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Pablo Dueñas
Assistant Researcher
Institute for Research in Technology
Advanced Technical Engineering School
Comillas Pontifical University
Madrid, Spain
Email: pablo.duenas@iit.upcomillas.es

María Gil
Assistant Researcher
Institute for Research in Technology
Advanced Technical Engineering School
Comillas Pontifical University
Madrid, Spain
Email: maria.gil@iit.upcomillas.es

Tommy Leung
PhD Student
Energy Initiative and Engineering Systems Division
Massachusetts Institute of Technology
Cambridge, Massachusetts, USA
Email: tcleung@mit.edu

Javier Reneses
Assistant Professor
Institute for Research in Technology
Advanced Technical Engineering School
Comillas Pontifical University
Madrid, Spain
Email: Javier.reneses@iit.upcomillas.es

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Pablo Dueñas, Tommy Leung, María Gil, and Javier Reneses

***Abstract*—As climate concerns, low natural gas prices, and renewable technologies increase the electric power sector's dependence on natural gas-fired power plants, operational and investment models for gas and electric power systems will need to incorporate the interdependencies between these two systems to accurately capture the impacts of one on the other. Currently, few hybrid gas-electricity models exist. This paper reviews the state of the art for hybrid gas-electricity models and presents a new model and case study to illustrate a few potential coupling effects between gas and electric power systems. Specifically, the proposed model analyzes the optimal operation of gas-fired power plants in a competitive electricity market taking into consideration gas purchases, gas capacity contracting, and residual demand uncertainty for the generation company due to renewable energy sources.**

***Index Terms*—Electric power market, natural gas market, optimization model, renewable energy integration, risk averseness**

NOTATION

The main notation used in this paper is stated below for quick reference. Other symbols are defined as needed throughout the paper.

Indices:

e: (e', e^*)	Gas consumers: (Genco, city)
z	Gas spot market
p	Pipeline
g	Thermal power plants
m	Months
d	Days
l	States of the system
k	Wind scenarios

Parameters:

α_0	Cost intercept of gas-demand price curve
α_1	Cost slope of gas-demand price curve
GD_{pe^*dk}	Gas demand of consumer e^*
GQ_p	Pipeline capacity
ω_k	Probability of each scenario
CF_p	Long-term pipeline capacity price
CF_{pm}	Medium-term pipeline capacity price
CF_{pd}	Short-term pipeline capacity price
CV_p	Pipeline utilization price
$DE_{pe'dk}$	Gas demand estimation of consumer e'
$Smin_{e'}$	Minimum average percentage of firm capacity
$\beta_{e'}$	Probability of reaching the minimum percentage
PD_{mlk}	Power demand in state of the system l
Qmx_g	Maximum power of power generator g
Qmn_g	Technical minimum of power generator g
CV_g	Variable cost of power generator g
CF_g	Commitment cost of power generator g
CY_g	Start-up cost of power generator g
CZ_g	Shut-down cost of power generator g
T_{dlk}	Time duration of state of the system l
$N_{mll'k}$	Number of transitions between states l and l'
F_g	Gas-to-power conversion factor of power generator g

Variables:

d_{pedk}	Gas demand of consumer e (a power generator)
h_{pe}	Long-term capacity contract of consumer e
h_{pem}	Medium-term capacity contract of consumer e
h_{pedk}	Short-term capacity contract of consumer e
th_{pedk}	Contract portfolio of consumer e
Δh_{pedk}	Capacity acquisition of consumer e
∇h_{pedk}	Capacity release of consumer e
$s_{e'k}$ ($s'_{e'k}$)	Average percentage of firm capacity in scenario k (Auxiliary variable)
$\hat{s}_{e'}$	Minimum average percentage of firm capacity reached with probability $\beta_{e'}$
q_{gmlk}	Power produced by power generator g
u_{gmlk}	Commitment of power generator g
$y_{gmll'k}$	Start-up of power generator g
$z_{gmll'k}$	Shut-down of power generator g

Pablo Dueñas, María Gil and Javier Reneses are with the Institute for Research in Technology (IIT), Advanced Technical Engineering School (ICAI), Comillas Pontifical University, 28015 Madrid, Spain. (e-mail: pablo.duenas@iit.upcomillas.es; maria.gil@iit.upcomillas.es; Javier.reneses@iit.upcomillas.es).

Tommy Leung is with the Energy Initiative (MITEI) and the Engineering Systems Division (ESD), Massachusetts Institute of Technology (MIT), 02139 Cambridge, Massachusetts, USA (e-mail: tcleung@mit.edu).

I. INTRODUCTION

Over the last two decades, natural gas has played an increasingly larger role as an input fuel for electricity production. Gas consumption in the United States electric power sector increased 2.24 times from 1997 to 2012. In the European Union, natural gas share of the generation mix increased from 8% in 1990 to 23% in 2010. Furthermore, technological improvements in shale gas extraction and the subsequent reduction in costs have boosted reliance on natural gas for electricity generation.

Beyond these facts and numbers, two main reasons explain the likelihood that gas will remain the preferred fossil fuel for electricity generation over other fossil fuels such as coal or oil distillates. First, while gas prices may not necessarily remain lower than coal prices in terms of monetary units per unit of released thermal energy, gas-fired power plants (GFPPs) have higher conversion efficiencies than coal plants. Typical gas plants operate with thermal efficiencies near 60%, while typical coal plants operate with thermal efficiencies near 30%. Consequently, in electric power systems with environmental regulations that limit or tax emissions such as CO_2, SO_2, and/or NO_x, gas technologies will habitually undercut other fossil fuel technologies. Second, because GFPPs have significantly lower investment costs relative to other types of thermal plants, the rate of return on investment for GFPPs is relatively large compared to other fossil fuel technologies. For these reasons, the generation mix for power systems will likely continue to feature GFPPs.

