimization, the scheduling horizon is initially chosen to span the time period between two consecutive steady-state scheduling, i.e. 1h. If the pressure scheduling optimization is unfeasible, the scheduling horizon will be shortened to make the problem feasible, and the pressure optimization is repeated multiple times to cover the entire period of 1h. In (20) and (21), time step Δt of the gas dynamics simulation is chosen as 100s and Nt is the total number of time instants for optimizing gas source pressures, decided by Δt and the length of scheduling horizon.

When considering the natural gas dynamics, pressures and mass flow rates at the two ending nodes of a pipeline are different. Moreover, their values at time t may be different from those at time $t+1$. Thus, 8 continuous variables $\pi'_{i,t}$, $M'_{i,t}$, $\pi'_{j,t}$, $M'_{j,t}$, $\pi'_{i,t+1}$, $M'_{i,t+1}$, $\pi'_{j,t+1}$, and $M'_{j,t+1}$ are needed to describe a pipeline with two end nodes i and j at two successive time points. The second-based scheduling optimization problem for the entire hour (i.e., 36 time points when considering 100s for each time step) is formulated as an LP problem (20)-(27), which can be solved by CPLEX in one shot. For instance, for the test IEGS system studied in Section IV, the second-based scheduling problem includes 4256 variables and 4218 equality constraints. The optimization problem calculates the minimal gas source pressures to ensure that inlet pressures of gas-fired generators will meet the operation requirements.

IV. SIMULATION RESULTS

The IEGS shown in Fig. 3 is used to illustrate effectiveness of the proposed security-constrained integrated coordination scheduling framework. As shown in Fig. 3, the IEGS is composed of a 15-node, 14-branch natural gas network and an IEEE 24-bus, 35-branch electricity network. The natural gas system includes 2 sources at nodes 1 and 15, 4 non-generation sink nodes 4, 7, 12, and 14, and 2 gas-fired generators at nodes 8 and 10. The electricity network includes 8 coal-fired generators and 2 gas-fired generators. The operating pressure range of gas-fired generators is [19.74, 20.00] bar. Active power flow limit of each transmission line is set as 250MW.

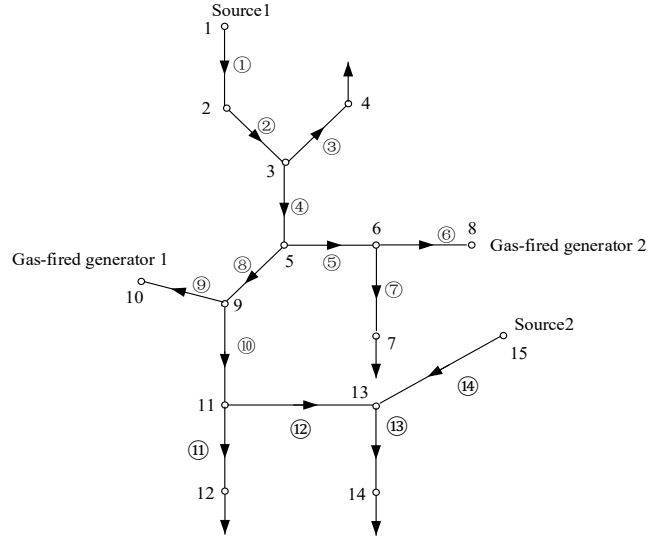
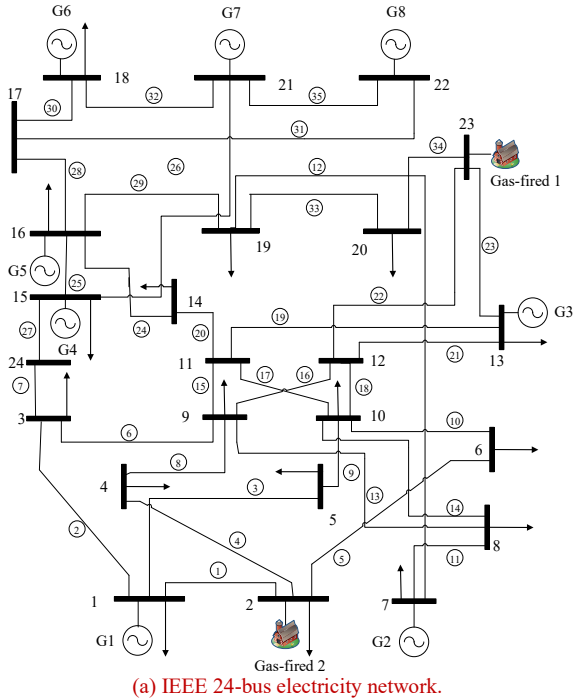


Fig. 3. Natural gas network and electricity network in IEGS.

