Technological University Dublin

ARROW@TU Dublin

Articles | School of Electrical and Electronic Engineering

2021-09-02

Dynamic stochastic joint expansion planning of power systems, natural gas networks, and electrical and natural gas storage

Arash Gholami
Amirkabir University of Technology-Iran

Hamed Nafisi
Technological University Dublin, hamed.nafisi@tudublin.ie

H. Askarian A.
Amirkabir University of Technology-Iran

See next page for additional authors

Follow this and additional works at: https://arrow.tudublin.ie/engscheleart2

Part of the Electrical and Computer Engineering Commons

Recommended Citation

Gholami, A., Nafisi, H., Askarian Abyaneh, H., Jahanbani Ardakani, A. Dynamic stochastic joint expansion planning of power systems, natural gas networks, and electrical and natural gas storage. IET Gener. Transm. Distrib. 2021; 1– 18. DOI: 10.1049/gtd2.12277

This Article is brought to you for free and open access by the School of Electrical and Electronic Engineering at ARROW@TU Dublin. It has been accepted for inclusion in Articles by an authorized administrator of ARROW@TU Dublin. For more information, please contact arrow.admin@tudublin.ie, aisling.coyne@tudublin.ie, gerard.connolly@tudublin.ie.

This work is licensed under a Creative Commons Attribution-Noncommercial-Share Alike 4.0 License

Authors

Arash Gholami, Hamed Nafisi, H. Askarian A., and Ali Jahanbani Ardakani

This article is available at ARROW@TU Dublin: https://arrow.tudublin.ie/engscheleart2/277

Received: 14 March 2021 | Revised: 30 July 2021 | Accepted: 3 August 2021

IET Generation, Transmission & Distribution

DOI: 10.1049/gtd2.12277

ORIGINAL RESEARCH PAPER

Dynamic stochastic joint expansion planning of power systems, natural gas networks, and electrical and natural gas storage

Arash Gholami[1] | **Hamed Nafisi**[1,2] | **Hossein Askarian Abyaneh**[1] | **Ali Jahanbani Ardakani**[3]

[1] Department of Electrical Engineering, Amirkabir University of Technology (Tehran Polytechnic), Tehran, Iran

[2] School of Electrical and Electronic Engineering, Technological University Dublin (TU Dublin)

[3] Department of Electrical and Computer Engineering, Iowa State University, Iowa, USA

Correspondence
Hamed Nafisi, Department of Electrical Engineering, Amirkabir University of Technology (Tehran Polytechnic), Tehran, Iran.
Email: nafisi@aut.ac.ir

Abstract

Over the last decades, electricity generation from natural gas has substantially increased, mostly driven by low natural gas prices due to fracturing and lower extraction costs. The geographic distance between natural gas resources and load centers calls for a holistic tool for joint expansion of power systems and natural gas networks. In this paper, a Dynamic Stochastic Joint Expansion Planning (DSJEP) of power systems and natural gas networks is proposed to minimize the investment and operational costs of power and natural gas systems. Electrical and natural gas storage (ENGS) are considered as an option for decision-makers in the DSJEP problem. The proposed approach takes into account long-term uncertainties in natural gas prices and electric and natural gas demands through scenario realizations. In dynamic planning, more scenario needs more time for computation; therefore, scenario reduction is implemented to eschew unnecessary scenarios. The proposed formulation is implemented on a four-bus electricity system with a five-node natural gas network. To demonstrate the efficiency and scalability of the proposed approach, it is also tested on the IEEE 118-bus system with a 14-node natural gas network. The numerical results demonstrate that ENGS can reduce the total investment cost, up to 52% in the test cases, and operational cost, up to 3%. In this paper, co-planning of power and natural gas systems considering natural gas and electrical storage is represented. Also, electrical and natural gas load growth uncertainties are taken into account to model the real situations. The purpose of the model is to minimize investing and operational costs.

1 | INTRODUCTION

In the past decades, the share of natural gas in electricity generation has increased from 24% to 39% [1]. As more coal generation is retired, and increasing investment in intermittent renewable resources demands more flexibility for secure operation of power systems, the investment in natural gas-fired generation units will increase [2]. Thereafter, the power systems and natural gas networks have become more interdependent. Natural gas resources are usually located far from electricity and natural gas demands, and therefore appropriate planning is required to carry the energy with minimum cost; for instance, electricity generation at the extraction spot or transferring natural gas to the electric load centers and generating electricity there [3].

The technological advances in electrical and natural gas storage (ENGS) present an opportunity to reduce the investment and operational cost of electric and natural gas networks. Therefore, these storage facilities must be incorporated in long term Dynamic Stochastic Joint Expansion Planning (DSJEP) models to model their effects. If natural gas storage (NGS) is categorized by their releasing and storing rates, two NGS types exist. The first type is characterised by high releasing and storing rates which has low reservoir capacity and high cost; it can be used for flattening hourly and daily demand variations. The second type has high reservoir capacity with low releasing and storing rates which can be used in flattening of seasonal natural gas demand fluctuations [4]. Investments in ENGS can postpone the investments in new infrastructure such as generation units, transmission lines, pipelines, and other critical infrastructure [5]. With growing demands in both Power and Natural Gas Systems (PNGS), comprehensive planning is necessary to meet the future demands. Given the interdependent

This is an open access article under the terms of the Creative Commons Attribution License, which permits use, distribution and reproduction in any medium, provided the original work is properly cited.
© 2021 The Authors. *IET Generation, Transmission & Distribution* published by John Wiley & Sons Ltd on behalf of The Institution of Engineering and Technology

nature of PNGS, if these networks are considered individually in planning, the resulting expansion plan may be suboptimal for both networks.

In a static approach to planning, all infrastructure are built in one shot, usually at the beginning of the planning horizon; however, a dynamic approach has the benefit of allowing planners to decide the optimal time in the planning horizon for investing in new infrastructure. The advantage of the dynamic expansion planning is that it more accurately represents the years of the planning horizon. Consequently, in the DSJEP, the best time and location for new infrastructure construction is determined, while meeting the candidate electrical and natural gas demands.

A significant body of research has been devoted to the expansion planning of joint power systems and natural gas networks. Uncertainties are considered as components of integrated expansion planning due to unpredictable characteristics of both networks [3, 6–9]. Static two-stage stochastic optimization is used by Zaho et al. [3] to represent the uncertainty of electricity and natural gas demands, finding the optimum balance between building electrical and natural gas infrastructure. The value of stochastic solution is defined as a criterion to evaluate stochastic planning merit in expansion planning. A stochastic multistage planning model with the presence of highly variable renewable energy resources is proposed by Nunes et al. [6], where short-term and long-term uncertainties are considered for the case of Queensland, Australia, to analyze the influence of these uncertainties on long-term integrated power systems and natural gas networks planning. In [7], a multistage stochastic model is applied to gain minimum operation and investment costs with nonanticipative constrains and the uncertainties that resulted from the stochastic nature of demands. Alternating direction method of multipliers is implemented by Khaligh and Anvari-Moghaddam [8] to exchange minimum data between electricity and natural gas companies. Different regulatory policies and demand response programs are modeled to analyze their effects on the planning of PNGS by considering uncertainties in wind power generation, annual load growth, and interest rate. In [9], social welfare is defined as the objective function for determining multistage expansion planning joint power systems and natural gas networks while considering uncertainties in load level, natural gas and electricity nodal price. In some researches like [10–14], reliability, security and resilience are evaluated in the integrated PNGS planning. In [10], the N-1 contingency in power systems and natural gas networks is considered to find a robust system. A piecewise linearization method is utilized to linearize gas flow equations. Reduced Disjunctive Model (RDM) is implemented to decrease decisions variables and constraints. In [11], Power to Gas (PtG) constraints are developed combined with probabilistic reliability and N-1 criteria to obtain a reliable and cost-effective power systems and natural gas network expansion plan. The robust model for joint natural gas networks and power systems is suggested by Shao et al. [12] to improve power grid resilience in catastrophic events. Multi-objective optimization for PNGS planning is investigated by Hu et al. [13] to decrease investment and production cost considering the N-1 electricity network and security benchmarks.

In [15–20] different energy storage is modeled in joint expansion planning of PNGS to store energy and is used when the energy is needed. In [15, 16], shortage of natural gas supplies can be alleviated by electrical energy storage (ES) in the expansion planning of PNGS. Mixed Integer Linear Programming (MILP) is applied to solve stochastic expansion planning. In [17], a long-term, multi-area, and multistage approach is proposed considering NGS and liquefied natural gas (LNG) as well as transmission losses to achieve a more realistic power systems and natural gas expansion plan. In [18], two types of storage, NGS and hydroelectric water plants with water reservoirs are used to replace the use of high price fuels in power plants. The effects of inclusion of storage on electrical and natural gas prices, calculated from marginal costs, is assessed.

Integrated expansion planning in Great Britain considering NGS and LNG is modeled by Chaudry et al. [20] with the goal of designing an energy system with the least cost and carbon emission.

PtG is considered as essential and usable energy storage. Even though electricity can not be stored on a large-scale, with PtG power change to gas, which is storable energy [21]. The effects of large-scale PtG on power and natural gas is discussed in [22]. coordination of power and natural gas systems based on information gap decision theory with aim of minimizing cost is described in [23]. Also, uncertainty in electricity price is considered.

Different methods are implemented to solve joint PNGS expansion planning. Some significant methods are described in [24–29]. In [24], a bi-level expansion planning is investigated, where the upper level problem solves a co-expansion plan to minimize total investment cost, and the lower level problem calculates the optimal operation cost. In addition to natural gas generators, PtG is also considered as another connection between PNGS. Electricity distribution and natural gas networks with considerable penetration of distributed generation (DG) are proposed by Saldarriaga *et al.* [25] to compare expansion cost with separate electricity and natural gas networks. Master/slave methodology is explained to solve MINLP optimization model. In [26], MINLP integrated expansion co-planning of gas and power systems is solved using fuzzy particle swarm optimization. Integrated expansion co-planning are formulated to boost benefit to investment cost ratio. Benefit is defined as the reduction in operation, expected unserved energy and carbon emission costs. In [27], a new approach to solve natural gas load flow is suggested to decrease computation time in large-scale systems, and genetic algorithm is implemented to solve MINLP. In [30], the first-order Taylor series and piecewise linear approximation are introduced to deal with non-linear power system models (power generator cost and losses) and the non-linear natural gas network models, that is, the marginal gas production cost curve and gas nodal balance constraints. Joint expansion planning power systems and natural gas networks are proposed by Borraz-Sanchez et al. [28], which convex relaxation for gas and AC-power flow is used to exploit voltage and pressure constraints in planning. A research gap exists between joint PNGS expansion planning, and market-based model that is discussed by Zahedi Rad et al. [29]. Mixed

TABLE 1 Recently literature on electrical and natural gas expansion planning

Ref	Type of optimization model	Dynamic	Stochastic	Storage	Other contributions
[3]	MILP	No	Yes	No	Value of stochastic solution (VSS)
[10]	MILP	No	No	No	N-1 contingency in both systems
[6]	MILP	No	Yes	No	–
[17]	MILP	Yes	Yes	LNG, NGS	Different kind of power generation plant
[18]	MILP	Yes	No	Water reservoir, NGS, line pack	Nodal electricity and natural gas price are obtained from shadow prices
[12]	MILP	Yes	No	No	Robust optimization
[7]	MILP	Yes	Yes	No	Nonanticipative constraints
[11]	MILP	Yes	Yes	No	PtG technology
[15]	MILP	No	Yes	ES	–
[8]	MINLP	Yes	Yes	No	Different regulatory policies and demand response
[24]	MINLP	Yes	No	NGS, linepack	PtG technology
[13]	MINLP	No	Yes	No	N-1 electricity network security criterion
[25]	MINLP	Yes	No	No	–
[9]	MINLP	Yes	Yes	No	Monte Carlo simulation is applied to create scenarios
[20]	MINLP	Yes	No	NGS	–

complementarity problem is explored to find the Nash equilibrium point of PNGS.

Table 1 is derived by comparing recent literature on electrical and natural gas expansion planning. This table compares the type of optimization model, dynamic, stochastic, and storage that is used.

