Impact of Natural Gas System on Risk-Constrained Midterm Hydrothermal Scheduling

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***Abstract*—This paper studies the impact of natural gas (NG) contracts and constraints on a GENCO's midterm risk-constrained hydrothermal scheduling problem. The NG contracts and constraints are modeled as a set of linear equations. The proposed model utilizes the stochastic price-based unit commitment (PBUC). The PBUC hourly solution considers uncertainties of market prices for energy and ancillary services, uncertainties of natural water inflows, and random NG infrastructure interruptions in Monte Carlo scenarios. Illustrative examples analyze the GENCO's risk levels when considering midterm schedules for generating units, target payoffs, and usages of water inflow, NG and other thermal resources. Simulation results show that a GENCO's midterm schedules and financial risks could be impacted significantly with the consideration of NG contracts and constraints.**

***Index Terms*—Financial and physical risks, generation companies, interdependency of natural gas and electricity, natural gas contracts, stochastic price-based unit commitment.**

NOMENCLATURE

Indices:

h	Index of hydro units.
i	Index of coal units.
j	Index of NG units.
k	Index of pumped-storage units.
l	Index of hydro catchments.
m	Index of pipelines.
n	Index of NG contracts.
p	Index of power plants.
r	Index of subareas.
s	Index of scenarios.
t	Index of time periods (hour).
w	Index of NG storage facilities.

Dimensions:

NCM	Number of hydro catchments.
NCO	Number of coal units.
NGC	Number of NG gas contracts.
NGS	Number of NG gas storage facilities.
NH_l	Number of hydro units of a hydro catchment l.
NNG	Number of NG units.
NPL	Number of NG plants.
NPP	Number of NG pipelines.
NPS	Number of pumped-storage hydro units.
NS	Number of scenarios.
NSA	Number of NG subareas.
NT	Number of time periods under study.

Sets:

SCT	Set of NG units utilizing a gas contract.
SFC	Set of firm NG contracts.
SIC	Set of interruptible NG contracts.
SPL	Set of NG units in a plant.
SPP	Set of gas contracts belonging to a pipeline.
SSA	Set of NG units in a subarea
SST	Set of NG units sharing a NG storage facility.

Variables:

C_{ns}	Cost of NG usage from contract n in scenario s.
C_{ws}	Cost of NG usage from storage facility w in scenario s.
F	Fuel usage by unit.
OR	Operating reserve.
P	Power generation.
PF_s	GENCO's payoff in scenario s.
q^{out}	NG withdrawn from storage facility w.
q^{in}	NG injected to storage facility w.
V_{wts}	Volume of NG in storage facility w at time t in scenario s.
$RISK_s$	GENCO's downside risks in scenario s.
SD	Shutdown cost.
SR	Spinning reserve.
SU	Startup cost.
λ	Lagrange multiplier.
γ_s	Lagrange multiplier for risk constraint in scenario s.

Constants:

α_n	Interruption rate of NG contract n.

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β_n	Restore rate of NG contract n.
$C_{0,n}$	Fixed cost for firm NG contract n.
$\overline{EDR}$	Expected downside risk tolerance.
$F_{\max,jt}$	Maximum NG usage allowed for unit j at time t.
$F_{\max,j}$	Maximum NG usage allowed for unit j in one year.
p_s	Probability for a scenario s.
T_0	Target payoff of a GENCO.
U_{nts}	Availability of NG contract n at time t in scenario n.
$V_{\max,w}$	Maximum NG volume limit in storage facility w.
$V_{\min,w}$	Minimum NG volume limit in storage facility w.
$V_{0,w}$	Volume of NG in storage facility w at time 0.
$V_{NT,w}$	Volume of NG in storage facility w at time NT.
p_n	Steady-state availability of NG contract n.
q_n	Steady-state unavailability of NG contract n.
ρf_{its}	Fuel price of coal unit i at time t in scenario s.
ρg_{ts}	Market price for energy at time t in scenario s.
ρ_n	Price of one MMCF of interruptible NG contract n.
ρor_{ts}	Market price for operating reserve at time t in scenario s.
ρsr_{ts}	Market price for spinning reserve at time t in scenario s.
ρ_w	Unit price of one MMCF of gas withdrawal from NG storage facility w.

Abbreviations:

GENCO	Generation company.
MIP	Mixed integer program.
$MMCF$	Million cubic feet.
NG	Natural gas.
PBUC	Price-based unit commitment.

I. Introduction

GENCOs are responsible for the midterm operation planning which provides a basis for the optimal hourly bidding in a day-ahead market. The midterm operation planning will determine the optimal utilization of resources such as fuel, emission allowance, and natural water resources [1]–[3]. The modeling of NG contracts in midterm operation planning studies provides a more robust scheduling of hydrothermal assets when considering uncertainties related to market prices, NG interruptions, and water inflows.

Several approaches are available for the optimal midterm operation planning problem. A variable metric method was used in [4] to solve the dual maximization for achieving a good convergence property. A composite representation of thermal and hydro units was used in [5] for economic dispatch based on weekly and monthly requirements. A dual-decomposition of long-term planning problem was applied in [6] and [7] for setting up easy-to-solve problems in subperiods. The framework in [8] is able to consider on and off-peak energy prices and user controlled multi-scenario water inflows. The interior point method is applied to solve the long-term scheduling problem, in which the hydro unit characteristics are linearly modeled. A two-stage dynamical programming (DP) method was proposed in [9] which is capable of handling nonconvex, nonlinear and stochastic characteristics of the problem. However, the DP technique might not be tractable in multi-reservoir systems due to the dimensionality problem. Reference [10] compared the stochastic dynamic programming and the deterministic optimization models with an inflow forecasting model for the long-term hydrothermal scheduling problem. The reference concludes that the two methods have similar performance and the deterministic model is superior in dry hydro periods. A two-phase nonlinear optimization model was proposed in [11] to model the integrated operation of NG network and power systems. In [12] and [13], a nonlinear optimization model was proposed by merging the traditional optimal power flow and NG network constraints. The short-term scheduling of integrated NG network and hydrothermal power system was solved in [14] by applying Lagrangian relaxation and dynamic programming. An integrated model was proposed in [15] for studying the interdependency of electricity infrastructure and NG system and the social sustainability of energy infrastructures. The integrated model considered NG network constraints as daily and hourly limits on pipelines, subareas, power plants, and generating units, and incorporated these constraints into the optimal solution of short-term security-constrained unit commitment.

In addition to the short-term NG scheduling, interdependencies were considered in midterm NG planning studies. A network-based stock and flow type model was created in [16] to analyze the NG network response to disruptions. The NG flows between regions were represented and stocks were the regional NG storages. The model was used to assess the NG network against transmission disruption scenarios. However, the model did not include contractual NG deliveries to other users which would likely worsen electric power supply scenarios. For example, there might be a sufficient transmission capacity available on an NG pipeline which would feed power plants. The NG flow can ramp up quickly in the event of a pipeline disruption elsewhere or unseasonably cold weather. However, that capacity could have already been contracted to other users. Logically, such emergencies would take precedence, but legally there might be no way out of contractual agreements. An analytical framework was proposed in [17] to study physical and economic aspects of interdependent infrastructures such as electric power, petroleum, NG, water, and communications systems. A modeling and analysis tool was developed to capture interdependencies, evaluate potential effects of disruptions in one infrastructure, and suggest strategies to mitigate shortcomings.

