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An integrated model for generation maintenance coordination in a restructured power system involving gas network constraints and uncertainties

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ABSTRACT

A maintenance coordination algorithm is proposed in this paper in which, the natural gas network constraints and uncertainties are taken into account. In this way, new communication lines between natural Gas Network Operator (GNO), Independent electricity Market Operator (IMO) and Independent electric System Operator (ISO) are created to coordinate the mid-term planning of the electric and the gas networks. The coordination process is an iterative process in which, initially, the GNO generates a complete set of non-electrical gas load scenarios. Then, the scenario-based maximum available gases for generating units are calculated and sent to the IMO and the ISO. The IMO declares the interval electricity prices in scenarios for the period of concern. The Generation Companies (GenCos) would then provide the ISO and the IMO with their maintenance proposals; considering their own objectives, constraints, scenario-based prices, and scenario-based maximum available gases. The ISO would evaluate the impact of maintenance proposals and scenario-based maximum available gases on reliability indices and assign some penalties/rewards to the GenCos, in proportion to their contribution in reliability index violation from a desirable level. On the other hand, the GNO would calculate the new scenario-based maximum available gas for the generating units, considering new maintenance proposals. Then, the IMO would provide new electricity prices, based on new maintenance proposals. These signals would be used by the GenCos to review and modify their maintenance proposals. The procedure is repeated until an equilibrium point is reached. For convergence assurance, a memory rate is introduced by which the GenCos earlier experiences in providing the ISO with maintenance proposals are, somehow, taken into account. The capabilities of the proposed algorithm are assessed and evaluated on IEEE-RTS.

1. Introduction

Share of natural gas (hereon, gas is used for simplicity), as a primary fuel, for electrical power generation has increased over the last decade. On the other hand, in households, growing usage of gas for heating is observed which it can threat the primary fuel availability for power generation. Therefore, dependency of power generation to gas network has become one of the concerns of energy policy makers [1–7].

Generation maintenance coordination process is an issue of concern in mid-term planning of restructured power systems [8,9]. The process is designed to coordinate the desired outage schedules of GenCos, in a planning horizon (e.g. one year) provided that the ISO's reliability criteria are met. The proposed coordination processes [10–13,1,4,15–17] do not concern the gas network impact. However, the generation maintenance coordination can be economically and technically influenced by gas network constraints and uncertainties, as follows:

– From the GenCos point of view, the maintenance outage time can be directly affected by the gas price uncertainty and variations. Price uncertainty is the result of gas market restructuring in which, the clients have the possibility to choose their suppliers. In a regulated environment, although, the price uncertainty is ignored, its seasonal variations have significant impact on maintenance schedules.
– An interruption or pressure loss in the gas network may lead to a decrease in available capacity which, it generally, reduces the GenCos profits and threats power system reliability. Therefore, the main coordination objectives are affected by derated capacities.
– In severe weather situations, the demand for electricity and gas may peak at the same time. Therefore, the available gas for power generation can be threatened. As a result, the GenCos profits and power system reliability may be affected. In these situations, dual fuel generating units can play an important role in keeping power system reliability.

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Nomenclature

Indices

el	index for an electrical gas load
i	index for a coordination process iteration
j	index for a gas well
k	index for a GenCo
m,n,p,q	indices for nodes of the gas network
nl	index for a non-electrical gas load
s	index for a scenario
t	index for a time interval
u	index for a generating unit

Constants and parameters

D	duration of an interval (h)
$EENS_{max}$	standard maximum expected energy not supplied (MW h)
FOR	forced outage rate
$HR^{gas}(HR^{alt})$	heat rate when gas (an alternative fuel) is burned (MBtu/MW h)
L	nodal non-electrical gas load
MGC	maximum contracted gas (Kcf/h)
$STDEIR$	standard expected index of reliability (%)
α	slope of the supply curve (MW^{-1})
β	supply shift index
μ	expected supply shift index
π_{m-n}	constant of a pipeline between nodes m and n (Kcf/Psig)

Sets

Δ	set of GenCos
$\Lambda(k)$	set of generating units of GenCo k
Ξ	set of electrical gas loads belonging to GenCo k

Variables

cap	available capacity (MW)
$cap^{gas}(cap^{alt})$	available capacity when gas (an alternative fuel) is burned (MW)
$cont$	contribution of a generating unit in $eens$ (MW h)
$eens$	expected energy not supplied (MW h)
f_{m-n}	gas flow between nodes m and n (Kcf/h)
$intr$	the amount of electrical gas load that is interrupted (Kcf/h)
p	nodal gas pressure (Psig)
pen	penalty assigned to a generating unit ($)
$rcap^{gas}(rcap^{alt})$	Bernoulli random variable for the available capacity when gas (an alternative fuel) is burned (MW)
rew	reward assigned to a generating unit ($)
$tcap$	total available capacity (MW)
$tpen(trew)$	total cumulative penalty (reward) assigned to a generating unit ($)
vc	total generation variable cost ($/h)
vc^{fuel}	total fuel based generation cost ($/h)
$vc^{gas}(vc^{alt})$	total fuel based generation cost when natural gas (an alternative fuel) is burned ($/h)
vc^{nfuel}	total non-fuel based generation cost ($/h)
w	production of a gas well (Kcf/h)
x	maintenance outage index of a generating unit (=1 if out, =0 if in service)
y^{gas}	gas burning index for a generating unit (=1 if natural gas is burned, =0 otherwise)
y^{alt}	alternative fuel burning index for a generating unit (=1 if other fuel is burned, =0 otherwise)
ρ	electricity market price ($/MW h)

Operators

$N[\cdot]$	number of objects associated to index (indices) (e.g. $N[u,k]$ is the total number of generating unit u belonging to GenCo k)
$PSGN[x]$	positive sign operator (=0, if $x < 0$ and $=x$ otherwise)
$SGN[x]$	Sign operator ($=-1$, if $x < 0$ and =1 otherwise)

– In the event of gas pipeline outages, gas-fired generators without dual fuel capabilities could constrain power system operation, due to lack of gas supply.

Such conditions necessitate an integrated view of mid-term gas and electrical network planning that has not been studied, yet [18–23]. However, to the best of our knowledge, some studies in the field of the impact of gas network constraints on a GenCo's maintenance scheduling are reported in [24]. In this paper, we focus on the system-wide generation maintenance coordination in the presence of gas network constraints. In the proposed coordination framework, some assumptions are made on studying the gas network influences introduced above. It is assumed that the gas price is determined in a regulated way, in which the price uncertainties are ignored. Moreover, due to high reliability of the gas pipelines, outage uncertainty of the gas network facilities can be neglected. Therefore, this type of uncertainty is also ignored [25,26].

In this paper, a new integrated model (as explained in Section 2) is introduced in which, the GenCos, the ISO, the Independent Market Operator (IMO) – independent from or a part of ISO – and the Gas Network Operator (GNO) collaborate to coordinate the generation maintenance schedules. In this way, initially, the GenCos are informed of the weekly electricity price, provided by the IMO and the scenario-based available gas, resulting from mid-term gas network operation planning by the GNO. In this scenario-based operation planning, nodal gas interruption is minimized, considering a mixed integer-linear gas network load flow model. Next, based on the provided information, GenCos submit their maintenance schedules to the ISO, in which, the GenCo's profits are maximized, subject to some maintenance constraints (e.g. maintenance continuity, separation, etc.). Based on the impact of each GenCos' proposed schedules on each interval system reliability index, the ISO will send interval-based penalty/reward signals to the GenCos to reschedule their maintenances. In parallel, the IMO and the GNO would determine and provide the GenCos with new weekly prices and possible available gas. These sequences are repeated until a convergence criterion (e. g. similar maintenance schedules in some consecutive iterations) is met.

The paper is organized as follows. Conceptual framework of the proposed model is discussed in Section 2. The GNO coordination function formulation is described in Section 3. The GenCos problem formulation is discussed in Section 4. The IMO and the ISO coordination problem formulation are illustrated in Sections 5 and 6, respectively. Penalties/rewards involvement in GenCo's objective function is presented in Section 7. Numerical results are demonstrated in Section 8. Some concluding remarks are provided in Section 9.

2. Conceptual framework

In the generation maintenance coordination process, the economic behavior of the GenCos may be either statically or dynamically simulated. The former is mainly based on game theory

[10–13] in which, decision making is performed by all agents at the same time. Some simplifying, sometimes unrealistic, assumptions should be made, in terms of the information required for the rivals and the predefined behaviors of the players. In the latter, the decisions are made through an iterative process so that each new decision is based on the earlier experiences and forecasting future behaviors. In this way, the simplifying assumptions are, to the best extent, avoided. This approach is employed in this paper.

Based on the dynamic process, [14–17] are four typical quasi-economic research reported for maintenance scheduling. The electricity price, as one of the most important factors in computational economics, is, however, assumed to be fixed. In [14], an iterative procedure is used to solve the problem. Initially, the GenCos provide the ISO with their proposals on maintenances. Optimizing the reliability criterion and based on some incentives/disincentives, the ISO and the GenCos communicate with each other to reach an agreement on maintenance schedules. [15] is an extension of the work reported in [14] in which the GenCos participation in preserving the reliability is taken into account. [16,17] are two research that improve the concept introduced in [14,15].

The present paper proposes a procedure, aiming at resolving the drawbacks of existing dynamic approaches as follows:

– The usefulness may be seriously affected by considering the probabilistic criteria to evaluate the reliability.
– The proposed procedures are based on fixed market prices, insensitive to maintenance schedules. However, the price variation can be used as extra information, in addition to incentives/disincentives, to help the GenCos and the ISO to adjust the maintenance schedules in a weaker conflicting way [27].
– The proposed coordination processes do not concern the gas network impact.

In this paper, a cobweb theory based model is proposed for maintenance coordination process. The cobweb theory was first proposed in [28] and, later on, developed and extended that is summarized in [29]. To the best of our knowledge, the only application of cobweb theory in an electricity market is reported in [30] for a bidding strategy.

The cobweb theory based model is a dynamical system that describes price fluctuations as a result of the interaction between demand function; depending on current price, and supply function; depending on the expected price. In this model, based on initial market price expectation, suppliers provide the best quantities. Based on these and with the due attention to the demand function, a new market price is achieved. This, in turn, leads to a modification in initial proposed quantities. The process is repeated until an equilibrium point is reached.

The stages of the cobweb theory based system are used for designing a maintenance coordination process. In the process, by using the initial market price, as prepared by the IMO, the GenCos provide the best maintenance schedules. Based on these, a new market price is achieved. This, in turn, leads to a modification in initial proposed schedules. The process is repeated until an equilibrium point is reached. The coordination process is carried out by the ISO; due to its responsibility in keeping the system reliability. This responsibility is implemented through penalty/reward control signals as devised by the ISO and considered by the GenCos in their decision making process.

