Multi-Stage Flexible Expansion Co-Planning Under Uncertainties in a Combined Electricity and Gas Market

Jing Qiu, *Student Member, IEEE*, Zhao Yang Dong, *Senior Member, IEEE*, Jun Hua Zhao, *Member, IEEE*, Yan Xu, *Member, IEEE*, Yu Zheng, *Student Member, IEEE*, Chenxi Li, and Kit Po Wong, *Fellow, IEEE*

***Abstract*—Natural gas is an important fuel source in the power industry. Electricity and natural gas are both energy that can be directly consumed. To improve the overall efficiency of the energy infrastructure, it is imperative that the expansion of gas power plants, electricity transmission lines and gas pipelines can be co-planned. The co-planning process is modeled as a mixed integer nonlinear programming problem to handle conflicting objectives simultaneously. We propose a novel model to identify the optimal co-expansion plan in terms of social welfare. To evaluate the robustness of plans under different scenarios, the *flexibility* criterion is used to identify each plan's adaptation cost to uncertainties, such as demand growth, fuel cost and financial constraints, etc. We developed a systematic and comprehensive planning model to understand, develop and optimize energy grids in order to reach higher social welfare, and is therefore of great importance in terms of supporting and guiding investment decisions for the power and gas industry. Meanwhile, we use the *sequential importance sampling* (SIS) to perform scenario reduction for achieving a higher computational efficiency. A comprehensive case study on the integrated IEEE 14-bus and a test gas system is conducted to validate our approach.**

***Index Terms*—Co-optimization, flexibility, power system planning, risk management.**

Manuscript received April 20, 2014; revised July 31, 2014 and September 08, 2014; accepted September 09, 2014. Date of publication September 29, 2014; date of current version June 16, 2015. This work was supported in part by an ARC Grant LP110200957, National Natural Science Foundation of China (Key Project 71331001, General Project 51277016, General Project 71401017), State Key Laboratory of Alternate Electrical Power System with Renewable Energy Sources (Grant No. LAPS14002), and a CSIRO Future Grid flagship grant. Paper no. TPWRS-00539-2014.

J. Qiu, J. H. Zhao, and Y. Zheng are with the Center for Intelligent Electricity Networks (CIEN), The University of Newcastle, Callaghan, NSW2308, Australia (e-mail: qiujing0322@gmail.com; andy.zhao@newcastle.edu.au; zhy9639@hotmail.com).

Z. Y. Dong and Y. Xu are with the School of Electrical and Information Engineering, The University of Sydney, Sydney, NSW2006, Australia (e-mail: zydong@ieee.org; eeyanxu@gmail.com).

C. Li is with China Railway Communication and Signal Survey & Design (Beijing) Co. Ltd. China and also with the School of Electrical and Information Engineering, The University of Sydney, Sydney, Australia (e-mail: kky01@sohu.com).

K. P. Wong is with the School of Electrical, Electronics and Computer Engineering, University of Western Australia, Perth, WA6009, Australia (e-mail: kitpo@ieee.org).

Color versions of one or more of the figures in this paper are available online at http://ieeexplore.ieee.org.

Digital Object Identifier 10.1109/TPWRS.2014.2358269

Nomenclature

a_1, b_1, c_1	First, second, and third order coefficient of the utility function for the power sector.
a_2, b_2, c_2	First, second, and third order coefficient of the utility function for the gas sector.
C_i^{CG}	Capital asset of power generators at bus i.
C_{ij}^{CT}	Capital asset of power transmission line $i-j$.
C_{ij}^{CP}	Capital asset of gas pipe $i-j$.
$C_i^{O\&M}$	Operation cost of power generator i.
$C_i^{C,VO\&M}$	Variable operation cost of power generator i.
$C_i^{C,FO\&M}$	Fixed operation cost of power generator i.
EUE_{Max}	Maximum expected unserved energy (EUE).
M	Short-run planning horizons.
N	Total bus number.
N_G	Total bus number with power generators.
N_{GPG}	Total bus number with gas power generators.
O_{sc}	Measure of system reliability of each scenario.
P_{Gi}, Q_{Gi}	Generated active and reactive power at i.
P_i^{elec}, Q_i^{elec}	Active and reactive power demand at bus i.
P_i^{gas}	Gad demand at bus i.
$P_i^{gas,\sup}$	Gas supply at bus i.
r	Risk free interest rate.
$S_{ij}^{gas}, S_{ij}^{elec}$	Gas flow and power flow between $i-j$.
t	Time.
$t_i^{exist}, t_{ij}^{exist}$	Ages of existing asset at bus i or between $i-j$.
T	Total planning horizon.
V_i, V_n	Bus voltages with angles δ_i, δ_n at bus i and n, respectively.
W	Number of short-run planning horizons.
Y_{ii}, y_{ii}^0	New and old diagonal element of admittance matrix $\mathbf{Y}$.
Y_{ij}, y_{ij}^0	New and old non-diagonal element of admittance matrix $\mathbf{Y}$.

θ_{in}	Angle of admittance element Y_{in} in $\mathbf{Y}$.
ρ_i, ρ_j	Gas pressures at bus i or j.
Ψ_i^{Min}	Minimum percentages of gas and electricity demands that can be mutually transferred.
Ψ_i^{Max}	Maximum percentages of gas and electricity demands that can be mutually transferred.
sgn	Gas flow direction index.
Φ_{ij}	Flow constant depending on pipeline factors such as diameter, length, temperature, altitude and roughness, etc.
λ^{ge}	Conversion ratio from gas demand to electricity demand.
η_i^{GG}	Planning decision variable for gas power generator with type β^{GG} at bus i.
η_{ij}^{ET}	Planning decision variable for power transmission line with type β^{ET} between $i-j$.
η_{ij}^{GP}	Planning decision variable for gas pipe with type β^{GP} between $i-j$.
ξ^{gas}, ξ^{elec}	Maintenance factors of gas pipes and power lines.
$l_{ij}^{gas}, l_{ij}^{elec}$	Length for gas pipes and power lines $i-j$.
$\mathbf{C}^{C}$	Vector of capital cost.
$\mathbf{C}^{O\&M}$	Vector of operation and maintenance cost.
$\mathbf{C}^{FO\&M}$	Vector of fixed operation and maintenance cost.
$\mathbf{C}^{VO\&M}$	Vector of variable operation and maintenance cost.
$\mathbf{C}^{C,exist}$	Vector of capital cost of existing asset.
$\mathbf{P}^{elec}$	Vector of power demand.
$\mathbf{P}^{gas}$	Vector of gas demand.
$\mathbf{t}^{exist}$	Vector of ages of existing asset.
$\mathbf{Y}$	Admittance matrix.
$\boldsymbol{\tau}$	Vector of construction periods.
$\boldsymbol{\eta}$	Vector of decision variables, proposed at time $\mathbf{t}_{\boldsymbol{\eta}}$.
$\mathbf{U}$	Array of ones.

I. Introduction

UNDER the background of global concerns on climate change, natural gas consumption in power generation has been ascending as a result of carbon pricing policies around the world [1]. Natural gas is considered more economically competitive in a carbon-constrained world, because it has comparatively lower emission intensity among traditional fossil fuels [2], [3]. Plenty of research has predicted gas proliferation in power generation [1], [2], [4], [5]. This may imply that on the supply side, gas power plants tend to take higher share in the electricity market; on the demand side, consumers would diversify their energy use due to the increasing electricity price. More new gas power generators are expected to be built, which may possibly lead to insufficient gas supply and the possibility to send out generated power [6]. This challenge is a new topic about energy network congestion management and will require a great deal of effort and capacity building to strengthen and augment the existing energy network infrastructure.

Natural gas pipelines have similarities to the electricity network in transporting energy [7]. More importantly, due to the increasing market share of natural gas power generation, the natural gas system will significantly influence the efficiency and long-term supply adequacy of the power system. Therefore, it would be increasingly necessary to study the *expansion co-planning* (ECP) problem for gas and electricity networks. In general, the expansion planning of combined gas and electricity networks is of great importance as following:

- Facilitating market competition: The energy infrastructure are required to provide non-discriminatory access to all market participants [8], [9]. Despite the advantages of gas power generation, insufficient gas supply will obstruct its development in the electricity market. Therefore, building a reliable gas network can ensure fair market opportunity to gas power generation.
- Ensuring energy security: Coal is still the fuel that contributes the largest share of electricity generation around the world [1]. As gas gradually takes up more shares in base-load generation, coal price would have less impact on electricity prices.
- Protecting environment: Gas power plants produce lower carbon emission than coal power plants [2]. The social benefits can be assessed in a quantitative way in expansion co-planning [10].