This paper incorporates the NG infrastructure model presented in [15] to develop an extended framework for the risk-constrained stochastic midterm hydrothermal scheduling problem [18]. The main theme of this paper is to assess the impact of the NG infrastructure and contracts on the stochastic midterm planning of electric power systems. Consider a GENCO with hydro, thermal, and NG contacts for supplying its gas power plants. Since the residential NG demand is very high at certain seasons, NG suppliers in severe weather conditions could interrupt the supply to power plants. Such interruptions could have a significant impact on the GENCO's expected payoffs. In addition, when the risk is considered, the behavior of NG units could vary under different hydro conditions. For instance, NG units would tend to increase their generation output for lowering the total financial risk. This case could occur in scenarios with water supply shortages to prevent GENCOs from defaulting on their bilateral energy contracts. However, the NG output in practice could be constrained by physical limitations and contracts.

The availability of NG storage could facilitate lower risks in such cases. The storage capacity should be determined in such cases based on forecasted market prices, and duration and frequency of NG interruptions.

The hourly MIP solution of price-based hydrothermal system presented in [18] is considered here. The NG interruptions are also considered as uncertainties similar to those of hourly market prices and water inflows. The performances of individual units for risk reduction are studied and compared with the risk reduction performance of all units considered together to evaluate possible alternatives in a GENCO's stochastic midterm scheduling.

This paper is organized as follows. The proposed model is formulated in Section II. Detailed simulation and solution methodologies are described in Section III. Examples are given in Section IV. Section V concludes this paper.

II. Stochastic Modeling of NG Infrastructure

This section starts by defining the objective function of midterm PBUC problem, which includes revenues and expenses for coal, NG, cascaded hydro, and pumped-storage hydro units. Generating unit constraints are discussed and NG contracts and constraints are presented. Financial risk constraints are also discussed.

The proposed objective function (1) is to maximize the expected payoff with respect to power generations (P), spinning and operating reserves (SR and OR) and unit commitment variables over all scenarios. The payoff of a scenario is defined as the difference between revenue and expense. The revenue (2) is due to sales of energy, spinning reserves, and operating reserves by coal, NG, cascaded hydro, and pumped-storage hydro units. The cost (3) includes that of 1) fuel, startup, and shutdown for coal units; 2) NG contracts, storage, startup cost, and shutdown for NG units; 3) startup and shutdown for cascaded hydro units; and 4) startup cost and shutdown for pumped-storage units:

$$\text{Max}: \sum_{s=1}^{NS} p_s \cdot PF_s = \sum_{s=1}^{NS} p_s \cdot \{REVENUE_s - COST_s\} \quad (1)$$

where

$$\begin{aligned} REVENUE_s = &\sum_{i=1}^{NCO}\sum_{t=1}^{NT}[\rho g_{ts}\cdot P_{its} + \rho sr_{ts}\cdot SR_{its} \\ &\quad + \rho or_{ts}\cdot OR_{its}] \\ &+\sum_{j=1}^{NNG}\sum_{t=1}^{NT}[\rho g_{ts}\cdot P_{jts} + \rho sr_{ts}\cdot SR_{jts} \\ &\quad + \rho or_{ts}\cdot OR_{jts}] \\ &+\sum_{l=1}^{NCM}\sum_{h=1}^{NH_l}\sum_{t=1}^{NT}[\rho g_{ts} P_{hts} + \rho sr_{ts}\cdot SR_{hts} \\ &\quad + \rho or_{ts}\cdot OR_{hts}] \\ &+\sum_{k=1}^{NPS}\sum_{t=1}^{NT}[\rho g_{ts}\cdot P_{kts} + \rho sr_{ts}\cdot SR_{kts} \\ &\quad + \rho or_{ts}\cdot OR_{kts}] \end{aligned} \quad (2)$$

and

$$\begin{aligned} COST_s = &\sum_{i=1}^{NCO}\sum_{t=1}^{NT}[\rho f_{its}\cdot F_{its} + SU_{it} + SD_{it}] \\ &+\sum_{n=1}^{NGC} C_{ns} + \sum_{w=1}^{NGS} C_{ws} \\ &+\sum_{j=1}^{NNG}\sum_{t=1}^{NT}[SU_{jt}+SD_{jt}] \\ &+\sum_{l=1}^{NCM}\sum_{h=1}^{NH_l}\sum_{t=1}^{NT}[SU_{ht}+SD_{ht}] \\ &+\sum_{k=1}^{NPS}\sum_{t=1}^{NT}[SU_{kt}+SD_{kt}]. \end{aligned} \quad (3)$$

A low-discrepancy Monte Carlo method, represented by Latin Hypercube, is used to generate a set of scenarios, which consider uncertainties in market prices, natural water inflows, and interruptions of NG interruptible contracts. The scenarios are then reduced based on backward and fast forward method. The probability p_s assigned to each scenario reflects the possibility of occurrence [19]. The details of the modeling of market prices and natural water inflows are given in [18] and [20]. A two-state continuous-time Markov chain model is used to represent available states of NG interruptible contracts [21]–[23]. The objective function defined in (1) is subject to the following generating unit and NG infrastructure constraints [18].

- Coal Unit Constraints
  a) Fuel consumption and emission allowance constraints for groups of coal units
  b) Energy and ancillary services supplied
  c) Minimum on/off time and ramping up/down constraints
- NG Unit Constraints
  NG units are subject to similar constraints to those of the coal units as well as the NG network constraints that will be discussed later in this section.
- Cascaded Hydro Unit Constraints
  a) Energy and ancillary services supplied
  b) Water-to-power conversion
  c) Operating regions (water discharge limits)
  d) Reservoir volume limits
  e) Initial and terminal reservoir volumes
  f) Water balance constraint
  g) Minimum on/off time and ramping up/down constraints
- Pumped-storage Units Constraints
  The pumped-storage units are subject to the same constraints b, d, e, and g of the cascaded hydro-unit constraints.

The energy and ancillary services, operating regions, and water balance constraints are extended to consider the pumping modes of the pumped-storage units.

- NG Contracts and Constraints
The eight NG units are fed from the NG transmission network as seen in Fig. 2. There are eight units related to Pipeline 1. Consequently, these units would be subject to limits on pipelines, contracts, and plants. Pipeline 2 is divided into two zones, and if Zone 1 is considered to be geographically far from gas well, the four units located in this zone would be able to access only a proportion of pipeline capacity due to subarea constraints. The units in Zone 3 of Pipeline 2 share a storage facility to which NG could be deposited. The stored NG could be withdrawn when necessary, i.e., the pipeline outage due to seasonal interruptions. The mathematical equations for NG contracts and network constraints are provided here which are used in the stochastic midterm operation planning problem.
NG contracts are modeled as firm (take-or-pay) or interruptible contracts with NG suppliers. Firm NG contracts have fixed costs. Interruptible NG contracts are utilized if it is either economical or required to satisfy certain constraints. The cost of a firm NG contract is specified as

$$C_{ns} = C_{0,n}, \quad \forall n \in SFC, \, \forall s. \tag{4}$$

An interruptible NG contract will have its own quantity and price. The cost of an interruptible NG contract depends on the gas usage

$$C_{ns} = \rho_n \sum_{t=1}^{NT} F_{nts}, \quad \forall n \in SIC, \, \forall s. \tag{5}$$

The NG usage from a specific NG contract at a specific scenario and time is limited by the availability of specific NG contracts defined by an integer availability variable U_{nts}:

$$F_{nts} \leq F_{\max,nt}.U_{nts}, \quad \forall n, \, \forall t, \, \forall s. \tag{6}$$

The NG usage from a firm contract n is equal to the contracted amount since it is prepaid:

$$\sum_{t=1}^{NT} F_{nts} = F_{\max,n}, \quad \forall n \in SFC, \, \forall s. \tag{7}$$