In addition to these favorable economic traits, GFPPs have also recently played a prominent role providing operational flexibility—specifically, with respect to ramp rates and start-up/shut-down times compared to other thermal technologies—to electric power systems with intermittent renewable energy sources. Yet, to provide this flexibility, the owners of gas generators in power systems with liberalized markets must incorporate the uncertainty of renewable energy sources into their decision-making process—particularly when they contract for pipeline capacity—well in advance of actually knowing their electricity commitments. The increasing importance of GFPPs in electric power systems for both economic and environmental reasons justifies the joint analysis of gas and electricity systems.

In particular, most electricity models today ranging from short-term unit commitment to long-term capacity expansion assume that gas generators have perfectly reliable fuel supplies. However, due to competition for both gas pipeline capacity and for gas in spot markets, this assumption about perfectly reliable fuel supplies may not always hold. Although pipeline companies have made large investments to adapt their infrastructure in anticipation of greater gas demand, electricity generation companies can still face pipeline capacity scarcities that prevent them from participating in electricity markets. For example, if several consumers (e.g., households, industries, and generation companies) share a common pipeline, and capacity on that pipeline becomes scarce in the middle of winter due to increased gas consumption for heat, electricity generation companies may not have access to the pipeline capacity that they need to receive their fuel. System operators such as the Independent System Operator of New England (ISO-NE) and the New York Independent System Operator (NYISO) have recently raised these types of capacity concerns with respect to the operation of the GFPPs within their systems.

In addition to physical constraints related to scarce pipeline capacity, economic issues may also prevent GFPPs from offering generation to electricity markets. Electricity generation companies must purchase their gas through long-term contracts or in the spot market. In gas spot markets, prices tend to be directly proportional to demand, and these prices directly influence the behavior of gas generators in electricity markets. Consequently, given the difficulties with forecasting electricity demand, renewable generation, and fuel price/capacity uncertainty, a GFPP may inadequately contract in advance for the fuel capacity that it needs on any given day. In particular, the owner of a GFPP may be risk averse to committing to long-term contracts for capacity and instead opt to rely mostly on secondary markets. As GFPPs increasingly compete with industrial users and utilities for pipeline capacity, the different daily demand profile of GFPPs versus other large consumers in the gas market, combined with the tendency for GFPPs to acquire capacity in secondary markets, may significantly alter the long-term investment signals of gas networks and exacerbate gas-electricity dependencies.

This paper's main contribution is a proposed model to investigate the long-term capacity contracting behavior of GFPPs under net electricity demand, i.e., after the renewable generation is dispatched. The model presented in Section III of this paper analyzes the decision process of a generation company that participates in both electricity and gas spot markets. The generation company must contract for pipeline capacity in competition with other gas consumers. Lastly, the electricity market that the generation company participates in clears subject to uncertainty from renewable energy sources.

Before this model description, Section II reviews the current state-of-the-art of hybrid gas-electricity models. Following the model description, Section IV describes the input data for the case study. Section V contains the results of the case study, and Section VI concludes.

II. Current Hybrid Gas-Electricity Models

Following a similar structure to classify current models according to their temporal scope as presented in [5], for a single snapshot time period, various authors have proposed models that jointly analyze the gas and power system by including the gas network and compressor stations. Their main objective is to examine the functioning of both systems from a technical point of view. For example, one such objective may be to evaluate the maximum amount of electric power generation possible from all of the combined-cycle power plants in a power system, taking into consideration gas demand by nonelectric customers, the gas network, and gas availability is evaluated in [6]. In addition to updating the treatment of GFPPs by including the gas system, [6] also introduces a new stakeholder in the gas-electric system that did not previously exist in the electric power system alone: nonelectric consumers whose demand for gas might preempt demand for gas in the electric sector. Other models recognize the welfare of all agents (consumers and producers) in both systems when determining the optimal set of gas and power flows and corresponding marginal prices [7], [8]. Interruptible gas contracts, which may modify the joint operation, are included in a cost-minimizing security-constrained unit commitment model that also takes into consideration optimal gas flows [9].

In the short term, the impact on the power system of different contingencies in the gas infrastructure that cut off the supply of GFPPs is discussed in [10]; the unit commitment problem subject to gas network constraints with the possibility of fuel switching is solved in [11]; line-pack capacity and gas storage facilities when minimizing the gas supply, gas operation and electricity generation costs are included in [12]; and besides gas storage, compressor stations to solve the unit commitment problem are consider in [13].

In the medium and long term there is little literature to our knowledge. In the medium term, a dynamic programming model to obtain the operation plan of hydrothermal and gas systems subject to stochasticity is proposed in [14], and a profit-maximization model that includes gas network congestions to manage gas supply contracts in imperfect power markets is proposed in [15]. In the long term, an extension of [8] to capacity expansion of both systems is shown in [16].

Previous models have only focused on one time horizon: single period [6]–[9]; short-term [10]–[13]; and medium- and long-term [14]–[16]. Hence, to the authors' knowledge, currently no gas-electricity model analyzes how long- and medium-term decisions may influence short-term decisions (or vice versa). Yet, coordination among different temporal decisions becomes critical when operating in two intertwined energy systems, such as the gas and electric power systems.

Consider, for example, short-term power generation decisions that are constrained by long-term pipeline capacity contracting decisions. Frequently, capacity contract decisions must be made years in advance, and optimizing these decisions requires taking into consideration future short-term scenarios. Therefore, in this paper, we propose an optimization model that spans multiple time horizons to analyze how a firm that owns a fleet of gas generation plants should make long- and medium- term contracting decisions in a perfectly competitive electric power market subject to short-term renewable sources uncertainty.