The proposed approach requires to be modified to consider the gas network impact on the generation maintenance coordination process. As, the process is a decentralized decision making type, the gas network impact on all the participants objectives should be modeled. In this way, the following modifications are introduced (as explained in the following sections):

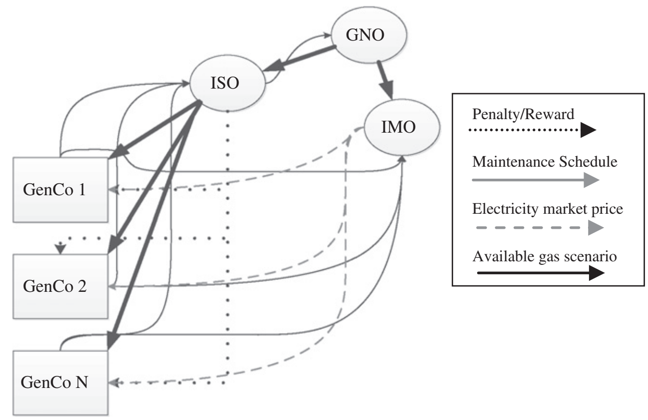

Fig. 1. Conceptual framework of generation maintenance coordination.

– A new function for the GNO is introduced and new communication lines between the ISO, the IMO, the GNO, and the GenCos are created to gain a better mid-term planning.
– Some gas network constraints are considered.
– A new method to consider the impact of dual fuel generating units on GenCos objectives, gas network loads and power system reliability is proposed.
– The ISO policy to consider the gas network impact on power system reliability is introduced.

The conceptual framework is illustrated in Fig. 1 in which, the information flows between the entities are also shown. The coordination process is represented in Fig. 2, in which, i is an index for the process iterations and z is the counter of feasible similar solutions in consecutive iterations. The process is implemented as follows:

(a) Initially, a complete set of non-electrical gas load scenarios with possible uncertainties is generated by the GNO (as explained in Section 3.1). Maximum available gases for electrical gas loads are calculated for each scenario, considering mid-term operation planning objectives and observing the technical constraints of the gas network (as explained in Section 3.2). Then, the GNO sends them to the ISO and the IMO.
(b) Using the scenario based maximum available gas and the weekly electricity prices provided by the IMO, the GenCos propose their generating units maintenance schedules by maximizing their own profits as a stochastic programming. In this stage, each GenCo assumes the rivals' behaviors to be unchanged (as explained in Section 4).
(c) Based on the proposals, given by the GenCos and the scenario-based maximum available gas (which can affect the maximum available capacities), determined by the GNO, the IMO would determine new weekly prices and provide the GenCos with the new prices (as explained in Section 5).
(d) The ISO would then calculate the reliability index and compare it with the acceptable level at each interval (e.g. week). Based on the contribution of each GenCo in reliability reduction/increase of each interval, the ISO will send penalty/reward signals to the GenCos to reschedule their maintenances (as explained in Section 6).
(e) The GNO would determine the new scenario-based maximum available gas and deliver it to the ISO and the IMO (as explained in Section 3.2).
(f) By considering the new electricity prices, the penalty/reward signals and the scenario-based maximum available gas, the GenCos would reschedule their maintenance proposals (as explained in Section 7).

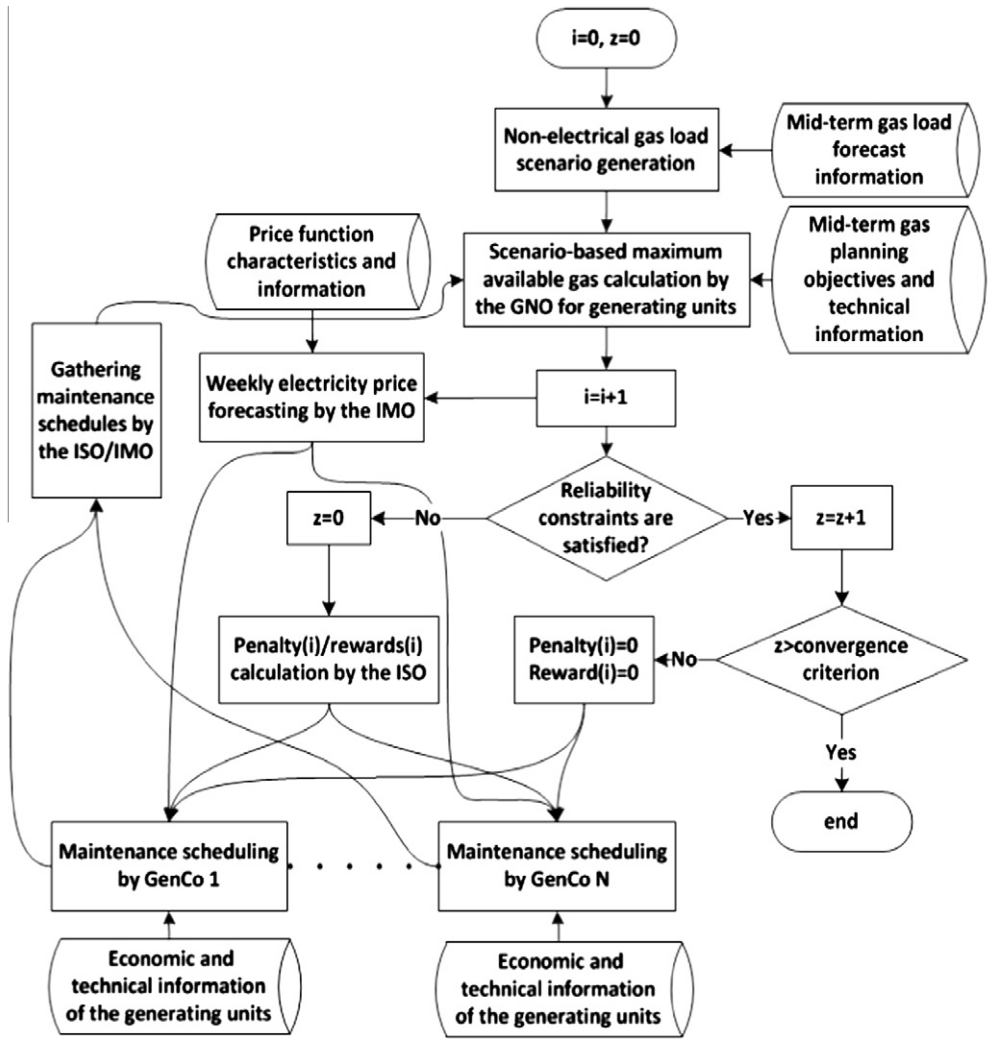

Fig. 2. Flow diagram of generation maintenance coordination process.

(g) The convergence criterion is checked to see if the whole process should be restarted from step (c). This criterion is chosen to be similar maintenance schedules proposed by the GenCos in consecutive iterations (three iterations in this paper).

In the proposed coordination process, in one hand, in each iteration, the GenCos try to maximize their expected profits without being aware of the rivals' behaviors and the effect on electricity prices. It is assumed that, GenCos do not have any market power to manipulate the price in order to achieve more profits. These GenCos' behaviors are in the direction of social welfare optimization. On the other hand, the ISO implicitly minimizes the consumers' loss of welfare; by devising penalty/reward signals that may be caused by unavailability of generating units due to improper maintenance schedules. Therefore, generation maintenances while the social welfare is improved.

The convergence property of the proposed model is crucial in terms of reaching an equilibrium point. As the quantities in each iteration are not determined in a coordinated way, if proper precautions are not foreseen, the algorithm may fail to converge. The ISO is, however, the final decision maker. So, the players should use the past experience on using the control (penalty/reward) signals as sent by the ISO. To improve the convergence performance of the coordination model, a memory rate, as explained in Section 7, is used in the process.

3. GNO coordination functions formulation

Gas network is one of the energy carrying infrastructures with a network, that is composed of gas wells (sources), pipelines (transmission systems), compressors, storage facilities and load centers (distribution systems and large consumers), as illustrated in Fig. 3.

A GNO is responsible for mid-term operation planning of the gas network. In this paper, the GNO activities are divided into two functions, namely, generating scenarios and calculating maximum available gas for the generating units.

3.1. Scenario generation

Gas consumers can be categorized as industrial, electrical, commercial and residential. To use the gas as fuel, a consumer signs two contracts, namely, a transportation service contract and a supply contract [1,4–6,24]:

– Transportation service contracts are divided into firm, interruptible and no-notice contracts, in accordance with the service priority. As an example, interruptible transportation services can be interrupted with little notice and penalties.

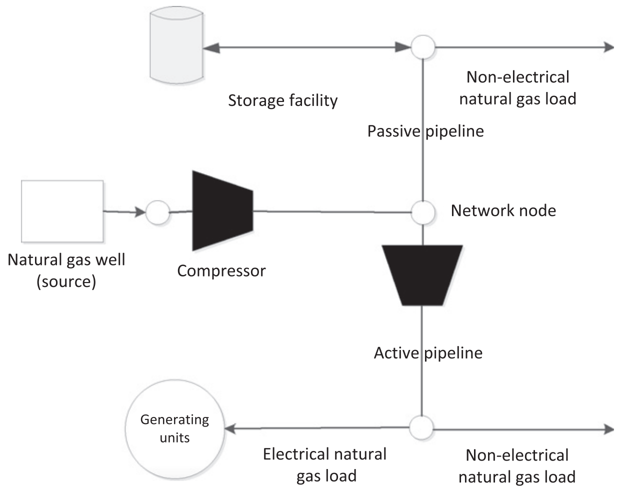

Fig. 3. Schematic of typical gas network.

– The supply contracts are divided into take-or-pay or flexible contracts. For take-or-pay contracts, total cost is fixed, regardless of the usage. For flexible contract, the price is usually higher than that of take-or-pay contract and the cost is usage dependent.

In one hand, industrial and electrical gas consumers, generally, have the interruptible service contract (as being more economical than firm services) and commercial and residential ones have the firm ones. On the other hand, commercial and residential gas consumers have stochastic demands. Therefore, the available gas to industrial and electrical consumers may be affected, as in emergency, these types of loads are, initially, interrupted [1,4,5].

Gas network operation uncertainties are due to prices, outages and temperature. As a regulated environment is considered for the gas network, price uncertainties are not considered in this paper. Moreover, due to high reliability of the gas transportation system, outage uncertainty of the gas network facilities can be neglected in comparison with that of a power system. Therefore, this type of uncertainty is also ignored [25,26]. As a result, the probabilistic modeling of the gas network is based on temperature as the main uncertainty driver.