The NG usage from an interruptible contract n cannot exceed the yearly contracted limit:

$$\sum_{t=1}^{NT} F_{nts} \leq F_{\max,n}, \quad \forall n \in SIC, \, \forall s. \tag{8}$$

Here, daily, weekly, and monthly contract limits may be included similarly.
The steady-state NG network equations define the nonlinear relationship between the gas flow and pressure. The pressures at network nodes and the gas flows in pipelines could be calculated based on the nodal balance approach with a large computation time. The linearized constraints would not calculate these parameters at each time step; however, the physical limitations of the network could still be enforced considering the maximum capacity of the network components at each time step with a significant drop in the computation time. The linearized approach is sufficient for the purpose of this paper since the algorithm aims to find the optimum fuel and resource scheduling rather than calculating the NG network parameters at each time step.
The modeling of storage is essential for a midterm study, since the storage facility could be used both for deposit and withdrawal purposes throughout the year. The storage model for the short-term study in [15] was simply represented by a gas inflow variable in the NG unit fuel balance equation. The short-term constraints considering capacity limits on pipelines, sub-areas, power plants, and units are adopted for the midterm stochastic model by increasing the time-span and introduction of s as scenario variables.
The hourly and yearly constraints are considered in this section. The daily, weekly, and monthly limits can be included similarly. The total NG usage from a contract n of pipeline m at time t in scenario s is equal to the sum of separate NG usages by individual NG units using that contract:

$$F_{nmts} = \sum_{j \in SCT(n)} F_{jnmts}, \quad \forall n, \, \forall m, \, \forall t, \, \forall s. \tag{9}$$

A gas pipeline can be fed by several NG contracts. The total NG usage of pipeline m at time t in scenario s is equal to the sum of NG usage from all such contracts:

$$F_{mts} = \sum_{n \in SPP(m)} F_{nmts}, \quad \forall m, \, \forall t, \, \forall s. \tag{10}$$

Generating units that are located far from NG pumping stations can only burn a certain percentage of available NG. Accordingly, a subarea is defined for the NG consumption of such units. The total NG usage at subarea r of pipeline m at time t in scenario s is equal to the sum of NG usages by individual NG units in that subarea:

$$F_{mrts} = \sum_{j \in SSA(r)} F_{jmrts}, \quad \forall m, \, \forall r, \, \forall t, \, \forall s. \tag{11}$$

An NG unit j can be supplied by multiple contracts, pipelines, and NG storage facilities:

$$F_{jts} = \sum_{m=1}^{NPP} \sum_{n \in SPP(m)} F_{jnmts} + \sum_{w=1}^{NGS} \left(q_{jwts}^{out} - q_{jwts}^{in}\right), \forall j, \quad \forall t, \, \forall s \tag{12}$$

where q_{jwts}^{out} and q_{jwts}^{in} are zero if the NG unit j is not connected to any storage facilities. The total NG injected into or withdrawn from the storage by individual units, which would share the same storage, is given as

$$q_{wts}^{in} = \sum_{j\in SST(w)} q_{jwts}^{in}, \quad \forall w,\, \forall t,\, \forall s \tag{13}$$

$$q_{wts}^{out} = \sum_{j\in SST(w)} q_{jwts}^{out}, \quad \forall w,\, \forall t,\, \forall s. \tag{14}$$

The NG volume balance equation for the storage facility w is

$$V_{w(t+1)s} = V_{wts} + q_{wts}^{in} - q_{wts}^{out}, \quad \forall w,\, \forall t,\, \forall s. \tag{15}$$

The term V_{wts} is the volume of the NG storage w at time t and scenario s. This term could be obtained using the initial volume and the net injection and withdrawal amounts at each time step starting from the initial time 0 to time $(t-1)$ as

$$V_{wts} = \sum_{j\in SCT(w)} \sum_{\tau=1}^{t-1} \left(q_{jw\tau s}^{in} - q_{jw\tau s}^{out}\right) + V_{w(0)s}. \tag{16}$$

The NG storage volume constraint of the storage facility w is

$$V_{\min,w} \le V_{wts} \le V_{\max,w}, \quad \forall w,\, \forall t,\, \forall s. \tag{17}$$

The initial and final volumes of the NG storage facility w are

$$V_{w(0)s} = V_{0,w}, \quad \forall w,\, \forall s \tag{18}$$

$$V_{w(NT)s} = V_{NT,w}, \quad \forall w,\, \forall s. \tag{19}$$

The total cost of NG withdrawal from the storage facility w is

$$C_{ws} = \rho_w . \sum_{t=1}^{NT} q_{wts}^{out}, \quad \forall w, \forall s. \tag{20}$$

The NG usage of unit j is subject to the following hourly and yearly limits:

$$F_{jts} \le F_{\max,jt}, \quad \forall j, \forall t, \forall s \tag{21}$$

$$\sum_{t=1}^{NT} F_{jts} \le F_{\max,j}, \quad \forall j, \forall s. \tag{22}$$

The NG units that belong to a specific power plant are subject to the following hourly and yearly limits:

$$\sum_{j\in SPL(p)} F_{jts} \le F_{\max,pt}, \quad \forall p, \quad \forall t,\, \forall s \tag{23}$$

$$\sum_{j\in SPL(p)} \sum_{t=1}^{NT} F_{jts} \le F_{\max,p}, \quad \forall p,\, \forall s. \tag{24}$$

The NG usage of pipeline m is subject to the following hourly and yearly limits:

$$F_{mts} \le F_{\max,mt}, \quad \forall m,\, \forall t,\, \forall s \tag{25}$$

$$\sum_{t=1}^{NT} F_{mts} \le F_{\max,m}, \quad \forall m,\, \forall s. \tag{26}$$

The NG usage at subarea r is subject to the following hourly and yearly limits:

$$F_{mrts} \le F_{\max,mrt}, \quad \forall m,\, \forall r,\, \forall t,\, \forall s \tag{27}$$

$$\sum_{t=1}^{NT} F_{mrts} \le F_{\max,mr}, \quad \forall m,\, \forall r,\, \forall s. \tag{28}$$

- Risk Constraints
  The stochastic formulation described above is a risk-neutral model that is only concerned with the optimization of expected payoff. However, a GENCO may also be concerned with its risk. A GENCO would set a target payoff T_0, and the risk associated with its decision is measured by the failure to meet the target payoff. That is, if the payoff for a scenario is larger than the target, the associated downside risk is zero; otherwise, it is the difference between the payoff and its target value, which is expressed as

$$RISK_s = \max\{0, T_0 - PF_s\}, \quad \forall s. \tag{29}$$

  The expected downside risk should be lower than a target risk level, which is stated as

$$\sum_{s=1}^{NS} p_s . RISK_s \le \overline{EDR}. \tag{30}$$

III. Proposed Solution Methodology

A. Decomposition Procedure

The original problem is decomposed into subproblems for coal, NG, hydro, and pumped-storage units. The unit status indicators (I) are defined for each scenario separately. Bundle constraints are utilized to force the undistinguishable scenarios to have the same rendered decision variables, namely unit status indicators [18]. In this study, the unit status indicators are the same for every scenario. This formulation removes the necessity of using bundle constraints at the expense of a longer solution time since the decomposition is not among scenarios. The removal of bundle constraints reduces the number of Lagrange multipliers and simplifies the updating of multipliers.