In this paper, the DSJEP of PNGS considering ENGS is proposed. Stochastic programming allows expansion planners to create uncertainties of possible future events in PNGS that can affect the long term plan. Use of a stochastic approach provides different options for different scenarios to ensure that the best decisions are taken. The expansion planning is generally done for the long-term; thereafter, many parameters are subject to uncertainty in the planning horizon. Hence, uncertainties in long-term natural gas prices and demand growth for natural gas and electricity are considered. For electrical and natural gas demands, k-means clustering approach is utilized to create representative operation conditions. Scenarios are used to model uncertainties. A scenario tree is constructed, and the backward scenario reduction method is employed. ENGS is modeled to show that they can postpone investments in new infrastructure and decrease operational costs. Energy can be stored in two shapes: electricity and natural gas. It should be mentioned that natural gas power plants are the only connection between power networks and natural gas systems in this work. The models are linearized to guarantee global solution.

The principal contributions of this paper are as follows:

- Two types of energy storage, ENGS, are taken into account,
- Long-term uncertainties in natural gas price and natural gas and electrical demand growth, as well as an hourly natural gas price change, are studied.
- The energy storage is taken into the account in the expansion planning and it shows how storage can reduce investment cost in the long-term; moreover, how two different kinds of storage can be beneficial in long-term expansion planning.
- It demonstrates that how energy storage can mitigate long-term uncertainties in natural gas price and electrical and natural gas demand growth.

The remainder of this paper is organized as follows. In Section 2, the proposed DSJEP problem formulation is presented. The simulation results are shown in Section 3, and finally, Section 4 concludes.

2 | PROBLEM FORMULATION

2.1 | Objective functions

2.1.1 | Minimization of investment cost

The Net Present Value (NPV) of total cost of investment and operational of electrical and natural gas systems are defined as the objective function. The NPV of the investment cost is defined in (1). The costs of new pipelines and transmission lines are represented in (1a); the costs of new generations, natural gas and thermal power plants are addressed in (1b). Finally, (1c) represents the expansion cost in ENGS.

These investment costs are multiplied by $(1 + ir_y)^{-st_y}$ to find NPV, as described in [31]; These costs are also multiplied by ρ_w^{scen} which defines the probability of each scenario, which will be explained later in this paper.

$$Z_{INV} = \sum_{w\in W}\left[\rho_w^{scen}\sum_{y\in Y}\left\{(1+ir_y)^{-st_y}\right.\right.$$
$$\left.\left.\times\left(z_{INV}^{PIL}+z_{INV}^{PGT}+z_{INV}^{ENGS}\right)\right\}\right], \tag{1}$$

$$z_{INV}^{PIL} = \sum_{pl\in\Omega^{PPL}} C_{pl}^{PLINV} R_{pl,y,w}^{INV} + \sum_{l\in\Psi^{PTL}} C_l^{TLINV} X_{l,y,w}^{INV}, \tag{1a}$$

$$z_{INV}^{PGT} = \sum_{g\in\Psi^{PG}} C_g^{PGINV} P_{g,y,w}^{GI} + \sum_{k\in\Psi^{PT}} C_k^{PTINV} P_{k,y,w}^{TI}, \tag{1b}$$

$$z_{INV}^{ENGS} = \sum_{es\in\Psi^{PES}} C_{es}^{ESINV} S_{es,y,w}^{ESINV}$$
$$+ \sum_{gs\in\Omega^{PGS}} C_{gs}^{GSINV} S_{gs,y,w}^{GSINV}. \tag{1c}$$

2.1.2 | Minimization of maintenance and operational cost

The NPV of operational cost is modeled in (2). The maintenance and operational costs of natural gas and thermal power plants are addressed in (2a). The operational and maintenance costs of NGS are described in (2b). Finally, the cost of natural gas extraction from natural gas supplies is shown in (2c).

Similar to investment costs, the operational costs are multiplied by $(1+ir_y)^{-st_y}$ to convert the costs to NPV, and by the probability of each scenario ρ_w^{scen}. Each stage contains several years, hence to find the present value, operational costs are multiplied by $\frac{(1+ir_y)^{st_y}-1}{ir_y(1+ir_y)^{st_y}}$. It is based on the assumption that operational costs are constant in every year of the stage. Finally, operational costs are multiplied by the weight of each operation condition ω_o.

$$Z_{OP} = \sum_{w\in W}\left[\rho_w^{scen}\sum_{y\in Y}\left\{(1+ir_y)^{-st_y}\left(\frac{(1+ir_y)^{st_y}-1}{ir_y(1+ir_y)^{st_y}}\right)\right.\right.$$
$$\left.\left.\times\left(\sum_{o\in O}\omega_o\sum_{t\in T}\left[z_{OP}^{PGT}+z_{OP}^{NGS}+z_{OP}^{GP}\right]\right)\right\}\right], \tag{2}$$

$$z_{OP}^{PGT} = \sum_g OC_g^{GU} P_{g,y,w,o,t}^{GU} + \sum_k OC_k^{TU} P_{k,y,w,o,t}^{TU}, \tag{2a}$$

$$z_{OP}^{NGS} = \sum_{gs} OC_{gs}^{GS}\left(SR_{gs,y,w,o,t}^{GS} + RR_{gs,y,w,o,t}^{GS}\right), \tag{2b}$$

$$z_{OP}^{GP} = \sum_{s\in S} XS_{s,y,w,o,t} Pr_{w,y}^{Change} \chi_{s,o,t}^{GAS}. \tag{2c}$$

2.2 | Constraints

In this section, we describe the constraints that are considered in solving the developed DSJEP. DSJEP is subject to investment and operational constraints, as follows.

2.2.1 | Investment constraints

The investment constraints of DSJEP model are presented in (3) to (6). The maximum available capacity that can be built for each of the natural gas and thermal power plants in the planning horizon is defined by (3). Constraint (4) ensures that the candidate transmission line investments are binary decision variables, and they are one time investment decision along the planning horizon. The maximum capacity of candidate pipeline in each scenario along the planning horizon is shown by (5). Constraint (6) imposes a maximum amount of ENGS capacity that can be built in each scenario in the planning horizon.

$$\sum_{y\in Y} P_{g,y,w}^{GI} \le P_g^{GI,MAX} \qquad \forall g\in\Psi^{PG}, w\in W,$$
$$\sum_{y\in Y} P_{k,y,w}^{TI} \le P_k^{TI,MAX} \qquad \forall k\in\Psi^{PT}, w\in W, \tag{3}$$

$$X_{l,y,w}^{INV} \in \{0,1\} \qquad \forall l\in\Psi^{PTL}, y\in Y, w\in W,$$
$$\sum_{y\in Y} X_{l,y,w}^{INV} \le 1 \qquad \forall l\in\Psi^{PTL}, w\in W, \tag{4}$$

$$\sum_{y\in Y} R_{pl,y,w}^{INV} \le R_{pl}^{INV,MAX} \qquad \forall pl\in\Omega^{PPL}, w\in W, \tag{5}$$

$$\sum_{y\in Y} S_{gs,y,w}^{GSINV} \le S_{gs}^{GSINV,MAX} \qquad \forall gs\in\Omega^{PGS}, w\in W,$$
$$\sum_{y\in Y} S_{es,y,w}^{ESINV} \le S_{es}^{ESINV,MAX} \qquad \forall es\in\Psi^{PES}, w\in W. \tag{6}$$

2.2.2 | Operational electricity network constraints

The operational electricity network constraints comprise of (7) to (13). Constraint (7) dictates the power balance for each bus n. Constraints (8) represent the DC power flow model for existing transmission lines and enforce power flow limits [32].

Constraints (9) dictate that if candidate transmission line is constructed at stage y or before that ($\sum_{y'\le y} X_{l,y',w}^{INV}=1$), power flow equation is the same as power flow equation of existing transmission line in (8). If the candidate transmission line is not built, power flow becomes zero, and the constraint does not limit voltage angle differences. Constraint (10) enforces voltage angle limits and ensures voltage angle at the reference node must be constant.

Constraints (11)–(13) impose limits on candidate and existing power plants output power. Constraints (11) dictate that the power produced by the candidate natural gas and thermal power plants at stage y must be less than the sum of invested capacity up to that stage. Ramping up and down limits of invested and existing thermal and natural gas power plants are enforced in (12). Finally, (13) enforces the generation limits on existing power plants.

$$\sum_{g\in\Psi_n^G} P^{GU}_{g,y,w,o,t} + \sum_{k\in\Psi_n^T} P^{TU}_{k,y,w,o,t} + \sum_{es\in\Psi_n^{ES}} (D^{ES}_{es,y,w,o,t} - Ch^{ES}_{es,y,w,o,t}) - \sum_{l\in\Psi^{SL}_{n,l}} PF_{l,y,w,o,t} + \sum_{l\in\Psi^{RL}_{n,l}} PF_{l,y,w,o,t} = L^E_n f^{ED}_{n,o,t} LG^E_{w,y}$$
$$\forall n\in N, y\in Y, w\in W, o\in O, t\in T, \quad (7)$$

$$PF_{l,y,w,o,t} = \beta_l\left(\sum_{n\in\Psi^{SL}_{n,l}} \theta_{n,y,w,o,t} - \sum_{n\in\Psi^{RL}_{n,l}} \theta_{n,y,w,o,t}\right)$$
$$\forall l \backslash l\in\Psi^{PTL}, y\in Y, w\in W, o\in O, t\in T$$
$$-PF^{MAX}_l \le PF_{l,y,w,o,t} \le PF^{MAX}_l$$
$$\forall l \backslash l\in\Psi^{PTL}, y\in Y, w\in W, o\in O, t\in T, \quad (8)$$

$$-\left(1-\sum_{y'\le y} X^{INV}_{l,y',w}\right) M \le PF_{l,y,w,o,t} - \beta_l\left(\sum_{n\in\Psi^{SL}_{n,l}} \theta_{n,y,w,o,t} - \sum_{n\in\Psi^{RL}_{n,l}} \theta_{n,y,w,o,t}\right)$$
$$\le (1-\sum_{y'\le y} X^{INV}_{l,y',w})M \quad \forall l\in\Psi^{PTL}, y\in Y, w\in W, o\in O,$$
$$t\in T - PF^{MAX}_l \sum_{y'\le y} X^{INV}_{l,y',w} \le PF_{l,y,w,o,t} \le PF^{MAX}_l \sum_{y'\le y} X^{INV}_{l,y',w}$$
$$\forall l\in\Psi^{PTL}, y\in Y, w\in W, o\in O, t\in T, \quad (9)$$

$$-\pi \le \theta_{n,y,w,o,t} \le \pi \quad \forall n\in N, y\in Y, w\in W, o\in O, t\in T$$
$$\theta_{n_{ref},y,w,o,t} = \theta_{ref} \quad \forall y\in Y, w\in W, o\in O, t\in T, \quad (10)$$

$$P^{GU}_{g,y,w,o,t} \le \sum_{y'\le y} P^{GI}_{g,y',w} \quad \forall g\in\Psi^{PG}, y\in Y, w\in W, o\in O, t\in T$$
$$P^{TU}_{k,y,w,o,t} \le \sum_{y'\le y} P^{TI}_{k,y',w} \quad \forall k\in\Psi^{PT}, y\in Y, w\in W, o\in O, t\in T, \quad (11)$$

$$-P^{PG,RD}_g \sum_{y'\le y} P^{PGINV}_{g,y',w} \le P^{GU}_{g,y,w,o,t} - P^{GU}_{g,y,w,o,t-1} \le P^{PG,RU}_g \sum_{y'\le y} P^{PGINV}_{g,y',w} \forall g\in\Psi^{PG}, y\in Y, w\in W, o\in O,$$
$$t\in T - P^{EG,RD}_g \le P^{GU}_{g,y,w,o,t} - P^{GU}_{g,y,w,o,t-1} \le P^{EG,RU}_g$$
$$\forall g\backslash g\in\Psi^{PG}, y\in Y, w\in W, o\in O, t\in T$$
$$-P^{PT,RD}_k \sum_{y'\le y} P^{TI}_{k,y',w} \le P^{TU}_{k,y,w,o,t} - P^{TU}_{k,y,w,o,t-1} \le P^{PT,RU}_k \sum_{y'\le y} P^{TI}_{k,y',w} \quad \forall k\in\Psi^{PT}, y\in Y, w\in W, o\in O, t\in T$$
$$-P^{ET,RD}_k \le P^{TU}_{k,y,w,o,t} - P^{TU}_{k,y,w,o,t-1} \le P^{ET,RU}_k$$
$$\forall k\backslash k\in\Psi^{PT}, y\in Y, w\in W, o\in O, t\in T, \quad (12)$$

$$P^{GU}_{g,y,w,o,t} \le P^{EG,MAX}_g \forall g\backslash g\in\Psi^{PG}, y\in Y, w\in W, o\in O, t\in T,$$
$$P^{TU}_{k,y,w,o,t} \le P^{ET,MAX}_k \forall k\backslash k\in\Psi^{PT}, y\in Y, w\in W, o\in O, t\in T. \quad (13)$$