The seasonal ARIMA model is widely used to model the stochastic energy demands (e.g. electricity, gas, etc.). Basic characteristics of a seasonal ARIMA-based stochastic process are explained in [31]. The weekly non-electrical gas loads,[1] in each node of the network is, thus, modeled as follows:

$$\left(1-\sum_{a=1}^{N[a,nl]}\eta(a,nl)BSA^{a}\right)\left(1-\sum_{a'=1}^{N[a',nl]}\eta'(a',nl)BSA^{a'\times SE}\right)(1-BSA)^{d}$$
$$(1-BSA^{SE})^{d'}sv(nl,t)=\left(1-\sum_{b=1}^{N[b,nl]}\lambda(b,nl)BSA^{b}\right)$$
$$\left(1-\sum_{b'=1}^{N[b',nl]}\lambda'(b',nl)BSA^{b'\times SE}\right)\varepsilon(nl,t) \quad (1)$$

where a' and a' (b and b') are the indices for autoregressive (moving average) parameters, d and d' show differentiation order, SE represents seasonality order, $BSA[a]$ stands for the backshift operator with order a (e.g. $BSA[a]sv(nl,t) = sv(nl,t-a)$), $\eta(a,nl)$ ($\lambda(b,nl)$) represents autoregressive (moving average) parameter of non-electrical gas load nl and $sv(nl,t)$ shows the stochastic variable of non-electrical gas load nl at interval t.

In (1), $\varepsilon(nl,t)$ stands for an uncorrelated normal stochastic process (white noise), uncorrelated with $sv(nl,t)$. $\varepsilon(nl,t)$ is commonly referred to as error term. The parameters of the model are estimated and adjusted using the real data [32].

Consider the ARIMA model of non-electrical gas load $NL(sv(NL,t))$. Initially, the real historical observations of $sv(NL,t)$ are gathered. Maximum values of indices ($N[a,NL]$, $N[a',NL]$, $N[b,NL]$, and $N[b',NL]$) are considered. Therefore, the considered ARIMA model would have $N[a,NL] + N[a',NL] + N[b,NL] + N[b',NL]$ parameters to be estimated, namely, $\eta(a,NL)$, $\eta(a',NL)$, $\lambda(b,NL)$ and $\lambda(b',NL)\forall$ $a = [1,N[a,NL]]$, $a' = [1,N[a',NL]]$, $b = [1,N[b,NL]]$ & $b = [1,N[b',NL]]$. Using least squares estimation method, the seasonal ARIMA process parameters can be estimated so that the impact of error term on parameter estimation is minimized [32].

The nature of geographical interdependency of loads makes the weekly ARIMA models of non-electrical gas loads to be statistically dependent. Such dependencies are transferred to the error terms ($\varepsilon(nl,t)$ $\forall nl \in \Omega$ & $t \in [1,N[t]]$, where Ω stands for the set of the gas nodes). Therefore the error terms would be cross-correlated (e. g. $\varepsilon(NL1,t)$) is correlated to $\varepsilon(NL2,t-1)$. Cross-correlogram can be used to analyze the dependency structure of the error terms [32], in which the cross-correlation coefficients for different time lags are represented. As the weekly gas loads are assumed to be modeled by (1), cross-correlation of error terms placed at lag more than 1 week can be considered statistically zero. Therefore, the seasonal ARIMA model in (1) is a quasi-contemporaneous stochastic process (cross-correlogram of error terms is triangular) [31].

To simplify the task of using the stochastic process in our model, the continuous process is replaced by a discrete scenario type. The main characteristics should, however, be preserved. Therefore, a proper scenario generation technique should be used [31].

In scenario generation process, the seasonal ARIMA models in (1) are independently calibrated. In each step of the scenario generation process (identified by index s), initially, a sample of standard error terms is independently produced. Based on the cross-correlation coefficients, the variance–covariance matrix of the error terms is calculated. Using the variance–covariance matrix and after some mathematical operations (as described in [31] in details), the resulting error terms are cross-correlated. These error terms are assumed to be known in (1). Therefore, the value of $sv(nl,t)$ can be calculated, straightforwardly and is named as $L(nl,s,t)$.

In one hand, the large number of generated scenarios can help the approximation error to be reduced. On the other hand, large number of scenarios may render the model to be computationally intractable. For this reason, an efficient scenario-reduction procedure has to be used. In this paper, without lack of generality, the probability distance based scenario reduction technique is employed, in which Kantorovich measure is used as the probability distance [31].

3.2. Maximum available gas calculation

In mid-term operation planning, the GNO should minimize the total gas load interruption, while considering scenarios and observing technical constraints. We assume that the electrical gas loads have the lowest priority to be supplied by the gas network. Therefore, if there is a need to interrupt the gas load in a gas network node, the available gas to the connected generating units is limited.

[1] Although the industrial gas loads are not stochastic (at least, as much as commercial and residential loads), it is assumed that these loads behaviors are aggregated in the non-electrical load models.

The objective function is presented as follows:

$$\min\ objgno(i,s)=\sum_{t=1}^{N[t]}\sum_{el=1}^{N[el]} intr\ (el,i,s,t)\ \forall s\in[1,N[s]] \tag{2}$$

where, $objgno(i,s)$ shows the mid-term operation planning objective function of GNO in iteration i and scenario s.

In (2), the GNO minimizes the sum of electrical gas load interruption at node el, at interval t and in scenario s. Therefore, the maximum available gas for electricity generation, at each interval and scenario, may be calculated.

Technical constraints are composed of gas network elements models and generation–consumption balance.

Pipeline model: Gas transmission is driven by pressures and is dependent on some physical factors such as the length and the diameters of pipelines, and operating temperature. Gas pipelines are either passive (pipelines without compressors), or active (pipelines with compressors) [6]. The gas flow through a passive pipeline is determined by the pressure difference as follows:

$$\begin{aligned}&SGN[f_{m-n}(i,s,t)]\times f_{m-n}(i,s,t)^2=\pi_{m-n}^2\times(p(m,i,s,t)^2-p(n,i,s,t)^2)\\&\forall t\in[1,N[t]],s\in[1,N[s]]\ \&\ m,n\in\Omega_p\end{aligned} \tag{3}$$

where Ω_p represents the set of passive pipelines.

π_{m-n} is determined by physical characteristics of the pipeline; connecting node m and n. Pressure may drop due to friction, as gas flows through the pipelines. Therefore, compressors may be installed to recover some part of this drop. However, if compressors are installed, the following inequality constraint must be met:

$$\begin{aligned}&SGN[f_{m-n}(i,s,t)]\times f_{m-n}(i,s,t)^2\geqslant\pi_{m-n}^2\times(p(m,i,s,t)^2-p(n,i,s,t)^2)\\&\forall t\in[1,N[t]],s\in[1,N[s]]\ \&\ m,n\in\Omega_a\end{aligned} \tag{4}$$

where Ω_a represents the set of active pipelines.

Moreover, for active pipelines, the gas flow is only in one direction, i.e. $f_{m-n}(i,s,t)\leqslant 0$.

A pipeline pressure should be within the specified limits, as follows:

$$\begin{aligned}&P_{min}(m)\leqslant p(m,i,s,t)\leqslant P_{max}(m)\\&\forall t\in[1,N[t]],s\in[1,N[s]]\ \&\ m\in[1,N[m]]\end{aligned} \tag{5}$$

where $P_{max}(m)$ ($P_{min}(m)$) shows the maximum (minimum) allowable gas pressure (Psig) of node m.

The pipeline constraints are generally nonlinear, but can be linearized with the details given in [6].

Gas storage: Based on the capacity and the operating characteristics, gas storages are categorized into long-term, mid-term and short-term. They are used to balance the demands in their respective periods. The gas network capacity may also be considered as a source of storage, if the pressure is increased during low demand periods. As for the proposed maintenance coordination process, the stored gas may behave as an alternative fuel, it is not, explicitly, modeled in the proposed framework [1,26].

Nodal constraints: These constraints indicate that the gas flow mismatch at each node of the gas network is equal to zero, while, the technical limitations of the injected and the extracted flows are observed.

The gas nodal balance is as follows:

$$\begin{aligned}&\sum_{j=1}^{N[w]}I(q,j)\times w(j,i,s,t)-\sum_{nl=1}^{N[nl]}I(q,nl)\times L(nl,s,t)\\&\quad-\sum_{el=1}^{N[el]}I(q,el)\times(MGC(el,t)-intr(el,i,s,t))-\sum_{n\in\Gamma(q)}f_{q-n}(i,s,t)=0\\&intr(el,s,t)\leqslant MGC(el,t),\ W_{min}(w)\leqslant w(j,i,s,t)\leqslant W_{max}(w)\\&\forall k\in\Delta,t\in[1,N[t]],s\in[1,N[s]],j\in[1,N[j]],q\in[1,N[q]],\ \&\ el\in\Xi(k)\end{aligned} \tag{6}$$

where, j is the index for a natural gas well (source), $\boldsymbol{I}(q,j)$, $\boldsymbol{I}(q,el)$ and $\boldsymbol{I}(q,nl)$ represent the node-natural gas source, node-electrical natural gas load and node-non-electrical natural gas load incidence matrix elements, respectively, $W_{max}(j)$ ($W_{min}(j)$) is the maximum (minimum) production capability of gas well j (Kcf/h) and $\Gamma(q)$ shows the set of nodes connected to node q through pipelines.

The first equation of (6) shows the gas flow balance constraint of node q, in which, four terms are, respectively, the sum of gas wells (sources) injections, the sum of non-electrical gas loads, the sum of electrical gas loads and the sum of gas pipelines flows. $intr(el,i,s,t)$, in the third term, takes value, if, instead of load interruption, there is no way to balance the flows in node el. Therefore, the electrical gas loads are interrupted, if required. Without loss of generality, it is also assumed that this interruption is sufficient to satisfy the technical constraints.

As a result, the maximum available gas for generating units can be calculated as follows:

$$\begin{aligned}&g_{max}(k,el,i,s,t)=MGC(el,t)-intr(el,i,s,t)\\&\forall k\in\Delta,t\in[1,N[t]],s\in[1,N[s]]\ \&\ el\in\Xi(k)\end{aligned} \tag{7}$$

4. GenCos problem formulation

4.1. GenCos objective function

GenCos are seeking to maximize their profits in proposal on their maintenance schedules. An energy only market is assumed in this paper; although other market mechanisms may also be considered. As a result, in each iteration of the coordination process, a GenCo profit function is as follows:

$$\max\ gencoprf(k,i)=\sum_{s=1}^{N[s]}SP(s)\times\sum_{t=1}^{N[t]}\sum_{u=1}^{N[u,k]}\begin{bmatrix}[\rho(i,s,t)\times\ cap(u,k,i,s,t)\times UT(u,k,t)-vc(u,k,i,s,t)-FC(u,k)]\times D(t)\\-[MC(u,k,t)-trew(u,k,i,s,t)+tpen(u,k,i,s,t)]\times x(u,k,i,t)\end{bmatrix}\quad\forall k\in\Delta \tag{8}$$

where, $gencoprf\,(k,i)$ shows the profit function of GenCo k in iteration i, $SP(s)$ is the occurrence probability of scenario s, $MC(u,k,t)$ and $FC(u,k)$ are the total maintenance ($) and generation fixed ($/h) costs of the generating unit u of GenCo k, respectively and $UT(u,k,t)$ stands for the utilization factor of the generating unit u of GenCo k at interval t.

(8), in general, is a stochastic programming formulation that maximizes the expected profit of GenCo k, considering all scenarios generated by the GNO.

