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Day-ahead coordinated operation of utility-scale electricity and natural gas networks considering demand response based virtual power plants

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HIGHLIGHTS

- A bi-level coordinated model to maximize profits for utility company is proposed.
- Virtual power plant models using interruptible-load and coupon based DRs are proposed.
- Profit increase of a utility company from VPP's bidding depends on the type of VPP.
- With VPP, the amount of LMP reduction depends on system size and utility scale.
- DR based VPP may reduce gas network congestion at peak hours with reduced profits.

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ABSTRACT

The steady-state coordinated operation of electricity networks and natural gas networks to maximize profits is investigated under market paradigm considering demand response. The components in its gas supply networks are modeled and linearized under steady-state operating conditions where combined cycle gas turbine (CCGT) generators consume natural gas and offer to the electricity market. Interruptible-load based and coupon-based demand response virtual power plants are considered trading in the market like physical generators. A bi-level programming optimization model is formulated with its upper-level representing the coordinated operation to maximize profits and its lower-level simulating the day-ahead market clearing process. This bi-level problem is formulated as a mathematical program with equilibrium constraints, and is linearized as a mixed-integer programming problem. Case studies on a 6-bus power system with a 7-node natural gas system and an IEEE 118-bus power system with a 14-node gas system verify the effectiveness of the coordinated operation model. The impacts of demand response based virtual power plants on the interactions between the two networks are also analyzed.

1. Introduction

Electricity generation comes from a mix of various primary energy resources such as coal, natural gas, nuclear energy, and renewables. Combined cycle gas turbines (CCGTs), which convert chemical energy to electric energy, are widely used due to their outstanding cost-effectiveness, low NO_x and SO_x emissions, and quick responses. According to the Annual Energy Outlook 2014 from US Energy Information Administration [1], the demand for natural gas in the power sector in 2013 is 232.22 billion cubic meters (Bcm). This amount is projected to rise to 266.21 Bcm by 2040 in the reference case in which the gas delivery price is assumed to be stable. Meanwhile, industry gas demand has been growing steadily throughout the decade. With CCGT units being the largest natural gas consumers outside the industry sector, electricity transmission systems and natural gas supply networks are more closely tied and are beginning to undergo new transformations.

The linkage of CCGT units between the electricity networks and natural gas networks in a utility company affect the supply and demand balance of both networks. On the gas network side, the fluctuations of industrial and residential demand may introduce volatility in the gas supply to CCGT units and consequently affect the daily scheduling. On the electricity network side, demand response (DR) programs aiming at reducing the electricity consumption at critical high load hours also affect the power output and the gas consumption of CCGTs, which are usually the marginal generating units at load peak hours. Hence, opportunities exist for the utility company to operate the integrated energy system in a coordinated way such that the overall scheduling is optimized.

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Nomenclature

Constants

α_i^O	estimated bidding price of non-strategic generator on bus i
ρ_i^{GAS}	unit price of natural gas at node i
C_l	power flow limit on transmission line l
$c_{i,0}$	gas consumption constant coefficient of CCGT unit i
$c_{i,1}$	gas consumption linear coefficient of CCGT unit i
$D_{i,t}$	electric demand on bus i at time t
$d_{i,t}^{max}$	maximum demand of gas load i at time t
$d_{i,t}^{min}$	minimum demand of gas load i at time t
F_c	daily natural gas supply limit
$G_{i,max}^S$	upper power limit of strategic generator i
$G_{i,max}^V$	upper power limit of virtual generator on i at time t
$G_{i,max}^O$	upper power limit of non-strategic generator on bus i at time t
$G_{i,min}^O$	lower power limit of non-strategic generator on bus i at time t
$G_{i,min}^S$	lower power limit of strategic generator i
K_{mn}^W	Weymouth factor of pipeline mn
L_j	number of hours VPP j must stay offline due to previous states
MD_j	minimum off-line time limit of VPP j
MU_j	maximum on-line time limit of VPP j
$p_{n,max}$	maximum natural gas pressure of node n
$p_{n,min}$	minimum natural gas pressure of node n
R_i^{DN}	ramp down limit of generator on bus i
R_i^{UP}	ramp up limit of generator on bus i
$R_{j,max}$	maximum compression ratio of compressor j
$R_{j,min}$	minimum compression ratio of compressor j
$s_{i,t}^{max}$	maximum supply output of well i at time t
$s_{i,t}^{min}$	minimum supply output of well i at time t
T	daily scheduling time horizon from 1 to 24
GSF_{l-i}	generation shift factor from bus i to line l