2.2.3 | Operational constraints of natural gas system

The operational constraints for natural gas system comprise (14)–(17) [3]. Gas consumption and generation equilibrium for each natural gas system node p is represented in (14). Constraints in (15) enforce gas flow limits on existing gas pipelines. Gas flow through candidate gas pipelines at stage y must be less than the sum of capacity constructed from the first stage to stage y. Constraint (16) imposes the maximum natural gas production for natural gas supply s. Constraint (17) defines the linkage between electricity and natural gas networks by natural gas power plants. Power is generated in natural gas power plants by consuming natural gas, assuming that the linkage is linear.

$$\sum_{s\in\Omega^S_P} XS_{s,y,w,o,t} + \sum_{gs\in\Omega^{GS}_P} \left(RR^{GS}_{gs,y,w,o,t} - SR^{GS}_{gs,y,w,o,t}\right) - \sum_{pl\in\Omega^{SP}_{p,pl}} GF_{pl,y,w,o,t} + \sum_{pl\in\Omega^{RP}_{p,pl}} GF_{pl,y,w,o,t} = \sum_{g\in\Omega^G_P} U^G_{g,y,w,o,t} + L^{NG}_P g^{NGD}_{p,o,t} LG^{NG}_{w,y}$$
$$\forall p\in P, y\in Y, w\in W, o\in O, t\in T, \quad (14)$$

$$-GF^{MAX}_{pl} \le GF_{pl,y,w,o,t} \le GF^{MAX}_{pl}$$
$$\forall pl\backslash pl\in\Omega^{PPL}, y\in Y, w\in W, o\in O, t\in T$$

$$-\sum_{y'\leq y} R^{INV}_{pl,y',w} \leq GF_{pl,y,w,o,t} \leq \sum_{y'\leq y} R^{INV}_{pl,y',w}$$
$$\forall pl \in \Omega^{PPL}, y \in Y, w \in W, o \in O, t \in T, \quad (15)$$

$$XS_{s,y,w,o,t} \leq XS^{MAX}_{s} \quad \forall s \in S, y \in Y, w \in W, o \in O, t \in T, \quad (16)$$

$$U^{G}_{g,y,w,o,t} = H_g P^{GU}_{g,y,w,o,t} \quad \forall g \in G, y \in Y, w \in W, o \in O, t \in T. \quad (17)$$

2.2.4 | Storage constraints

ENGS constraints are shown in (18)–(21) and in (22)–(25) for NGS and ES, respectively. The level of natural gas stored in the NGS at hour t is shown in (18). Constraints in (19) denote capacity limits on existing and candidate NGSs. These constraints show how much natural gas is available, which is known as working gas [33]. Constraints in (20) enforce limits on storing and releasing of natural gas in existing and future NGSgs. Constraint (21) imposes that the amount of natural gas stored in the storage in final hour of t_T must be specified, which is usually assumed to be equal to the amount at the first hour t_0.

Constraint (22) defines the State of Charge (SoC) of ES at hour t to be equal to SoC at hour $t-1$ plus charging and minus discharging at hour t. The energy stored in ES must be equal to or greater than minimum SoC and equal to or less than maximum SoC for existing and candidate ES,

which are defined in (23). Constraints (24) enforce bounds on charging and discharging of existing and future ES. For future ES, these limits are determined by the capacity that is built in each stage. Constraint (25) imposes that in the final hour t_T, SoC must be specified, which is usually equal to the amount of the first hour t_0.

$$S^{GS}_{gs,y,w,o,t} = S^{GS}_{gs,y,w,o,t-1} + \eta^{SR}_{gs} SR^{GS}_{gs,y,w,o,t} -$$
$$\frac{1}{\eta^{RR}_{gs}} RR^{GS}_{gs,y,w,o,t} \quad \forall gs \in GS, y \in Y, w \in W, o \in O, t \in T, \quad (18)$$

$$S^{GS,MIN}_{gs} \leq S^{GS}_{gs,y,w,o,t} \leq S^{GS,MAX}_{gs}$$
$$\forall gs \backslash gs \in \Omega^{PGS}, y \in Y, w \in W, o \in O, t \in T$$
$$PS^{GS,MIN}_{gs} \sum_{y'\leq y} S^{GSINV}_{gs,y',w} \leq S^{GS}_{gs,y,w,o,t} \leq \sum_{y'\leq y} S^{GSINV}_{gs,y',w}$$
$$\forall gs \in \Omega^{PGS}, y \in Y, w \in W, o \in O, t \in T, \quad (19)$$

$$SR^{GS}_{gs,y,w,o,t} \leq SR^{GS,MAX}_{gs}$$
$$\forall gs \backslash gs \in \Omega^{PGS}, y \in Y, w \in W, o \in O, t \in T$$
$$RR^{GS}_{gs,y,w,o,t} \leq RR^{GS,MAX}_{gs}$$
$$\forall gs \backslash gs \in \Omega^{PGS}, y \in Y, w \in W, o \in O, t \in T$$
$$SR^{GS}_{gs,y,w,o,t} \leq PSR^{GS,MAX}_{gs} \sum_{y'\leq y} S^{GSINV}_{gs,y',w}$$
$$\forall gs \in \Omega^{PGS}, y \in Y, w \in W, o \in O, t \in T$$
$$RR^{GS}_{gs,y,w,o,t} \leq PRR^{GS,MAX}_{gs} \sum_{y'\leq y} S^{GSINV}_{gs,y',w}$$
$$\forall gs \in \Omega^{PGS}, y \in Y, w \in W, o \in O, t \in T, \quad (20)$$

$$S^{GS}_{gs,y,w,o,t_0} = S^{GS}_{gs,y,w,o,t_T}$$
$$\forall gs \in GS, y \in Y, w \in W, o \in O, t \in T, \quad (21)$$

$$S^{ES}_{es,y,w,o,t} = S^{ES}_{es,y,w,o,t-1} + \eta^{ES}_{es} Ch^{ES}_{es,y,w,o,t} - D^{ES}_{es,y,w,o,t}$$
$$\forall es \in ES, y \in Y, w \in W, o \in O, t \in T, \quad (22)$$

$$S^{ES,MIN}_{es} \leq S^{ES}_{es,y,w,o,t} \leq S^{ES,MAX}_{es}$$
$$\forall es \backslash es \in \Psi^{PES}, y \in Y, w \in W, o \in O, t \in T$$
$$PS^{ES,MIN}_{es} \sum_{y'\leq y} S^{ESINV}_{es,y',w} \leq S^{ES}_{es,y,w,o,t} \leq \sum_{y'\leq y} S^{ESINV}_{es,y',w}$$
$$\forall es \in \Psi^{PES}, y \in Y, w \in W, o \in O, t \in T, \quad (23)$$

$$Ch^{ES}_{es,y,w,o,t} \leq Ch^{ES,MAX}_{es}$$
$$\forall es \backslash es \in \Psi^{PES}, y \in Y, w \in W, o \in O, t \in T$$
$$D^{ES}_{es,y,w,o,t} \leq D^{ES,MAX}_{es}$$
$$\forall es \backslash es \in \Psi^{PES}, y \in Y, w \in W, o \in O, t \in T$$
$$Ch^{ES}_{es,y,w,o,t} \leq PCh^{MAX}_{es} \sum_{y'\leq y} S^{ESINV}_{es,y',w}$$
$$\forall es \in \Psi^{PES}, y \in Y, w \in W, o \in O, t \in T$$
$$D^{ES}_{es,y,w,o,t} \leq PD^{MAX}_{es} \sum_{y'\leq y} S^{ESINV}_{es,y',w}$$
$$\forall es \in \Psi^{PES}, y \in Y, w \in W, o \in O, t \in T, \quad (24)$$

$$S^{ES}_{es,y,w,o,t_0} = S^{ES}_{es,y,w,o,t_T} \quad \forall es \in ES, y \in Y, w \in W, o \in O, t \in T. \quad (25)$$

2.2.5 | Nonanticipativity constraints

The constraints in (26)-(27) ensure nonanticipativity that prevent anticipating future information [32].

Constraints in (26) imply that the investment decision results in the first stage are the same for all scenarios and do not depend on future information; due to the fact that uncertainties does not happen at the beginning of the first stage, when investment decisions are made. All scenarios are indistinguishable and the same investment decisions are made in all scenarios at this stage [34]. For the other stages, constraints in (27) impose that if every uncertainty parameter, for example $LG^{E}_{w,y}$, $LG^{NG}_{w,y}$ and $Pr^{Change}_{w,y}$, in stage y and whole stages before that for two scenarios are identical, the investment decisions for that scenarios and stage are the same. In other words, scenarios whit a common history must have the same set of decisions.

$$
\begin{aligned}
&P^{GI}_{g,y_0,w} = P^{GI}_{g,y_0,w'} && \forall g \in \Psi^{PG}, w, w' \in W,\\
&P^{TI}_{k,y_0,w} = P^{TI}_{k,y_0,w'} && \forall k \in \Psi^{PT}, w, w' \in W,\\
&X^{INV}_{l,y_0,w} = X^{INV}_{l,y_0,w'} && \forall l \in \Psi^{PTL}, w, w' \in W,\\
&R^{INV}_{pl,y_0,w} = R^{INV}_{pl,y_0,w'} && \forall pl \in \Omega^{PPL}, w, w' \in W,\\
&S^{GSINV}_{gs,y_0,w} = S^{GSINV}_{gs,y_0,w'} && \forall gs \in \Omega^{PGS}, w, w' \in W,\\
&S^{ESINV}_{es,y_0,w} = S^{ESINV}_{es,y_0,w'} && \forall es \in \Psi^{PES}, w, w' \in W,
\end{aligned}
\tag{26}
$$

$$
\begin{aligned}
&P^{GI}_{g,y,w} = P^{GI}_{g,y,w'} \,|\, LG^{E}_{w,y} = LG^{E}_{w',y'}, LG^{NG}_{w,y} = LG^{NG}_{w',y'},\\
&Pr^{Change}_{w,y} = Pr^{Change}_{w',y'} \quad \forall g \in \Psi^{PG}, y' \leq y \in Y, w, w' \in W\\
&P^{TI}_{k,y,w} = P^{TI}_{k,y,w'} \,|\, LG^{E}_{w,y} = LG^{E}_{w',y'}, LG^{NG}_{w,y} = LG^{NG}_{w',y'},\\
&Pr^{Change}_{w,y} = Pr^{Change}_{w',y'} \quad \forall k \in \Psi^{PT}, y' \leq y \in Y, w, w' \in W\\
&X^{INV}_{l,y,w} = X^{INV}_{l,y,w'} \,|\, LG^{E}_{w,y} = LG^{E}_{w',y'}, LG^{NG}_{w,y} = LG^{NG}_{w',y'},\\
&Pr^{Change}_{w,y} = Pr^{Change}_{w',y'} \quad \forall l \in \Psi^{PTL}, y' \leq y \in Y, w, w' \in W\\
&R^{INV}_{pl,y,w} = R^{INV}_{pl,y,w'} \,|\, LG^{E}_{w,y} = LG^{E}_{w',y'}, LG^{NG}_{w,y} = LG^{NG}_{w',y'},\\
&Pr^{Change}_{w,y} = Pr^{Change}_{w',y'} \quad \forall pl \in \Omega^{PPL}, y' \leq y \in Y, w, w' \in W\\
&S^{GSINV}_{gs,y,w} = S^{GSINV}_{gs,y,w'} \,|\, LG^{E}_{w,y} = LG^{E}_{w',y'}, LG^{NG}_{w,y} = LG^{NG}_{w',y'},\\
&Pr^{Change}_{w,y} = Pr^{Change}_{w',y'} \quad \forall gs \in \Omega^{PGS}, y' \leq y \in Y, w, w' \in W\\
&S^{ESINV}_{es,y,w} = S^{ESINV}_{es,y,w'} \,|\, LG^{E}_{w,y} = LG^{E}_{w',y'}, LG^{NG}_{w,y} = LG^{NG}_{w',y'},\\
&Pr^{Change}_{w,y} = Pr^{Change}_{w',y'} \quad \forall es \in \Omega^{PES}, y' \leq y \in Y, w, w' \in W.
\end{aligned}
\tag{27}
$$

2.3 | Solution algorithm

The solution procedure of DSJEP is presented in Algorithm 1.