A. Case 1

In this study, the daily electricity demand peak occurs at $T=9h$. Maximum mass flow rates of the two gas source nodes are set as 28 kg/s. The scheduling results of electricity generators during 8h-11h while considering electricity transmission $N-1$ contingencies are given in Fig. 4. The balance between supply and demand of electricity power is kept strictly. The scheduling results of natural gas mass flow rates are depicted in Fig. 5. Since upper limits on mass flow rates of gas sources are relative higher than the total gas demand, the balance between supply and demand of natural gas mass flow rate can be well achieved.

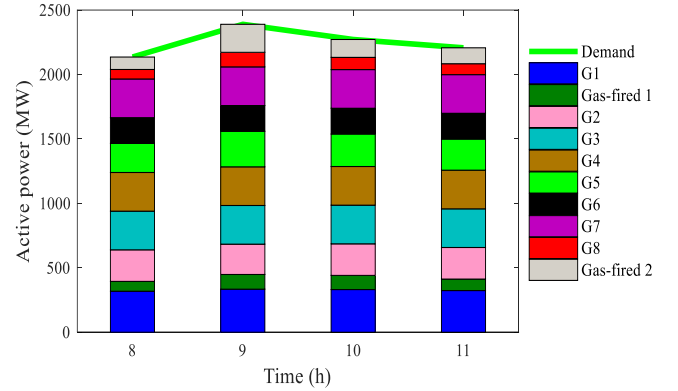


Fig. 4. Scheduling results of electricity generators considering transmission $N-1$ contingencies in Case 1.

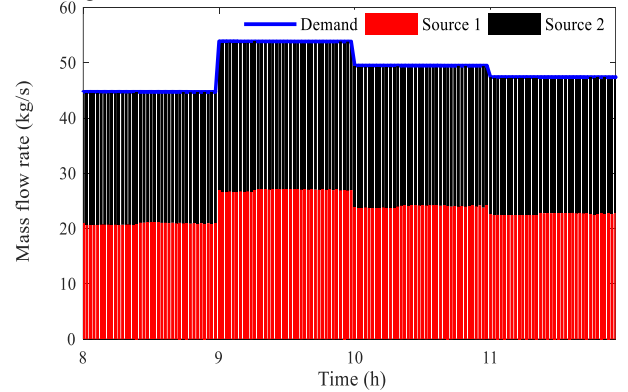


Fig. 5. Scheduling results of natural gas mass flow rates considering transmission $N-1$ contingencies and gas dynamics in Case 1.

Fig. 4 shows that, due to higher electricity demand at

$T=9h$, power output of gas-fired generator 2 at $T=9h$ has a sharp increase as compared to $T=8h$. As a result, mass flow rates at gas source nodes are also raised significantly to meet the growing generation gas demand as shown in Fig. 5.

Fig. 6 shows that at the beginning of each hour, the optimal pressure values at gas source nodes are reset. With the settings of scheduled gas source pressures, inlet pressures of gas-fired generators located at terminal nodes of pipelines can be maintained within the required range during the scheduled horizon and close to the required lower limits at the end of the horizon, which can ensure normal operation of gas-fired generators while also achieving the economic goal.

At $T=9h$, among all the 35 electricity transmission lines, lines 24, 26, 28, and 29 are the top four heavily loaded lines in the normal operation. Active powers of these four lines in individual $N-1$ contingency scenarios are depicted in Fig. 7. It shows that in each of the four $N-1$ contingency scenarios corresponding to outages of lines 24, 26, 28, and 29, power flow through one of these four top loaded lines approaches to its upper limit. This shows effectiveness of the proposed security-constrained scheduling approach against $N-1$ contingencies.