Sets

$A(j)$	set of nodes connected to node j
I_{ccgt}^{NG}	set of buses having CCGT units
I_{load}^{NG}	set of nodes having natural gas load, including CCGT units
I_{sp}^{NG}	set of nodes having natural gas well
I_{comp}^{NG}	set of natural gas compressors
$I_{comp}^{NG}(j)$	set of terminal nodes of compressor j
J	set of demand response based virtual power plants
N	set of natural gas nodes
A_{load}^{NG}	incidence matrix between natural gas loads and gas nodes
A_{sp}^{NG}	incidence matrix between natural gas wells and gas nodes

Units

GJ	gigajoules
kPa	kilopascal
Mcm	thousand cubic meters

Variables

α_i^S	bidding price for strategic generator on bus i
α_i^V	bidding price for strategic virtual power plant on bus i
λ_t	dual variable associated with network power balance
$\mu_{l,t}^{max}$	dual variables associated with line l flow upper limit
$\mu_{l,t}^{min}$	dual variables associated with line l flow lower limit
$\omega_{i,t,max}^O$	dual variables associated with upper limit of non-strategic generator on bus i at time t
$\omega_{i,t,min}^O$	dual variables associated with lower limit of non-strategic generator on bus i at time t
$\omega_{i,t,max}^S$	dual variables associated with upper limit of strategic generator on bus i at time t
$\omega_{i,t,min}^S$	dual variables associated with lower limit of strategic generator on bus i at time t
$\omega_{i,t,max}^V$	dual variables associated with upper limit of virtual power plant on bus i at time t
$\omega_{i,t,min}^V$	dual variables associated with lower limit of virtual power plant on bus i at time t
$\pi_{i,t}$	locational marginal price of bus i at time t
$d_{i,t}$	gas demand of gas load i at time t
$d_{i,t}$	gas demand on gas node i at time t
$f_{c,j,t}$	natural gas flow through compressor j at time t
$F_{i,t}$	fuel consumption of CCGT unit i at time t
$G_{i,t}$	power output of CCGT unit i at time t
$G_{i,t}^O$	power output of non-strategic generator on bus i
$G_{i,t}^S$	power output of strategic generators
$G_{i,t}^V$	power output of virtual power plants
$H_{j,t}$	power consumption of compressor j at time t
p_n	nodal pressure of node n
p_{mn}^{in}	nodal pressure on the inlet node of pipeline mn
p_{mn}^{out}	nodal pressure on the outlet node of pipeline mn
$R_{j,t}$	compression ratio of compressor j at time t
$s_{i,t}$	gas output of gas well i at time t
$v_{j,t}$	power output of virtual power plant j at time t
$W_{i,t}$	natural gas cost of CCGT unit i at time t
WM_{mn}	gas flow in pipeline mn
$p_{n,t}$	gas imbalance on node n at time t

In this paper, we consider a utility company that operates an integrated energy system that consists of a power plant and a gas network. The power plant consists of CCGT units and DR based virtual power plants. The gas network contains gas wells at the supply side and residential, industrial and CCGT units on its demand side. In a broader range, this company must strategically offer its generation at a price (or following a piece-wise price curve) to independent system operator (ISO) or a regional transmission operator (RTO) (see Fig. 1). The market operator clears the day-ahead market generation offers and load bids on a social welfare maximization basis. As for the money flow, this company pays for natural gas purchases and receives payments at the rate of locational marginal pricing (LMP) for each megawatt-hour generation output.

This paper focuses on the steady-state coordinated operation of the integrated energy system in an electricity market scheme, while taking into account the impacts of DR based virtual power plants. We formulate a bi-level optimization programming model that describes the utility company's motivation to maximize its profit by participating in the electricity market at the upper-level and simulates the market clearing process performed by the system operator at the lower level.