The gas and electricity network co-planning is a relatively new and difficult problem. Firstly, gas and power systems are independent systems, but gas is an important fuel for power generation. In the literature, there are no commonly agreed objectives for ECP problem. Market benefit seems to be a reasonable measure applicable for both gas and electricity sectors. However, market benefits are hard to calculate with many stakeholders, such as generation companies, power and gas transmission companies, and independent system operators (ISOs). Secondly, in a deregulated power system, transmission network planners will face many uncertainties, including energy prices, load forecast inaccuracies, government policies etc. Because of uncertainties of expansion planning, it is crucial to cope with risks exposed uncertainties. When gas system models are taken into account, the dimensionality of ECP would be greatly increased. How to quantify and minimize planning risks becomes a key question, and it would be difficult for decision makers to select flexible and robust strategies. A measure called *adaptation cost* is appropriate for quantifying future uncertainties [9]. *Adaptation cost* is defined as the additional capital investments required for a proposed plan, if an unexpected scenario happens. References [9] and [11] have proved that flexible transmission expansion planning can better handle uncertainties, compared to traditional reliability-driven least-cost planning methods. Thirdly, ECP is a multi-objective optimization problem. Traditionally, minimizing expansion investments while fulfilling system reliability requirements are the major planning objectives [12], [13], so we have to reach a trade-off between minimum expansion investments and highest reliability. However, due to market deregulation, many planning objectives are conflicting [14] and cannot be satisfied simultaneously [15], [16].

Moreover, power and gas systems are coupled by two means: 1) gas is an important fuel for power generation; 2) electricity and gas demands can be transformed into each other in some circumstances [7], [17]. However, gas and power markets are coordinated by separate trading mechanisms. Some temporal mismatches of the two markets might result in unavailability of gas, then influencing the system reliability consequently. Therefore, at the expansion planning level, unilateral evaluations of expansion plans cannot reflect an integrated energy market. Although the two markets cannot totally merge together in the near future, it would be feasible to analyze the co-expansion planning once they have common investment stimulations and information exchange by a combined market operator. One good example is the Australian Energy Market Operator (AEMO) which focuses on delivering competitive and efficient electricity and gas markets and supports long-term investments in Australia. AEMO provides planning advice and facilitates energy infrastructure augmentation if network constraints/bottlenecks are identified. AEMO will facilitate third party asset owners to make final investment decisions and maintain their infrastructures [18].

In the literature, studies on joint electricity and gas system have focused on optimal operation planning. Many attempts have been made to optimize operation costs in an existing power system [19], [20]. Others have proposed an integrated generation and transmission expansion planning of power system. Reference [7] studied the gas transmission networks as a conceptual design case instead of an optimization problem. Reference [21] mainly focused on generation expansion considering emissions. Reference [22] optimized the generation and transmission expansion planning but fuels are only considered as constraints. Reference [5] discussed the value chain of natural gas and electricity, but fail to take into account the power system reliability and stability. To sum up, none of their efforts would allow a systematic investigation on the most economically efficient network configurations, enabling the electricity sector to make cost-effective investment decisions, which are required to successfully develop and evolve the future energy grid.

By contrast, this study is inspired by the concept of Transnational Asian Grid supported by Asian Development Bank. The Pan-Asian Energy infrastructure for the first time puts forward the idea of joint planning of primary and secondary energy networks [4]. In this paper, a novel flexible expansion co-planning (ECP) approach is proposed to address the above challenges and to bridge the gap between theoretical research and practical needs for future scenarios. The proposed approach is valuable in the context of efforts to involve parameters and variables of gas and power systems into a novel multi-stage co-optimization problem. Our major contribution is based on fulfilling system operating and planning criteria of the integrated behavior of a coupled energy grid. The integrated system expansion planning is capable of giving strategic augmentation recommendations to both sectors simultaneously. By simulating interacting operations of the two systems, this approach can effectively improve the network asset utilization. The development of co-planning model is aimed to guide the energy industry to form a holistic approach to supporting operating and planning decisions. Also, our integral perspective can effectively identify the energy infrastructure weakness, in order to enable safe and reliable energy supply in long-term while meeting the planning criteria and other characteristic requirements.

Our co-optimization model has adopted *a mixed integer nonlinear programming* approach. We define the social welfare as the main objective for ECP. Two stochastic processes, namely *geometric Brownian motion* and *mean reverting process* are employed to model uncertainties in long-term ECP including system load and market price. Each possible system state of a combined gas and electricity market is represented by a scenario. The Monte Carlo (MC) simulation is applied to create scenarios that simulate random system characteristics over a given planning horizon [23], [24]. Adaptation costs are calculated to quantify risks of uncertainties, in order to satisfy the flexibility criterion. To reach higher computation efficiency, the *sequential importance sampling* (SIS) is used for scenario reduction. We also suggest the use of a uniform reliability measure, i.e., *expected unserved energy* (EUE) for the two systems. The $\mathrm{N}-1$ power system security criterion is also considered.

The remainder of this paper is organized as follows. Section II describes the problem and key factors to be considered. The proposed ECP model is discussed in Section III, followed by a comprehensive study on IEEE 14-bus and a test gas system in Section IV. Section V concludes our paper.

II. Natural Gas Network Model

Expansion planning focuses on determining the locations and numbers of new transmission lines or generation units. This problem is usually solved by minimizing a cost function subject to power system technical constraints. It is well-known that $\dot{\mathbf{I}} = \mathbf{Y}\dot{\mathbf{V}}$ represents the relationship between voltage, current and admittance in the power system.

Usually, gas flows in a gas network is modeled with the *Newton loop-node method* [7], [25]. The *Bernoulli fluid equation* can be used to describe the steady-state flow of gas in pipelines, as Fig. 1 shows [25]. The relationship between pressure and gas volumetric flow is expressed by (1) and (2), subject to nodal balance constraints [7]:

$$S_{ij}^{gas} = \mathrm{sgn}\left(\rho_i,\rho_j\right) \cdot \Phi_{ij} \cdot \sqrt{\left|\rho_i^2 - \rho_j^2\right|} \tag{1.1}$$

$$\mathrm{sgn}\left(\rho_i,\rho_j\right) = \begin{cases} 1; & \text{if } \rho_i \geq \rho_j \\ -1; & \text{if } \rho_i < \rho_j \end{cases} \tag{1.2}$$

$$P_i^{gas,\mathrm{sup}} + \sum S_{ij}^{gas} = \sum S_{ji}^{gas} + P_i^{gas} \tag{2}$$

where

S_{ij}^{gas}	gas flow rate (m^3/s) between pipeline $i-j$;
sgn	gas flow direction index;
Φ_{ij}	flow constant depending on pipeline factors such as diameter, length, temperature, altitude and roughness, etc., as shown in Fig. 1;
ρ_i, ρ_j	nodal gas pressures;
$P_i^{gas,\mathrm{sup}}$	gas supply at bus i;
P_i^{gas}	gas demand at bus i.

The fluid equations describe the gravity of gas, the internal diameter and the length of a pipe, and the inlet and outlet absolute pressures. Those parameters reflect a gas transmission system's capacity to transport energy. The planning of gas networks will also involve uncertainties such as system load, availability of sources, lines and supportive facilities, installation/retirement/

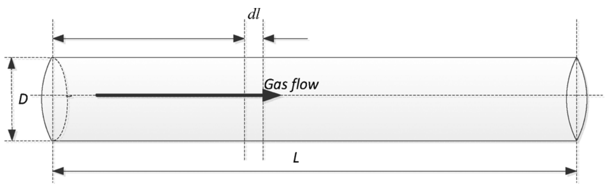

Fig. 1. Gas flow model.