The term, $[\rho(i,s,t) \times cap(u,k,i,s,t) \times UT(u,k,t) - vc(u,k,i,s,t) - FC(u,k)] \times D(t)$, shows the interval-based GenCo profit achieved in supplying electric energy to the market in scenario s. $UT(u,k,t)$, generally, depends on the commitment policy, the generating unit type and the bidding strategy. As the first one is the dominant parameter, it is assumed here that the utilization factor can be properly estimated using the historical data. The last term, $[MC(u,k,t) - trew(u,k,i,s,t) + tpen(u,k,i,s,t)] \times x(u,k,i,t)$, is the cost incurred due to the maintenance of generating unit u in which, the penalties/rewards imposed by the ISO are also observed. In the first iteration of the coordination process, these are considered to be zero. The penalties/rewards for the next iterations would be considered with the details given in Sections 6 and 7.

From the stochastic programming points of view, maintenance coordination variables ($x(u,k,i,t)$) must satisfy the non-anticipativity conditions which guarantee that the decision on the maintenance outage cannot be dependent on the scenario realization. For more explanations of the non-anticipativity conditions see [31].

Total variable generation cost ($vc(u,k,i,s,t)$) in (8) is divided into two parts; namely non-fuel based generation cost that is, generally, independent of the fuel type and, fuel based cost that depends on the fuel type. Therefore, the total variable generation cost can be calculated as follows:

$$vc(u,k,i,s,t) = vc^{nfuel}(u,k,i,s,t) + vc^{fuel}(u,k,i,s,t) \\ \forall k \in \Delta, t \in [1,N[t]], s \in [1,N[s]] \;\&\; u \in \Lambda(k) \tag{9}$$

where $vc^{nfuel}(u,k,i,s,t)$ presents the total non-fuel based cost that is calculated as follows:

$$vc^{nfuel}(u,k,i,s,t) = cap(u,k,i,s,t) \times UT(u,k,t) \times Q^{nfuel}(u,k) \\ \forall k \in \Delta, t \in [1,N[t]], s \in [1,N[s]] \;\&\; u \in \Lambda(k) \tag{10}$$

where $Q^{nfuel}(u,k)$ is the non-fuel based generation cost of generating unit u of GenCo k ($/MW h).

The fuel-based part of the total variable generation cost is explained in the next subsection.

4.2. Constraints

4.2.1. Generation and dual fuel capability constraints

The available capacity of a dual fuel generating unit ($cap(u,k,i,s,t)$) depends on the burning fuel type. Therefore, based on the fuel type, it takes the value of either gas based ($cap^{gas}(u,k,i,s,t)$) or alternative fuel based ($cap^{alt}(u,k,i,s,t)$) available capacity. This is enforced by the constraints below:

$$\begin{aligned} &cap(u,k,i,s,t) = cap^{gas}(u,k,i,s,t) + cap^{alt}(u,k,i,s,t) \\ &cap^{gas}(u,k,i,s,t) \leqslant y^{gas}(u,k,i,s,t) \times CAP^{gas}_{max}(u,k) \\ &cap^{gas}(u,k,i,s,t) \geqslant y^{gas}(u,k,i,s,t) \times CAP^{gas}_{min}(u,k) \\ &cap^{alt}(u,k,i,s,t) \leqslant y^{alt}(u,k,i,s,t) \times CAP^{alt}_{max}(u,k) \\ &cap^{alt}(u,k,i,s,t) \geqslant y^{alt}(u,k,i,s,t) \times CAP^{alt}_{min}(u,k) \\ &\forall k \in \Delta, t \in [1,N[t]], s \in [1,N[s]] \;\&\; u \in \Lambda(k) \end{aligned} \tag{11}$$

where $y^{gas}(u,k,i,s,t)$ ($y^{alt}(u,k,i,s,t)$) is a binary variable which indicates natural gas (alternative fuel) burning status (=1 if natural gas (alternative fuel) is burned, =0 otherwise) of generating unit u of GenCo k at interval t and in scenario s and $CAP^{alt}_{max}(u,k)$ ($CAP^{alt}_{min}(u,k)$) and $CAP^{gas}_{max}(u,k)$($CAP^{gas}_{min}(u,k)$) are the maximum (minimum) generation capability (MW) of generating unit u of GenCo k when an alternative fuel and gas is burned, respectively.

Generally, for some technologies, switching between fuels may affect the maximum available capacity as observed in (11). Moreover, it guarantees that the maximum capacity is within its limits, when burning either gas or alternative fuel.

For a dual fuel generating unit, the possibility of using, only, a single type of fuel in an interval is assumed. Therefore, $y^{gas}(u,k,i,s,t)$ and $y^{alt}(u,k,i,s,t)$ could not be equal to 1, simultaneously. Moreover, both must be equal to zero, if the associated generating unit is on maintenance. So:

$$y^{gas}(u,k,i,s,t) + y^{alt}(u,k,i,s,t) \leqslant (1 - x(u,k,i,t)) \\ \forall k \in \Delta, t \in [1,N[t]], s \in [1,N[s]] \;\&\; u \in \Lambda(k) \tag{12}$$

For a single-fuel generating unit, depending on the fuel type we would have:

$$\begin{aligned} &y^{gas}(u,k,i,s,t) = 0 \\ &\forall k \in \Delta, t \in [1,N[t]], s \in [1,N[s]], \;\&\; u \in \nabla^{gas}(k) \\ &y^{alt}(u,k,i,s,t) = 0 \\ &\forall k \in \Delta, t \in [1,N[t]], s \in [1,N[s]], \;\&\; u \in \nabla^{alt}(k) \end{aligned} \tag{13}$$

where $\nabla^{alt}(k)$ ($\nabla^{gas}(k)$) stands for the set of single fuel generating units of GenCo k that burn an alternative fuel (gas).

In calculating the available capacity, a maximum available fuel should be assumed. (14) presents the relation between available capacities of the generating units belonging to GenCo k, connected to node q and the maximum available gas in node q.

$$\sum_{u=1}^{N[u,k]} \left(cap^{gas}(u,k,i,s,t) \times \frac{HR^{gas}(u,k)}{GHV}\right) \leqslant g_{max}(k,el,i,s,t) \\ \forall k \in \Delta, t \in [1,N[t]], s \in [1,N[s]], u \in \Phi(k,el), \;\&\; el \in \Xi(k) \tag{14}$$

where, GHV shows the gas heat value (MBtu/Kcf), $\Phi(k,el)$ is the set of generating units of GenCo k that are categorized as electrical natural gas load el and $g_{max}(k,el,i,s,t)$, stands for the maximum available natural gas (Kcf/h) in gas network node el, in iteration i, scenario s and interval t.

Without loss of generality, it is assumed that the maximum available alternative fuel does not constrain the available capacity.

4.2.2. Fuel cost constraints

As already explained, to use the gas as fuel, a GenCo signs two contracts; namely, a transportation service contract and a supply contract. Moreover, some GenCos may construct fuel storage facilities for dual fuel generating units.

Therefore, the fuel based part of the generation cost ($vc^{fuel}(u,k,i,s,t)$) in (8) is calculated as follows:

$$vc^{fuel}(u,k,i,s,t) = vc^{gas}(u,k,i,s,t) + vc^{alt}(u,k,i,s,t) \\ \forall k \in \Delta, t \in [1,N[t]], s \in [1,N[s]] \;\&\; u \in \Lambda(k \tag{15}$$

where $vc^{gas}(u,k,i,s,t)$ ($vc^{alt}(u,k,i,s,t)$) stands for the total gas (alternative fuel) based generation cost that means the cost of gas contract (alternative fuel storage).

Gas based generation cost: The GenCos generally prefer interruptible transportation services, as being more economical than firm services [1,4–6,24]. In terms of the supply contracts, they, generally, may sign either take-or-pay or flexible contracts.

In this paper, both the supply and the transportation service contracts are modeled together. Therefore, each supply contract corresponds to a priority level of service and the corresponding price includes the cost of transportation.

For take-or-pay contracts, total cost is fixed, regardless of the usage. Therefore:

$$vc^{gas}(u,k,i,s,t) = ToPC(u,k,t)$$
$$\forall k \in \Delta, t \in [1,N[t]], s \in [1,N[s]], \ \& \ u \in \Theta(k) \quad (16)$$

where $ToPC(u,k,t)$ is the total cost (\$/h) of take or pay contract of generating unit u of GenCo k at interval t and $\Theta\ (k)$ is the set of generating units of GenCo k with take or pay gas contract.

For flexible contract, the price is usually higher than that of take-or-pay contact and the cost is usage dependent. In this case, $vc^{gas}(u,k,i,s,t)$ is calculated as follows:

$$vc^{gas}(u,k,i,s,t) = cap^{gas}(u,k,i,s,t) \times UT(u,k,t)$$
$$\times HR^{gas}(u,k) \times Q^{gas}(u,k,t)$$
$$\forall k \in \Delta, t \in [1,N[t]], s \in [1,N[s]], u \in \Psi(k) \ \& \ u \in \Lambda(k) \quad (17)$$

where $Q^{gas}(u,k,t)$ is the flexible gas price (\$/MBtu) of generating unit u of GenCo k at interval t and $\Psi(k)$ is the set of generating units of GenCo k with flexible gas contract.

As evident from (17) and (11), $vc^{gas}(u,k,i,s,t)$ would take a value, when generating unit u of GenCo k burns gas.

Alternative fuel based generation cost: Alternative fuel may be used if:

1. Gas price is very high.
2. The available gas is not sufficient.

The cost of using alternative fuel is as follows:

$$vc^{alt}(u,k,i,s,t) = cap^{alt}(u,k,i,s,t) \times UT(u,k,t)$$
$$\times HR^{alt}(u,k) \times Q^{alt}(u,k,t)$$
$$\forall k \in \Delta, t \in [1,N[t]], s \in [1,N[s]], \ \& \ u \in \Lambda(k) \quad (18)$$

where $Q^{alt}(u,k,t)$ is the fuel cost (\$/MBtu) of generating unit u of GenCo k in interval t when an alternative fuel is burned.

4.2.3. Maintenance constraints

The set of maintenance constraints to be observed is specified below, as explained in details in [10–17]. [14] justifies all these constraints by using illustrative examples.

Maintenance continuity: The maintenance of any generating unit must be completed once it begins; considering the required number of time intervals. This is considered using (19):

$$\sum_{t=1}^{N[t]} x(u,k,i,t) = MD(u,k)$$
$$x(u,k,i,t) - x(u,k,i,t-1) \leqslant x(u,k,i,t+MD(u,k)-1) \quad (19)$$
$$\forall k \in \Delta, t \in [1,N[t]], \ \& \ u \in \Lambda(k)$$

where $MD(u,k)$ is the maintenance duration of generating unit u of GenCo k.