ALGORITHM 1 Dynamic Stochastic Joint Expansion Planning

Algorithm 1: Dynamic Stochastic Joint Expansion Planning

```
Input: determine the number of stages, scenarios and
   operation conditions (y, w, o) for problem.
Output: generate scenarios considering uncertainties at each
   stage & construct scenario tree ⟹ w^Generate
if w ≤ w^Generate then
 | scenario reduction is employed ⟹ w & ρ_w^scen;
else
 | Continue;
end
Input: real natural gas price and electricity and natural gas
   consumption, hourly data for ten years.
Output: using k-means clustering ⟹ find o and ω_o
for y ∈ Y do
 | if uncertainties at w = uncertainties at w' then
 | | investment decision at w = Investment decision at w'
 | end
end
for Networks do
 | find minimum Z_INV + Z_OP
 | s.t.
 | investment constraints
 | operation electricity and natural gas constraints
 | export output
end
```

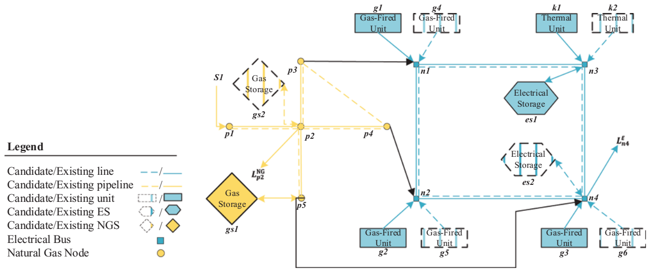


FIGURE 1 The topology of a modified four-bus power system and a five-node natural gas network

3 | SIMULATION RESULTS

All the mathematical equations are implemented in the version 25.1.3 of GAMS software to solve DSJEP. In CPLEX solver, MILP is applied according to [35]. The computation times of all cases, for the example system in Section 3.1 and IEEE 118-bus system in Section 3.2 are less than 1 h and 72 h, respectively.

3.1 | Example system

The proposed DSJEP is implemented on a modified five-node natural gas network and a modified four-bus power system network. The topology is depicted in Figure 1. The blue lines show the power system, and the yellow lines indicate the natural gas network. The natural gas network node is connected to the power system bus by a natural gas power plant shown by a black line. Candidate infrastructures are shown with dashed lines on both networks.

TABLE 2 Data for existing generation units

Type of unit	Unit	Max capacity	Ramping up/ down (MW)	Operation cost ($/MW)	Heat rate (MBTU/MW)
Natural gas power plant	g1	220 MW	110/110	11	11
Natural gas power plant	g2, g3	200 MW	120/120	10	10
Thermal power plant	k1	200 MW	100/100	65	–
Natural gas production unit	s1	300 000 MBTU	–	–	–

TABLE 3 Data for candidate generation units

Unit	Maximum investible capacity (MW)	Proportion of ramping up/down	Operation cost ($/MW)	Investment cost ($/MW)	Heat rate (MBTU/MW)
g4, g5, g6	250	0.7/0.7	8	95 000	8
k2	250	0.6/0.6	60	105 000	–

3.1.1 | Natural gas and electricity network data

The details of the characteristics of existing natural gas and electricity units are given in Table 2.

The details of the characteristics of candidate units are listed in Table 3. Column three defines the up and down ramping limits; for example, if the maximum capacity of unit $g4$ is built, the ramping limits will be 175 MW/h.

The data of existing transmission lines and pipelines are detailed in Tables 4 and 5, respectively. Characteristics of the candidate transmission lines are the same as existing ones with the capital cost of 50 million dollars for lines one and two and 20 million dollars for lines three and four.

The data of the candidate pipelines are presented by Table 6.

TABLE 4 Data for transmission lines

Transmission line	Send bus	Receiving bus	Max capacity (MW)	Susceptance (S)
l1	n1	n2	700	505
l2	n1	n3	700	505
l3	n2	n4	220	202
l4	n3	n4	220	202

TABLE 5 Data for existing pipelines

Pipeline	Send node	Receiving node	Max capacity (MBTU/h)
pl1	p1	p2	15 000
pl2	p2	p3	1 800
pl3	p2	p4	2 000
pl4	p2	p5	500

The characteristics of NGS and ES are presented in Tables 7 and 8, respectively. The investment cost of candidate NGSs is 5000 $/MBTU according to [36] and 10,000 $/MWh for ESs.

3.1.2 | Operation and scenario data

The base electrical demand at power system node four is 670 MW, and natural gas demand at node two is 15,000 MBTU. k-means clustering is implemented to obtain ten 24-h operation conditions to model 365 days of a year using MATLAB [38]. Operation conditions for demand are derived from the electricity demand in France from 2006 until 2015 [39]. Natural gas price, which is shown in the twenty-fifth data in Figure 2 is obtained from daily Henry Hub natural gas price in [40]. Figure 2 shows ten operation conditions after the implementation of k-means clustering. The number of days for each Operation condition is shown in Table 9, which represents how many days are assigned to each operation condition.

The planning horizon is assumed to be 20 years and is broken down into four planning stages, each comprising of five years, and is depicted in Figure 3. The investment decisions are made at the beginning of each stage. There are a total of eight scenarios which include uncertainties in electrical load growth,

TABLE 6 Data for candidate pipelines

Pipeline	Send node	Receiving node	Max capacity (MBTU/h)	Investment cost ($/MBTU/h)
pl5	p1	p2	15 000	750 000
pl6	p2	p3	1 800	35 000
pl7	p2	p4	2 000	35 000
pl8	p2	p5	500	350 000
pl9	p3	p4	1 500	35 000

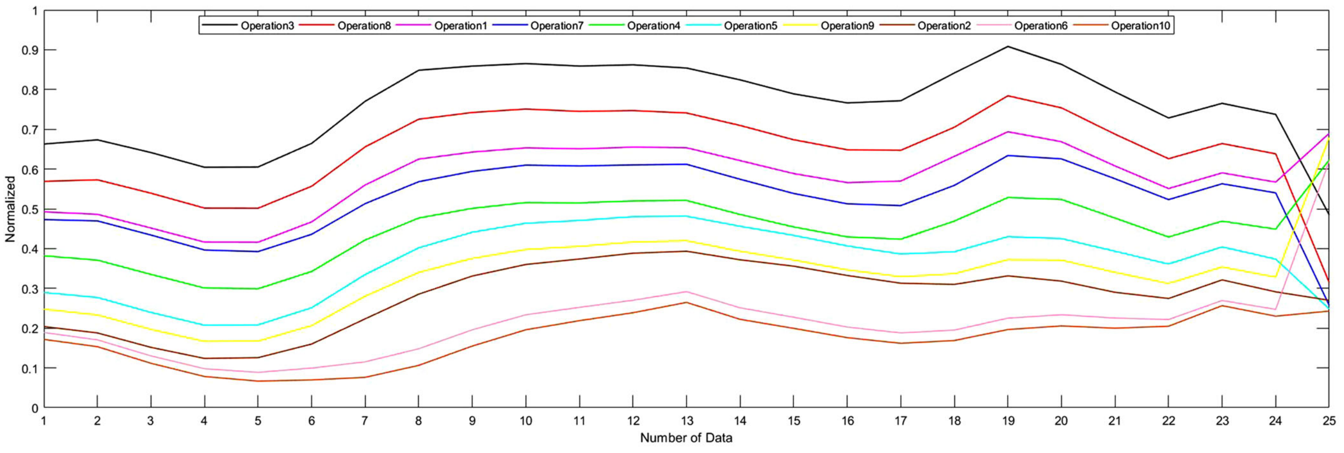


FIGURE 2 Ten operation conditions after k-means clustering

TABLE 7 Data for NGS [37]

Existing NGS gs1		Candidate NGS gs2	
Parameter	**Value**	**Parameter**	**Value**
$S_{gs}^{GS,MIN}/S_{gs}^{GS,MAX}$	100/1 000 (MBTU)	$PS_{gs}^{GS,MIN}/S_{gs}^{GSINV,MAX}$	0.1/20 000 (MBTU)
$SR_{gs}^{GS,MAX}/RR_{gs}^{GS,MAX}$	300/300 (MBTU/h)	$PSR_{gs}^{GS,MAX}/PRR_{gs}^{GS,MAX}$	0.5/0.5
$\eta_{gs}^{SR}/\eta_{gs}^{RR}$	0.85/0.85	$\eta_{gs}^{SR}/\eta_{gs}^{RR}$	0.9/0.9
OC_{gs}^{GS}	0.4 ($/MBTU/h)	OC_{gs}^{GS}	0.3 ($/MBTU/h)

namely, high and low electrical load growth (HELG, LELG) and uncertainties in natural gas load growth, high and low gas load growth (HGLG, LGLG), and uncertainties in natural gas price, increasing and decreasing gas price (IGP and DGP) in each year. Therefore, there are a total of eight scenarios in each stage.

Percent of fluctuation in a year and the probability of uncertainties are declared in Table 10. There are several methods for scenario generation which are described in [41]. In this paper, 512 scenarios are generated by combining all possible scenarios as shown in Figure 4. With this numbers of scenarios, the most optimum answer to the problem is collected after a long time A scenario reduction technique is employed using GAMS software, in which the backward scenario reduction method is employed [35] to reduce the number of scenarios and therefore alleviate the computational burden. Figure 5 shows the results of scenario reduction. The scenario probability for the five selected scenarios are 0.243, 0.25, 0.257, 0.125 and 0.125, respectively.

TABLE 9 Number of days

Operation condition	o1	o2	o3	o4	o5	o6	o7	o8	o9	o10	Total
Number of days	26	62	26	34	42	29	30	35	43	38	365

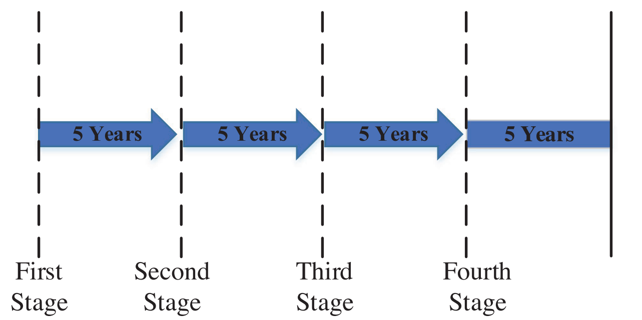


FIGURE 3 The whole planning horizon and stages

TABLE 8 Data for ES

Existing ES es1		Candidate ES es2	
Parameter	**Value**	**Parameter**	**Value**
$S_{es}^{ES,MIN}/S_{es}^{ES,MAX}$	100/600 (MWh)	$PS_{es}^{ES,MIN}/S_{es}^{ESINV,MAX}$	0.1/10 000 (MWh)
$Ch_{es}^{ES,MAX}/D_{es}^{ES,MAX}$	500/500 (MW)	$PCh_{es}^{MAX}/PD_{es}^{MAX}$	0.5/0.5
η_{es}^{ES}	0.8	η_{es}^{ES}	0.8

TABLE 10 Uncertainty and probability data

Type of uncertainty	Parameter	Fluctuation in a year	Probability
Electrical load	HELG	+4 %	0.6
	LELG	+2 %	0.4
Natural gas load	HGLG	+3 %	0.7
	LGLG	+1 %	0.3
Natural gas price	IGP	+10 %	0.5
	DGP	-10 %	0.5