1) Decoupling Expected Downside Risk Constraint: The expected downside risk constraint (30) is the only coupling constraint among different types of generating units. The constraint can be decoupled by relaxing it into the objective function by using the Lagrange multiplier γ_s. With the constant terms dropped, we have

$$Min \sum_{s=1}^{NS} p_s \cdot (-PF_s + \gamma_s . RISK_s). \tag{31}$$

Considering the definition of downside risk (29), we have

$$Min \sum_{s=1}^{NS} p_s \cdot (-PF_s + \gamma_s . \max\{0, T_0 - PF_s\}). \tag{32}$$

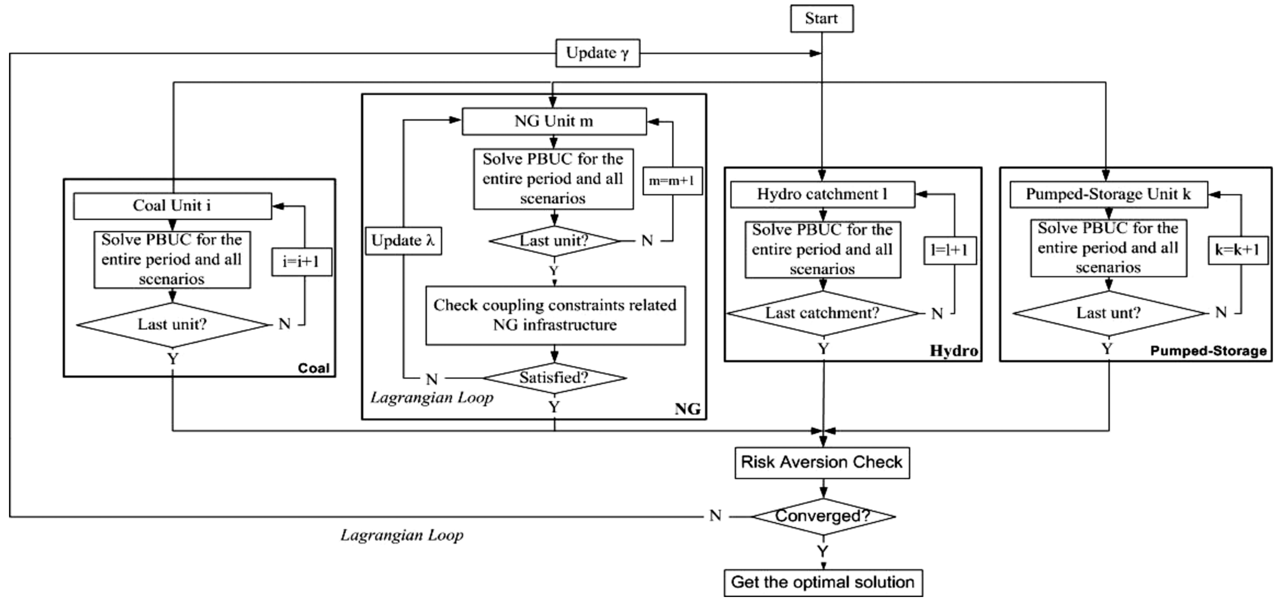

Fig. 1. Flowchart of the midterm stochastic hydrothermal scheduling.

If the payoff of a scenario s is higher than the target payoff

$$-PF_s + \gamma_s.\max\{0, T_0 - PF_s\} = -PF_s. \tag{33}$$

Otherwise

$$-PF_s + \gamma_s.\max\{0, T_0 - PF_s\} = -(1+\gamma_s)PF_s + \gamma_s.T_0. \tag{34}$$

Here, (33) can be viewed as a special case of (34) where $\gamma_s = 0$. After relaxing the risk constraint, we proceed by decomposing different unit types to single unit problems.

2) Decoupling Constraints Among Coal Units: The coal unit subproblem is given in (35). Fuel allocation and emission allowance are considered by applying the Lagrangian relaxation [18]. The coal unit subproblem is further decomposed into single coal unit i subproblems in (36):

$$Min\left\{\sum_{i=1}^{NCO}\sum_{t=1}^{NT}\sum_{s=1}^{NS} p_s.(1+\gamma_s).\right.$$
$$\left.\{-[\rho g_{ts}\cdot P_{its} + \rho sr_{ts}\cdot SR_{its} + \rho or_{ts}\cdot OR_{its}] + SU_{it} + SD_{it} + \rho f_{its}.F_{its}\}\right\} \tag{35}$$

$$Min\left\{\sum_{t=1}^{NT}\sum_{s=1}^{NS} p_s.(1+\gamma_s).\right.$$
$$\left.\{-[\rho g_{ts}\cdot P_{its} + \rho sr_{ts}\cdot SR_{its} + \rho or_{ts}\cdot OR_{its}] + SU_{it} + SD_{it} + \rho f_{its}.F_{its}\}\right\}, \quad \forall i. \tag{36}$$

3) Hydro Subproblems for Each Catchment: In order to avoid the decomposition of coupling constraints among hydro units in one catchment, we solve hydro subproblems for each catchment given in (37):

$$Min\left\{\sum_{h=1}^{NH_l}\sum_{t=1}^{NT}\sum_{s=1}^{NS} p_s.(1+\gamma_s).\right.$$
$$\left.\{-[\rho g_{ts}\cdot P_{hts} + \rho sr_{ts}\cdot SR_{hts} + \rho or_{ts}\cdot OR_{hts}] + SU_{ht} + SD_{ht}\}\right\}, \quad \forall l. \tag{37}$$

4) Pumped-Storage Subproblems for Each Unit: The pumped-storage hydro unit subproblem is given as

$$Min\left\{\sum_{t=1}^{NT}\sum_{s=1}^{NS} p_s.(1+\gamma_s).\right.$$
$$\left.\{-[\rho g_{ts}\cdot P_{kts} + \rho sr_{ts}\cdot SR_{kts} + \rho or_{ts}\cdot OR_{kts}] + SU_{kt} + SD_{kt}\}\right\}, \quad \forall k. \tag{38}$$

5) NG Subproblems for Each Unit: The NG infrastructure constraints are coupling constraints that are relaxed by applying the Lagrangian relaxation method. The subproblems for NG units are given in (39), which are further decomposed into subproblems for each NG unit in (40). In (39), the first term is the expected revenue of selling energy and ancillary services minus the startup and shutdown costs for NG units. The second and third terms are the cost of NG usage from contracts and the NG withdraw from storage facilities, respectively. The fourth to seventh terms represent plant (24), pipeline (26), subarea (28), and max contracts for NG usage constraints (7) and (8), respectively. The last three terms relax upper and lower volume limits (17) and final volume (19) for gas storage facilities, respectively. Emission allowance constraints may be relaxed similarly [18]. See (39) and (40) on the next page.

B. Proposed Solution Steps

The algorithm flowchart is shown in Fig. 1. The subproblems for coal, NG, cascaded hydro, and pumped-storage hydro units are solved in parallel when the coupling risk constraint is relaxed. Each subproblem related to an individual unit is solved to maximize the expected payoff of all scenarios in the entire study horizon. For the NG unit subproblem in particular, coupling constraints are checked for constraints on NG contracts, pipelines, plants, subareas, and gas storage. The Lagrange multipliers are updated using the subgradient method and iterations continue until the difference between the objective functions in two consecutive iterations is smaller than a predefined threshold and an optimal or suboptimal solution is reached:

$$
\begin{aligned}
Min \Bigg\{ & \sum_{j=1}^{NNG}\sum_{t=1}^{NT}\sum_{s=1}^{NS} p_s.(1+\gamma_s)\left\{\begin{matrix} -\begin{bmatrix} \rho g_{ts}\cdot P_{jts}+\rho sr_{ts}\cdot SR_{jts}+ \\ \rho or_{ts}\cdot OR_{jts}\end{bmatrix} \\ +SU_{jt}+SD_{jt}\end{matrix}\right\} \\
& + \sum_{m=1}^{NPP}\sum_{t=1}^{NT}\sum_{n\in SPP(m)}\sum_{j\in SCT(n)}\sum_{s=1}^{NS} p_s.\rho_n.F_{jnmts} \\
& + \sum_{w=1}^{NGS}\sum_{t=1}^{NT}\sum_{j\in SST(w)}\sum_{s=1}^{NS} p_s.\rho_w.q_{jwts}^{out} \\
& + \sum_{p=1}^{NPL}\sum_{s=1}^{NS} p_s\cdot\left\{\lambda_{\max,ps}\cdot\left(\sum_{j\in SPL(p)}\sum_{t=1}^{NT} F_{jts}-F_{\max,p}\right)\right\} \\
& + \sum_{m=1}^{NPP}\sum_{s=1}^{NS} p_s\cdot\left\{\lambda_{\max,ms}\cdot\left(\sum_{n\in SPP(m)}\sum_{j\in SCT(n)}\sum_{t=1}^{NT} F_{jnmts}-F_{\max,m}\right)\right\} \\
& + \sum_{r=1}^{NSA}\sum_{s=1}^{NS} p_s\cdot\left\{\lambda_{\max,rs}\cdot\left(\sum_{j\in SSA(r)}\sum_{t=1}^{NT} F_{jts}-F_{\max,r}\right)\right\} \\
& + \sum_{m=1}^{NPP}\sum_{n\in SPP(m)}\sum_{s=1}^{NS} p_s\cdot\left\{\lambda_{\max,ns}\cdot\left(\sum_{j\in SCT(n)}\sum_{t=1}^{NT} F_{jnmts}-F_{\max,n}\right)\right\} \\
& + \sum_{w=1}^{NGS}\sum_{s=1}^{NS} p_s\cdot\left\{\lambda_{\max,ws}\cdot\left(\sum_{t=1}^{NT} V_{wts}-V_{\max,w}\right)\right\} \\
& - \sum_{w=1}^{NGS}\sum_{s=1}^{NS} p_s\cdot\left\{\lambda_{\min,ws}\cdot\left(\sum_{t=1}^{NT} V_{wts}-V_{\min,w}\right)\right\} \\
& + \sum_{w=1}^{NGS}\sum_{s=1}^{NS} p_s\cdot\lambda_{NT,ws}\cdot\left(V_{wNTs}-V_{NT,w}\right)\Bigg\}
\end{aligned}
\tag{39}
$$

$$
\begin{aligned}
Min \Bigg\{ & \sum_{t=1}^{NT}\sum_{s=1}^{NS}\left\{\begin{matrix}\left[p_s.(1+\gamma_s)\cdot\begin{bmatrix} -\rho g_{ts}\cdot P_{jts}+\rho sr_{ts}\cdot SR_{jts}+ \\ \rho or_{ts}\cdot OR_{jts}+SU_{jt}+SD_{jt}\end{bmatrix}\right] \\ +\left[p_s\cdot(\lambda_{\max,ps}+\lambda_{\max,rs})\cdot F_{jts}\right]\end{matrix}\right\} \\
& + \sum_{m=1}^{NPP}\sum_{t=1}^{NT}\sum_{n\in SPP(m)}\sum_{s=1}^{NS} p_s.\rho_n.F_{jnmts} + \sum_{w=1}^{NGS}\sum_{t=1}^{NT}\sum_{s=1}^{NS} p_s.\rho_w.q_{jwts}^{out} \\
& + \sum_{m=1}^{NPP}\sum_{s=1}^{NS} p_s\cdot\left\{\lambda_{\max,ms}\cdot\left(\sum_{n\in SPP(m)}\sum_{t=1}^{NT} F_{jnmts}\right)\right\} \\
& + \sum_{m=1}^{NPP}\sum_{n\in SPP(m)}\sum_{s=1}^{NS} p_s\cdot\left\{\lambda_{\max,ns}\cdot\left(\sum_{t=1}^{NT} F_{jnmts}\right)\right\} \\
& + \sum_{w=1}^{NGS}\sum_{s=1}^{NS} p_s\cdot\left\{(\lambda_{\max,ws}-\lambda_{\min,ws})\cdot\left(\sum_{t=1}^{NT}\sum_{\tau=1}^{t-1}\left(q_{jw\tau s}^{in}-q_{jw\tau s}^{out}\right)\right)\right\} \\
& + \sum_{w=1}^{NGS}\sum_{s=1}^{NS} p_s\cdot\left\{\lambda_{NT,ws}\cdot\left(\sum_{\tau=1}^{NT-1}\left(q_{jw\tau s}^{in}-q_{jw\tau s}^{out}\right)\right)\right\}\Bigg\}
\end{aligned}
\tag{40}
$$

After the solution of individual unit subproblems, the risk is calculated. If the risk aversion limit is met, the optimal solution is calculated. Otherwise, the Lagrange multipliers γ_s is updated for the risk inequality constraint (30) and returned to recalculate individual unit subproblems. The risk Lagrange multipliers are initially set to zero for all scenarios and updated using the subgradient method afterwards [24].

The target risk and profit are essential factors, which could impact the convergence of the algorithm. A GENCO might calculate the factors based on the following steps:

1) The problem is solved by assuming an initial target profit and without considering risk constraints. The proposed algorithm would calculate the appropriate expected risk. Otherwise, go to step 2 if the risk is not within the GENCO's tolerance.
2) The proposed algorithm is implemented with risk constraints to calculate the optimum profit. If the target profit is too high and the target risk is not attainable, the GENCO would decrease its target profit and repeat this step.

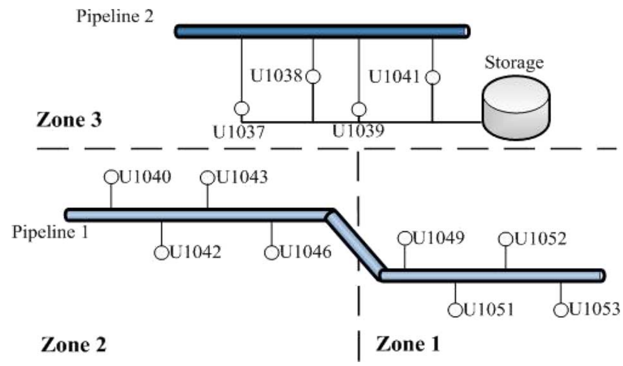

Fig. 2. NG units and infrastructure.

TABLE I
NG CONTRACTS

Pipeline #	Contract #	Type	Amount (MMCF)	Cost or Price
1	1	Firm	36,000	$70,200,000
1	2	Interruptible	117,500	$2,170 / MMCF
2	3	Interruptible	88,400	$2,100 / MMCF

IV. CASE STUDIES

A GENCO with three coal units, 12 NG units, 11 hydro units, and three pumped-storage units is considered to analyze the effect of NG constraints on the midterm hydrothermal scheduling problem. The scheduling horizon is one year with hourly intervals. The detailed generating unit data and market prices for energy and ancillary services are given in http://motor.ece.iit.edu/data/NGInfraPBUC.

We assume uniform market clearing prices (MCPs) for all units. Locational marginal prices (LMPs) can be incorporated similarly. The NG infrastructure feeding NG units is shown in Fig. 2. Zone 1 is considered as a subarea since it is far from the NG supply. The yearly NG usage limit for Zone 1 is 37 200 MMCF (subarea limit).

In this study, NG storage facilities are not considered except in Case 4, where an NG storage facility with a capacity of 1000 MMCF is located in Zone 3 for supplying NG units within Zone 3. The cost of utilizing the storage is $2170 per MMCF. NG contracts are shown in Table I. Pipeline 1 has one firm and one interruptible contract while Pipeline 2 has one interruptible contract. The yearly pipeline constraints are 155 000 and 90 000 MMCF for Pipelines 1 and 2, respectively.

