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Generation risk assessment in volatile conditions with wind, hydro, and natural gas units

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ABSTRACT

This paper studies a generating company (GENCO)'s midterm (a few months to a year) scheduling payoffs and risks in volatile operating conditions. The proposed algorithm considers the integration of intermittent wind units into a GENCO's generation assets and coordinates the GENCO's hourly wind generation schedule with that of natural gas (NG) units (with volatile gas prices) and hydro units (with water inflow forecast) for maximizing the GENCO's payoff. The proposed midterm GENCO model applies market price forecasts to the risk-constrained stochastic price-based unit commitment (PBUC) for calculating the GENCO's risk in energy and ancillary services markets. The proposed PBUC minimizes the cost of (a) NG contracts, storage, startup and shutdown, (b) startup and shutdown of cascaded hydro units, and (c) penalty for defaulting on the scheduled power delivery. Simulation results show that the diversification of generating assets including bilateral contracts (BCs) could enhance the GENCO's midterm planning by increasing the expected payoff and decreasing the financial risk.

1. Introduction

Generating companies (GENCOs) are self-interested entities in restructured power systems, which are responsible for the midterm operation planning of their respective generating units. This paper proposes an optimization framework for a GENCO's midterm coordinated operation planning with wind, hydro, and NG units.

When considering the volatility of NG prices, it is imperative to include the NG transmission system and the uncertainties related to NG transmission system interruptions, which could further impose limits on the availability of NG and the scheduling of NG-fired units by GENCOs. Ref. [1] presented the impact of NG infrastructure contingencies on power system operations and discussed the role of renewable resources on reducing the dependence of electricity infrastructure on the NG infrastructure. Ref. [2] presented an integrated model for assessing the impact of electricity and NG networks on power system security. The integrated model incorporated the simplified linear NG network constraints into the optimal solution of SCUC. Ref. [3] included nonlinear NG network equations in the security-constrained unit commitment (SCUC) problem using a decomposition approach. Ref. [4] proposed a component-based model for the scheduling of combined-cycle gas units by mixed-integer programming. Ref. [5] considered a linear NG network model for representing NG network constraints and interruption uncertainties in evaluating GENCO's risk.

Wind power is the fastest growing renewable energy resource since it is clean, indigenous, fast to deploy and economically competitive with other generation types. However, the intermittent and volatile nature of wind energy should be properly modeled in operational planning analyses. The stochastic SCUC solution with integrated wind energy has usually focused on the short-term operation planning. The effect of wind energy uncertainty on the day-ahead planning was included in SCUC [6]. The impact of wind generation on regulation and load following was analyzed in [7]. Ref. [8] studied the impact of high wind penetration on the day-ahead scheduling. Ref. [9] investigated the short-term wind energy forecast errors on the day-ahead generation scheduling. However, a GENCO would be concerned with its midterm risks when inexpensive and volatile wind units are utilized. The proposed algorithm for the midterm operation planning of a GENCO would consider the volatility of wind units when minimizing the risk of forecast errors for water inflows in hydro units and market prices of electricity and gas.

Forward BCs may hedge GENCO's volatilities. However, a large BC in a volatile environment could expose GENCOs to high penalty payments for defaulting on contracts. In [10], a stochastic decision framework for energy procurement of large customers was proposed. The supply portfolio was optimized considering uncertain pool prices, BCs, and self generation. CVaR was used to formulate risks, and the risk term was added to the objective function with

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Nomenclature

Indices

h	index of hydro units
j	index of NG units
l	index of hydro catchments
n	index of NG contracts
s	index of scenarios
t	index of time in BC period (h)
u	index of NG storage facilities
w	index of wind units
z	index of BC periods

Dimensions

NCM	number of hydro catchments
NGC	number of NG contracts
NNG	number of NG-fueled units
NGS	number of NG storage facilities
NH_l	number of hydro units of a hydro catchment l
NS	number of scenarios
NT	number of hours
NW	number of wind units
NZ	number of BC periods under study