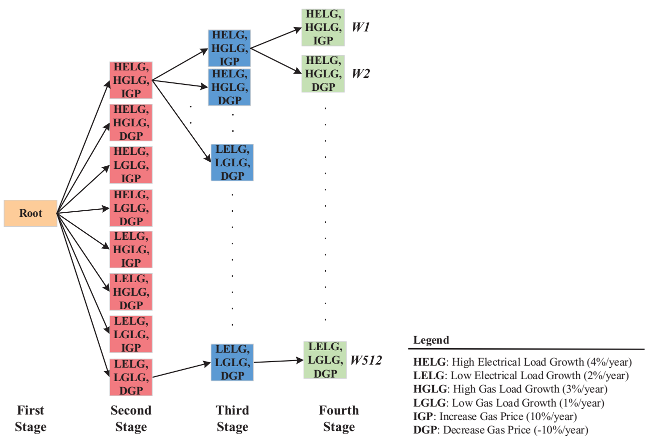


FIGURE 4 All possible scenarios are generated

In this paper, the following four cases are considered to demonstrate the effects of energy and natural gas storage on investment and operation costs. Five scenario are used in each case. The four cases are:

- **Case study 1**: Without any energy storage,

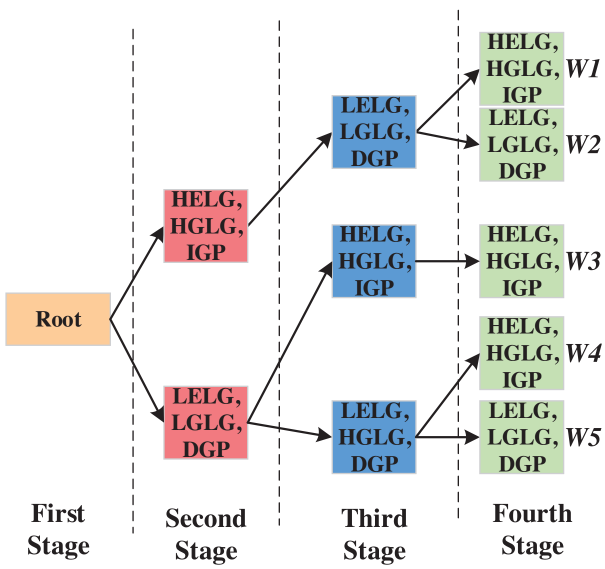


FIGURE 5 After scenario reduction

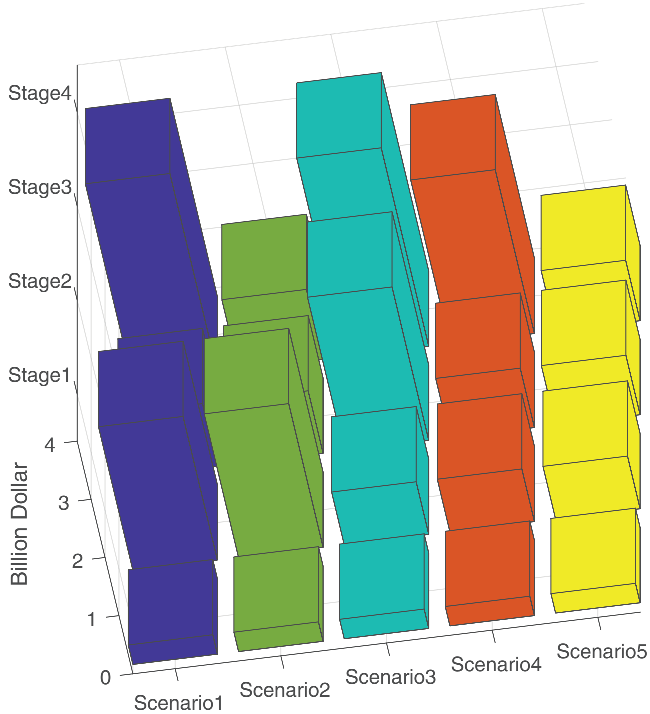


FIGURE 6 Investment cost in different stages for case 1

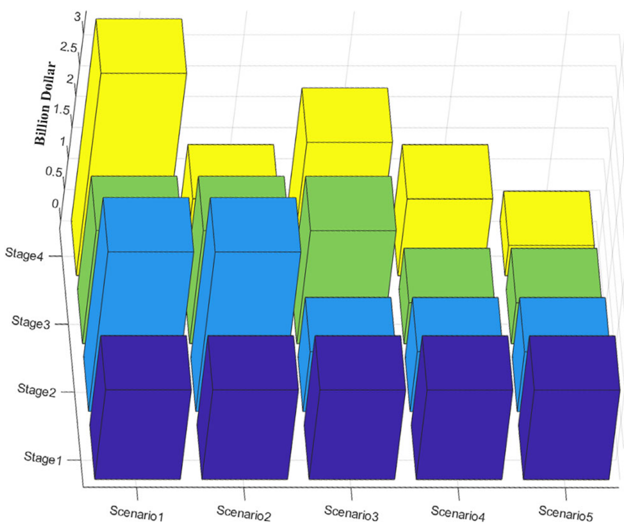


FIGURE 7 Operation cost in different stages for case 1

- **Case study 2**: Only ES is considered,
- **Case study 3**: Only NGS is considered,
- **Case study 4**: Both ENGS are considered.

3.1.3 | Case study 1 results

The network in Figure 1 without any storage is considered for this case. Investment and operation costs in each stage are illustrated in Figures 6 and 7, respectively. Investment costs in all

TABLE 11 Investment decisions result for different scenario at each stage for case 1

Scenario	Stage 1		Stage 2		Stage 3		Stage 4	
Scenario 1	g4	225 MW	g5	7 MW	g5	38 MW	g6	63 MW
	g5	205 MW	l3	1	g6	41 MW	l1	1
	g6	21 MW	pl1	3 225 MBTU	pl1	1 421 MBTU	pl1	4 209 MBTU
	k2	200 MW					pl3	506 MBTU
	pl1	293 MBTU					pl4	500 MBTU
	l4	1					pl5	231 MBTU
Scenario 2	g4	225 MW	g5	7 MW	g5	38 MW	l1	1
	g5	205 MW	l3	1	g6	41 MW	pl1	1 533 MBTU
	g6	21 MW	pl1	3 225 MBTU	pl1	1 421 MBTU		
	k2	200 MW						
	pl1	293 MBTU						
	l4	1						
Scenario 3	g4	225 MW	g6	41 MW	g5	45 MW	g6	63 MW
	g5	205 MW	pl1	1 202 MBTU	l3	1	l1	1
	g6	21 MW			pl1	3 445 MBTU	pl1	4 209 MBTU
	k2	200 MW					pl3	737 MBTU
	pl1	293 MBTU					pl4	500 MBTU
	l4	1						
Scenario 4	g4	225 MW	g6	41 MW	g5	45 MW	l1	1
	g5	205 MW	pl1	1 202 MBTU	l3	1	pl1	3 689 MBTU
	g6	21 MW			pl1	1 290 MBTU		
	k2	200 MW						
	pl1	293 MBTU						
	l4	1						
Scenario 5	g4	225 MW	g6	41 MW	g5	45 MW	pl1	1 385 MBTU
	g5	205 MW	pl1	1 202 MBTU	l3	1		
	g6	21 MW			pl1	1 290 MBTU		
	k2	200 MW						
	pl1	293 MBTU						
	l4	1						

scenarios at the first stage are the same; stage two scenarios 1-2 and scenarios 3-5 and stage three scenarios 1-2 and scenarios 4-5 have the same investment cost; these same investment costs result from nonanticipative constraints, which are described in Section 2.2.5.

DSJEP results of case 1 are shown in Table 11. It can be observed that, nonanticipativity constraints forces the scenarios with the same uncertainties at each stage to have the same results. Expansion decisions made at the first stage are the same for all five scenarios. In the second stage, scenarios 1 and 2 have the same uncertainties in the first and second stages; therefore, the expansion decisions are the same, as shown in Table 11. If two scenarios have the same uncertainty in stages 1 and 2, those two scenarios have the same investment decisions at stage 2 [7]. It means that decision-maker has one choice at the first stage, three choices at stage 2, three choices at stage 3 and five choices at stage 4. They can decide these choices at different stages due to the uncertainties that realized.

3.1.4 | Case study 2 results

In this case study, the network in Figure 1 including ES is considered. Investment and operation costs in each stage are illustrated by Figures 8 and 9, respectively.

The invested capacity of ES in each stage and scenario is shown in Table 12. In the first stage, the system needs 1 151 MWh ES capacity for all scenarios. In the second stage for scenarios 1 and 2, there is a need for more capacity than the three other scenarios since these scenarios have low load growth for both electrical and natural gas demand. In the third stage and scenario 3, 504 MWh ES is invested because of HELG and

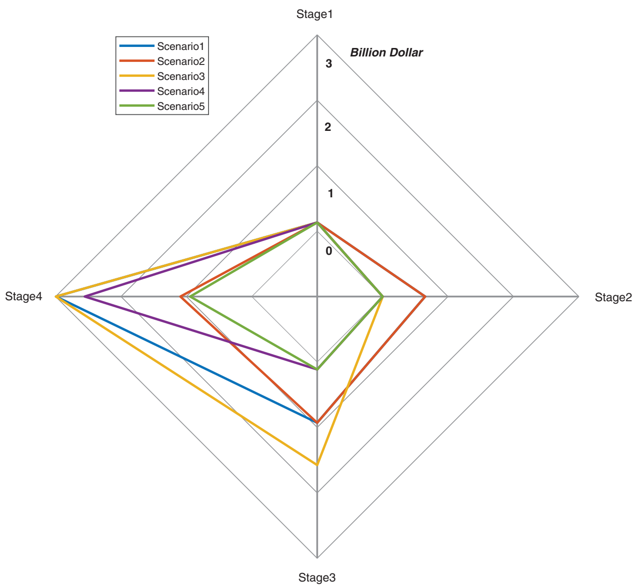


FIGURE 8 Investment cost in different stages for case 2

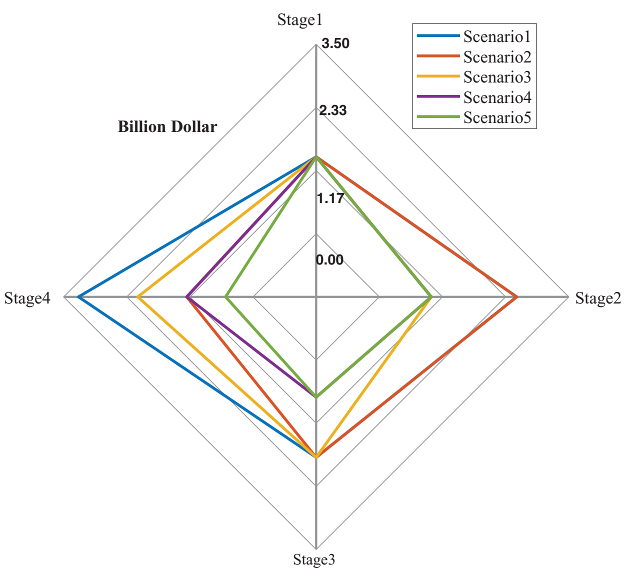


FIGURE 9 Operation cost in different stages for case 2

HGLG. In the fourth stage, for scenarios 1–3, the invested ES capacity before this stage is sufficient, but scenarios 4 and 5 need more ES capacity.

The SoC of candidate ES in scenario 1 for four stages is illustrated in Figure 10. The average SoC of 10 operating conditions in each stage is calculated. At the beginning and end of the operational day the SoC is the same; the Candidate ES charges from hour one to seven, when the electrical demand is low, as is shown in Figure 2; 40% of the energy, which was stored in storage, is discharging between hour ten and fourteen, and the rest of energy is discharging between hour nineteen and twenty-three when the electrical peak demand happens. Figure 10 shows how ES can help the system and store

TABLE 12 The capacity of invested ES

Scenario	Stage 1	Stage 2	Stage 3	Stage 4	Total
Scenario 1	1 151 MWh	269 MWh	222 MWh	–	1 642 MWh
Scenario 2	1 151 MWh	269 MWh	222 MWh	–	1 642 MWh
Scenario 3	1 151 MWh	–	504 MWh	–	1 655 MWh
Scenario 4	1 151 MWh	–	352 MWh	116 MWh	1 619 MWh
Scenario 5	1 151 MWh	–	352 MWh	115 MWh	1 618 MWh

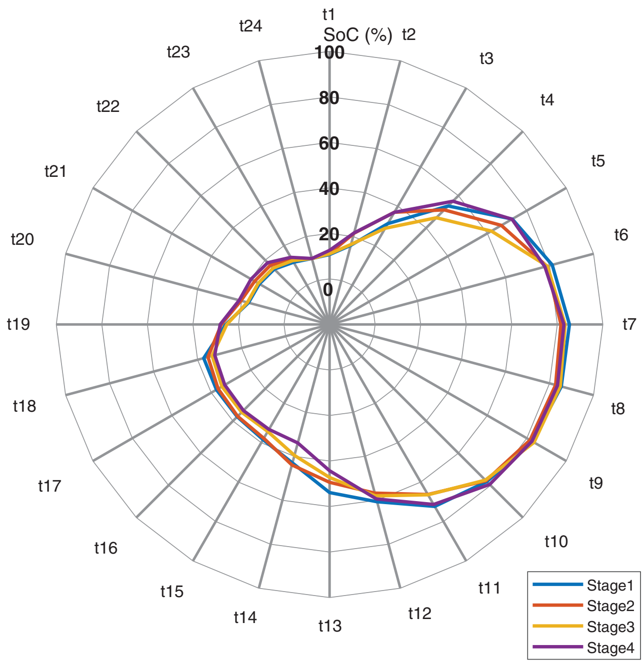


FIGURE 10 The SoC candidate ES at different stages

electricity in off-peak hours and then use it when the electric demand is high.