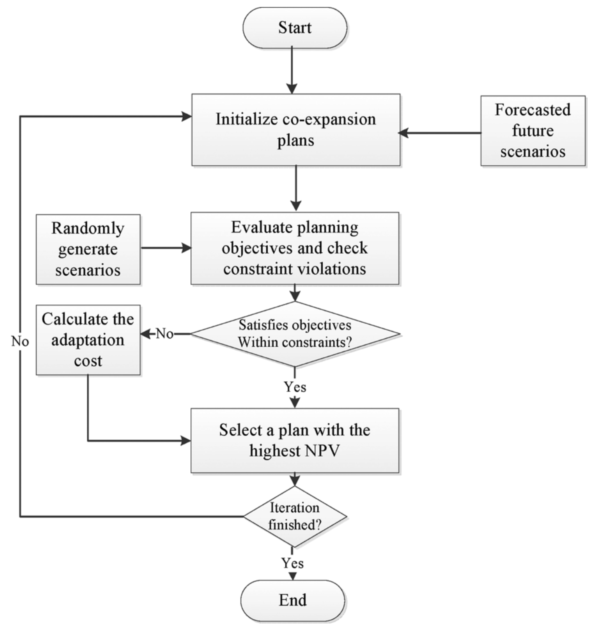

Fig. 2. Proposed co-planning method.

placement of grid facilities, energy prices, carbon costs, market game theories and government polices, etc. Expansion planning (EP) should also consider the distance between power plants and the fuel resources as well as the distance between power plants and load buses. To properly determine locations and capacity, future uncertainties should also be considered. Expansion planning results would be inappropriate if uncertainties are not well addressed. References [9] and [11] have applied the criterion of flexibility to evaluate the risks of a plan under various future scenarios.

III. Proposed Co-Planning Model

The proposed co-planning model is based on the assumption that there is a market operator managing gas and electricity markets like AEMO [18]. The main function of this combined gas and power market operator is to perform long term market forecasting and planning guidance. The major steps of the proposed co-planning method are given in Fig. 2. More information regarding adaptation costs can be found in [9].

A. Formulation of the Co-Planning Model

The objective of the co-planning model is to maximize the net present value (NPV) of the social welfare of the combined gas and power infrastructure subject to three constraints: reliability, security and flexibility [26], [27]. Our expansion options include types and locations of new gas power plants, gas pipelines and electricity transmission lines. A certain percentage of electricity and gas demand can be mutually transformed. For instance, a family can use either gas or electricity for heating. The utility function measures the benefits that will be received by consuming gas and electricity. The utility function is the sum of N quadratic functions of gas and electricity demands, $P^{elec,}$, P^{gas} as shown in (3), where a, b, and c denote the first, second, and third order coefficients. N is the total bus number. In this paper, alternating current (AC) power flow models are used. AC models have higher accuracy and can reflect the real situation of a power system, e.g., reactive power, voltage magnitude and transmission loss. Besides, since system planning is not a time critical problem, and with the development of high performance computers and modern power flow solution methods, solving AC flows is no longer a difficult problem:

$$f_1\left(\sum P_i^{elec}\right) + f_2\left(\sum P_i^{gas}\right) = \sum_{i=1}^{N}\left[\begin{array}{l} a_1 + b_1 P_i^{elec} + c_1\left(P_i^{elec}\right)^2 \\ +a_2 + b_2 P_i^{gas} + c_2\left(P_i^{gas}\right)^2 \end{array}\right]. \quad (3)$$

We assume that each expansion plan consists of a series of short-run planning horizons M with equal length. If the number of short-run planning horizons is denoted by W, the planning horizon is expressed as $T = WM$. Moreover, we assume that in each short-run horizon, the system planner design the plan for next horizon based on its corresponding forecasted load. Therefore, the planning becomes a "forecasting-optimizing-implementing" loop over time horizons. The social welfare is the result of the utility function minus supply costs. Supply costs are comprised of two parts: capital costs plus operation and maintenance costs. Systems components that have been taken into account are power plants, power transmission lines and gas pipes. Note that future values should be discounted. Asset values of components in the existing system are also discounted by their service ages. Depreciations of capital assets are expressed by exponential functions. Fig. 3 demonstrates the concepts of the present values of capital assets and the discounted cash flow.

New entries of gas power plants, power transmission lines and gas pipes are denoted by a decision vector $\boldsymbol{\eta}$. The detailed model is given in (4)–(15). Our model is to find the optimal co-expansion plan regarding time, location and type of new gas power plants, transmission lines and gas pipes under market uncertainties.

Maximize

$$\sum_{t=1}^{T}\left\{\begin{array}{c} \dfrac{\left[\begin{array}{l} \left(f_1(\sum \mathbf{p}^{elec}) + f_2(\sum \mathbf{p}^{gas})\right) 8760 \\ -\mathbf{C}^{C,exist}\exp\left(-r(\mathbf{t}^{exist} + t\mathbf{U})\right) \\ -\boldsymbol{\eta}\mathbf{C}^{C}\exp\left(-r(t\mathbf{U} - \mathbf{t}_{\boldsymbol{\eta}})\right) \\ -\mathbf{C}^{O\&M} \end{array}\right]}{(1+r)^t} \\ -\dfrac{\left(\boldsymbol{\eta}\mathbf{C}^{O\&M}\right)}{(1+r)^{t-\boldsymbol{\tau}}} \end{array}\right\} \quad (4)$$

$$\mathbf{C}^{O\&M} = \left(\mathbf{C}^{VO\&M}\mathbf{P}^{elec}\right) 8760 + \mathbf{C}^{FO\&M} \quad (5)$$

where $\mathbf{C}^{C}$ and $\mathbf{C}^{O\&M}$ are vectors of capital and operational & maintenance costs, including variable and fixed costs as shown in (5). r is the risk-free interest rate for discounted cash flows. $\boldsymbol{\eta}$ denotes the decision variables, and they are proposed at time $\mathbf{t}_{\boldsymbol{\eta}}$. $\mathbf{t}^{exis}$ denotes the ages of the existing system components in service. Construction periods $\boldsymbol{\tau}$ are also taken into account. $\mathbf{U}$ is an array of ones.

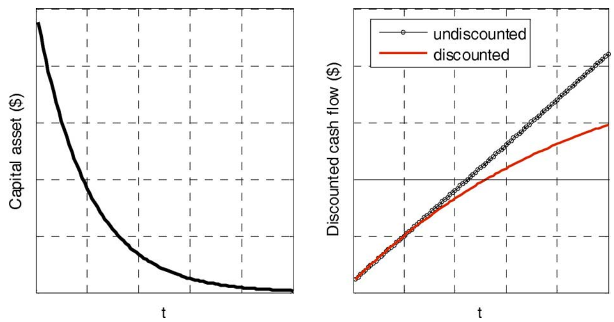

Fig. 3. Concepts of the life-cycle of capital assets and discounted cash flow.

Subject to

1) *Nodal gas flow constraints*

$$\begin{cases} P_i^{gas,\sup} + \sum S_{ij}^{gas} = \sum S_{ji}^{gas} + P_i^{gas} \\ \Psi_i^{Min} \le \frac{P_i^{elec}}{P_i^{elec} + \lambda^{ge} P_i^{gas}} \le \Psi_i^{Max} \end{cases} \tag{6}$$

where $P_i^{gas,\sup}$, P_i^{gas} are natural gas supply and demand at node i. S_{ij}^{gas} is the gas volumetric flow between corridor $i - j$, with the maximum flow rate $S_{ij}^{gas,Max}$. λ^{ge} is the conversion ratio from gas demand to electricity demand. The unit of λ^{ge} is $\mathrm{MWh/m^3}$. Ψ_i^{Min} and Ψ_i^{Max} denote the minimum and maximum percentages of gas and electricity demands that can be mutually transferred .

2) *Gas pipe volumetric flow constraints*

$$S_{ij}^{gas} \le S_{ij}^{gas,Max}. \tag{7}$$

3) *Gas nodal pressure constraints*

$$\rho_i^{Min} \le \rho_i \le \rho_i^{Max} \tag{8}$$

where ρ_i is the gas pipe pressure at node i,with the minimum and maximum pressure requirement ρ_i^{Min} and ρ_i^{Max}.

4) *Power balance constraint*

$$P_{Gi} - P_i^{elec} = \sum_{n=1}^{N} |Y_{in} V_i V_n| \cos(\theta_{in} + \delta_n - \delta_i) \tag{9}$$

$$Q_{Gi} - Q_i^{elec} = \sum_{n=1}^{N} |Y_{in} V_i V_n| \sin(\theta_{in} + \delta_n - \delta_i) \tag{10}$$

where P_{Gi}, Q_{Gi} are real and reactive power outputs of generator i. Q_i^{elec} is the forecasted reactive power demand. θ_{in} is the angle of admittance element Y_{in} in $\mathbf{Y}$. V_i, V_n are bus voltages with angles δ_i, δ_n, respectively.