III. Gas-Electricity Decision Model

Our main objective is to simulate a generation company that owns a set of GFPPs, purchases gas in a spot market, and contracts pipeline capacity. We have tried to fill a gap of interest in current deregulated gas and power systems by modeling how long- and medium-term decisions related to pipeline capacity contracting influence short-term decisions related to GFPP operation, which is simultaneously subject to renewable power generation uncertainty.

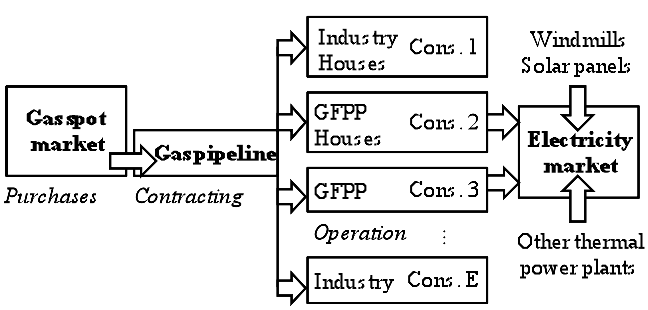

Fig. 1. Overall model structure

In this model, the gas spot market is connected with the electricity market through a gas pipeline (Fig.1). The purchased gas flows through the pipeline, as long as capacity has been contracted, to either the electricity market or to other gas consumers such as industrial users or households. However, gas consumption in the electricity market also depends on a market-clearing process in which gas must compete with other fossil fuels (coal, oil, etc.). Let us assume that intermittent wind and solar are always dispatched.

Additionally, there is a zonal gas spot market, z. A gas pipeline, p, (there may be other pipelines, but we focus on one specific pipeline,) connects the market with two main consumers, e' (a power generation company; hereinafter, Genco) and e^* (a city), although an extension to more consumers, e=1,2,…,E, is straightforward. A balance between inflows (market purchases) and outflows (demands) is monitored each day, d=1,2,…,D. Gas covers industrial users and households demand and feeds GFPPs. These GFPPs and the other thermal power plants in this system constitute the group of power generators, g=1,2,…,G, that satisfy the residual thermal electricity demand after dispatching renewable generation. As long as renewable power generation and temperature are subject to uncertainty, residual electricity and gas city demands are defined for different scenarios, k=1,2,…,K.

The model is formulated as a mixed-integer programming (MIP) problem. We start with the description of the gas spot market model. Then we present the capacity contracting model, which accounts for risk averseness. Finally, we introduce the electricity market model and its link to the gas system. In this model description, uppercase letters represent parameters, while lowercase letters represent continuous and positive variables (except where explicitly indicated otherwise).

A. Minimizing gas acquisition costs

Let us consider that the functional form of the marginal cost curve of gas $C(GD_{zdk})$ for daily purchases GD_{zdk} in the balancing zone can be represented by an affine function with cost intercept α_0, and cost slope α_1:

$$C(GD_{zdk}) = \alpha_0 + \alpha_1 \cdot GD_{zdk}. \quad (1)$$

As previously noted, there is a gas pipeline, p, connected to this balancing zone, which supplies gas to two consumers: a city, e^*, and a Genco, e'. For the sake of simplicity, let us suppose that the city demand, GD_{pe^*dk}, which is subject to uncertainty, determines the gas price in each scenario; i.e., GD_{zdk}= GD_{pe^*dk}. The Genco behaves as a price-taker and minimizes its expected gas acquisition costs in order to supply the demand of its GFPPs, $d_{pe'dk}$, which is simultaneously obtained when the electric power market is cleared as described in section III.C and by applying the power-to-gas conversion (19) defined in Section III.D:

$$\min_{d_{pedk}} \sum_{d,k} \omega_k \cdot C(GD_{pe^*dk}) \cdot d_{pe'dk}, \quad (2)$$

where parameter ω_k represents the scenario occurrence probability. Although the gas spot market is liquid and large, and purchases are not limited, total gas demand for the Genco is constrained by pipeline capacity, GQ_p. In addition, the Genco must share the total pipeline capacity with the city:

$$d_{pe'dk} + GD_{pe^*dk} \leq GQ_p \quad \forall d,k. \tag{3}$$

Objective function (2) subject to constraint (3) constitutes a LP problem that minimizes the Genco's expected gas acquisition costs.

B. Minimizing capacity contract portfolio costs

Generally, the pipeline operator offers capacity contracts with different time scopes. Accordingly, consumers can contract capacity in the long term h_{pe} (i.e., during several years), in the medium term h_{pem} (i.e., during a month), and in the short term h_{pedk} (i.e., during a day). The correspondence between time scopes and time horizons follows a standard that commonly takes place in reality. Standardized long-term contracts expire several years later. Medium-term contracts expire the next month, and short-term capacity contracts expire the next day. In addition, we consider that long- and medium- term contracts represent firm capacity commitments, while short-term contracts represent non-firm capacity commitments because gas consumers are unaware that enough free capacity will be made available to them when the contracting time comes. The immediate consequence is that short-term contracting decisions are different for each scenario k and are thus subject to renewable energy and gas city demand uncertainty, while long- and medium-term contracting decisions are common for every scenario.

Capacity prices vary with time scope. Additionally, we assume that it is less expensive to contract for capacity in the long term CF_p than in the medium term CF_{pm}, and that it is less expensive to contract for capacity in the medium term than in the short term CF_{pd}. This assumption reflects with the pipeline operator's anticipation of income and reduction of risk due to idle pipeline capacity and is in line with the decisions that an operator would make to support the recovery of its costs of service. Furthermore, the pipeline operator may apply a variable tariff CV_p to gas flows as a value-of-service rate which covers direct costs, such as fuel consumption or gas leakages.