3.1.5 | Case study 3 results

In this case study, network in Figure 1 with only NGS candidates is considered. Investment and operational costs in each stage are illustrated by Figures 11 and 12, respectively.

The invested capacity of NGS in each stage and scenario is shown in Table 13. In Stage 1, no new NGS is needed, and the existing NGS is sufficient for this stage. In Stage 2, in scenarios 1 and 2, 19,210 MBTU NGS capacity are built, which is more than scenarios 3–5, due to high electrical and natural gas demand growth. In Stage 3, scenarios 3–5 are built with higher capacity than scenarios 1 and 2, since natural gas load growth is high. Only in scenario 5, the maximum investible capacity is not built since there is a low electrical and natural gas demand growth in all stages.

The gas stored in the candidate NGS in scenario 1 for ten operation conditions is depicted in Figure 13. In Stage 1, there

TABLE 13 The capacity of NGS that is built

Scenario	Stage 1	Stage 2	Stage 3	Stage 4	Total
Scenario 1	–	19 210 MBTU	790 MBTU	–	20 000 MBTU
Scenario 2	–	19 210 MBTU	790 MBTU	–	20 000 MBTU
Scenario 3	–	2 390 MBTU	17 610 MBTU	–	20 000 MBTU
Scenario 4	–	2 390 MBTU	16 115 MBTU	1 495 MBTU	20 000 MBTU
Scenario 5	–	2 390 MBTU	16 115 MBTU	1 328 MBTU	19 833 MBTU

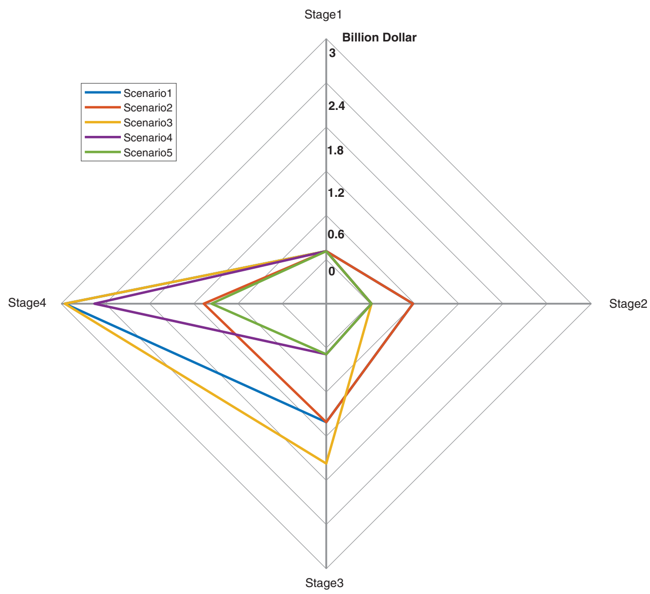


FIGURE 11 Investment cost in different stages for case 3

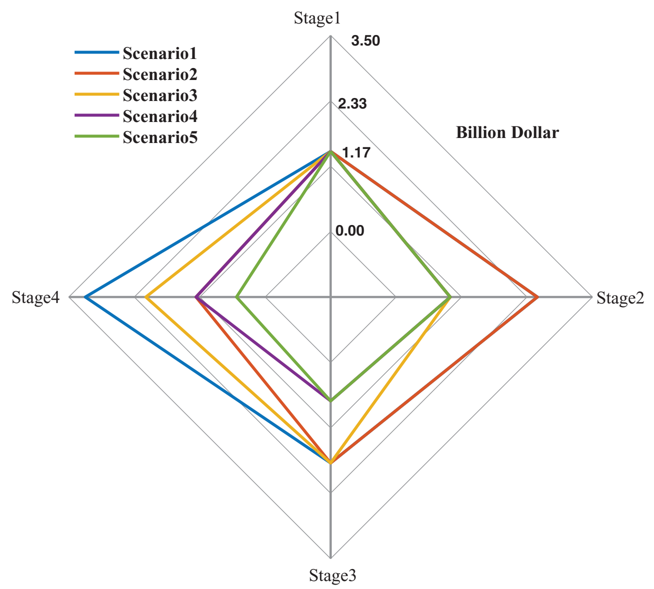


FIGURE 12 Operation cost in different stages for case 3

is no investment in NGS. In other stages, only in operation conditions 3 and 8 natural gas is stored. The reason this happens is that the Operation 3 and 8 has the highest demand as shown in Figure 2. The NGS stores natural gas between hours one to seven and fifteen to seventeen when the demand is low, and then it releases natural gas between hours eight to twelve and eighteen to twenty when the demand is high.

3.1.6 | Case study 4 results

In this case study, the network in Figure 1 with both ENGS are considered. The topology of the PNGS in each stage are illustrated in Figure 14. In this figure, color red indicates an infrastructure that is built in that stage.

3.1.7 | Comparison case study 1–4 results

The investment and operation cost of the four cases are shown in Figure 15. For the sake of clarity, investment and operation costs of scenarios are multiplied by the probability of that scenario. Then scenario costs at each stage are summed and shown in one column. All investment and operation costs for different cases can be compared with each other in Figure 15. The highest investment cost is for Case 1 in all stages.

TABLE 14 Investment and operation costs for all cases (Dollar)

Case	NPV of Z_{INV}	NPV of Z_{OP}	NPV of Total
Case 1	3.742×10^9	4.640×10^9	8.382×10^9
Case 2	1.993×10^9	4.610×10^9	6.601×10^9
Case 3	1.964×10^9	4.608×10^9	6.574×10^9
Case 4	1.798×10^9	4.588×10^9	6.386×10^9

In Case 1, the investment cost in Stage 2 is very high compared to other cases implying that infrastructures are built sooner and are not postponed. In Cases 2 and 3, the investment cost is almost the same in each stage; it shows the PNGS that has electrical or natural gas storage can decrease investment costs 47%. The lowest investment cost is for Case 4, which the investment cost 10% lower than Cases 2 and Case 3. The operation cost for all cases is almost the same. In Case 2, the system has a lower operation cost, about 3%, compared to Case 3 because ES has the least maintenance cost. In Table 14 NPV of all investment and operation costs for different cases are denoted.

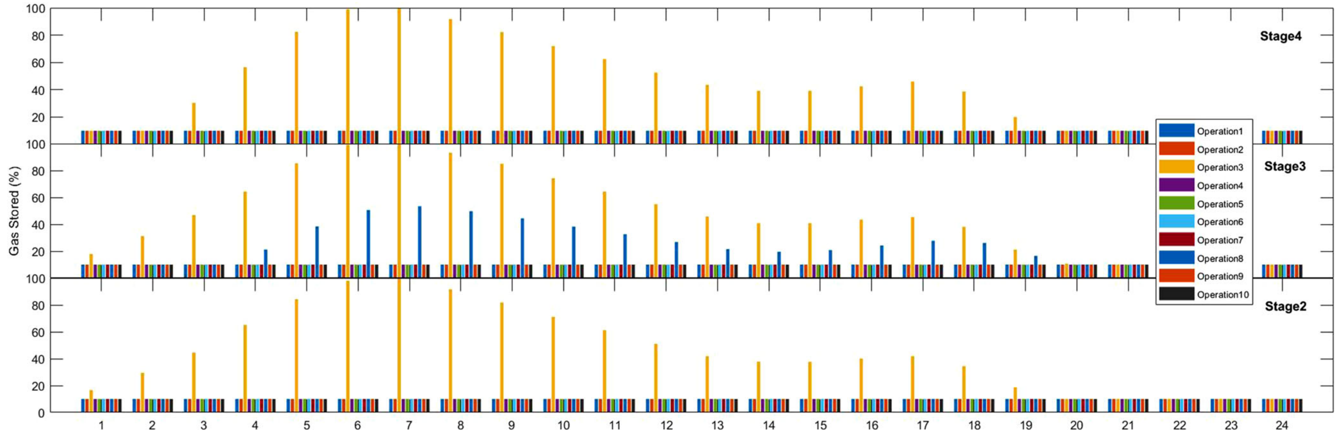


FIGURE 13 Gas stored in candidate NGS for case 3

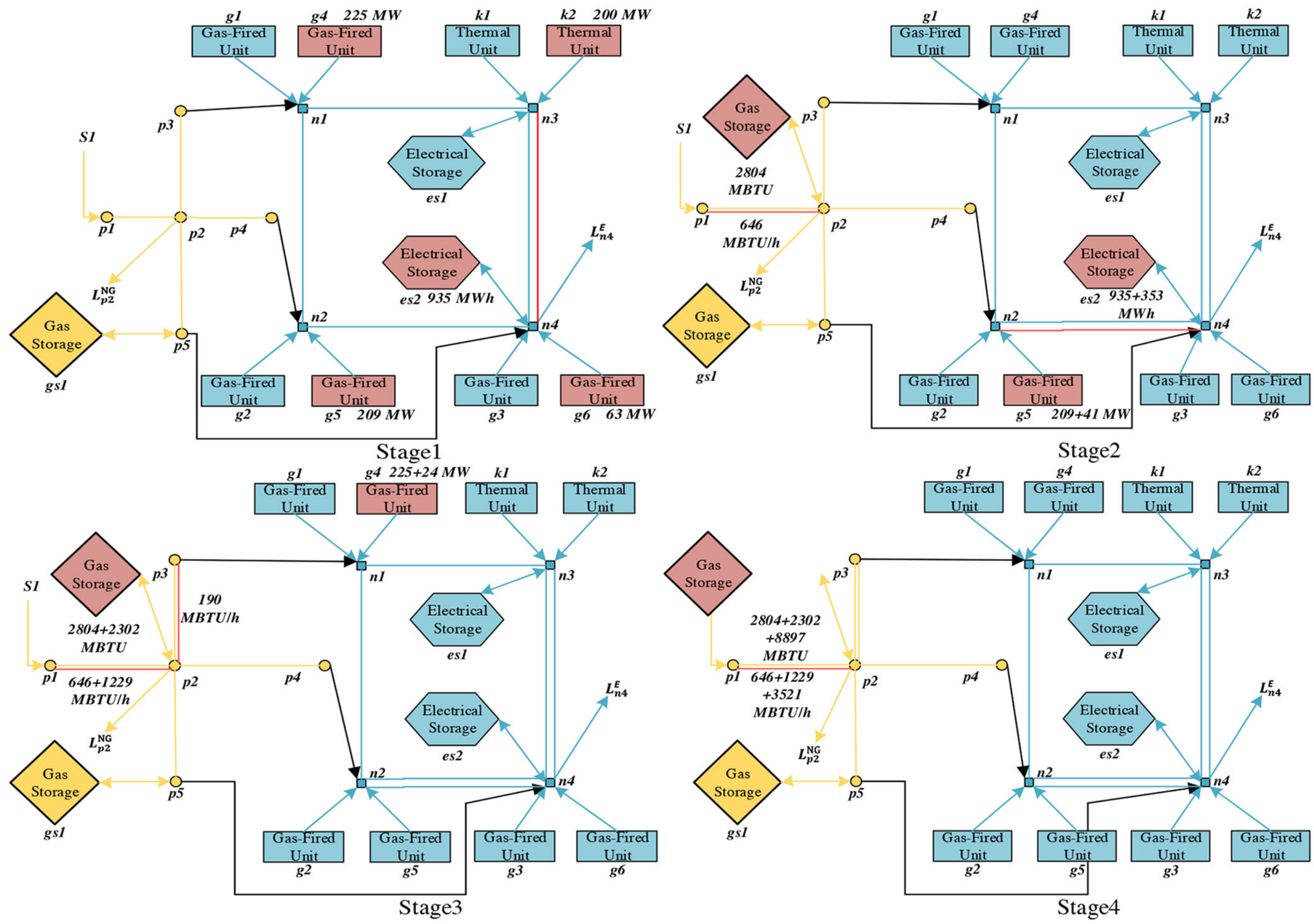


FIGURE 14 Topology of the system at different stages

3.2 | IEEE 118-bus

A tremendous challenge in the expansion planning of power and natural gas systems is due to the large-scale system; therefore, linear equations which are utilized in this paper relieve the challenge. Nevertheless, a drawback of the method is here where pressure and voltage are eliminated from the equations.