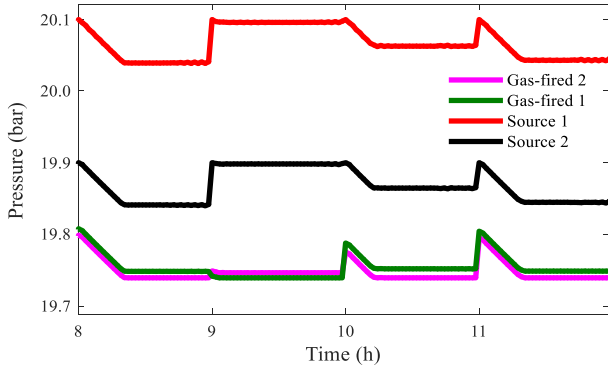


Fig. 6. Scheduling results of natural gas pressures in Case 1.

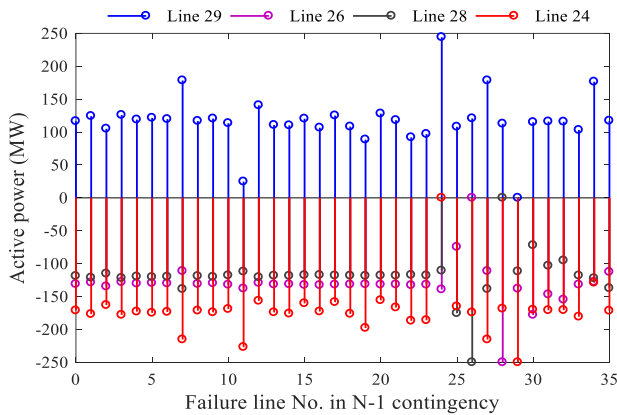


Fig. 7. Active power flow through the top loading lines at $T=9h$ after transmission $N-1$ contingencies in Case 1.

B. Case 2

In this case, the maximum mass flow rate at gas source nodes is reduced to 26 kg/s. At $T=9h$, this maximum gas source mass flow rate cannot meet the total generation and non-generation gas demands. As a result, no feasible solution can be achieved from the coordinated scheduling model with electricity transmission $N-1$ contingencies.

Considering that the linepack within gas pipelines can provide flexibility and reliability to the natural gas system, the scheduling of gas source pressures can help supply the desired mass flow rate to gas loads even when the balance

between supply and demand cannot be achieved.

The scheduling results of natural gas pressures from $T=8h$ to $T=12h$ are depicted in Fig. 8. The scheduling results of natural gas mass flow rates with $N-1$ contingencies and gas dynamics are depicted in Fig. 9. At the beginning of $T=8h$, 10h, and 11h, the increases in pressures at source nodes 1 and 15 are not very significant, since the balance between supply and demand during those three periods can be achieved by solely scheduling mass flow rates at gas source nodes. On the other hand, as shown in Fig. 9, during the periods 9h-10h, the total demand of mass flow rate is larger than its total supply. As a result, at the beginning of $T=9h$, pressures at gas source nodes have to be raised to a much higher level to ensure the desired mass flow rate to gas-fired generators with the required pressure levels.

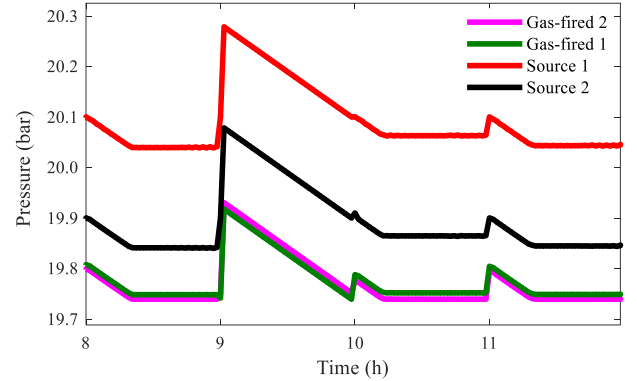


Fig. 8. Scheduling results of natural gas pressures in Case 2.

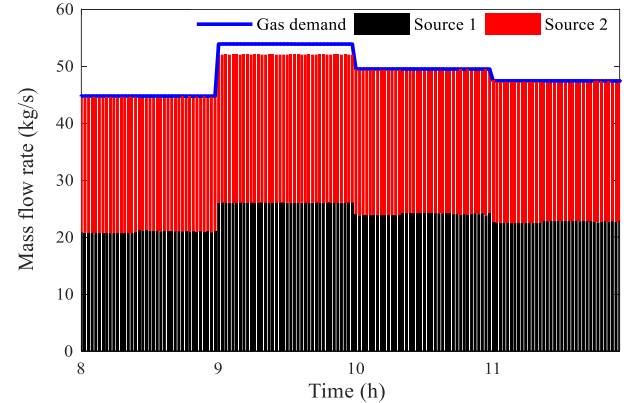


Fig. 9. Scheduling results of natural gas mass flow rates considering transmission $N-1$ contingencies and gas dynamics in Case 2.