The following four cases are considered:

Case 1) Base case without any NG constraints or supply interruptions
Case 2) Effect of NG infrastructure constraints
Case 3) Effect of NG supply interruptions
Case 4) Effect of NG storage facilities

These cases are discussed as follows.

Case 1: Base Case Without any NG Constraints or Supply Interruptions: This base case includes all the units but does not consider NG constraints or supply interruptions. This case is to be used as reference to show the effect of NG infrastructure and its interruptions in the following cases. The uncertainties in

TABLE II
PROBABILITY OF EACH SCENARIO AFTER SCENARIO REDUCTION

Scenario	1	2	3	4	5	6
Probability	0.07	0.11	0.02	0.07	0.08	0.08
Scenario	7	8	9	10	11	12
Probability	0.1	0.05	0.09	0.09	0.13	0.11

TABLE III
CASE 1 PAYOFF

Scenario	**Risk Neutral Payoff ($)**	**Risk Constrained Payoff ($)**	**Change (%)**
1	496,829,660	492,811,146	-0.81
2	455,159,262	457,308,285	0.47
3	470,330,464	469,255,240	-0.23
4	478,319,870	481,583,723	0.68
5	486,346,522	485,826,120	-0.11
6	507,895,434	501,879,197	-1.18
7	468,243,935	471,056,266	0.60
8	460,055,586	461,652,104	0.35
9	488,026,721	485,933,588	-0.43
10	493,015,056	487,823,577	-1.05
11	531,379,691	523,638,213	-1.46
12	467,052,288	469,049,789	0.43
Expected Payoff ($)	485,849,996	484,407,904	-0.30
Target ($)	485,849,996		-
Downside Risk ($)	9,331,555	8,309,323	-10.95

TABLE IV
CASE 1 USAGE OF NG CONTRACTS

Scenario	**Contract 1 NG (MMCF)**		**Contract 2 NG (MMCF)**		**Contract 3 NG (MMCF)**	
	Risk Neutral Case	**Risk Cons. Case**	**Risk Neutral Case**	**Risk Cons. Case**	**Risk Neutral Case**	**Risk Cons. Case**
1	36,000	36,000	88,517	86,424	41,591	41,286
2	36,000	36,000	76,479	75,708	39,106	39,060
3	36,000	36,000	81,876	80,441	39,987	39,814
4	36,000	36,000	84,181	83,409	40,544	40,483
5	36,000	36,000	83,865	82,446	40,498	40,341
6	36,000	36,000	91,697	88,965	41,921	41,670
7	36,000	36,000	82,393	81,655	40,374	40,266
8	36,000	36,000	77,743	76,966	38,811	38,702
9	36,000	36,000	85,611	83,758	40,872	40,648
10	36,000	36,000	85,266	83,140	40,957	40,611
11	36,000	36,000	91,562	88,319	42,185	41,726
12	36,000	36,000	80,332	79,756	39,912	39,868
Exp. Value	36,000	36,000	84,429	82,827	40,661	40,462

TABLE V
CASE 2 PAYOFF

Scenario	**Risk Neutral Payoff ($)**	**Risk Constrained Payoff ($)**	**Change (%)**
1	492,174,884	487,461,689	-0.96
2	452,984,686	455,218,835	0.49
3	467,379,771	466,489,686	-0.19
4	474,772,772	478,266,777	0.74
5	483,012,610	481,939,429	-0.22
6	502,690,545	494,945,756	-1.54
7	465,237,823	468,108,097	0.62
8	457,819,092	459,446,279	0.36
9	484,277,365	482,318,666	-0.40
10	489,136,100	482,952,060	-1.26
11	525,411,762	515,473,413	-1.89
12	464,728,792	466,871,393	0.46
Expected Payoff ($)	482,164,144	480,180,559	-0.41
Target ($)	482,164,144		-
Downside Risk ($)	8,850,597	7,791,967	-11.96

market price and natural water inflow are considered in the scenarios. The scenarios are reduced to 12 since the value of the objective function does not change much based on this number of scenarios [25]. The probability of each reduced scenario is given in Table II. A risk neutral model is considered first which aims to maximize the expected scenario payoffs. Scenarios 2 and 8 have lower payoffs as a function of market prices and natural water inflows. If the GENCO sets its target payoff at \$485 849 996, which is the expected payoff for the risk neutral case, the corresponding probability for the set of scenarios below the target payoff is 0.46 (i.e., $0.11 + 0.02 + 0.07 + 0.1 + 0.05 + 0.11$). The expected downside risk is \$9 331 555. The expected downside risk would be decreased with the inclusion of risk constraints. Table III shows scenario payoffs for risk neutral and risk-constrained models (minimum risk). The downside risk is \$8 309 323 with the inclusion of risk constraints, which shows a 10.95% less risk than that of the risk neutral case. However, the expected payoff decreases by 0.3% in the risk-constrained case. This is the cost of risk aversion. Table IV shows the NG usage of different contracts for risk neutral and risk-constrained cases. The firm NG contract is fully utilized in both cases, and the interruptible NG is consumed when market prices are high. The interruptible NG contract usage decreases in all scenarios with the introduction of risk constraints. This is because NG units are shut down in specific hours to reduce the downside risk.

Case 2: Effect of NG Infrastructure Constraints: All units and NG infrastructure constraints are used to show the effect of NG constraints on the midterm hydrothermal scheduling. These constraints, formulated in Section II, are on pipelines, subareas, plants, and units. Table V shows scenario payoffs with risk neutral and risk-constrained model when considering NG infrastructure constraints. The downside risk is decreased by 11.96% against a drop in the expected payoff of 0.41%. When we adopt commitment decisions given in Case 1, the expected payoff changes to \$481 881 658. The difference in the expected payoff is \$282 486 (i.e., 482 164 144 − 481 881 658) which represents the cost of ignoring NG infrastructure constraints in decision-making.

Therefore, the target payoff in this case should not be the same as that in the previous case when the NG infrastructure constraints were not considered. The GENCO would experience a lower payoff than its expectation if it does not update the target payoff. The value of the downside risk is \$8 850 597 for a target payoff \$481 881 658. If the GENCO sets its target payoff at \$485 849 996 as in Case 1, the probability for the set of scenarios below the target payoff would be 0.63 (i.e., $0.11 + 0.02 + 0.07 + 0.08 + 0.1 + 0.05 + 0.09 + 0.11$) with an expected downside risk of \$10 914 617. This indicates that ignoring NG constraints could affect the GENCO's midterm schedule and increases the financial risk. Table VI shows the total NG usage of generating units located in Zone 1 for Cases 1 and 2. We observe that the subarea constraint would limit the NG usage of units in Zone 1 to slightly lower than the upper limit

TABLE VI
ZONE GAS USAGES OF UNITS IN CASES 1 AND 2 (RISK NEUTRAL CASE)

Scenario	Zone 1 NG (MMCF)		Zone 2 NG (MMCF)		Zone 3 NG (MMCF)	
	Case 1	Case 2	Case 1	Case 2	Case 1	Case 2
1	60,283	37,045	64,234	64,234	41,591	41,591
2	53,100	37,162	59,379	59,379	39,106	39,106
3	55,156	37,073	62,720	62,720	39,987	39,987
4	56,927	37,037	63,253	63,253	40,544	40,544
5	56,237	37,181	63,628	63,628	40,498	40,498
6	60,820	37,075	66,877	66,877	41,921	41,921
7	55,605	37,092	62,788	62,788	40,374	40,374
8	52,262	36,957	61,482	61,482	38,811	38,811
9	57,384	37,103	64,227	64,227	40,872	40,872
10	57,848	37,169	63,418	63,418	40,957	40,957
11	61,340	37,188	66,222	66,222	42,185	42,185
12	53,967	37,136	62,365	62,365	39,912	39,912
Exp. Value	56,968	37,116	63,460	63,460	40,661	40,661