5) *Electricity branch flow limit*

$$S_{ij}^{elec} \le S_{ij}^{elec,Max}. \tag{11}$$

6) *Nodal voltage limit*

$$V_i^{Min} \le V_i \le V_i^{Max}. \tag{12}$$

7) *Active and reactive power limit of power generators*

$$\begin{cases} P_{Gi}^{Min} \le P_{Gi} \le P_{Gi}^{Max} \\ Q_{Gi}^{Min} \le Q_{Gi} \le Q_{Gi}^{Max} \end{cases} \tag{13.1}$$

$$P_{Gi}^{Min} \le P_{Gi} \le \lambda^{ge} P_i^{gas}; (\text{if } i \in N_{GPG}) \tag{13.2}$$

where N_{GPG} is nodes with gas power plants whose outputs will be constrained by gas availability in gas networks.

8) *Electricity network topology constraints*

$$\begin{cases} Y_{ii} = y_i^0 + \sum \left(y_{ij}^0 + \eta_{ij}\gamma_{ij}\right), (i \ne j) \\ Y_{ij} = -\left(y_{ij}^0 + \eta_{ij}\gamma_{ij}\right), (i \ne j) \end{cases} \tag{14}$$

where y_{ii}^0, y_{ij}^0 are elements of the initial admittance matrix $\mathbf{Y}$, and Y_{ii}, Y_{ij} are elements of the admittance matrix $\mathbf{Y}$ after expansion planning. γ_{ij} is the new circuit admittance.

9) *Reliability constraints*

$$O_{sc} \le EUE_{Max} \tag{15}$$

where O_{sc} is the measure of system reliability of each scenario. The security and adequacy assessments are indispensable in expansion planning. The N $-$ 1 criterion is a common operational security criterion used for power systems, i.e., the system should be able to maintain its normal function given the failure of any single component in the system. However, in this paper, the N $-$ 1 criterion does not apply to the gas system, as we have not found such criterion in gas systems. Moreover, gas scheduling is executed in accordance with gas supply contracts. In order to be competitive in power markets, gas-fired power generators often choose the flexible and take or pay (ToP) interruptible gas supply contracts, because prices for those contracts are relatively lower. Therefore, gas load for gas power generators will be curtailed first when a gas contingency happens. The expected unserved energy (EUE) will be used as a measure of reliability for the combined energy network. EUE is the expected amount of electricity that is not supplied due to inadequate power generation and transmission capacities, or compromised gas-fired power generation capacities when considering gas flow constraints and gas network contingencies (e.g., pressure loss, supply interruption, storage shortage or pipeline outage). Monte Carlo simulations are used to randomly generate scenarios representing different system load levels and component outages in power and gas systems. AC optimal power flow (OPF) can be calculated to find the amount of unsupplied energy. By calculating the average of the unsupplied energy in the simulation, the EUE can be finally obtained.

Equation (16) describes capital assets in planning period T of the existing power and gas system. Equation (17) describes the capital assets of candidate planning components, including gas power generators, power lines and gas pipelines. N_G denotes the number of existing power generators, C_i^{CG}, C_{ij}^{CT} and C_{ij}^{CP} are the capital assets of power generators at node i, power transmission lines and gas pipes between corridor $i - j$ respectively. Moreover, $\eta_i^{GG}(w, m, \beta^{GG})$, $\eta_{ij}^{ET}(w, m, \beta^{ET})$ and $\eta_{ij}^{GP}(w, m, \beta^{GP})$ denote planning decision variables at the wth short horizon at year m with different types denoted by β^{GG}, β^{ET} and β^{GP} for gas power generators, power transmission lines and gas pipes, and $\forall i, j \in N$:

$$\begin{aligned} &\sum_{i=1}^{NG} \left[C_i^{CG} \cdot \exp\left(-r(t_i^{exist} + T)\right)\right] \\ &\quad + \sum_{\substack{i\in N \\ j \in N}} \left[C_{ij}^{CT} \cdot \exp\left(-r(t_{ij}^{exist} + T)\right)\right] \\ &\quad + \sum_{\substack{i\in N \\ j \in N}} \left[C_{ij}^{CP} \cdot \exp\left(-r(t_{ij}^{exist} + T)\right)\right] \end{aligned} \tag{16}$$

$$\sum_{\substack{i\in N \\ j \in N}} \begin{bmatrix} \eta_i^{GG}(w, m, \beta^{GG}) \cdot C_i^{CG} \\ +\eta_{ij}^{ET}(w, m, \beta^{ET}) \cdot C_{ij}^{CT} \\ +\eta_{ij}^{GP}(w, m, \beta^{GP}) \cdot C_{ij}^{CP} \end{bmatrix} \cdot \exp\left(-r(T - wm)\right). \tag{17}$$

The calculations of operation and maintenance (O&M) costs for existing assets and candidate planning components are given in (18) and (19), respectively. O&M costs of power generators include variable (depending on outputs) and fixed (constant) costs, denoted by $C_i^{C,VO\&M}$ and $C_i^{C,FO\&M}$ at node i. For gas pipelines and power lines, O&M costs are only determined by the lengths of gas pipelines and power lines. ξ^{gas} and ξ^{elec} are maintenance factors of gas pipes and power transmission lines, their units are \$/km. l_{ij}^{gas} and l_{ij}^{elec} denote the lengths for them between $i-j$:

$$\sum_{i=1}^{NG}\begin{pmatrix} C_i^{C,VO\&M}\cdot P_i^{elec}\cdot 8760 \\ +C_i^{C,FO\&M} \end{pmatrix} + \sum_{\substack{i\in N\\ j\in N}}\left(\xi^{gas}\cdot l_{ij}^{gas}\right) + \sum_{\substack{i\in N\\ j\in N}}\left(\xi^{elec}\cdot l_{ij}^{elec}\right) \tag{18}$$

$$\eta_i^{GG}(w,m,\beta^{GG})\cdot\sum_{i=1}^{NG}\begin{pmatrix} C_i^{C,VO\&M}\cdot P_i^{elec}\cdot 8760 \\ +C_i^{C,FO\&M} \end{pmatrix} + \eta_{ij}^{ET}(w,m,\beta^{ET})\cdot\sum_{\substack{i\in N\\ j\in N}}\left(\xi^{gas}\cdot l_{ij}^{gas}\right) + \eta_{ij}^{ET}(w,m,\beta^{ET})\cdot\sum_{\substack{i\in N\\ j\in N}}\left(\xi^{gas}\cdot l_{ij}^{gas}\right). \tag{19}$$

B. Stochastic Models

Future scenarios are constructed based on market forecasting and expert knowledge. Many uncertainties, such as load levels and bidding strategies, can affect the system planning. Each scenario is constructed by a value combination of variables, which can be expressed as a vector. For example, a scenario can be, "gas price $= \$4.5/\mathrm{GJ}$, electricity nodal price $= \$35/\mathrm{MWh}$, load level $=$ forecasted load, the percentage of electricity load that can be transferred to gas $= 20\%$". The stochastic processes of energy load including power and loads, and energy prices are modeled by *geometric Brownian motion* and *a mean reverting process*, respectively [28], [29]. More information of mathematical formulations can be found in [11]. The legitimacy of applying the two stochastic models into our ECP problem with regard to fuel prices and gas demand is proved by [30]. Moreover, the percentage of energy load that can be mutually transferred between gas and power is modeled by a standard normal distribution at each node. After that, the Monte Carlo (MC) simulation approach is used to generate scenarios randomly. Suppose N_{MC} is the number of MC simulations. The optimal plan η_i under a particular scenario i is again put back into simulation under other scenarios j where $j \neq i$. The required additional capital investments will be formed a $N_{MC}\times N_{MC}$ matrix, whose diagonal values are zero. We choose the maximum adaptation costs as the *flexibility* criterion for each plan. Later, risk measures in the form of adaptation costs are calculated and added to the objective function. With this comprehensive approach, we can find the most flexible plan under uncertainties.

C. Solution Methods

Our ECP problem comprises of two systems bounded by nonlinear constraints. Given it is a multi-stage, discrete and mixed integer programming, classical mathematical programming techniques are not able to solve. We suggest the use of a modified differential evolution (DE) algorithm with fitness sharing, which is given in [31]. Meanwhile, because the ECP problem is high-dimensional, we use the *sequential importance sampling* (SIS) to sequentially build up biased probability distributions to reduce variance. By integrating the SIS method, the computational efficiency of Monte Carlo simulations can be greatly improved [23]. More details about SIS can be found in [24].