Maintenance priority: In some cases, a GenCo may wish to give a priority of maintenance to some of its generating units. This may be accomplished using (20).

$$\sum_{t'=1}^{N[t]} x(u_1,k,i,t'-1) - x(u_2,k,i,t) \geqslant 0$$
$$\forall k \in \Delta, t \in [1,N[t]], \ \& \ u_1,u_2 \in \Lambda(k) \quad (20)$$

Maintenance coincidence: The maximum number of the generating units which can be maintained at an interval may be limited. This may be observed using (21).

$$\sum_{u=1}^{N[u,k]} x(u,k,i,t) \leqslant MN(k,t) \quad \forall k \in \Delta \ \& \ t \in [1,N[t]] \quad (21)$$

where $MN(k,t)$ is the maximum number of generating units of GenCo k allowed to go on maintenance at interval t.

Maintenance exclusion: This constraint enforces the impossibility of maintaining two prespecified generating units at the same interval:

$$x(u_1,k,i,t) + x(u_2,k,i,t) \leqslant 1$$
$$\forall k \in \Delta, t \in [1,N[t]], \ \& \ u_1,u_2 \in \Lambda(k) \quad (22)$$

Any other constraints such those introduced in [8,14] may also be observed and included.

The GenCo's maintenance scheduling problem as described in (8), (8), (10)–(22) is a stochastic mixed integer optimization problem which can be solved using various solvers, such as CPLEX [15,33].

5. The IMO coordination problem formulation

An extended modeling, based on what shown in [27,34], is proposed and used in this paper. The electricity market price, considering both the supply and the demand, as the main drivers, can be modeled as follows:

$$\rho(s,t) = e^{\alpha \times \delta(t) + \beta(i,s,t)} \quad \forall t \in [1,N[t]], s \in [1,N[s]] \quad (23)$$

where $\delta(t)$ presents the load level (MW) at interval t.

The model captures basic physical and economic relationships, present in the production and the trading of the electricity. $\delta(t)$ (load) and $\beta(i,s,t)$ (supply shift index in iteration i and scenario s) have, in general, stochastic behaviors, quantifying the uncertainty of price movements. To model the supply seasonality and uncertainty; resulting from fuel price fluctuations, strategic gaming, etc., $\beta(i,s,t)$ is introduced [27,34].

As in the electricity price model, the available capacity should be properly reflected, a probabilistic model of $\beta(i,s,t)$ is assumed as:

$$\beta(i,s,t) = \mu(t) - \alpha \times tcap(i,s,t)$$
$$\forall \ t \in [1,N[t]], \ \& \ s \in [1,N[s]] \quad (24)$$

where $\mu(t)$ is a deterministic variable which captures the average supply seasonality (to be forecasted through historical data) and $tcap(i,s,t)$ is a probabilistic variable showing the available capacity. This random variable is defined a summation of Bernoulli random variables as follows:

$$tcap(i,s,t) = \sum_{k=1}^{N[k]} \sum_{u=1}^{N[u,k]} (rcap^{gas}(u,k,i,s,t) + rcap^{alt}(u,k,i,s,t))$$
$$\forall t \in [1,N[t]], \ \& \ s \in [1,N[s]] \quad (25)$$

in which $rcap^{gas}(u,k,i,s,t)$ and $rcap^{alt}(u,k,i,s,t)$ are calculated as shown in (26) where, PRB stands for the probability operator.

$$rcap^{gas}(u,k,i,s,t) = \begin{cases} cap^{gas}(u,k,i,s,t) & PRB[rcap^{gas}(u,k,i,s,t) = cap^{gas}(u,k,i,s,t)] = 1 - FOR(u,k) \\ 0 & PRB[rcap^{gas}(u,k,i,s,t) = 0] = FOR(u,k) \end{cases}$$
$$rcap^{alt}(u,k,i,s,t) = \begin{cases} cap^{alt}(u,k,i,s,t) & PRB[rcap^{alt}(u,k,i,s,t) = cap^{alt}(u,k,i,s,t)] = 1 - FOR(u,k) \\ 0 & PRB[rcap^{alt}(u,k,i,s,t) = 0] = FOR(u,k) \end{cases}$$
$$\forall k \in \Delta, t \in [1,N[t]], s \in [1,N[s]], \ \& \ u \in \Lambda(k) \quad (26)$$

In (25), the term, $rcap^{gas}(u,k,i,s,t) + rcap^{alt}(u,k,i,s,t)$ calculates the randomly available capacity of a generating unit, influenced by fuel type, fuel uncertainties and forced outage rate.

In both (23) and (24), α is a parameter, depending mainly on load levels (such as peak and off-peak), reflecting proper seasonal price response to available capacity. $\delta(t)$ is forecasted using historical data.

Considering each scenario, the modeling as proposed above, makes the possibility of taking the effect of available gas and the FORs of generating units on electricity price, into account. Therefore, the price would change, provided that a substantial change of available capacities occurs due to maintenance programs and possible change of maximum available gas.

6. The ISO coordination problem formulation

The GenCos are not worried about system reliability and are looking for maximizing their own profits. As shown in [27], the electricity price alone cannot be regarded as an efficient signal for conflict resolution. Therefore, appropriate penalty/reward signals should also be devised and proposed, so that the GenCos on their own try to reschedule their maintenance proposals to the preferred ISO periods.

To keep the system reliable from the fuel resources point of view, the ISO should communicate with the GNO to get the information on scenario-based maximum available gas for the generating units. The ISO uses this information to scrutinize the reliability calculation and sends the information to the GenCos.

From various reliability indices, categorized as being probabilistic and deterministic [35], the EIR (Energy Index of Reliability), as an index from the former category is employed in this paper. For each iteration of the coordination process, it is calculated for each scenario in each interval, as follows:

$$eir(i,s,t) = 1 - \frac{eens(i,s,t)}{TE(t)} \quad \forall t \in [1, N[t]],\ \&\ s \in [1, N[s]] \tag{27}$$

where $TE(t)$ stands for the total energy (MW h) required to be supplied at interval t and $eir(i,s,t)$ presents the expected index of reliability in iteration i, scenario s and interval t.

In (27), $eens(i,s,t)$, as the Expected Energy Not Supplied ($EENS$) in interval t of scenario s, is calculated as given in [35]. Initially, the interval based Load Duration Curves (LDCs) are drawn. Based on technical characteristics of the available generating units, the Capacity Outage Probability Table (COPT) is generated for each interval in each iteration. Therefore, $eens(i,s,t)$ can be calculated.

For each standard EIR ($STDEIR$), there would be a maximum $EENS$ ($EENS_{max}(i,t)$), calculated based on the maximum available capacity of generating units when no limit on available fuel is imposed. If maintenance of generating unit u results in $EENS$ exceeding $EENS_{max}(i,t)$ for interval t of scenario s and in iteration i, its contribution in increasing EENS is calculated as shown in (28).

$$\begin{aligned} cont(u,k,i,s,t) = {} & \frac{\left(\dfrac{cap^{gas}(u,k,i,s,t)+cap^{alt}(u,k,i,s,t)}{1-FOR(u,k)}\right)}{\sum_{k=1}^{N[k]}\sum_{u=1}^{N[u,k]}\left(\dfrac{cap^{gas}(u,k,i,s,t)+cap^{alt}(u,k,i,s,t)}{1-FOR(u,k)}\right)} \\ & \times PSGN[eens(i,s,t) - EENS_{max}(i,t)] \\ & \forall k \in \Delta, t \in [1, N[t]], s \in [1, N[s]],\ \&\ u \in \Lambda(k) \end{aligned} \tag{28}$$

where the term $(cap^{gas}(u,k,i,s,t) + cap^{alt}(u,k,i,s,t))$, calculates the available capacity of a generating unit, influenced by fuel type.

In practice, the exact value for the contribution of a generating unit is more complicated than the one shown in (28). However, assuming that the available capacity is the most important factor of ensuring the reliability level, the approach presented in (28) is sufficient for our purposes. In addition, the approach guarantees that more unreliable generating units would pay more penalties (per MW).

Based on the value of $cont(u,k,i,s,t)$, the penalty assigned to each generating unit is calculated as:

$$\begin{aligned} & pen(u,k,i,s,t) = CUE \times cont(u,k,i,s,t) \\ & \forall k \in \Delta, t \in [1, N[t]], s \in [1, N[s]],\ \&\ u \in \Lambda(k) \end{aligned} \tag{29}$$

where Cost of Unserved Energy (CUE) typically represents the cost of a substitute energy, which could be from an expensive generation or the ISO's payments for an interrupted power [15]. In general, CUE is valued differently in different hours of the year. In this paper, for the sake of simplicity, an annual average value is used.

As the ISO is an independent entity, in each iteration, the penalties as imposed should be, somehow, prorated among the generating units that improve the reliability index, as rewards. With aiming of equating the penalties and the rewards for each iteration, the rewards are calculated as in (30).

The way that (30) is formulated results in assigning rewards of each scenario to each generating unit in proportion of its contribution in improving $eens(i,s,t)$ (with respect to $EENS_{max}(i,t)$) and only for those intervals for which, proposals on maintenance exist.

The first term in (30) shows the contribution of each generating unit in each interval of scenario s. The second term shows the penalty contribution of those intervals of scenario s for which there are some maintenance proposals. $\left((1 - \prod_{k=1}^{N[k]}\prod_{u=1}^{N[u,k]}(1 - x(u,k,i,t))\right)$ is nonzero, provided that, at least, one maintenance proposal at interval t exists). The third term is due to the total penalties allocated.

Penalty/rewards are designed based on the ISO policy of keeping the system reliability. In this paper, the ISO calculates the contributions of generating units in affecting reliability for all

$$\begin{aligned} rew(u,k,i,s,t) = {} & \frac{\left(\begin{matrix}1- \\ FOR(u,k)\end{matrix}\right) \times (cap^{gas}(u,k,i,s,t) + cap^{alt}(u,k,i,s,t))}{\sum_{k=1}^{N[k]}\sum_{u=1}^{N[u,k]}(cap^{gas}(u,k,i,s,t) + cap^{alt}(u,k,i,s,t)) \times \left(\begin{matrix}1- \\ FOR(u,k)\end{matrix}\right)} \\ & \times \frac{\left(1-\prod_{k=1}^{N[k]}\prod_{u=1}^{N[u,k]}(1-x(u,k,i,t))\right) \times PSGN(EENS_{max}(i,t) - eens(i,s,t))}{\sum_{t=1}^{N[t]}\left(1-\prod_{k=1}^{N[k]}\prod_{u=1}^{N[u,k]}(1-x(u,k,i,t))\right) \times PSGN(EENS_{max}(i,t) - eens(i,s,t))} \\ & \times \sum_{k=1}^{N[k]}\sum_{u=1}^{N[u,k]}\sum_{t=1}^{N[t]} pen(u,k,i,s,t)\ \forall k \in \Delta, t \in [1, N[t]], s \in [1, N[s]],\ \&\ u \in \Lambda(k) \end{aligned} \tag{30}$$

scenarios. As an example, in a strict policy, the penalty/rewards may be calculated for the worst scenario from the reliability viewpoint, only. Assessment of the ISO policies to keep the system reliability can be studied, but, it is not in the scope of this research.