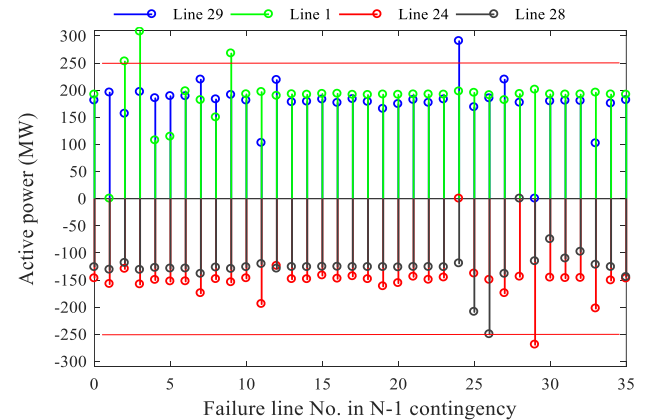


Fig. 10. Active power flow through the top loading lines at $T=9h$ after transmission $N-1$ contingencies when gas-fired generator 1 is off.

Indeed, if improper scheduling of gas source pressures is implemented that cannot guarantee required inlet pressures of gas-fired generators, forced outages of gas-fired generators may occur. At $T=9h$, when coal-fired generators

work at their scheduled operating points while gas-fired generator 1 is offline due to the lower inlet pressure, active power flows through lines 1, 24, 28, and 29 in individual transmission $N-1$ contingency scenarios are depicted in Fig. 10. As shown in Fig. 10, when line 24 fails, power flow through line 29 will significantly exceed its upper limit and the reliable operation of IEGS cannot be ensured.

C. Case 3

In this case, the electricity demand at $T=9h$ is increased by 2% compared with Case 2. With it, even if at the start of $T=9h$ we raise pressures at gas source nodes to elevate the inlet pressure of gas-fired generator to its upper limit, inlet pressure of gas-fired generators cannot be maintained within its required range during the following one hour due to the larger mass flow rate requirement. Consequently, in the gas source pressure scheduling optimization, the horizon is shortened to 0.5h, i.e., the pressure scheduling optimization is repeated twice in this hour.

The scheduling results of natural gas pressures and mass flow rates are depicted in Figs. 11 and 12. As shown in Fig. 11, comparing with Fig. 8, at the start of $T=9h$, the gas source pressures become higher to deal with the increased generation gas demand, and during 9h-10h the pressure optimization scheduling is implemented twice to ensure that inlet pressures of the two gas-fired generators are within the required range. The supply and demand imbalance of natural gas mass flow rate during 9h-10h still exists, and the mismatch is even larger than that in Case 2. Fig. 13 further shows that power flows through all electric branches are kept within their safe ranges under individual $N-1$ contingencies.

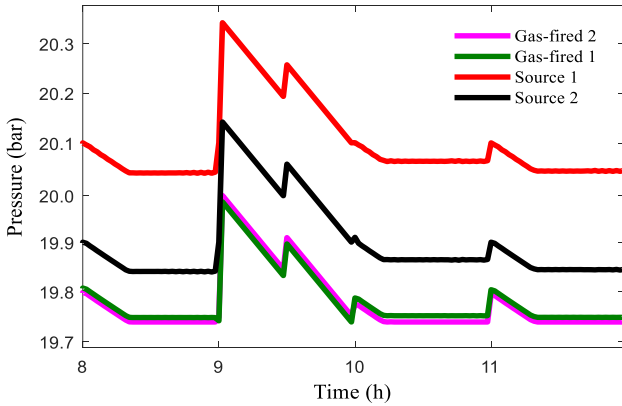


Fig. 11. Scheduling results of natural gas pressures in Case 3.