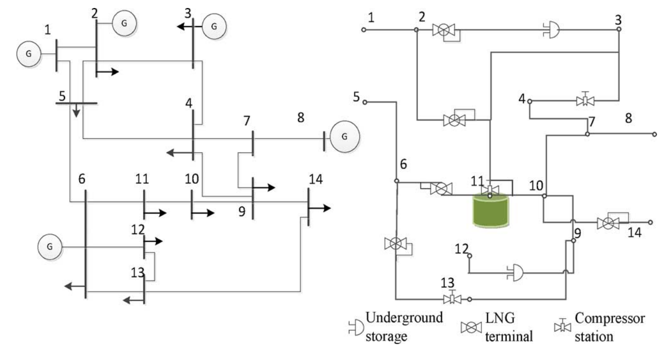

Fig. 4. Base case of the combined power and gas system.

TABLE I
LOAD BLOCKS IN BASE YEAR

Subperiod	1	2	3	4
Duration (%)	1	29	50	20
Power load (MW)	638	586.96	510.40	459.36
Gas load (TJ/hour)	16.8	15.46	13.44	12.10
Notes: Gas load can be described by volumetric flow rate (m^3/s) or energy flow rate (TJ/hour). 1 TJ/hour is about 0.278GJ/s, which is approximatelyequal to 278 MW.				

IV. CASE STUDIES

A. Experiment Setting

The proposed co-planning approach was validated on the IEEE 14-bus system, plus a test gas system, as Fig. 4 shows. We assume that the future load growth will be met completed by building natural gas power plants. Considering the fast development of natural gas extraction technology and the global trend of carbon trading, this is a highly possible future scenario. The 14-bus system initially has five power generators that all are assumed to be coal power plants, and 20 transmission corridors. The total generation capaciy of the base power system is 952.4 MW, while the total power system load is 638 MW. The maximum daily natural gas demand is 50 TJ. To better demonstrate the operation model within each year, a load duration curve is used. The detailed load blocks in base year are set according to [19], as given in Table I. The gas and power networks are coupled at each node. Gas pipe temperature are assumed constant at 298 K. Life spans of gas power plants, gas pipelines and electricity lines are assumed to be 40, 80, and 100 years. For simplicity in our studies, serving ages of the existing system are assumed at half of their life-spans. The power system data are set according to [8] and parameters of combined cycle gas turbine (CCGT) plants are set accroding to [16].

TABLE II
STUDY PARAMETERS

Type		Voltage (kV)	Pressure (kPa)	Diameter (mm)	Compressor Numbers each 100km	Capacity (p.u.)	Cost (M$/MW or M$/km)
Gas power plant		-	-	-	-	0-250	1
Electricity lines	I	330	-	-	-	150	0.5
	II	220	-	-	-	100	0.45
Gas pipelines	I	-	10,150	660	25	12	0.6
	II	-	9,650	400	20	10	0.5
Notes: 1 hour= 1 p.u.; for gas power plant, 1 p.u.=1 MW; for electricity line, 1 p.u.=1 MVA; for gas volumetric flow, 1 p.u.=100 m^3/hour							

TABLE III
EXISTING GAS NETWORK PARAMETERS

Nodes	Lengths (km)	Capacity (p.u.)	Nodes	Lengths (km)	Capacity (p.u.)
1-2	100	10	6-11	200	10
2-3	120	10	7-8	150	10
2-11	150	10	7-10	200	10
3-4	80	10	9-10	160	10
3-11	80	10	9-12	40	10
4-7	100	10	9-13	60	10
5-6	150	10	10-11	80	10
6-13	60	10	10-14	120	10

The gas reservoir is assumed to be located at node 11. Construction time is proportional to the length of the line or the capacity of the gas power plants, ranging from 3 to 6 years. Our system planning horizon is 12 years consisting of 3 stages. The discount rate and the annual growth rate of energy demand are assumed at 5%. The $\boldsymbol{EUE_{Max}}$ is chosen to be 0.3% of the total demand. The forced outage rates (FOR) for power generators, power lines and gas pipes are 1%, 0.5%, and 0.5%, respectively. The key study parameters of the proposed transmission lines, gas pipelines and gas power plants are in Tables II and III.

B. Interactions of the Two Systems

Gas market price can directly affect the generation cost of gas power generators. Moreover, the output of gas power generators will be constrained by the gas availability in gas networks. Therefore, gas systems have significant impacts on power production cost, power generation scheduling, electricity price, power transmission congestion management and network expansion planning. To demonstrate the impacts of gas on power system operations, we give the simulation results with the load duration curve of the base year in this section. As illustrated in Fig. 5, we select 25 out of total 8760 h (i.e., two-week intervals for a whole year 52 weeks in peak hours) to compare the results of total power generation cost and curtailed power load without and with the consideration of gas network constraints. Without gas network constraints, power load curtailment only occurs when power load reaches its peak or there is an component outage in power systems (see hour 6 and 15 in the upper part of Fig. 5). Besides, the generation cost is relatively lower in the upper part of Fig. 5, because affordable and reliable fuel supply can be guaranteed for gas power generators, if there are no flow constraints in gas systems.

When gas network constraints taken into account, power load curtailments are more frequent. This is because the interruption of gas supply (e.g., gas pipe outage) will compromise the output of gas power generators, thus jeopardizing the security of power systems. In addition, when gas and power load peak simultaneously (e.g., in extreme cold winters), pressure losses in gas networks due to excessive gas withdrawal will also result in a loss of gas powered generation, leading to load curtailment in power systems. In peak demand periods, high gas price will punch up the marginal cost of gas power generators, which is a direct signal for high power generation cost and high electricity market price (see hour 22 in the lower part in Fig. 5). However, in off-peak demand periods such as hour 9 and 11, there is more use of power generators with lower cost fuels like coal, leading to low generation cost

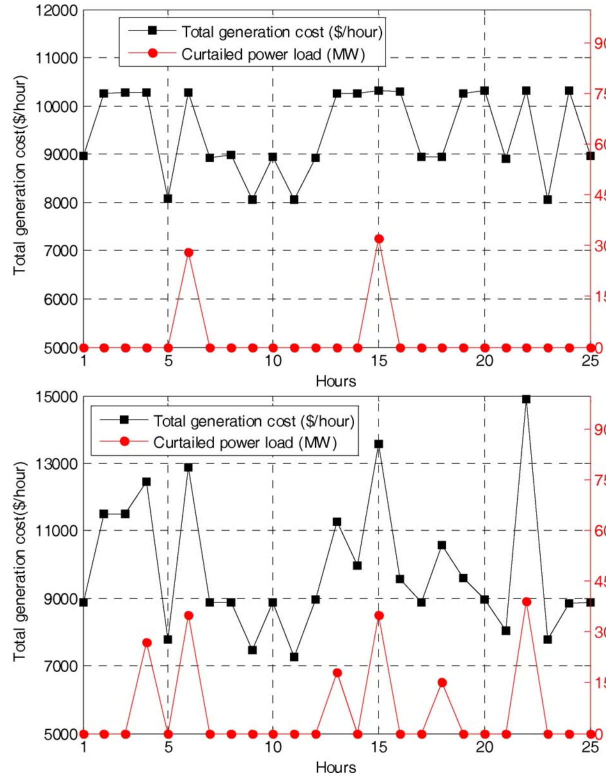

Fig. 5. Total power generation cost ($/h) and curtailed power load (MW) without (the upper one) and with gas network constraints (the lower one).

C. Computational Efficiency

The *sequential importance sampling* (SIS) is applied to perform scenario reduction for our studies. The convergence threshold of MC simulations is defined as the ratio of the standard deviation against the expected value of the objective (set as 0.5%). Also, simulations are performed by 100 times todemonstrate the effectiveness of SIS. Detailed results of average, standard deviation, minimum and maximum for iteration numbers are given in Table IV. As seen, the standard deviations of the objective NPV can reach the acceptable convergence criterion. By applying SIS in power system planning, there is a reduction in average iteration numbers from 1895.14 to 1648.77. This reduction for expansion co-planning is from 1998.55 to 1655.68. The efficiency improvement is more obvious in the complicated co-planning simulation. SIS is therefore especially useful for high-dimensional problems.