In general, any gas consumer will minimize the resulting costs from contracting firm and non-firm capacity and utilizing pipeline capacity:

$$\min_{\substack{h_{pe},h_{pem},\\ h_{pedk},d_{pedk}}} \left. \begin{array}{l} CF_p \cdot h_{pe} + \sum_m (CF_{pm} \cdot h_{pem}) + \\ \sum_{d,k} \omega_k \cdot (CF_{pd} \cdot h_{pedk} + CV_p \cdot d_{pedk}) \end{array} \right\} \forall p, e \in (e', e^*). \tag{4}$$

Daily, each gas consumer holds a portfolio th_{pedk} of long-, medium-, and short-term capacity contracts:

$$th_{pedk} = h_{pe} + h_{pem} + h_{pedk} \quad \forall e \in (e', e^*), m/d \in m, d, k. \tag{5}$$

Similar to gas demand, which is limited by pipeline capacity (3), total consumers' capacity portfolios are also restricted by the maximum pipeline capacity:

$$th_{pe'dk} + th_{pe^*dk} \leq GQ_p \quad \forall d,k. \tag{6}$$

If a consumer has contracted enough capacity including acquisitions Δh_{pedk} and releases ∇h_{pedk}, the operator will let gas flow through the pipeline:

$$\begin{array}{l} d_{pe'dk} \leq th_{pe'dk} + \Delta h_{pe'dk} - \nabla h_{pe'dk} \quad \forall d,k, \\ GD_{pe^*dk} \leq th_{pe^*dk} + \Delta h_{pe^*dk} - \nabla h_{pe^*dk} \quad \forall d,k, \end{array} \tag{7}$$

in which the demand of the GFPPs, $d_{pe'dk}$ is simultaneously obtained when the electric power market is cleared as described in section III.C and by applying the power-to-gas conversion (19) defined in Section III.D

These agents acquire needed capacity and release excess capacity in the secondary capacity market. The dual variable of the capacity balance constraint, π_{pdk}, provides the secondary capacity market price. Again, this price does not necessarily coincide with the short-term capacity price:

$$\Delta h_{pe'dk} + \Delta h_{pe^*dk} = \nabla h_{pe'dk} + \nabla h_{pe^*dk} \quad \forall d,k \quad : \pi_{pdk} \tag{8}$$

Acquisitions in secondary capacity markets depend on the willingness of a capacity holder to release its unused capacity. In addition to the unknown acquisition price that results from the secondary market clearing, "willingness" is the main difference between acquisitions in secondary markets and short-term contracts in primary markets. Nevertheless, unwillingness to release unused capacity due to anticompetitive behaviors, such as capacity hoarding, does not occur within the perfectly competitive framework that we are assuming. Therefore, in this model, capacity acquired via secondary markets and short-term contracts will differ only in price. Although the released capacity may include the equivalent gas commodity, we maintain both products separately; consequently, capacity acquisitions are not directly influenced by gas purchases.

Furthermore, it seems reasonable to think that any gas consumer will not contract short-term capacity to subsequently release it in secondary markets. For this reason, releases are limited to the portion of contract portfolios that consists of long- and medium-term capacity contracts:

$$\nabla h_{pedk} \leq h_{pe} + h_{pem} \quad \forall e \in (e', e^*), m/d \in m, d, k. \tag{9}$$

However, the act of acquiring released capacity from another gas consumer involves greater uncertainty than contracting for short-term capacity from the pipeline operator. Acquiring released capacity depends on the capacity requirements of other market agents. The risk is modeled in the same way as Value at Risk (VaR) and Conditional Value at Risk (CVaR) measures are incorporated into optimization problems [17, 18], but adapted to our purpose, which is to consider the insecurity of participating in secondary capacity markets.

Let us define the average percentage of daily non-firm contracted capacity, $s_{e'dk}$, in each scenario as one plus a tolerance, ε, minus the relationship between the daily contract portfolio and an estimation of the demand, $DE_{pe'dk}$:

$$s_{e'dk} \geq (1+\varepsilon) - (th_{pe'dk} / DE_{pe'dk}) \quad \forall d,k. \tag{10}$$

As $s_{e'dk}$ is a positive variable, contracting capacity over the estimated demand is ineffective when ε=0. Nevertheless, ε>0 allows the consideration of contracting (1+ε)·100% capacity over the estimated demand.

Let us now define the average percentage of firm capacity, $s_{e'k}$, as:

$$s_{e'k} = 1 - (\sum_d s_{e'dk}) / \#\text{days} \quad \forall k. \tag{11}$$

A minimum average percentage of firm capacity, $Smin_{e'}$, can be established with the following constraints:

$$\hat{s}_{e'} - (\sum_k \omega_k \cdot s'_{e'k} / (1-\beta_{e'})) \geq Smin_{e'}, \tag{12}$$

$$s'_{e'k} \geq \hat{s}_{e'} - s_{e'k} \quad \forall k, \tag{13}$$

where $\hat{s}_{e'}$ is the minimum average percentage of firm capacity that will be reached with a probability of $\beta_{e'}$; and $s'_{e'k}$ is an auxiliary and positive variable which is zero when $s_{e'k}$ is higher than $\hat{s}_{e'}$.

Objective function (4) subject to constraints (5)–(13) constitutes an LP problem in which gas consumers minimize pipeline contracting and operation costs considering risk associated to participating in secondary capacity markets.

C. Minimizing power plants operation costs

One of the main consequences of electric power system gasification is the dependence of electricity prices on gas costs. Moreover, in high demand scenarios, if generation companies have not accurately predicted pipeline capacity requirements or gas purchases, the power system may face non-supplied energy situations. Examining how generation companies operate in gas systems is, therefore, economically and technically justified.