7. Penalty/reward involvement in the GenCo's objective function

The key point in the involvement of penalty/reward signals in the GenCo's objective function is that any rational GenCo avoids repetition of the earlier undesirable decisions and adoption of the earlier desirable decisions. Therefore, the GenCo's behavior is modeled by considering a memory rate of penalty/reward signal in the GenCo's objective function. In this approach, the expectation of the probable penalty/reward is the weighted mean of the past observations with decreasing weights given by a normalized geometrical progression of parameter $\gamma(k)$ (the so called the memory rate of GenCo k). Therefore, penalty/reward of generating unit u of GenCo k in scenario s is calculated as follows:

$$\begin{aligned} &tpen(u,k,i,s,t) = pen(u,k,i,s,t) + \gamma(k) \times tpen(u,k,i-1,s,t) \\ &trew(u,k,i,s,t) = rew(u,k,i,s,t) + \gamma(k) \times trew(u,k,i-1,s,t) \\ &\forall k \in \Delta, t \in [1, N[t]], \; \& \, s \in [1, N[s]], \; \& \, u \in \Lambda(k) \end{aligned} \quad (31)$$

where $\gamma(k)$ is the memory rate of GenCo k.

The less the memory rate is, the faster forgetting would occur. In the direction towards the equilibrium point, through iterations, the effect of previous decisions is reduced by a factor of $\gamma(k)$. For example, after R iterations, the effect of the first iteration decision appears as a multiple of $(\gamma(k))^R$ in the objective function.

Due to the binary nature (0 or 1) and the temporary interdependence (continuous maintenance) of decision variables (e.g. $x(u,k,i,t)$) in the GenCos decision making problem, the proposed coordination process is very complicated for mathematically convergence analysis. Therefore, there is no way to give an analytical proof of the main contribution of the memory rate in reaching the equilibrium point in the process. However, numerical simulations using different electric energy systems show appropriate convergence behavior.

8. Numerical results

The details of electrical test system, based on IEEE-RTS, are given in Table 1 [36]. It is assumed that two types of fuels are available for generating units (except generating units 10–15 that are hydro); namely, gas and fuel oil No. 2 (hereon, oil is used for simplicity). Without lack of generality, it is assumed that all the gas supply contracts are flexible with a regulated gas price, changing week by week. Weekly gas and oil prices are gathered from US EIA report on weekly gas and oil prices in 2009 [37,38]. We assume that 1 kilo-cubic feet of gas can generate 1 MBtu of energy and 1 gal of oil can generate 0.14 MBtu of energy.

α (in (23)) is assumed to be $4.66 \times 10^{-4}\,\mathrm{MW}^{-1}$ for offpeak loads, $9.6 \times 10^{-4}\,\mathrm{MW}^{-1}$ for medium loads and $12.9 \times 10^{-4}\,\mathrm{MW}^{-1}$ for peak loads. Load pattern is characterized in Fig. 4.

The values of $\mu(t)$ are assumed to be as reported in Table 2, considering weekly intervals. $\mu(t)$ can be calculated based on the historical cumulative bidding behavior of the GenCos that shapes the supply curve. Since there is no historical data of bidding on IEEE RTS, we assume supply shift indices that could follow the load variations.

The gas network is presented in Fig. 5. It is composed of 3 wells, 13 nodes and 12 pipelines (10 passive and 2 active) that supplies 17 loads (7 electrical and 10 non-electrical). Its technical characteristics are shown in Tables 3 and 4.

The parameters of considered contemporaneous dependent weekly ARIMA models are shown in Table 5. Based on the probability distance method, the generated scenarios are reduced to 20, with labeled occurrence probabilities (Table 6). As an example, the resulting scenarios for 2 non-electrical gas loads are shown in Fig. 6a and b.

Table 1
Generating unit data for the IEEE-RTS.

ID no.	Size (MW)	FOR	Maintenance weeks $\left(\frac{Weeks}{Year}\right)$	$HR^{gas}(u,k)\left(\frac{MBtu}{MW\,h}\right)$	$Q^{nfuel}(u,k)\left(\frac{\$}{MW\,h}\right)$	Dual fuel	GenCo no.	Candidate units
1–5	12	0.02	2	12	4.3	Yes	1	1.2
6–9	20	0.10	2	14.5	5	Yes	2	8.9
10–15	50	0.01	2	0	0	No	3	–
16–19	76	0.02	3	12	2.6	No	2	16.17
20–22	100	0.04	3	10	3.5	Yes	4	20.21
23–26	155	0.04	4	9.7	1.4	No	1	23.26
27–29	197	0.05	4	9.6	3.2	Yes	5	27.28
30	350	0.08	5	9.5	3	No	5	30
31–32	400	0.12	6	10	2.8	Yes	6	32

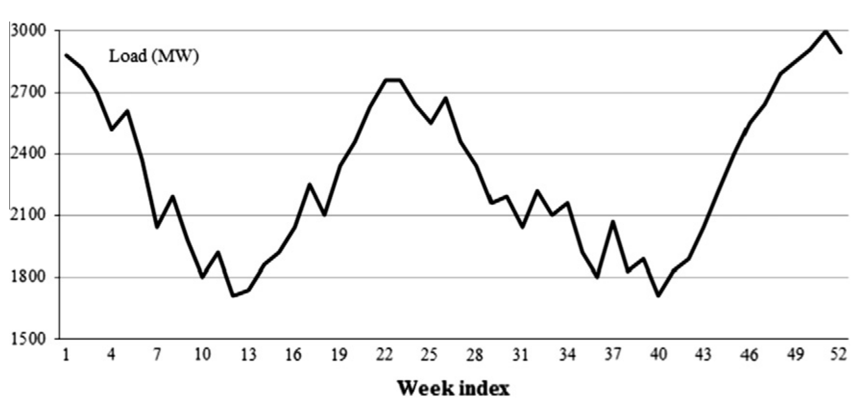

Fig. 4. Weekly load level.

Table 2
Values of weekly supply shift indices ($\mu(t)$).

No.	$\mu(t)$	No.	$\mu(t)$	No.	$\mu(t)$	No.	$\mu(t)$	No.	$\mu(t)$	No.	$\mu(t)$	No.	$\mu(t)$
1	4.675	9	4.376	17	4.779	25	4.714	33	4.532	41	4.701	49	4.506
2	4.701	10	4.350	18	4.805	26	4.636	34	4.558	42	4.656	50	4.571
3	4.779	11	4.428	19	4.870	27	4.610	35	4.584	43	4.636	51	4.610
4	4.727	12	4.519	20	4.883	28	4.493	36	4.623	44	4.610	52	4.623
5	4.753	13	4.597	21	4.831	29	4.467	37	4.649	45	4.571		
6	4.740	14	4.662	22	4.792	30	4.441	38	4.662	46	4.532		
7	4.649	15	4.610	23	4.740	31	4.480	39	4.675	47	4.571		
8	4.454	16	4.675	24	4.779	32	4.493	40	4.714	48	4.532		

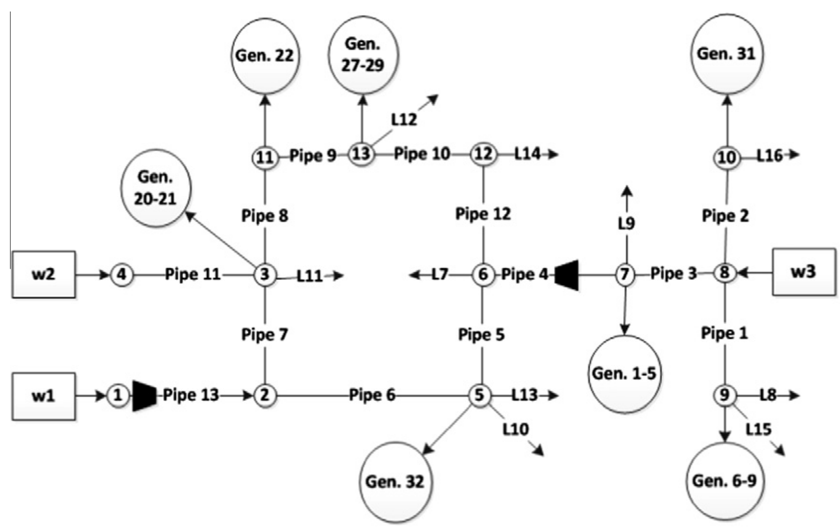

Fig. 5. Gas network under study.

Table 3
Technical characteristics of gas pipelines.

Pipe no.	From	To	$\pi_{m-n}\,\frac{Kcf}{Psig}$	Pipe no.	From	To	$\pi_{m-n}\,\frac{Kcf}{Psig}$
1	8	9	20	7	2	3	16
2	8	10	25	8	3	11	25
3	8	7	45	9	11	13	20
4	7	6	20	10	12	13	23
5	6	5	10	11	4	3	10
6	2	5	10	12	6	12	25

Table 4
Technical characteristics of gas nodes.

Node no.	$P_{\min}$ (Psig)	$P_{\max}$ (Psig)	Well index	$W_{\min}$ (Kcf/h)	$W_{\max}$ (Kcf/h)
1	225	60	1	1000	6000
2	450	125	–	–	–
3	375	110	–	–	–
4	600	180	2	1500	6000
5	375	110	–	–	–
6	375	115	–	–	–
7	270	65	–	–	–
8	330	90	3	1500	15000
9	300	65	–	–	–
10	300	65	–	–	–
11	330	95	–	–	–
12	330	100	–	–	–
13	292.5	85	–	–	–

CUE is assumed to be 2500 \$/MW h [15]. *STDEIR* is considered to be 98.55%. The convergence criterion is chosen to be three similar solutions in consecutive iterations.

Two cases are studied in this section. In the first case, the maintenance schedules are coordinated regardless of gas network constraints. In this case, the evolution of the process and the effect of memory rates are studied. In the second case, initially, the importance of considering gas network constraints and uncertainties are shown. Then, the impacts of gas network on maintenance coordination are presented, when there is no dual fuel generating unit. Finally, the dual fuel capability of generating units is taken into account.

8.1. Case 1

In this case, the gas network constraints are not taken into account. Therefore, only one scenario is considered, in which, there is no gas limits to supply the generating units.

The model is implemented in MATLAB linked with GAMS 23.1.1 [33] on a computer equipped with Intel Corei5 CPU clocking at 2.4 GHz with 4 GB of RAM. The CPU time, required to attain the solution in 7 iterations, is about 10 s.

Considering three values for $\gamma(k)$, (0.5, 0.75 and 0.9) for all GenCos, Fig. 7 shows the annual EENS variation through iterations. The process is converged to the acceptable coordinated maintenance schedules in 8, 7 and 7 iterations, considering three values for $\gamma(k)$, 0.5, 0.75 and 0.9, respectively. As seen, higher memory rate enforces the coordination process to converge sooner. It is obvious that there is no penalty to assign to the GenCos in the last iteration. As seen, the value of $\gamma(k)$ affects the acceptable schedules. For the

Table 5
Weekly ARIMA parameters.