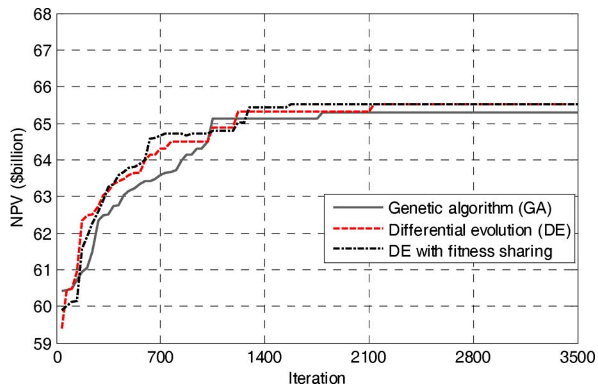

Fig. 6. Optimization processes of three different algorithms.

TABLE IV
SCENARIO REDUCTION EFFECTS IN 100 TIMES OF SIMULATIONS

	Iteration numbers				NPV (billion$)	Std. of NPV
	Aver.	Std.	Min.	Max.		
Power system planning without SIS	1895.14	15.28	1695	2107	42.07	0.1893
Power system planning with SIS	1648.77	12.79	1308	2013	42.15	0.2023
Expansion co-planning without SIS	1998.55	13.99	1703	2287	64.38	0.3091
Expansion co-planning with SIS	1655.68	12.62	1408	2008	64.49	0.3032

Furthermore, the optimization is performed with three different optimization algorithms, i.e., genetic algorithm (GA), DE and the modified DE with fitness sharing. According to the optimization results provided in Fig. 6, the computational performance of the DE with fitness sharing outweighs the other two algorithms in solving the formulated mixed-integer nonlinear optimization problem.

D. Comparison and Discussion

The purpose of our novel expansion co-planning (ECP) research is to effectively model system interactions between natural gas and electricity markets, so as to improve the holistic energy utilization efficiency for the better social welfare. We established two cases for comparing our proposed co-planning approach with the single flexible power system expansion planning (EP). Our results for ECP are given in Table V. In the following part, we will give comparison and discussion for EP and ECP in detail.

Cases for Comparisons of the System Expansion Planning

1) Flexible power system expansion planning proposed by [10]. Form the uncertainty of new entries of generation capacity as six scenarios. Scenarios are locations at node 1, 2, and 3 with capacities of 50 p.u. and 100 p.u.
2) Flexible combined expansion planning: gas pipelines, gas power plants and electricity transmission lines with stochastic processes mentioned in Section IV-B.

In power system EP, load growth and new generation capacity entry are two crucial uncertainties. See the results of adaptation costs for case 1 of six scenarios in Table VI. We use the minimax adaptation cost criterion to measure the flexibility of an expansion plan. Firstly, the maximum adaptation cost of an expansion plan under all unexpected scenarios will be considered as the final adaptation cost. Then the expansion plan with the minimum adaptation plus capital cost will be chosen as the most flexible plan. More detailed information about the minimax adaptation cost criterion can be found in [9]. Total costs of plans are given in Table VII. It can be seen that Plan 4 is more robust with uncertainties. We chose Plan 4 as the flexible EP result. Nevertheless, comparing to ECP (208 \$M), the total cost for the flexible EP (310 \$M) is higher. In our ECP methods, the availability of gas for power generation is modelled by the gas system, subjecting to gas flow constraints in pipes. With gas network simulations, the operation and expansion of gas power plants become known factors. Risks due to uncertainties of power generation are alleviated in ECP. Our risk measure in the form of adaptation costs clearly demonstrates that. ECP is therefore more flexible.

Fig. 7 illustrates the detailed flexible EP and ECP for power systems. The flexible ECP result for the gas system is visualized in Fig. 8. As observed, because of time requirements for construction, all potential new circuits are proposed at the first or second year of each stage. Compared to case 2, case 1 requires three extra circuits in stage 3, reflecting transmission capacity

TABLE V
PROPOSED CO-PLANNING FOR THREE STAGES

Node/Type/Year	Stage 1	Stage 2	Stage 3
Electricity lines	2-3; type I;1st year	9-10; type II; 1st year	3-4; type I, 1st year
Gas pipelines	5-6; type I; 1st year	3-11; type II; 1st year	7-10; type II; 1st year
Gas power plants	-	3; 75 MW; 2nd year	-
NPV (billion $)	64.49		

TABLE VI
ADAPTATION COSTS ($M) FOR CASE 1 WITH NEW GENERATION CAPACITY UNCERTAINTIES

		Initial plans					
		Plan1	Plan 2	Plan 3	Plan 4	Plan 5	Plan 6
Unexpected scenarios	Scenario1	0	90	100	0	208	148
	Scenario2	108	0	150	50	150	0
	Scenario3	245	100	0	60	100	120
	Scenario4	50	50	0	0	0	240
	Scenario5	0	108	60	0	0	0
	Scenario6	100	228	50	60	50	0

TABLE VII
COMPARE THE TOTAL COST ($M) WITH ECP PLAN FOR FLEXIBILITY UNDER UNCERTAINTIES OF NEW GENERATION CAPACITY ENTRY

	Plan 1	Plan 2	Plan 3	Plan 4	Plan 5	Plan 6	ECP plan
Initial construction cost	240	201	360	250	201	250	208
Maximum adaptation cost	245	228	150	60	208	240	0
Total cost	485	429	510	310	409	490	208

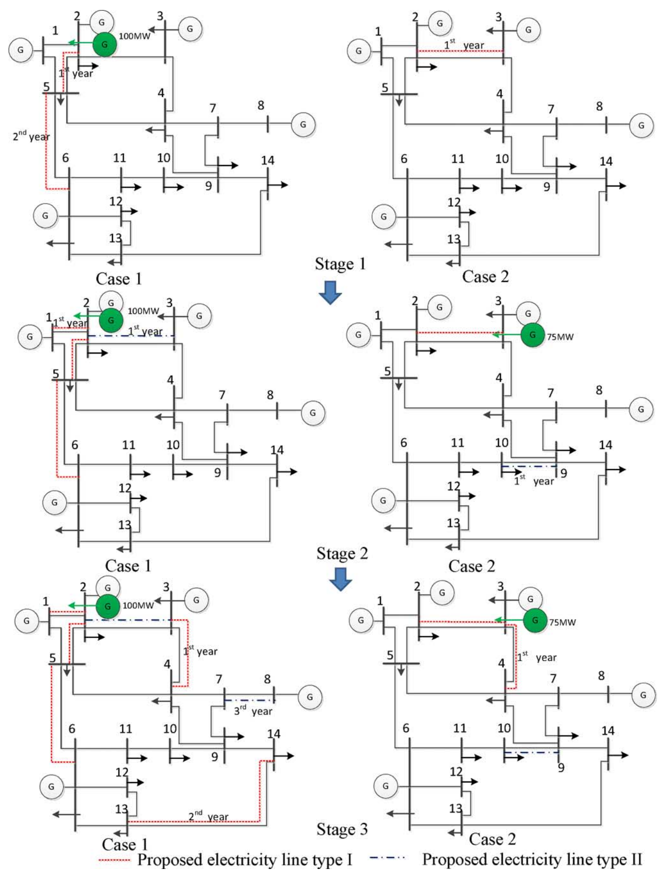

Fig. 7. Comparison of the power system for two cases.

deficiencies due to load growth. In case 2, with the new gas generation entry, proposed new circuits are located near buses with generators. This reveals that lines connecting to these buses possess spare transmission capacity.

The comparison of multi-stage flexible EP and ECP including stochastic processes is illustrated in Fig. 9 in the context of adaptation costs, power transmission loss, power transmission capacity and NPV of the social welfare.

Firstly, as shown in Fig. 9, ECP has much lower the maximum adapation cost. This proves that ECP is more robust in the face of uncertainties. Secondly, part of transmission burdens is apportioned by the two networks. In this paper, we use power transmission losses as an indicator to demonstrate that. ECP saves tremendous transmission losses in all stages. So the combined gas and power system is more efficient in terms of energy transmission.

Thirdly, for ECP, the transfer capabilities of both systems are maximized, as energy load at a node is satisfied and guaranteed by gas and power. Besides, changes in transmission capacity for ECP seem to be more flat. ECP reflects a coordinated system expansion of an integrated energy transmission network, which leads to less periodic constructions. Fourthly, the NPV of the social welfare in co-planning is markedly higher. Since the future cash flow is discounted, the extents of NPV rises seem to be smaller towards the end [32]. This phenomenon of NPV has been explained in Fig. 3.