TABLE VII
CASE 2 EXPECTED USAGES FROM NG CONTRACTS

Contract 1 NG (MMCF)		Contract 2 NG (MMCF)		Contract 3 NG (MMCF)	
Risk Neutral	Risk Cons.	Risk Neutral	Risk Cons.	Risk Neutral	Risk Cons.
36,000	36,000	64,577	62,157	40,661	40,465

(37 200 MMCF) even though the higher gas utilization in Zone 1 would lead to a higher payoff. The generating units in Zones 2 and 3 are unaffected since their NG usage remains within limits. The decrease in scenario payoffs is due to NG subarea limits. The expected NG usages from contracts for risk neutral and risk-constrained cases are given in Table VII. When compared with the risk neutral case in Case 1, we see that the NG usage from the interruptible contract of Pipeline 1 has decreased by 19 582 (i.e., 84 429 − 64 577) MMCF, which is due to binding subarea constraints in Zone 1. The units in Zone 1 would utilize the firm NG and the interruptible NG usage is limited by the subarea constraint. The interruptible contract in Pipeline 2 has not changed when compared to that in Case 1 since the midterm scheduling of units fed from Pipeline 2 does not violate the NG constraints.

It is cumbersome to represent the sensitivity of the risk with respect to the expected payoff analytically due to the complexity of the problem. Instead, the change of risk is evaluated for Case 2 by evaluating the minimum achievable risk at different target profits. The results are depicted in Fig. 3. The expected payoff for the risk neutral case was $482 164 144 with a downside risk of $8 850 597. The analysis for case 2 is repeated for the GENCO's target payoffs starting at $460 000 000 to $485 000 000 with a step of $5 000 000. The points are connected with linear curves to obtain five linear segments. The slopes of the curve segments given in Fig. 3 is calculated as 0.16, 0.33, 0.40, 0.45, and 0.53 from segment 1 to segment 5, respectively. This shows that the rate of change in the lowest achievable risk increases as the GENCO increases its target profit. Consider that the GENCO has two different target

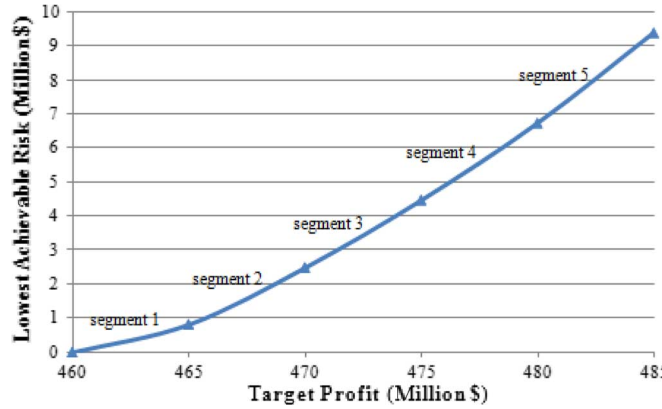

Fig. 3. Downside risk versus target payoff for Case 2.

profits, namely $460 000 000 and $480 000 000, with lowest achievable risks 0 and $6 730 647, respectively.

The $1 000 000 of increase in target profit will result $163 250 and $529 779 of increase in lowest achievable risk, respectively. Consequently, the extra risk exposition increases when the GENCO updates its target profits in the ascending direction. A similar analysis is trivial when the GENCO updates its target profit in the descending direction. Even though the downside risk was decreased by 11.96% with the consideration of risk constraints in Case 2, the GENCO would have to update the target payoff to $460 000 000 in order to reduce the risk to zero.

Case 3: Effect of NG Supply Interruptions: In this case, we study the effect of NG interruptions on the GENCO's payoff in a midterm scheduling. In severe weather conditions, the increasing NG demand for heating in residential areas is supplied by interruptible NG contracts. The interruption rate, which is defined as the ratio of the mean interruption time to the sum of mean interruption and mean available times [21], is taken as 0.1 for this case study, and interruptions are simulated for the winter period. Table VIII depicts the scenario payoffs when considering NG interruptions and constraints for both risk neutral and risk-constrained conditions. If the GENCO determines a target payoff $465 492 606 for the risk neutral case, the downside risk probability is 0.46 (i.e., $0.11+0.02+0.07+0.1+0.05+0.11$). The downside risk is $8 469 522 and the expected payoff is decreased by $16 671 538 (i.e., $482 164 144 − $465 492 606). This is the potential loss in the midterm stochastic hydrothermal scheduling due to NG interruptions. When compared with Case 1, the consideration of NG interruptions with NG infrastructure constraints further decreases the GENCO's expected payoff by $20 357 390 (i.e., $3 685 852-$16 671 538). The amount of decrease could change with the rate of the NG interruptions. If the GENCO sets its target payoff to $485 849 996 as in Case 1, the probability for the set of scenarios below the target payoff would be 0.87 (i.e., $0.07+0.11+0.02+0.07+0.08+0.08+0.1+0.05+0.09+0.09+0.11$) with an expected downside risk of $23 126 635. This indicates that ignoring the NG network constraints could affect the GENCO's midterm schedule and further increases financial risks. With the consideration of risk constraints, the downside risk decreases by 12.19% against a drop in the expected payoff of 0.37%. Table IX gives the NG usage of gas contracts for each scenario for both risk neutral and risk considered cases. The NG contract utilization further

TABLE VIII
CASE 3 PAYOFF

Scenario	Risk Neutral Payoff ($)	Risk Constrained Payoff ($)	Change (%)
1	474,871,828	470,491,695	-0.92
2	437,655,315	439,855,079	0.50
3	451,281,020	450,284,507	-0.22
4	458,324,947	461,706,329	0.74
5	466,314,926	465,310,161	-0.22
6	484,836,849	477,901,647	-1.43
7	449,183,674	451,958,605	0.62
8	442,057,657	443,691,623	0.37
9	467,325,199	465,484,983	-0.39
10	472,370,528	466,607,116	-1.22
11	507,151,877	498,283,516	-1.75
12	448,957,954	451,049,157	0.47
Expected Payoff ($)	465,492,606	463,761,550	-0.37
Target ($)	465,492,606		-
Downside Risk ($)	8,469,522	7,436,840	-12.19

TABLE IX
CASE 3 EXPECTED USAGES FROM NG CONTRACTS

Contract 1 NG (MMCF)		Contract 2 NG (MMCF)		Contract 3 NG (MMCF)	
Risk Neutral	Risk Cons.	Risk Neutral	Risk Cons.	Risk Neutral	Risk Cons.
36,000	36,000	64,577	62,550	30,086	29,975

TABLE X
CASE 4 PAYOFF

Scenario	Risk Neutral Payoff ($)	Risk Constrained Payoff ($)	Change (%)
1	489,727,434	486,554,727	-0.65
2	451,626,645	453,729,519	0.47
3	465,703,256	465,115,114	-0.13
4	472,760,956	475,928,829	0.67
5	480,924,774	481,293,666	0.08
6	499,767,150	493,687,013	-1.22
7	463,433,285	466,117,361	0.58
8	456,442,454	457,561,335	0.25
9	482,096,447	481,359,263	-0.15
10	486,971,597	481,762,048	-1.07
11	522,165,865	515,108,551	-1.35
12	463,117,388	464,735,786	0.35
Expected Payoff ($)	480,028,588	478,840,621	-0.25
Target ($)	480,028,588		-
Downside Risk ($)	8,618,523	7,674,844	-10.95

decreases when compared with Case 2 due to NG interruptions. The NG usage does not decrease in Pipeline 1 with respect to Case 2 even if there are any NG interruptions. This is due to the fact that NG usage in Case 2 was already limited by subarea constraints and the unused gas at interrupted hours are shifted to other hours in Case 3. The decrease in gas usage from Contract 2 due to the interruptions is 10 575 MMCF (i.e., 40 661 − 30 086).