	L (8,t)	L (9,t)	L (10,t)	L (11,t)	L (13,t)	L (15,t)	L (16,t)
BSA^1	1.006	1.0334	0.9043	1.0077	1.0068	0.9432	0.9432
BSA^2	0	0	0.1194	0.0603	0.0612	0.0887	0.089
BSA^3	0	0	0	−0.0828	−0.0829	0	0
BSA^{52}	0.2652	0.3333	0.3588	0.235	0.2363	0.2568	0.2561
BSA^{53}	−0.1715	−0.2766	−0.3148	−0.1223	−0.1238	−0.1939	−0.1934
BSA^{54}	−0.0872	0	0	−0.0942	−0.094	−0.0582	−0.058
BSA^{104}	0.2067	0.249	0.211	0.2691	0.2708	0.1531	0.1528
BSA^{105}	−0.1599	−0.2482	−0.168	−0.1909	−0.192	−0.151	−0.1506
BSA^{106}	−0.051	0.0734	0	−0.1213	−0.1226	0	0
Standard deviation	11.71	10.8	9.4	12.33	18.25	14.21	15.73

Table 6
Occurrence probabilities of gas network scenarios.

No.	SP	No.	SP	No.	SP	No.	SP		
1	0.11	5	0.038	9	0.047	13	0.062	17	0.052
2	0.033	6	0.066	10	0.038	14	0.027	18	0.048
3	0.042	7	0.074	11	0.08	15	0.012	19	0.025
4	0.029	8	0.065	12	0.073	16	0.028	20	0.051

sake of simplicity, the remaining study in case 1 is done by assuming $\gamma(k)$ to be 0.75.

Figs. 8 and 9 demonstrate the evolution of EIR and total maintenance outages throughout the weeks of the year for the first and the last iterations. For instance, in weeks 30–34 and 42–45, EIR is improved while for some remaining weeks (e.g. 8–12 and 16–18), it is slightly reduced. This happened due to shifting of some of the maintenance schedules in weeks 30–34 and 42–45 (the low price periods) to weeks 8–12, 16–18 and 27–28 (the medium price weeks) so that the reliability indices are affected. Therefore, excess trend of maintenance schedules towards low price periods; which may unduly affect the system reliability, is moderated so that annual reliability index is improved for the last iteration (see Fig. 7).

8.2. Case 2

Initially, in this case, without considering maintenance schedules, the impacts of various gas network constraints on power system reliability index and the GenCos profits are shown. Moreover, the dual fuel capability of generating units is forborne. Therefore, due to such consideration, the available capacities of gas-burning generating units that may be affected due to fuel availability in various scenarios. This, in turn, would affect system reliability and the GenCos profits. Table 7 and Fig. 10 show the impacts as follows:

- The reliability index evolutions, considering different scenarios, are illustrated in Fig. 10. Moreover, the reliability index evolution, while ignoring any gas availability is also shown (indicated in Fig. 10. as ‘‘without limitation’’). As seen, the weekly reliability index is affected in some scenarios.
- To show the impact of gas availability scenarios on GenCos profits,, as a typical case, the amount of scenario-based gas interruption for generating units 27–29, in some week (s) in which, the gas interruption is applied, at least, in one scenario, is (are) presented in Table 7. Therefore, the profit of GenCo 5 (owner of units 27–29) is affected due to the generating units capacity deratings in some scenarios.

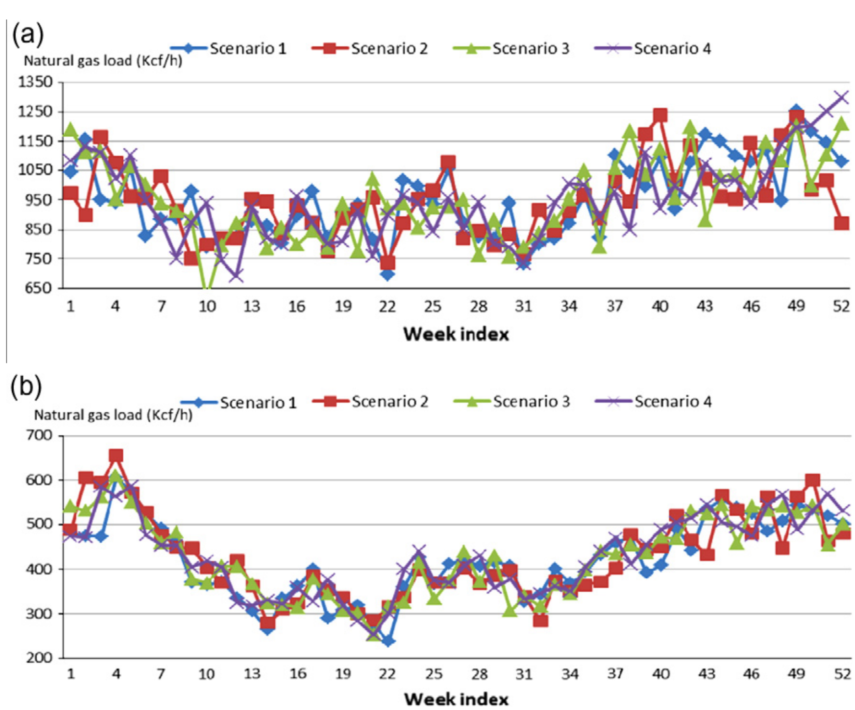

Fig. 6. Gas loads in scenarios 1–4, (a): load 4 and (b) load 6.

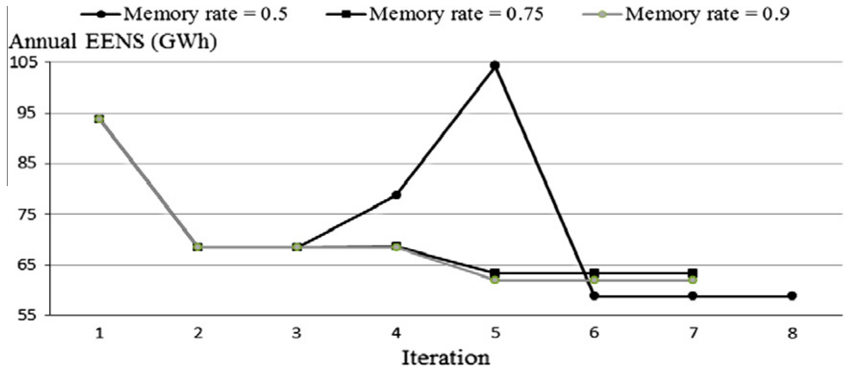

Fig. 7. Annual EENS evolution in coordination process.

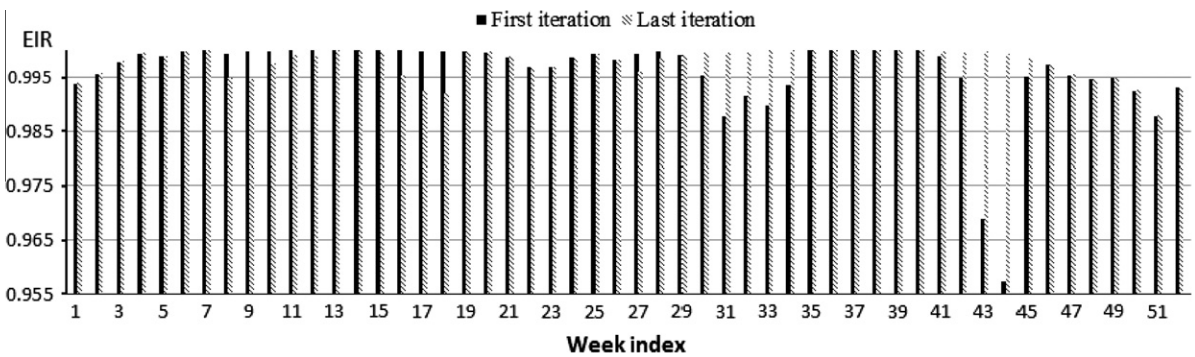

Fig. 8. Evolution of EIR throughout the weeks (the first and the last iteration).

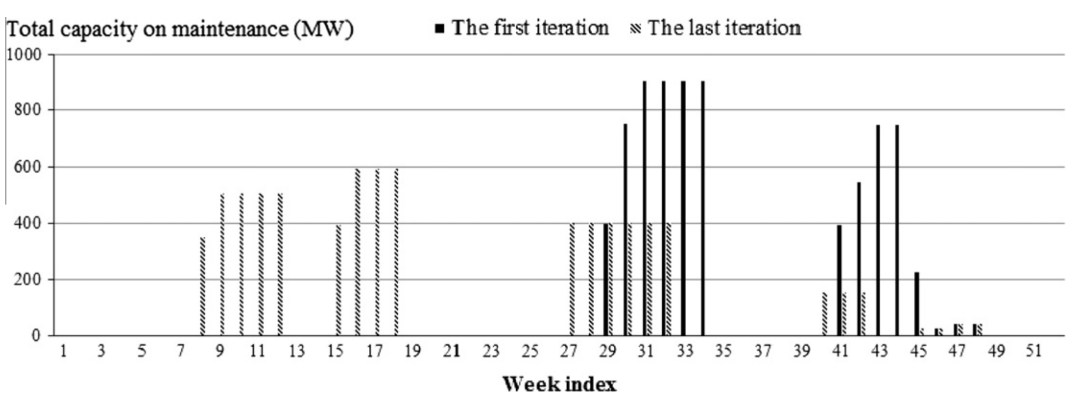

Fig. 9. Evolution of total maintenance outages throughout the weeks.

The results show that the reliability index and the GenCos profits that play the main roles in maintenance coordination process are affected by some gas network constraints and uncertainties.

Following, the maintenance coordination process in the presence of the gas network constraints and uncertainties are studied. However, the dual fuel capability of generating units is not considered.

Considering $\gamma(k)$ to be 0.75, variation of total expected annual EENS is shown in Fig. 11. Weekly expected EENS is calculated by summing up the scenarios weekly EENSs, weighted by scenario occurrence probabilities. Summing up the weekly expected EENS results in expected annual EENS. As seen in Fig. 11, the expected annual EENS is converged to an acceptable level through process iterations.

Considering scenario 18, as an example, Table 8 presents the amount of gas interruption for the generating units 27–29 and the maintenance starting week of generating unit 27 in weeks 44 and 45. The available gas of these generating units, calculated by the GNO, is modified due to maintenances of other generating units. In iteration two, due to the maintenance schedules in weeks 43–45, the gas interruption is zero. Therefore, a GenCo's generating unit maintenance schedules can encourage the shift of the other GenCos schedules due to change in available gas. Quantifying this encourage is not easy; since, changing the maintenance starting week from 29 to 8 is affected not only by available gas, but also by penalty/rewards.

Total maintenance outages throughout the weeks of the year are shown in Fig. 12. As seen, in the first iteration, the maintenance schedules for the winter weeks are more than those of in Fig. 9. The proposed schedules seem unusual, as high electricity prices generally encourage the GenCos not to schedule the maintenances in these weeks. However, the maintenance in cold weeks can be

Table 7
Amount of gas interruption in scenarios for generating units 27–29 (Kcf/h).