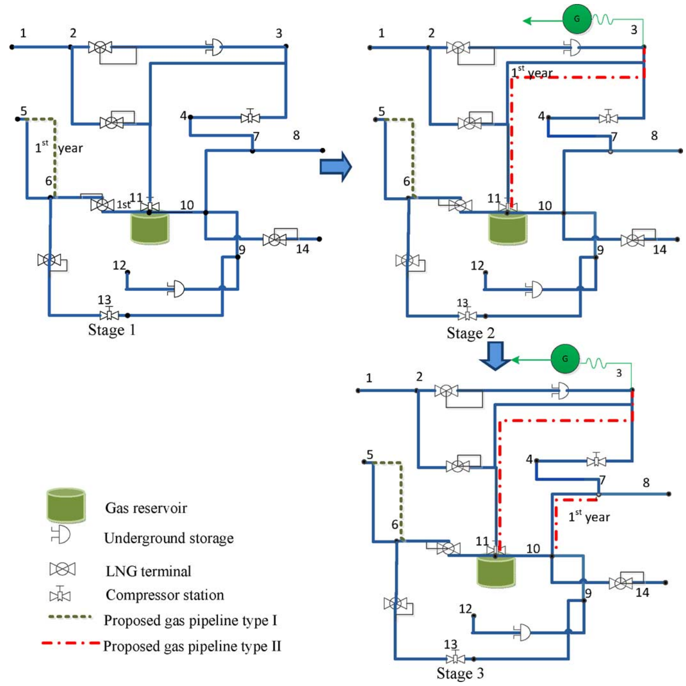

Fig. 8. Results of the gas network planning.

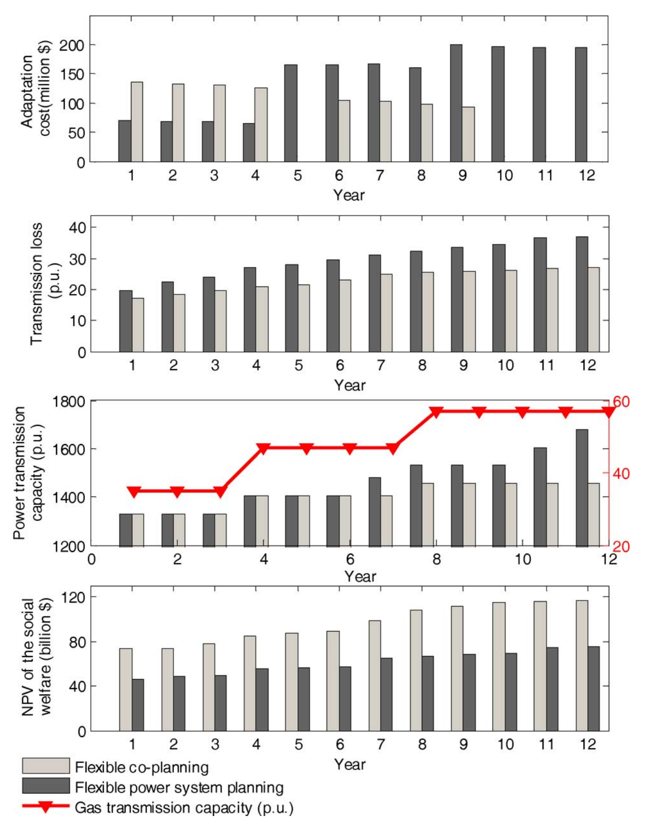

Fig. 9. Comparison of the flexible co-planning and power system planning.

Furthermore, because both gas and power systems are networks that transport energy and their demands can be transformed into each other in some circumstances, the combined gas and power system is more reliable and efficient as an integrated energy transmission infrastructure. For example, part of power load curtailed due to power system faults can be compensated by gas load. Heating is the most obvious energy demand that can be satisfied by electricity or gas alternatively. This can be comprehensive as when the power is cut off for a household, a consumer may still choose to use a gas oven to cook. Therefore, when gas networks and power systems are planned together, their overall reliability can be increased.

V. Conclusion

With increasing worldwide climate change concerns, natural gas draws more attention as a clean generation resource in the power industry. The availability of gas for power plants can significantly influence the reliability of power systems. Also, uncertainties in multi-stage system expansion planning can fundamentally change the feasibility of a plan, particularly in a combined gas and electricity market. In this paper, we have developed a novel system modelling technique with more efficient solution algorithms. This novel expansion co-planning approach can effectively identify expansion plans regarding where, when and what type for gas power plants, gas pipes and power transmission lines. The proposed co-planning approach can provide the strategic contemplation of the interactions of the two systems. In addition, the proposed expansion co-planning approach is able to guide the energy industry to form a holistic approach to operating and planning of gas and electricity networks, subject to various technical constraints. This integral perspective can: 1) better identify energy infrastructure weakness for meeting long-term energy demand; 2) understand the physical and economic interactions between the two systems and support system operating and planning decisions; 3) effectively improve the network asset utilization by simulating interacting operations of the two systems; 4) achieve higher social welfare to benefit the overall society. An application example of IEEE 14-bus plus a test gas system is illustrated in this paper to verify the effectiveness of the proposed method. The results show that the method is promising for long term market forecasting and planning guidance.

References

[1] X. Zhou, G. James, A. Liebman, Z. Y. Dong, and C. Ziser, "Partial carbon permits allocation of potential emission trading scheme in Australian electricity market," *IEEE Trans. Power Syst.*, vol. 25, no. 1, pp. 543–553, Feb. 2010.

[2] G. Liu, J. H. Zhao, F. Wen, X. Yin, and Z. Y. Dong, "Option-game-based method for generation investment analysis considering uncertain carbon reduction policy in the electricity market," *IET Gen., Transm., Distrib.*, vol. 4, no. 8, pp. 917–927, Aug. 2010.

[3] A. I. Tolis and A. A. Rentizelas, "An impact assessment of electricity and emission allowances pricing in optimised expansion planning of power sector portfolios," *Appl. Energy*, vol. 88, no. 11, pp. 3791–3806, Nov. 2011.

[4] S. Taggart, G. James, Z. Y. Dong, and C. Russell, "The future of renewables linked by a Transnational Asian Grid," *Proc. IEEE*, vol. 100, no. 2, pp. 348–359, Feb. 2012.

[5] C. Unsihuay-Vila, J. W. Marangon-Lima, A. C. Z. de Souza, I. J. Perez-Arriaga, and P. P. Balestrassi, "A model to long-term, multiarea, multistage, and integrated expansion planning of electricity and natural gas systems," *IEEE Trans. Power Syst.*, vol. 25, no. 2, pp. 1154–1168, May 2010.

[6] M. Shahidehpour, Y. Fu, and T. Wiedman, "Impact of natural gas infrastructure on electric power systems," *Proc. IEEE*, vol. 93, no. 5, pp. 1042–1056, May 2005.

[7] A. Kabirian and M. R. Hemmati, "A strategic planning model for natural gas transmission networks," *Energy Policy*, vol. 35, no. 11, pp. 5656–5670, May 2007.

[8] Z. Xu, Z. Y. Dong, and K. P. Wong, "Transmission planning in a deregulated environment," *IEE Proc. Gen., Transm., Distrib.*, vol. 153, no. 3, pp. 326–334, 2006.

[9] J. H. Zhao, Z. Y. Dong, P. Lindsay, and K. P. Wong, "Flexible transmission expansion planning with uncertainties in an electricity market," *IEEE Trans. Power Syst.*, vol. 24, no. 1, pp. 479–488, Feb. 2009.

[10] E. Baker and K. Adu-Bonnah, "Investment in risky R&D programs in the face of climate uncertainty," *Energy Econ.*, vol. 30, no. 2, pp. 465–486, Mar. 2008.

[11] J. H. Zhao, J. Foster, Z. Y. Dong, and K. P. Wong, "Flexible transmission network planning considering distributed generation impacts," *IEEE Trans. Power Syst.*, vol. 26, no. 3, pp. 1434–1443, Aug. 2011.

[12] B. Alizadeh and S. Jadid, "Reliability constrained coordination of generation and transmission expansion planning in power systems using mixed integer programming," *IET Gen., Transm., Distrib.*, vol. 5, no. 9, pp. 948–960, Sep. 2011.

[13] A. K. Kazerooni and J. Mutale, "Transmission network planning under security and environmental constraints," *IEEE Trans. Power Syst.*, vol. 25, no. 2, pp. 1169–1178, May 2010.