Before describing the electricity market model, let us focus on electricity demand. Demand and supply must be balanced instantaneously because electricity in most power systems cannot be stored at competitive costs. Modeling power systems with such a level of temporal detail would be intractable. For instance, system and/or market operators that utilize algorithms to determine the optimal dispatch "group these instants" into hours [19]. But even modeling each hour in the long or medium term may be troublesome. For this reason, traditionally, a load duration curve has been constructed and some load levels (e.g., peak and off-peak, working and non-working days) that were able to capture the behavior of hydro-thermal systems with no penetration of renewable energy sources have been established. Recently, to accommodate renewable energy deployment, a net load duration curve (demand minus renewable power generation) is sometimes used to define load levels. The main disadvantage of using this procedure to define load levels is that off-peak load levels will combine hours of high demand and high wind conditions with (significantly different) hours of low demand and low wind conditions. Moreover, maintaining hourly chronology leads to a more realistic representation of demand because renewable energy intermittency can heavily influence the operation of power plants. For these reasons, we define load levels using "system states." A system state is a predefined set of circumstances that occur simultaneously and frequently in a power system during an analyzed period of time (a week, a month, a year, etc.); hence, each hour is assigned to a state with the advantage of maintaining the chronology because transitions between states, i.e., transitions between hours, are known. Further details on the system states definition are provided in [20].

Returning to the model description, we can define several system states l=1,2,…,L. Consequently, each day is made up of different states, and the duration of each state in hours T_{dlk} is known. As previously mentioned, load levels are defined for a period of time (hereinafter, a month). The chronology is maintained because the number of transitions between two states, l and l', within a month m is known $N_{mll'k}$.

We have defined the net electricity demand PD_{mlk} in each load level within a month as the difference between the electricity power demand and the renewable power generation. Therefore, there is a net demand curve as well as different system state durations and transition matrices for each renewable power generation scenario. Generation companies that own thermal power plants produce electric power q_{gmlk}:

$$PD_{mlk} = \sum_g q_{gmlk} \quad \forall m,l,k \quad :\lambda_{mlk}. \tag{14}$$

One advantage of using QP and LP problems is the possibility of obtaining dual variables of technical constraints whose economic interpretation is usually of interest. For instance, the dual variables of (14), divided by the duration, are the marginal system prices for electricity given each residual demand scenario, month, and load level.

The generated quantity is limited by a maximum power level Qmx_g a technical minimum level Qmn_g, and a binary decision variable u_{gmlk} that reveals whether the group is committed:

$$q_{gmlk} \leq Qmx_g \cdot u_{gmlk} \quad \forall g,m,l,k, \tag{15}$$

$$q_{gmlk} \geq Qmn_g \cdot u_{gmlk} \quad \forall g,m,l,k. \tag{16}$$

Nonetheless, group commitments actually depend on start-up and shut-down decisions. If a group starts up between states l and l' (obviously, it was not committed in state l), it will be committed during state l'. In contrast, a group will not be committed if it was committed in state l and shuts down between states l and l'. Last, if a group does not start up or shut down between states l and l', it remains in its current commitment mode during both l and l'. Constraint (17), which includes start-up $y_{gmll'k}$ and shut-down decisions $z_{gmll'k}$, describes these processes:

$$u_{gmlk} - u_{gml'k} = y_{gmll'k} - z_{gmll'k} \quad \forall g,m,l,l',k. \tag{17}$$

Note that start-up and shut-down decision variables need not be binary, but only bounded between zero and one, because their value is automatically determined by the binary commitment decisions.

The behavior of generation companies in perfectly competitive markets is equivalent to minimizing the operating costs of all the thermal power plants in a system plus the cost to consumers of unmet demand (Appendix). The main costs of thermal groups can be summarized in variable costs CV_g (related to generation); fixed costs CF_g (related to commitment); start-up costs CY_g and shut-down cost CZ_g:

$$\min_{\substack{q_{gmlk}, u_{gmlk} \\ y_{gmll'k}, z_{gmll'k}}} \begin{array}{l} \sum_{g,m,l,k} \omega_k \cdot [\sum_{d \in m} (T_{dlk} \cdot (CV_g \cdot q_{gmlk} + CF_{gml} \cdot u_{gmlk})) \\ + \sum_{l'} (N_{mll'k} (CY_g \cdot y_{gmll'k} + CZ_g \cdot z_{gmll'k}))] \end{array}. \tag{18}$$

Observe that power plant operation is a short-term decision. In addition, start-up and shut-down decisions are multiplied by the number of transitions between states to internalize properly these costs. (GFPP variable costs connected to a zonal spot market are already considered in (2) and, hence, CVg=0).

Objective function (18) subject to constraints (14)–(17) constitutes a MIP problem, in which thermal power plants are dispatched.

D. Coupling gas and electricity markets

So far, we have broken down a model that optimizes gas purchases and, in particular, long-term pipeline capacity contracting under uncertainty of renewable energy sources within a perfectly competitive framework. From the point of view of company e', the gas demand is given by the cost-minimizing operation problem in which it (and every Genco) behaves as a price-taker. Conditioned to this demand, the company e' minimizes the costs associated with its participation in gas spot and capacity markets in which gas and pipeline capacity are purchased, respectively. Moreover, it also internalizes the risks of participating in secondary capacity markets. These decisions are actually obtained at the same time as the above optimization problems are merged into a single optimization problem. However, a constraint that links GFPP production to gas operation has not been established yet. In detail, each day, GFPPs connected to the analyzed pipeline consume a quantity of gas that depends on their gas-to-power conversion factor F_g:

$$d_{pe'dk} = \sum_{g \in (p,e'),l} F_g \cdot T_{dlk} \cdot q_{gmlk} \quad \forall p, m / d \in m, d, k. \tag{19}$$

After incorporating constraint (19), we obtain a MIP model that achieves our main objective of analyzing the long- and medium-term contracting decisions of company e' while taking into consideration short-term operations and risks:

$$\begin{array}{ll} \min & (2)+(4)+(18) \\ s.t. & \left| \begin{array}{l} (3);(5)-(13) \\ (14)-(17) \\ (19) \end{array} \right. \end{array}$$

IV. Case Study: Data Description

Our objective is to analyze a Genco that only owns GFPPs. Therefore, the Genco must coordinate its purchases in the gas spot market with its pipeline capacity contract portfolio. Simultaneously, this Genco must compete in the electricity market with other power producers. We do not intend to represent an actual system, but a system that reproduces actual operating conditions. Our system consists of a gas spot market, a shared gas pipeline and an electricity market. Capacities, prices, etc. are inspired by real systems, but do not represent a specific system. The time scope is one year.