Scen. no.\week index	1	2	3	4	5	6	43	44	45	46	47	48	49	50	51	52
2	34	248	48	38	0	0	0	0	142	280	0	38	527	249	39	243
3	0	17	38	0	34	0	144	93	138	0	0	0	338	39	414	0.00
4	439	84	0	83	85	38	0	0	0	0	0	338	0	5	39	339
5	0	248	0	338	39	0	0	13	0	656	0	0	274	39	0	377
6	0	338	14	0	0	0	0	3	38	39	0	314	0	0	339	0.00
7	0	0	38	0	0	0	0	0	0	417	0	160	38	39	7	0.00
8	0	0	38	0	0	0	0	0	0	138	38	243	0	39	39	0.00
10	0	0	874	0	11	0	0	39	138	237	113	38	13	39	0	39
11	38	438	0	16	0	48	0	18	64	0	39	0	332	39	0	39
12	38	14	6	38	0	23	338	13	0	0	0	38	22	0	5	2
13	0	0	387	0	0	0	0.42	0	0	0	248	10	12	791	470	8.8
14	0	38	248	26	5	0	0	0	0	0	0	313	0	39	39	489
15	36	38	6	24	0	0	0	0	0	33	7	527	38	638	79	671
18	48	0	9	31	0	0	248	248	48	0	39	0	14	601	22	39
19	0	6	0	0	0	0	39	23	0	39	0	0	39	0	354	39
20	3860	38	280	236	413	0	0	0	0	184	3	39	0	94	0.00	16

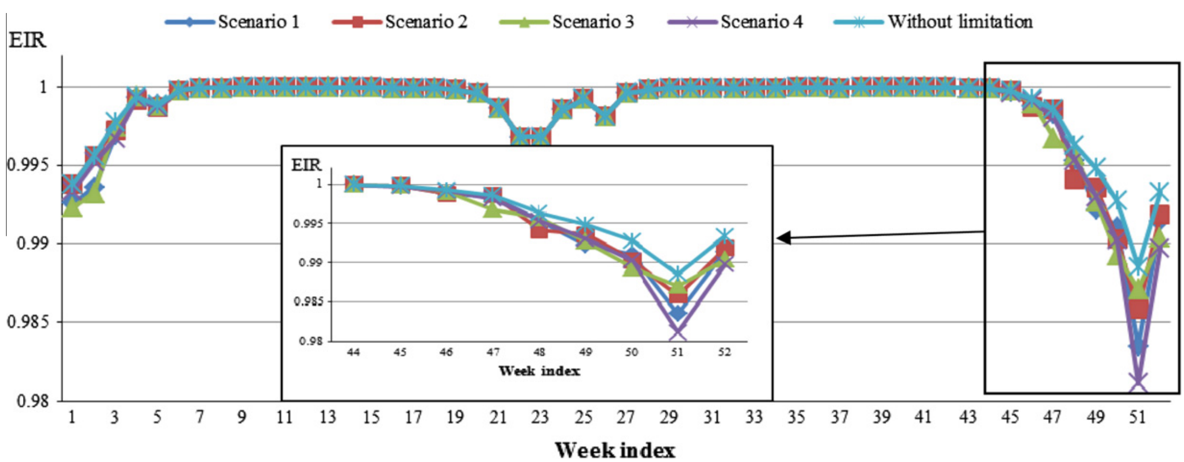

Fig. 10. Scenario based evolution of weekly reliability index.

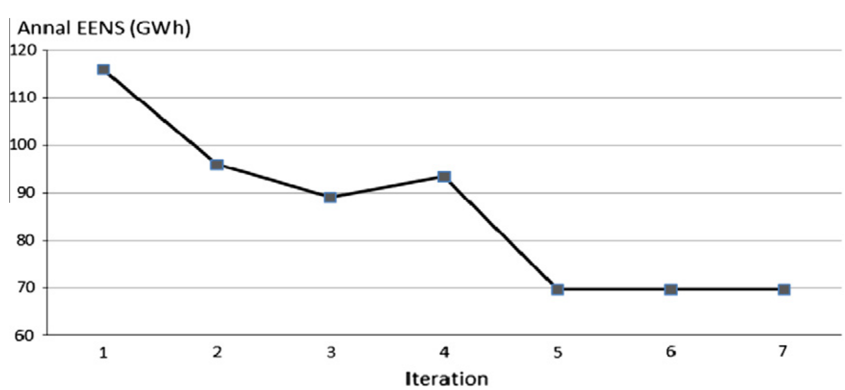

Fig. 11. Expected annual EENS evolution in coordination process.

Table 8
The gas interruption for generating units 27–29 and maintenance starting week of generating unit 27.

Iteration	Starting week	Interruption in week 44 (Kcf/h)	Interruption in week 45 (Kcf/h)
1	29	248.6	48.6
2	8	0	0
3	31	120	0
4	6	248.6	48.6
5	33	248.6	48.6

justified, due to less reliable gas supply. Therefore, the GenCos should schedule the maintenances so that the maximum profits are achieved and gas availability risk is hedged. These may threaten the system reliability in weeks that the expected available capacities of gas burned generating unit are noticeably low. However, as seen in the last iteration results, the coordination process can tackle it, so that the maintenance schedules are moved from winter weeks to lower demand weeks. Therefore, the penalty/reward signals can help the ISOs to keep the system reliability.

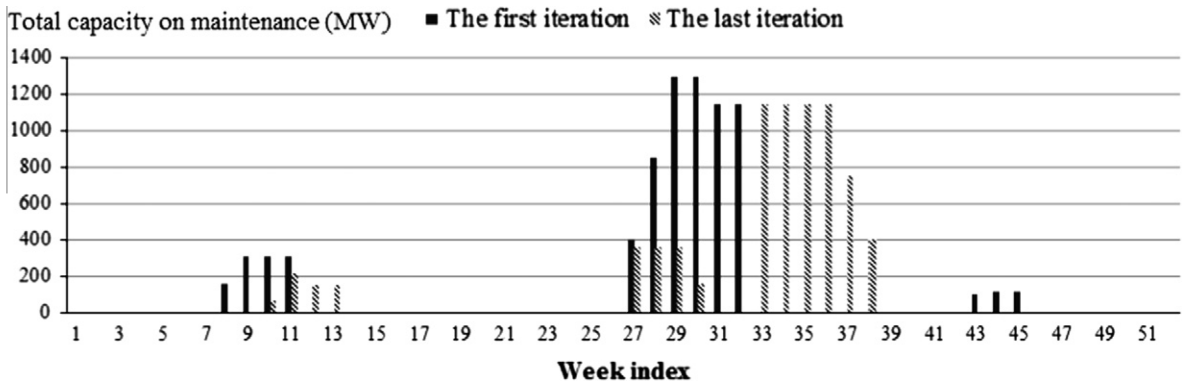

Fig. 12. Evolution of total maintenance outages throughout the weeks (assuming no dual fuel capability).

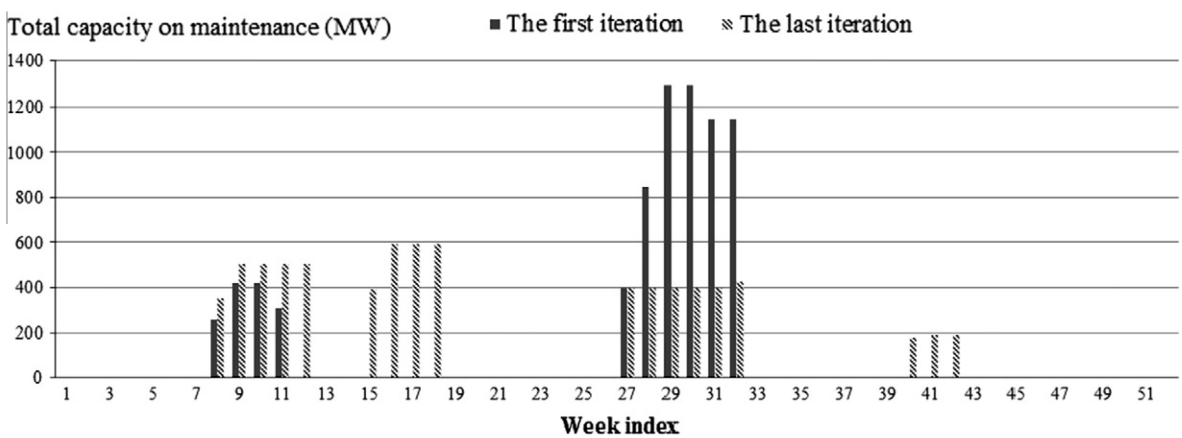

Fig. 13. Evolution of total maintenance outages throughout the weeks (assuming generating units with dual fuel capability).

Comparing Figs. 12 and 9 shows that, the maintenances that are scheduled in autumn weeks are noticeably high when gas network uncertainties are taken into account. Fig. 6a and b illustrate that the non-electrical gas load in spring weeks are typically higher than that of in autumn. Therefore, the expected available gas to generating units can be more limiting in autumn, so that the GenCos prefer this season from maintenance viewpoint.

As the final case, the impacts of dual fuel capability of generating units are taken into account. In one hand, dual fuel capability helps the GenCos to operate the generating units, when the primary fuel (gas) availabilities are limited. Therefore, the ISO's reliability indices could be improved, due to improvement of maximum available capacities. On the other hand, often, the alternative fuel prices (such as oil) are higher than that of gas. These, may cause the price spikes during intervals in which the available gas is probably low. As a consequence, the generating units with dual fuel capability may not be interested in scheduling the maintenances during these intervals; resulting in further improvement of reliability indices. Therefore, the way of coordination process is to be less conflicting than the previous case in which, the generating units with dual fuel capability are not taken into account. Fig. 13 shows the total maintenance capacity outage in this case.

Comparing Figs. 12 and 13 shows that if dual fuel generating units are involved, there are a few discrepancies between the maintenance schedules as determined from the last iteration. However, the maintenance schedules in the last iteration, as seen in Fig. 13, are more similar to those of in Fig. 9. Therefore, in the cases that gas network constraints and uncertainties may affect the power system reliability, if there are generating units with dual fuel capability, the proposed iterative process can direct the GenCos to schedule their maintenances in weeks that they would schedule, if there are no gas network uncertainties.

9. Conclusions

As an iterative process among the GenCos, the GNO, the IMO and the ISO, a maintenance coordination process was proposed in which, the effect of gas network was considered. The impact of gas availability on reliability index was shown illustrating the importance of creating communication lines between gas and electric operators to coordinate the mid-term planning. It was shown that the proposed coordination process could solve the gas impact issues that may threaten the power system reliability. Considering the scenario-based penalties/rewards signals, calculated by the ISO, and observing a memory rate by the GenCo, guarantee reaching an equilibrium point. Moreover, the importance of dual fuel capability of generating units was examined. It was shown that by considering these types of units, more flexible maintenance schedules and more improvement in reliability index could be achieved; even in the cases that the alternative fuel prices are noticeably high.

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