[14] P. A. J. Fonseka, T. K. Saha, and Z. Y. Dong, "A price-based approach to generation investment planning in electricity markets," *IEEE Trans. Power Syst.*, vol. 23, no. 4, pp. 1859–1870, Nov. 2008.

[15] P. R. Shukla, S. Dhar, D. G. Victor, and M. Jackson, "Assessment of demand for natural gas from the electricity sector in India," *Energy Policy*, vol. 37, no. 9, pp. 3520–3534, Aug. 2009.

[16] R. Wiser, D. Bachrach, M. Bolinger, and W. Golove, "Comparing the risk profiles of renewable and natural gas-fired electricity contracts," *Renew. Sustain. Energy Rev.*, vol. 8, no. 4, pp. 335–363, Sep. 2004.

[17] J. Jackson, "Promoting energy efficiency investments with risk management decision tools," *Energy Policy*, vol. 38, no. 8, pp. 3865–3873, Mar. 2010.

[18] Australian Energy Market Operator (AEMO) [Online]. Available: http://www.aemo.com.au/

[19] R. J. Hyung, M. Shahidehpour, and W. Lei, "Market-based generation and transmission planning with uncertainties," *IEEE Trans. Power Syst.*, vol. 24, no. 3, pp. 1587–1598, Aug. 2009.

[20] L. Wu and M. Shahidehpour, "Optimal coordination of stochastic hydro and natural gas supplies in midterm operation of power systems," *IET Gen., Transm., Distrib.*, vol. 5, no. 5, pp. 577–587, Mar. 2011.

[21] H. Tekiner, D. W. Coit, and F. A. Felder, "Multi-period multi-objective electricity generation expansion planning problem with Monte-Carlo simulation," *Elect. Power Syst. Res.*, vol. 80, no. 12, pp. 1394–1405, Dec. 2010.

[22] I. Sharan and R. Balasubramanian, "Integrated generation and transmission expansion planning including power and fuel transportation constraints," *Energy Policy*, vol. 43, no. 0, pp. 275–284, Jan. 2012.

[23] J. Huang, Y. S. Xue, Z. Y. Dong, and K. P. Wong, "An adaptive importance sampling method for probabilistic optimal power flow," in *Proc. IEEE PES General Meeting*, 2011, pp. 1–6.

[24] J. Huang, Y. Xue, Z. Y. Dong, and K. P. Wong, "An efficient probabilistic assessment method for electricity market risk management," *IEEE Trans. Power Syst.*, vol. 27, no. 3, pp. 1485–1493, Aug. 2012.

[25] M. Chaudry, N. Jenkins, and G. Strbac, "Multi-time period combined gas and electricity network optimisation," *Elect. Power Syst. Res.*, vol. 78, no. 7, pp. 1265–1279, Jul. 2008.

[26] X. Zou, "Double-sided auction mechanism design in electricity based on maximizing social welfare," *Energy Policy*, vol. 37, no. 11, pp. 4231–4239, Nov. 2009.

[27] K. Singh, N. P. Padhy, and J. Sharma, "Influence of price responsive demand shifting bidding on congestion and LMP in pool-based day-ahead electricity markets," *IEEE Trans. Power Syst.*, vol. 26, no. 2, pp. 886–896, May 2011.

[28] A. Eydeland and K. Wolyniec, *Energy and Power Risk Management*. Chichester, U.K.: Wiley, 2003.

[29] D. Maxwell and Z. Zhu, "Natural gas prices, LNG transport costs, and the dynamics of LNG imports," *Energy Econ.*, vol. 33, no. 2, pp. 217–226, Mar. 2011.

[30] R. C. Garcia, J. Contreras, P. F. Correia, and J. I. Muñoz, "Transmission assets investment timing using net present value curves," *Energy Policy*, vol. 38, no. 1, pp. 598–605, 2010.

[31] G. Y. Yang, Z. Y. Dong, and K. P. Wong, "A modified differential evolution algorithm with fitness sharing for power system planning," *IEEE Trans. Power Syst.*, vol. 23, no. 2, pp. 514–522, May 2008.

[32] Y. Xu, Z. Y. Dong, K. P. Wong, E. Liu, and B. Yue, "Optimal capacitor placement to distribution transformers for power loss reduction in radial distribution systems," *IEEE Trans. Power Syst.*, vol. 28, no. 4, pp. 4072–4079, Nov. 2013.

Jing Qiu (S'12) received the B.Eng. degree in control engineering from Shandong University, China, and the M.Sc. degree in environmental policy and management, majoring in carbon financing in the power sector, from the University of Manchester, U.K.

He is a Research Associate at the Center for Intelligent Electricity Networks (CIEN), The University of Newcastle, Australia. His areas of interest include electricity market modeling, power system planning, renewable energy, and risk management.

Zhao Yang Dong (M'99–SM'06) received the Ph.D. from the University of Sydney, Australia, in 1999.

He is now Professor and Head of School of Electrical and Information Engineering, University of Sydney, Australia. He was previously Ausgrid Chair and Director of the Center for Intelligent Electricity Networks (CIEN), The University of Newcastle, Australia, and is now a conjoint professor there. He also held academic and industrial positions with the Hong Kong Polytechnic University and Transend Networks, Tasmania, Australia. His research interest includes Smart Grid, power system planning, power system security, load modeling, electricity market, and computational intelligence and its application in power engineering.

Prof. Dong is an editor of the IEEE TRANSACTIONS ON SMART GRID, the IEEE TRANSACTIONS ON SUSTAINABLE ENERGY, IEEE POWER ENGINEERING LETTERS, and *IET Renewable Power Generation*.

Jun Hua Zhao (S'04–M'07) received the B.E. and Ph.D. degrees from Xi'an Jiaotong University, China, and The University of Queensland, Australia, in 2003 and 2007, respectively.

He then worked as a postdoctoral research fellow at the University of Queensland, Australia. He is now a Senior Lecturer in Center for Intelligent Electricity Networks, The University of Newcastle, Australia. His research interests include power system analysis and computation, smart grid, energy Internet, data mining, and computational intelligence and their applications in power engineering.

Yan Xu (S'10–M'13) received the B.E. and M.E. degrees from South China University of Technology, China, in 2008 and 2011, respectively, and the Ph.D. degree from the University of Newcastle, Australia, in 2013.

He is now a Research Fellow at the Center for Intelligent Electricity Networks (CIEN), University of Newcastle, Australia, and also with the School of Electrical and Information Engineering, University of Sydney. His research interests include power system stability and control, power system planning, Smart Grid, and intelligent system applications to power engineering.

Yu Zheng (S'12) received the B.E. degree from Shanghai Jiao Tong University, China. He is pursuing the Ph.D. degree at the Center for Intelligent Electricity Networks (CIEN), The University of Newcastle, Australia.

He was previously with Department of Electrical Engineering, The Hong Kong Polytechnic University, Hong Kong. His research interests include power electronic applied in power system, power system planning, smart grid, and intelligent system applications to power engineering.

Chenxi Li received the B.E. degree in electrical engineering from Beijing Jiaotong University, China, in 2013.

He is now with China Railway Communication and Signal Survey and Design (Beijing) Co. Ltd., China. His research interests include railway power supply, renewable energy and (railway) signal processing.

Kit Po Wong (M'87–SM'90–F'02), received the M.Sc, Ph.D., and D. Eng degrees from the University of Manchester, Institute of Science and Technology, U.K., in 1972, 1974, and 2001, respectively.

Since 1974, he has been with the School of Electrical, Electronic and Computer Engineering, The University of Western Australia, Perth, Australia, where he currently is a Winthrop Professor. From 2002 to 2011, he was also with Department of Electrical Engineering, The Hong Kong Polytechnic University, as Chair Professor and Head (2002–2007). He is a con-joint professor of The University of Newcastle, Australia. His current research interests include power system analysis, planning and operations, smart grids, and renewable energy.

Prof. Wong received three Sir John Madsen Medals (1981, 1982, and 1988) from the Institution of Engineers Australia, the 1999 Outstanding Engineer Award from IEEE Power Chapter Western Australia, and the 2000 IEEE Third Millennium Award. He was the General Chairman of IEEE/CSEE PowerCon2000. He is now Editor-in-Chief of IEEE POWER ENGINEERING LETTERS and was Editor-in-Chief of *IEE Proc. Generation, Transmission & Distribution*. He is a Fellow of IET, HKIE, and IEAust.