The gas spot market is characterized by a price-quantity curve. The minimum daily price is 12 €/MWh-t. ('-t' indicates units of thermal energy. Later, '-e' is used for units of electric energy.) The slope of the price-quantity curve amounts to 0.05 (€/MWh-t)/GWh-t. In addition, the gas spot market establishes gas system prices for GFPPs that are not connected to the shared pipeline. For the sake of clarity, we consider neither the contracting nor the operation of other pipelines whose reference price is determined by the gas spot market.

Gas pipeline capacity amounts to 85 GWh-t/day. The pipeline supplies a city. Of importance, during times of congestion, the city's gas demand takes priority over other demand. Moreover, the city's demand determines gas prices. The city demand is subject to uncertainty as shown in Fig. 2. We define five scenarios: central, ±5% and ±10%. These scenarios reflect two relevant cold snaps that can reduce free pipeline capacity by up to 10% for other gas consumers. In this example, the stylized Genco owns the following four GFPPs that are connected to the same pipeline as the city: CCGT1, CCGT2, OCGT1 and OCGT2 (shown in Table II and Table III). One of the basic concerns about gas-power systems that we have tried to represent with this system is how scarce capacity affects the contracting and operation of a Genco. In the worst scenario, free pipeline capacity after supplying the city allows the Genco to use its four GFPPs at full capacity during 184 days, or its two CCGTs during 325 days and its two OCGTs during 349 days (each at full capacity).

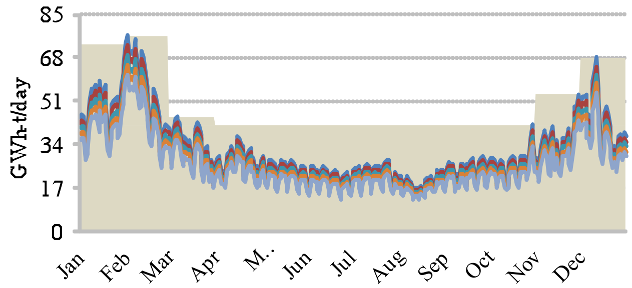

Fig. 2. Daily city demand per scenario and unique contract portfolio

The long-term capacity contract price is 26,415 €/(GWh-t/day). The Genco pays monthly for the corresponding pipeline capacity during the years that the long-term contract is active, instead of paying for the capacity all at once, in accordance with some regulatory frameworks. Medium- and short-term contract prices are obtained after multiplying long-term prices by a monthly factor (Table I). As cold months are strongly penalized, the Genco has an incentive to contract properly during high demand months. For instance, the short-term capacity costs incurred over 10 days are enough to secure capacity for a cold month via a medium-term contract (the same is true for short-term capacity costs incurred over 20 days for a warm month). Lastly, a tariff is applied to gas flowing through the pipeline equal to 567 €/GWh-t.

TABLE I
MEDIUM- AND SHORT-TERM FACTORS

Month	Medium-term factor (Monthly)	Short-term factor (Daily)
Jan-Mar	2	0.20
Apr-Sep	1	0.05
Oct-Dec	2	0.20

In contrast, the city holds a portfolio of long- and medium-term contracts at the beginning of the year. This portfolio provides the city with enough gas to cover its uncertain, but foreseen, demand. The portfolio, which has been optimized separately with the model from section III.B, is shown as the background shape in Fig.2.

The power system consists of gas (CCGT and OCGT), coal and oil power plants whose technical characteristics and operation costs are shown in Table II and Table III, respectively.

We have utilized a real, although scaled, hourly demand curve (from Portugal during 2012) and five real hourly wind profiles (obtained between 2008-2012) to obtain five net electricity demand curves with their corresponding transition matrices and state durations. System states have been computed with MATLAB® clustering function k-means. Mean electric power demand is 2.7 GW-e, while mean wind power scenarios range from 0.2 to 0.8 GW-e (in detail, 9%, 18%, 20%, 23%, and 29% wind penetration). Each scenario occurs with an equal probability of 0.20.

TABLE II
THERMAL GROUPS TECHNICAL CHARACTERISTICS

Thermal group	Maximum power (MW-e)	Minimum power (MW-e)	Gas-to-power factor (MW-t/MW-e)
CCGT1	400	200	1.7
CCGT2	400	200	1.7
CCGT3	400	200	1.7
CCGT4	400	200	1.7
Coal1	600	300	-
Coal2	600	300	-
OCGT1	200	-	2.5
OCGT2	200	-	2.5
OCGT3	200	-	2.5
OCGT4	200	-	2.5
Oil	600	100	-

TABLE III
THERMAL GROUPS COSTS

Thermal group	Variable cost (€/MWh-e)	Fixed cost (€/h)	Start-up cost (€)	Shut-down cost (€)
CCGT1	*Gas market*	650	50,000	3,000
CCGT2	*Gas market*	650	50,000	3,000
CCGT3	*Gas market*	650	50,000	3,000
CCGT4	*Gas market*	650	50,000	3,000
Coal1	35	900	100,000	7,000
Coal2	35	900	100,000	7,000
OCGT1	*Gas market*	1,000	10,000	1,000
OCGT2	*Gas market*	1,000	10,000	1,000
OCGT3	*Gas market*	1,000	10,000	1,000
OCGT4	*Gas market*	1,000	10,000	1,000
Oil	70	1,200	30,000	2,000

V. CASE STUDY: RESULTS

The MIP model has been formulated in GAMS and solved using CPLEX 12 on an Intel® Core™ i7 at 3.40GHz with 16GB RAM. The computational time to solve the case study (310,000 variables, 25,200 integer variables, and 237,120 equations) was 2 hours with *epgap*=1%, 30 minutes with *epgap*=3% and 14 seconds when the problem is relaxed, using 6 threads.