The DSJEP performance is analyzed through a modified 14-node natural gas, and IEEE 118-bus power systems. Natural gas and electricity network data are obtained from [42].

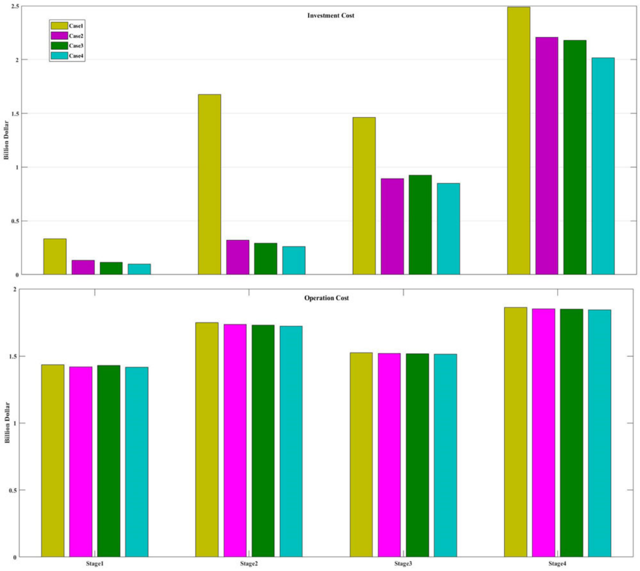
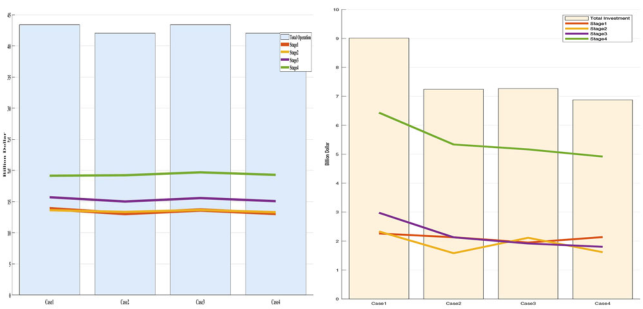


FIGURE 15 Investment and Operation costs for all cases



(a) (b)

FIGURE 16 IEEE 118-bus cost in different cases and stages. (a) Operation cost. (b) Investment cost

Twenty years of planning time is broken into four equal stages. The uncertainties which are described in Section 3.1.2, are used to model three scenarios with probability of 0.375, 0.5 and 0.125. Five operation conditions are derived from Section 3.1.2 to model different load patterns. Five candidate and one existing ES are located in the electric system on buses 11, 17, 37, 63, 92, 117. The ES data are provided in Table 8. Five candidate and one existing NGS are located in the natural gas network nodes 3, 5, 7, 9, 11, 13. The NGS data are provided in Table 7. All candidate ENGSs are assumed to have the same characteristics.

3.2.1 | Results

The operation and investment costs of IEEE 118-bus for all cases in different stages are shown in Figure 16(a) and Figure 16(b), respectively. Operation and investment costs can be reduced 3% and 24 when ENGS are used, compared to a system without storage. When ENGS are used individually in the large system, investment cost decreases by 19%. However, most benefits are derived when ENGS are implemented in PNGS. The investment cost decrease by 24%.

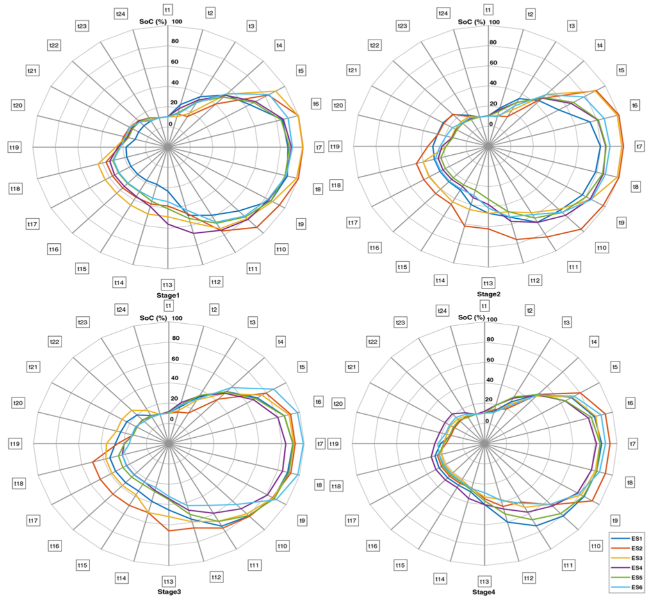


FIGURE 17 SoC all ES at different stages for case 4

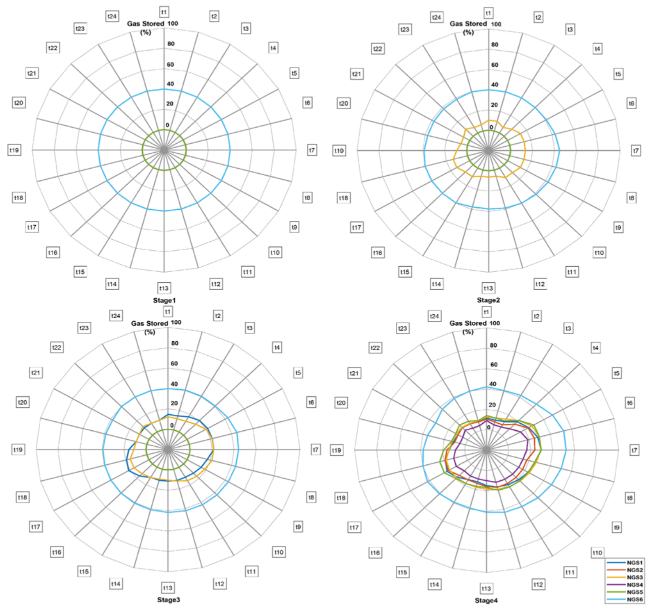


FIGURE 18 SoC all ES at different stages for case 4

Four case are studies, which are described in Section 3.1.2 to compare the influence of ENGS on the planning decisions for the test system. In Figure 17, SoC of six ESs at all stages are shown, in which the first ES is existing and others are candidate ESs. The three scenarios, five operation conditions and six ESs, result in 90 SoCs, which is hard to identify in a plot. For the sake of clarity, SoC in each scenario and operation condition is multiplied by the probability of scenario and number of days in operation condition, respectively. SoC of each ES is depicted in Figure 17. ES is charging between hours one and five, and they are discharging after hour nine. In Figure 18, gas stored in NGS in different stages are depicted. None of candidate NGS are invested in Stage 1. Demands increase in the next stages, thereafter new NGS is built. It can be seen in Figures 17 and Figure 18 that, the NGS is used in high natural gas demand operation conditions, compared to ES, which is mostly used in all operation conditions. The reason for this is that NGS has higher operational costs than ES. Although NGS has higher operation costs, it can reduce the investment cost 19% compared to the systems without NGS, as shown in Figure 16.

4 | CONCLUSIONS

In this paper, dynamic stochastic joint expansion planning of natural gas systems and power networks with electrical and natural gas storage is proposed. The problem is modeled as a mixed integer linear programming. Furthermore, a scenario-based stochastic expansion planning is proposed where uncertainties in natural gas prices and electricity and natural gas consumption growth rates are considered. The optimization algorithm minimizes investment costs which include generation and transmission investment, electrical storage, pipeline, and natural gas storage, in addition to operating costs. Scenario generation and reduction and k-means clustering for operation conditions were implemented.

This paper is focused on electrical and natural gas storage as a mean for decreasing investment and operation costs. The numerical results demonstrate that electrical and natural gas storage reduces total investment and operational costs in the dynamic stochastic joint expansion planning problem. The scenario without any storage has the highest investment cost in the whole planning horizons at different stages. Electrical energy storage reduces investment cost 46% and 19% and natural gas storage reduces investment cost 47% and 19% for small and large networks used in this work, respectively. Best results were obtained when both electrical and natural gas storage were implemented together, where investment cost decreased by 52% and 24%, and operation cost decreased by 2% and 3% for small and large test systems, respectively. Also, electrical and natural gas storage prevent extensive new infrastructure in the first stage and postpone them, which investment cost at the fourth stage, 89% more than the first stage. Electrical and natural gas storage's role is vital. It was shown energy cand be stored in the shape of natural gas or electricity at the off-peak hours and they were used at high demand hours.

DATA AVAILABILITY STATEMENT

The data that support the findings of this study are available on request from the corresponding author. The data are not publicly available due to privacy or ethical restrictions.

NOMENCLATURE: Indices and Sets

es, gs	Index of electrical and gas storage in the set, ES, GS.
g, k	Index of natural gas and thermal power plants in set, G, K.
l, pl	Index of transmission line and natural gas pipeline.
n, p	Index of power system bus and natural gas network node in set, N, P.
o, t, w, y	Index of operation conditions, hours, scenarios and stages in set, O, T, W, Y.
s	Index for natural gas supplies in set, S.
$\Psi_n^{ES}, \Omega_p^{GS}$	Set of electrical and natural gas storage at node n, p.
Ψ_n^{G}, Ψ_n^{T}	Set of natural gas and thermal power plants at node n.
Ω_p^{G}	Set of natural gas units at natural gas network node p.
Ψ^{PES}, Ω^{PGS}	Set of candidate electrical and natural gas storage.
Ψ^{PG}, Ψ^{PT}	Set of candidate natural gas and thermal power plants.
Ψ^{PTL}, Ω^{PPL}	Set of candidate transmission lines and natural gas pipelines.
$\Psi_{n,l}^{RL}, \Psi_{n,l}^{SL}$	Set of receiving and sending-end power system node n for transmission line l.
$\Omega_{p,pl}^{RP}, \Omega_{p,pl}^{SP}$	Set of receiving and sending-end natural gas network node p for pipeline pl.
Ω_p^{S}	Set of natural gas supplies at node p.

Parameters

C_g^{PGINV}, C_k^{PTINV}	Candidate natural gas, thermal power plants g, k investing cost.
$C_{es}^{ESINV}, C_{gs}^{GSINV}$	Candidate electrical, natural gas storages es, gs investing cost.
$C_l^{TLINV}, C_{pl}^{PLINV}$	Candidate transmission line, pipeline l, pl investing cost.
$Ch_{es}^{ES,MAX}, D_{es}^{ES,MAX}$	Maximum rate for charging, discharging of existing electrical storage es.
$f_{n,o,t}^{ED}, g_{p,o,t}^{NGD}$	Percentage of electricity, gas consumption at node n, p of operation o at hour t.
GF_{pl}^{MAX}	Capacity of existing natural gas pipeline pl.
H_g	Natural gas power plant g heat rate.
ir_y	Interest rate of stage y.
L_n^{E}, L_p^{NG}	Electricity, natural gas consumption at node n, p.
$LG_{w,y}^{E}, LG_{w,y}^{NG}$	Electricity, natural gas consumption growth at stage y and scenario w.
OC_{gs}^{GS}	Operation cost of natural gas storage gs.
OC_g^{GU}, OC_k^{TU}	Operation cost of natural gas, thermal power plants g, k.
$P_g^{EG,MAX}, P_k^{ET,MAX}$	Maximum production of existing natural gas, thermal power plants g, k.