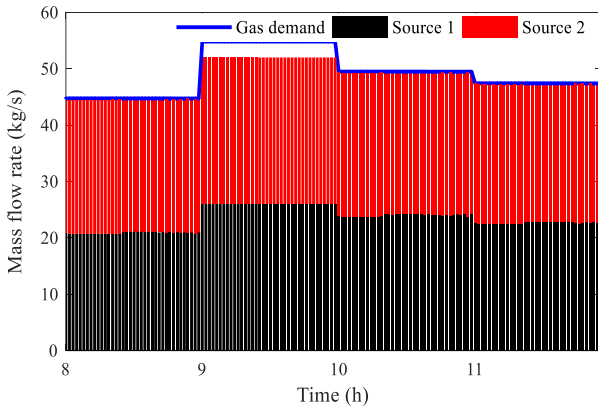


Fig. 12. Scheduling results of natural gas mass flow rates considering transmission $N-1$ contingencies and gas dynamics in Case 3.

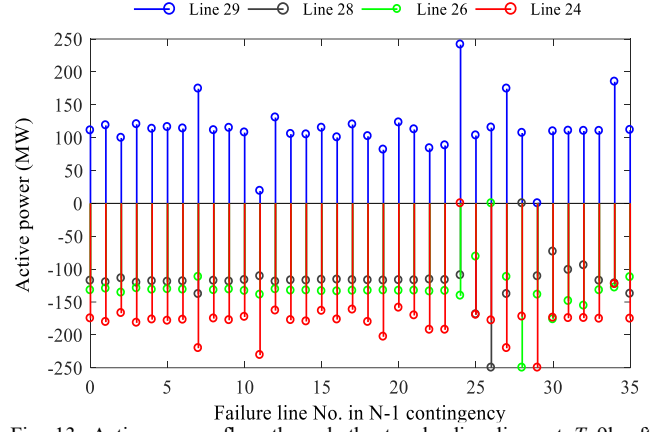


Fig. 13. Active power flow through the top loading lines at $T=9h$ after transmission $N-1$ contingencies in Case 3.

D. Discussion

Detailed results of the three cases at $T=9h$ are listed in Table I for further discussion. In Case 1, the balance between supply and demand of mass flow rate can be achieved by adjusting gas source mass flow rates. In comparison, demand-supply mismatch occurs in both Cases 2 and 3, while the mismatch in Case 3 is more significant. Indeed, with a larger demand-supply mismatch, pressures at gas source nodes become higher. This phenomenon can be understood as follows. When the demand of mass flow rate cannot be satisfied due to the gas source mass flow limits, a higher pressure at the gas source node is needed in order to utilize the compressibility of natural gas for providing more linepack in the pipeline, aiming at maintaining pressures at gas-fired generator nodes within the required range. Moreover, in all the three cases, the maximum power flows through electricity transmission lines after $N-1$ contingency are within their limits, showing effectiveness of the proposed approach.

Table I. Comparison among the three cases at $T=9h$

	Case 1	Case 2	Case 3
Maximum power flow after $N-1$ contingencies (MW)	-249.99	-249.00	-249.99
Mass flow rate unbalance (kg/s)	0	1.864	2.531
Pressure at gas source 1 (bar)	20.100	20.270	20.340
Pressure at gas source 2 (bar)	19.900	20.076	20.140

V. CONCLUSIONS

In this paper, a coordinated scheduling approach for IEGS is proposed, in which a security-constrained hourly-based steady-state economic scheduling on power outputs of electricity generators and mass flow rates of natural gas sources with electricity transmission $N-1$ is executed, followed by a second-based scheduling to optimize pressures of gas sources. The proposed scheduling approach can achieve the overall economic operation against electricity transmission $N-1$ contingencies, while ensuring that gas-fired generators can be supplied with the required natural gas pressures and mass flow rates. The two optimizations represent distinguished time constants of the two systems. If the balance between supply and demand of mass flow rate cannot be achieved due to gas source flow constraints, pressure scheduling can be utilized to handle the mismatch while guaranteeing inlet pressures of gas-fired generators within the required operating range, which shows the flexibility provided by linepack to the IEGS. Otherwise, low inlet pressure of gas-fired generators can cause generator outages, and lead to unreliable operation of the IEGS by

overloading electricity lines. In summary, the proposed approach offers a secure and economic solution to the coordinated scheduling of IEGS with electricity transmission $N-1$ contingencies.

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