Regarding the Genco behavior, let us compare three different behaviors: 1) risk neutrality with β=0 and $Smin_e$=0; 2) risk averseness with β=0.8 and $Smin_e$=0.8; and 3) risk averseness with β=0.6 and $Smin_e$=0.9. In short, the Genco may contract less than 80% (or 90%) firm capacity in at most 20% (or 40%) of all scenarios (ε=0).

Gas flow demands and contract portfolios for the different behaviors are shown in Fig. 3, Fig. 4, and Fig. 5. At first sight, we can observe the relevance of the parameter $Smin_{e'}$. Firm capacity contracts due to acquisitions in primary markets represent 39%, 81% and 93% of total utilized capacity. In contrast, total profits decrease from 51.7 to 48.5 and to 46.9 million euro because capacity in secondary markets, in which gas consumers trade with pipeline capacity, is much cheaper than short-term capacity (Fig. 6). As a matter of fact, the city generally releases its unused capacity for free except when capacity is extremely scarce, that is, when constraint (6) is also binding. Even for days when constraint (6) binds, secondary market capacity prices are low (the maximum price is equal to 252.53 €/(GWh-t/day)) because the city has no interest in exercising its dominant position. Given that other market participants may not behave competitively, the trade-off between firm capacity and profits can compromise power system stability in reality, as mentioned in Section I.

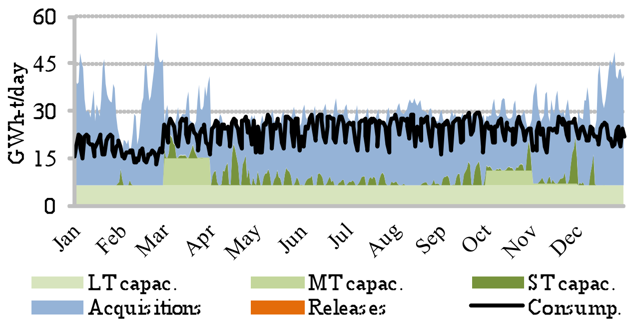

Fig. 3. Gas demand and contract portfolio of a risk-neutral Genco

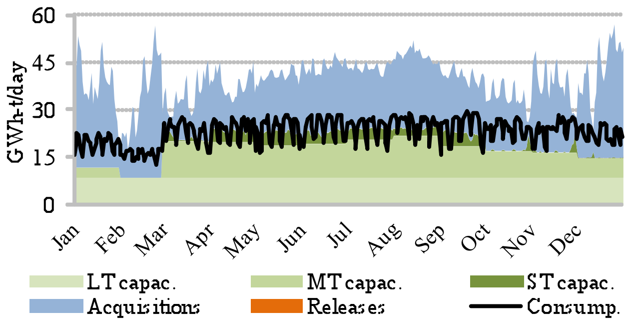

Fig. 4. Gas demand and contract portfolio of a risk-averse Genco, β=0.8 and $Smin_e$=0.8

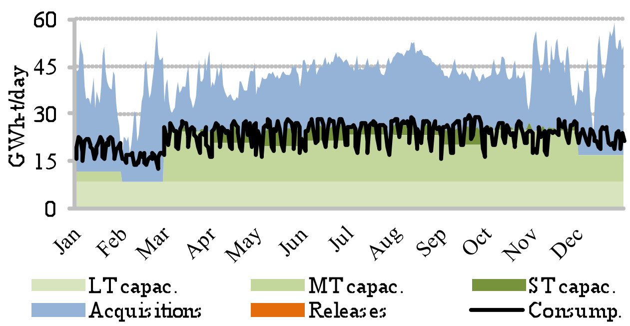

Fig. 5. Gas demand and contract portfolio of a risk-averse Genco, β=0.6 and $Smin_e$=0.9

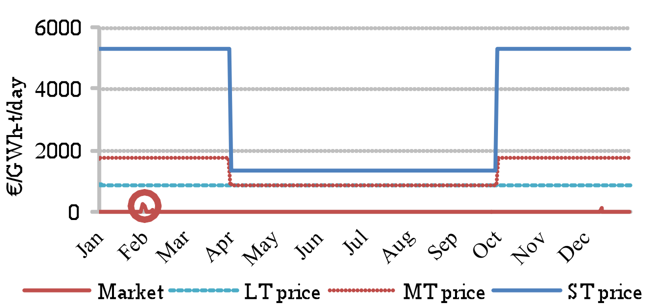

Fig. 6. Secondary capacity price vs. short-term capacity price

The following results correspond to the first case, in which the Genco is risk neutral. Nevertheless, the results are in practice equal. Focusing on the whole system, we can observe a relationship between gas prices and expected electricity prices (Fig. 7). As a matter of fact, electricity price level increases during both cold snaps, although thermal production is almost constant along the year (background shape in Fig. 7). Moreover, electricity price volatility is greatly noticeable due to the internalization of start-up and shut-down costs. Its coefficient of variation, 0.31, is much higher than the gas price volatility's 0.05 coefficient of variation.