$P_g^{EG,RU}$, $P_g^{EG,RD}$ Ramping up, down restraints of existing natural gas power plant g.

$P_k^{ET,RU}$, $P_k^{ET,RD}$ Ramping up, down restraints of existing thermal power plant k.

$P_g^{GI,MAX}$, $P_k^{TI,MAX}$ Investible capacity for candidate natural gas, thermal power plants g, k.

$P_g^{PG,RU}$, $P_g^{PG,RD}$ Ramping up, down restraints for candidate natural gas power plant g.

$P_k^{PT,RU}$, $P_k^{PT,RD}$ Ramping up, down restraints for candidate thermal power plant k.

PCh_{es}^{MAX}, PD_{es}^{MAX} Maximum charging, discharging rates of candidate electrical storage es.

PF_l^{MAX}, $PF_l^{INV,MAX}$ Maximum power flow for existing, candidate transmission line l.

$\chi_{s,o,t}^{GAS}$ Natural gas price of supply s of operation o in hour t.

$Pr_{w,y}^{Change}$ Natural gas price change in scenario w and stage y.

$PS_{es}^{ES,MIN}$, $PS_{gs}^{GS,MIN}$ Minimum capacity of candidate electrical, natural gas storage es, gs.

$PRR_{gs}^{GS,MAX}$, $PSR_{gs}^{GS,MAX}$ Maximum releasing, storing rates of candidate gas storage gs.

$R_{pl}^{INV,MAX}$ Investible capacity for candidate natural gas pipeline pl.

$RR_{gs}^{GS,MAX}$, $SR_{gs}^{GS,MAX}$ Maximum releasing, storing rates of existing natural gas storage gs.

$S_{es}^{ESINV,MAX}$, $S_{gs}^{GSINV,MAX}$ Investible capacity for candidate electrical, gas storage es, gs.

$S_{es}^{ES,MAX}$, $S_{es}^{ES,MIN}$ Maximum, minimum capacity of existing electrical storage es.

$S_{gs}^{GS,MAX}$, $S_{gs}^{GS,MIN}$ Maximum, minimum capacity of existing natural gas storage gs.

St_y Duration of stage y.

XS_s^{MAX} Maximum capacity of gas supply s.

η_{gs}^{SR}, η_{gs}^{RR} Storing, releasing efficiency of natural gas storage gs.

η_{es}^{ES} Efficiency of electrical storage es.

β_l Susceptance of transmission line l.

θ_{ref} Phase angle of reference node n_{ref}.

Variables

$Ch_{es,y,w,o,t}^{ES}$ Charging for electrical storage es in stage y, scenario w of operation o in hour t.

$D_{es,y,w,o,t}^{ES}$ Discharging for electrical storage es in stage y, scenario w of operation o in hour t.

$GF_{pl,y,w,o,t}$ Flow of natural gas in pipeline pl at stage y and scenario w of operation o in hour t.

$P_{g,y,w,o,t}^{GU}$ Production of gas power plant g in stage y, scenario w of operation o in hour t.

$P_{k,y,w,o,t}^{TU}$ Production of thermal power plant k in stage y, scenario w of operation o in hour t.

$P_{g,y,w}^{GI}$ Capacity of candidate natural gas power plant g is constructed in stage y, scenario w.

$P_{k,y,w}^{TI}$ Capacity of candidate thermal power plant k is constructed in stage y and scenario w.

$PF_{l,y,w,o,t}$ Transmission line l power flow in stage y, scenario w of operation o in hour t.

$R_{pl,y,w}^{INV}$ Capacity of candidate pipeline pl is built in stage y and scenario w.

$RR_{gs,y,w,o,t}^{GS}$ Releasing rate of gas storage gs in stage y, scenario w of operation o in hour t.

$SR_{gs,y,w,o,t}^{GS}$ Storing rate of gas storage gs in stage y, scenario w of operation o in hour t.

$S_{es,y,w,o,t}^{ES}$ Electrical storage es state of charge in stage y, scenario w of operation o in hour t.

$S_{es,y,w}^{ESINV}$ Capacity of candidate electrical storage es is built in stage y and scenario w.

$S_{gs,y,w}^{GSINV}$ Capacity of candidate natural gas storage gs is built in stage y and scenario w.

$S_{gs,y,w,o,t}^{GS}$ Natural gas stored at storage gs in stage y and scenario w of operation o in hour t.

$U_{g,y,w,o,t}^{G}$ Gas is consumed by power plant g in stage y, scenario w of operation o in hour t.

$X_{l,y,w}^{INV}$ Binary variable for investment of candidate transmission line l in stage y, scenario w.

$XS_{s,y,w,o,t}$ Production of gas from supply s in stage y and scenario w of operation o in hour t.

$\theta_{n,y,w,o,t}$ Voltage angle for power system bus n at stage y, scenario w of operation o in hour t.

ORCID

Arash Gholami https://orcid.org/0000-0002-2230-5492
Hamed Nafisi https://orcid.org/0000-0001-7076-8558

REFERENCES

1. Energy Information Association: Electric Power Monthly with Data for January 2015. U.S. Energy Information Administration, Washington DC (2015)
2. Figueroa-Acevedo, A.L., et al.: Design and valuation of high-capacity hvdc macrogrid transmission for the continental us. IEEE Trans. Power Syst. 1–1 (2020)
3. Zhao, B., et al.: Coordinated expansion planning of natural gas and electric power systems. IEEE Trans. Power Syst. 33(3), 3064–3075 (2018)
4. Thompson, M.: Natural gas storage valuation, optimization, market and credit risk management. J. Commod. Markets 2(1), 26–44, (2016)
5. Dehghan, S., Amjady, N.: Robust transmission and energy storage expansion planning in wind farm-integrated power systems considering transmission switching. IEEE Trans. Sustainable Energy 7(2), 765–774 (2016)
6. Nunes, J.B., et al.: A stochastic integrated planning of electricity and natural gas networks for Queensland, Australia considering high renewable penetration. Energy 153(2018), 539–553 (2018)
7. Ding, T., et al.: Multi-Stage stochastic programming with nonanticipativity constraints for expansion of combined power and natural gas systems. IEEE Trans. Power Syst. 33(1), 317–328 (2017)
8. Khaligh, V., Anvari-Moghaddam, A.: Stochastic expansion planning of gas and electricity networks: A decentralized-based approach. Energy 186, 115889 (2019)
9. Qiu, J., et al.: Multi-Stage flexible expansion co-planning under uncertainties in a combined electricity and gas market. IEEE Trans. Power Syst. 30(4), 2119–2129 (2015)

10. Zhang, Y., et al.: A mixed-integer linear programming approach to security-constrained co-optimization expansion planning of natural gas and electricity transmission systems. IEEE Trans. Power Syst. 33(6), 6368–6378 (2018)
11. He, C., et al.: Robust co-optimization planning of interdependent electricity and natural gas systems with a joint N-1 and probabilistic reliability criterion. IEEE Trans. Power Syst. 33(2), 2140–2154 (2018)
12. Shao, C., et al.: Integrated planning of electricity and natural gas transportation systems for enhancing the power grid resilience. IEEE Trans. Power Syst. 32(9), 4418–4429 (2017)
13. Hu, Y., et al.: An NSGA-II based multi-objective optimization for combined gas and electricity network expansion planning. Appl. Energy 167, 280–293 (2016)
14. Zou, B., et al.: Resilient co-expansion planning between gas and electric distribution networks against natural disasters. IET Gener., Transm. & Distrib. 14(17), 3561–3570 (2020)
15. Zhao, B., et al.: Using electrical energy storage to mitigate natural gas-supply shortages. IEEE Trans. Power Syst. 33(6), 7076–7086 (2018)
16. Gholami, A., et al.: Second-order cone programming for linepack in multi-stage stochastic co-expansion planning power and natural gas systems with natural gas storage. AUT J. Electr. Eng. (2021)
17. Unsihuay-Vila, C., et al.: A model to long-term, multiarea, multistage, and integrated expansion planning of electricity and natural gas systems. IEEE Trans. Power Syst. 25(2), 1154–1168 (2010)
18. Ojeda-Esteybar, D.M., et al.: Integrated operational planning of hydrothermal power and natural gas systems with large scale storages. J. Modern Power Syst. Clean Energy 5(3), 299–313 (2017)
19. Odetayo, B., et al.: A chance constrained programming approach to the integrated planning of electric power generation, natural gas network and storage. IEEE Trans. Power Syst. 33(6), 6883–6893 (2018)
20. Chaudry, M., et al.: Combined gas and electricity network expansion planning. Appl. Energy 113, 1171–1187 (2014)
21. Zhang, B., et al.: Dynamic energy conversion and management strategy for an integrated electricity and natural gas system with renewable energy: Deep reinforcement learning approach. Energy Convers. Manage. 220, 113063 (2020)
22. Vandewalle, J., et al.: Effects of large-scale power to gas conversion on the power, gas and carbon sectors and their interactions. Energy Convers. Manage. 94, 28–39 (2015)
23. Sohrabi, F., et al.: Coordination of interdependent natural gas and electricity systems based on information gap decision theory. IET Gener., Transm. & Distrib. 13(15), 3362–3369 (2019)
24. Zeng, Q., et al.: A bi-level programming for multistage co-expansion planning of the integrated gas and electricity system. Appl. Energy 200, 192–203 (2017)
25. Saldarriaga, C.A., et al.: A holistic approach for planning natural gas and electricity distribution networks. IEEE Trans. Power Syst. 28(4), 4052–4063 (2013)
26. Qiu, J., et al.: Low carbon oriented expansion planning of integrated gas and power systems. IEEE Trans. Power Syst. 30(2), 1035–1046A (2015)
27. Barati, F., et al.: Multi-Period integrated framework of generation, transmission, and natural gas grid expansion planning for large-Scale systems. IEEE Trans. Power Syst. 30(5), 2527–2537 (2015)
28. Borraz-Sánchez, C., et al.: Convex optimization for joint expansion planning of natural gas and power systems. Proceedings of the Annual Hawaii International Conference on System Sciences, 2016-March. pp. 2536–2545. (2016)
29. Zahedi Rad, V., et al.: Joint electricity generation and transmission expansion planning under integrated gas and power system. Energy 167, 523–537 (2019)
30. Qiu, J., et al.: A linear programming approach to expansion co-planning in gas and electricity markets. IEEE Trans. Power Syst. 31(5), 3594–3606 (2016)
31. Ross, S.A., et al.: Fundamentals of Corporate Finance, vol. 1. McGraw-Hill/Irwin, New York (2013)
32. Conejo, A.J., et al.: Investment in Electricity Generation and Transmission. Springer, Cham (2016)
33. Hasle, G., et al.: Optimization models for the natural gas value chain. Geometric Modelling, Numerical Simulation, and Optimization: Applied Mathematics at SINTEF, pp. 521–558. Springer, New York (2007)
34. Nunes, J.B., et al.: Multi-stage co-planning framework for electricity and natural gas under high renewable energy penetration. IET Gener., Transm. Distrib. 12(19), 4284–4291 (2018)
35. GAMS - Cutting Edge Modeling.
36. Lochner, S.: The Economics of Natural Gas Infrastructure Investments Theory and Model-based Analysis for Europe. Universität Köln 1–168 (2011)
37. He, Y., et al.: Robust constrained operation of integrated electricity-Natural gas system considering distributed natural gas storage. IEEE Trans. Sustain. Energy 9(3), 1061–1071 (2018)
38. k-means clustering - MATLAB kmeans - MathWorks United Kingdom.
39. Data Platform – Open Power System Data.
40. Henry Hub Natural Gas Spot Price (Dollars per Million Btu).
41. Gröwe-Kuska, N., Heitsch, H., ömisch, W.R.: Scenario reduction and scenario tree construction for power management problems. In: 2003 IEEE Bologna PowerTech - Conference Proceedings, vol. 3, pp. 152–158. IEEE, Piscataway (2003)
42. Zhao, B.: Electricity-Gas Systems : Operations and Expansion Planning Under Uncertainty. The Ohio State University (2018)

How to cite this article: Gholami, A., Nafisi, H., Askarian Abyaneh, H., Jahanbani Ardakani, A. Dynamic stochastic joint expansion planning of power systems, natural gas networks, and electrical and natural gas storage. IET Gener. Transm. Distrib. 2021;1–18. https://doi.org/10.1049/gtd2.12277