Case 4: Effect of NG Storage Facility: This case includes all the units, NG infrastructure constraints, NG interruption cases,

TABLE XI
CASE 4 EXPECTED USAGES FROM NG CONTRACTS

Contract 1 NG (MMCF)		Contract 2 NG (MMCF)		Contract 3 NG (MMCF)	
Risk Neutral Case	Risk Cons. Case	Risk Neutral Case	Risk Cons. Case	Risk Neutral Case	Risk Cons. Case
36,000	36,000	64,577	63,577	30,977	30,763

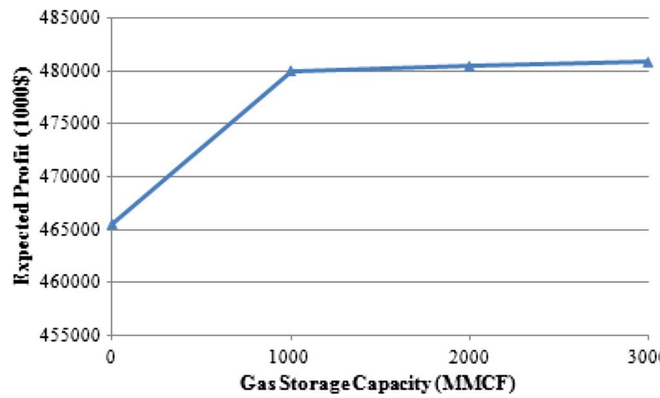

Fig. 4. NG storage capacity versus expected payoff, risk neutral case.

and NG storage facilities. NG can be stored for use at constrained hours. In this case, the NG storage in Zone 3 is considered. The storage is assumed to be full prior to the study period and NG injection to the storage by units is assumed to be zero at all periods (i.e., $q_{wts}^{in} = 0, \forall t, \forall s$). Table X depicts the scenario payoffs for both risk neutral and risk-constrained cases. Table XI gives the expected usage of NG contracts under risk neutral and risk-constrained cases. Fig. 4 depicts the expected payoff against the NG storage size.

When there is no storage, the expected payoff is $465 492 606 as given in Case 3. The expected payoff is improved by 3.03% to $480 028 588 for the first 1000 MMCF storage. However, the improvement is only 0.09% with a payoff of $480 456 556 for adding the second 1000 MMCF of storage, and 0.08% with a payoff of $480 841 268 for the third 1000 MMCF of storage. This is because the GENCO would choose to burn NG from the storage at the most profitable hours. The payoff improvement for the first 1000 MMCF storage is higher than the next 2000 MMCF since the GENCO uses the first 1000 MMCF of additional NG at most profitable hours. The expected payoff is could be improved significantly with the addition of 1000 MMCF of NG storage when compared with the no-storage Case 3. The downside risk for this case has decreased by 10.95% against a drop in the expected payoff of 0.25% with the addition of risk constraints.

The four cases are summarized in Table XII. The GENCO's expected payoff decreases when considering NG constraints and interruptions. Furthermore, the expected financial downside risk and downside risk probability increase if the GENCO does not update its midterm target payoff and uses the target payoff determined in the base case for Cases 2 and 3. Thus, the GENCO could run a risk-free case when considering NG constraints and interruptions and then determine a suitable target payoff and reduce the risk, which would lead to a more realistic

TABLE XII
COMPARISON OF RESULTS OF CASES 1–4 WITH RISK NEUTRAL SOLUTIONS

	Case 1	Case 2	Case 3	Case 4
Expected Payoff ($)	485,849,996	482,164,144	465,492,606	480,028,588
Downside Risk ($)	9,331,555	10,914,617	23,126,635	12,028,208
Down. Risk Probability	0.46	0.63	0.87	0.63
Target ($)	485,849,996			

TABLE XIII
COMPARISON OF RISK NEUTRAL CASES RESULTS

Cases	Expected Payoff ($)	Downside Risk ($)	Target ($)
5: Coal Units Only	22,423,534	1,101,054	22,423,534
6: NG Units Only	140,688,206	4,396,534	140,688,206
7: Hydro Units Only	232,620,703	2,178,677	232,620,703
8: PS Units Only	69,760,163	995,095	69,760,163
Sum of Cases 5-8	465,492,606	8,671,360	465,492,606
9: All Units Together	465,492,606	8,469,522	465,492,606
Change (%)	0.00	2.33	0.00

TABLE XIV
COMPARISON OF RISK REDUCTION OF CASES

Cases	Expected Payoff ($)	Downside Risk ($)	Target ($)
5: Coal Units Only	22,338,606	1,052,037	22,423,534
6: NG Units Only	140,117,126	4,231,735	140,688,206
7: Hydro Units Only	232,370,729	2,054,221	232,620,703
8: PS Units Only	69,464,139	551,639	69,760,163
Sum of Cases 5-8	464,290,600	7,889,632	465,492,606
9: All Units Together	463,761,550	7,436,840	465,492,606
Change (%)	0.11	5.74	0.00

risk-constrained midterm scheduling results. A reduction of 10 575 MMCF of NG was observed for Contract 3 in Case 3 as compared to Case 2 due to an NG interruption. The interruption resulted in an expected payoff reduction of $16 671 538. However, the expected payoff increased to $14 535 982 when a 1000 MMCF NG storage was considered in Zone 3. In other words, 87.2% of the reduction in expected payoff, which was due to the NG interruption, was recovered with the addition of storage. The NG storage was 9% of the interrupted NG. In this case, the GENCO utilized the stored NG at most profitable hours. Tables XIII and XIV list the results of optimizing the individual types of units separately or together for risk neutral and risk-constrained cases, respectively.

The results of risk neutral case show that the scheduling of all units together with a target payoff that is equal to the sum of individual payoffs would result in a lower expected downside risk than the sum of those for individual risks. This could be explained by the fact that the variance of the sum of two normal distributed random variables is always less than or equal to the sum of their variances. Hence, a GENCO should determine a target by including all of its units rather than considering them individually. For the risk-constrained case, the sum of lowest achievable risk for Case 3, which represents a combined solution of all generating units, is lower than the sum of separate downside risks of individual groups of units. The 5.75% improvement is because the consideration of all the units with a single total target payoff would provide more alternatives for risk reduction.

V. CONCLUSIONS

In this paper, the NG infrastructure constraints are incorporated into the GENCO's risk-constrained hydrothermal scheduling. Test results show that besides uncertainties in market prices and water inflow, GENCOs must further consider the NG infrastructure limitations in the optimal midterm scheduling. The NG storage facilities would improve the expected payoff of the GENCO against NG interruptions by providing NG at interrupted hours. The effect of utilizing the NG storage on the expected payoff is analyzed, and it is observed that a considerable improvement in the expected payoff would be attainable even by a limited storage capacity in comparison with any NG interruptions. In addition, the solution for the optimization of the individual types of units separately is compared with that of all units together. It is observed that the solution of all units together would provide a better chance for any risk reductions.

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