Gas accounts for 54% of thermal generation, while coal accounts for 45%. In contrast, a meager 1% of thermal power generation corresponds to oil power plants, although they are essential to prevent non-supplied energy. The case study could be a mirror of an actual system that is transiting from a coal-based production to a gas-based production with renewable energy sources. Notice that hydro power plants, which often play a relevant role in power systems, have not been considered in this paper.

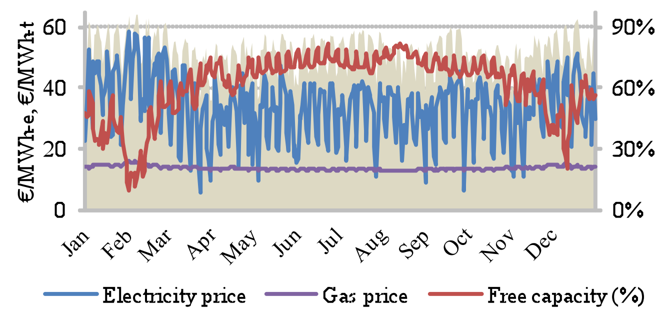

Fig. 7. Relationship between electricity and gas prices and free gas pipeline capacity

VI. Conclusion

We have addressed an intertwined energy system consisting of gas and electricity markets. The link between both markets is the GFPP that, in the framework of liberalized markets, is operated by a Genco which is in charge of acquiring gas, contracting for pipeline capacity and submitting production offers to an electricity market under uncertainty. With the objective of supporting and analyzing the decision-taking process of such Genco, we have developed a novel model that optimizes simultaneously gas purchases in a zonal spot market, pipeline capacity contract portfolios and thermal power plant operation under renewable energy uncertainty. The main contribution is to highlight how a Genco would make optimal long- and medium-term decisions subject to short-term uncertainty (and, explicitly, not to provide a model to guide short-term decisions). Furthermore, we have introduced risk aversion into the model which allows a Genco to evaluate the trade-off between contracting for firm capacity or potentially obtaining larger profits.

Nonetheless, additional work is still required for a thorough analysis of the integration between gas and electric power systems. Immediate future research guidelines mainly involve analyzing the capacity contracting effects when perfect competition in both markets does not exist (e.g., market concentration in the electric power market or capacity hoarding in pipelines) because anticompetitive behaviors may increase perverse effects for the power system. Furthermore, other consumers with different interests should be included in the model in order to fully capture the Genco's behavior.

Appendix

For the sake of clarity, let us suppose there are several thermal power plants, g=1,2,…,G. Each thermal power plant generates electric power q_g in order to satisfy an elastic demand with demand intercept PD and elasticity δ with the objective of maximizing its profits subject to its maximum power level Qmx_g, and its technical minimum level Qmn_g:

$$\left.\begin{array}{lll}\max\limits_{q_g} & \lambda\cdot q_g - C_g(q_g) & \\ s.t. & q_g \le Qmx_g & :\bar{\mu}_g \\ & q_g \ge Qmn_g & :\underline{\mu}_g\end{array}\right\}\forall g$$
$$\sum\nolimits_g q_g = PD - \delta\cdot\lambda$$

where λ is the market-clearing price. The KKT conditions of the above problem within a perfectly competitive environment in which all generators are price-takers, that is, $d\lambda/dq_g=0$, are the following:

$$\lambda - C_g'(q_g) - \bar{\mu}_g + \underline{\mu}_g = 0$$
$$\bar{\mu}_g\cdot(q_g - Qmx_g) = 0$$
$$\underline{\mu}_g\cdot(Qmn_g - q_g) = 0$$
$$\sum\nolimits_g q_g = PD - \delta\cdot\lambda$$

which exactly coincide, after easy operations, with the KKT conditions of the following cost-minimizing problem:

$$\begin{array}{lll}\max\limits_{q_g} & -\sum\nolimits_g C_g(q_g) + [PD\cdot d - d^2/2]/\delta & \\ s.t. & q_g \le Qmx_g & :\bar{\mu}_g \\ & q_g \ge Qmn_g & :\underline{\mu}_g \\ & d = \sum\nolimits_g q_g & :\lambda\end{array}$$

For inelastic demand, $d=PD$, and, therefore, the second term of the objective function is constant.

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Pablo Dueñas received the Industrial Engineering degree (2007) and a PhD in Industrial Engineering (2013) from the Universidad Pontificia Comillas, Madrid, Spain. Currently, he is an Assistant Researcher at the Instituto de Investigación Tecnológica, Advanced Technical Engineering School (ICAI), Universidad Pontificia Comillas. His areas of interest include energy systems and markets.

Tommy Leung is currently pursuing a PhD in Engineering Systems at the Massachusetts Institute of Technology (MIT) in Cambridge, Massachusetts, USA. He holds a Master's in Technology and Policy (2012) from MIT and a Bachelor's in Engineering (2005) from Harvey Mudd College in Claremont, California, USA. His research interests include energy policy, electric power systems regulation, and electricity/gas market design.

María Gil was born in Madrid, Spain, in 1986. She received the degree of Industrial Engineer in 2009 from Universidad Pontificia Comillas, Madrid, Spain. Since September 2012, she is an Assistant Researcher at the Instituto de Investigación Tecnológica, Universidad Pontificia Comillas. Her areas of interest include operation, simulation models, and planning of electricity and gas markets.

Javier Reneses obtained his Electrical Engineering Degree (1996) and a PhD in Industrial Engineering (2004) from the Universidad Pontificia Comillas, Madrid, Spain, and a Degree in Mathematics from the Open University in Spain (UNED) in

2005. At present, he is an Assistant Professor at the Instituto de Investigación Tecnológica. His areas of interest include operation, simulation models and planning of electricity and natural gas markets, as well as regulation of power systems.