Sets

SBC	set of units assigned to honor a BC
ST_z	set of hours for the BC period z

Variables

C_{ns}	cost of NG usage from contract n in scenario s
$C_{pen,zs}$	penalty for deficient BC in period z
C_{us}	cost of NG usage from storage facility u in scenario s
$E_{bc,z}$	BC in period z
$E_{bc,\max}$	upper energy limit for the flexible BC
$E_{bc,\min}$	lower energy limit for the flexible BC
$E_{def,zs}$	deficient BC in period in scenario s
$E_{del,zs}$	delivered BC in period z and scenario s
I	commitment state
OR	operating reserve
P	power generation
$P_{\Psi,wts}$	wind generation of unit w at time t and scenario s
P_{bc}	power generation to satisfy BC
PF_s	GENCO's payoff in scenario s
$R_{bc,z}$	BC revenue in period z
$RISK_s$	GENCO's downside risk in scenario s
SD	shutdown cost
SR	spinning reserve
SU	startup cost
TP	generation capacity offered to a day-ahead market
W_{zs}	binary index indicating that the GENCO is defaulting on its BC at period z under scenario s
λ	lagrange multiplier
ψ_{wts}	stochastic speed of wind unit w at hour t in scenario s

Constants

A_w	area swept by the rotor of wind unit w
$c_{P,w}$	power coefficient of wind unit w
$\underline{EDR}$	expected downside risk
$\overline{EDR}$	upper limit for expected downside risk
p_s	probability for a scenario s
T_0	target payoff of a GENCO
$\rho_{air,w}$	density of air at region where wind unit w is located
ρ_{bc}	BC price
$\rho_{g,ts}$	market price for energy at time t in scenario s
$\rho_{or,ts}$	market price for operating reserve at time t in scenario s
ρ_{pen}	penalty price for a deficient BC
$\rho_{sr,ts}$	market price for spinning reserve at time t in scenario s
$v_{CI,w}$	cut-in wind speed of wind unit w
$v_{CO,w}$	cut-out wind speed of wind unit w
$v_{R,w}$	rated wind speed of wind unit w

a weight factor to address tradeoffs between cost and risk minimization. Ref. [11] presented the optimal bidding strategy as a nonlinear mathematical program with equilibrium constraints. The GENCO's payoff was maximized and expected offers, uncertain system loads, and BCs were modeled as constraints.

In this paper, we consider the simultaneous coordination of BC with several inexpensive but uncertain units in a GENCO for hedging payoffs. The proposed model, which is an extension of [5], considers the uncertain wind model and utilizes the risk-constrained stochastic PBUC framework. A GENCO with uncertain wind, hydro, and NG resources would use the proposed midterm planning for analyzing market risks and coordinating the hourly commitment schedules with BCs for maximizing the GENCO's financial payoffs.

The paper is organized as follows. The risk-based mathematical model is described in Section 2. The MIP-based PBUC solution is introduced in Section 3. Case studies are given in Section 4. Section 5 concludes this paper.

2. Risk-based MIP model

This section starts with defining the objective function of the risk-based MIP model. Then the unit, BC coordination and risk constraints are described.

2.1. Objective function

The stochastic operational planning problem is modeled using Monte-Carlo scenarios. The objective (1) is to maximize the expected payoffs over all scenarios. The payoff is the difference between revenues and expenses. The revenue (2) is due to sales of energy, spinning reserves, and operating reserves by NG, cascaded hydro, and wind units and the income from BC sales. The cost (3) includes that of (i) NG contracts, storage, startup and shutdown of NG units; (ii) startup and shutdown for cascaded hydro units; (iii) penalty for defaulting on the scheduled generation delivery.

$$\mathrm{Max} \sum_{s=1}^{NS} p_s \cdot PF_s = \sum_{s=1}^{NS} p_s \cdot \{REVENUE_s - COST_s\} \tag{1}$$

where

$$\begin{aligned} REVENUE_s = & \sum_{j=1}^{NNG} \sum_{t=1}^{NT} [\rho_{g,ts} \cdot TP_{jts} + \rho_{sr,ts} \cdot SR_{jts} + \rho_{or,ts} \cdot OR_{jts}] \\ & + \sum_{l=1}^{NCM} \sum_{h=1}^{NH_l} \sum_{t=1}^{NT} [\rho_{g,ts} TP_{hts} + \rho_{sr,ts} \cdot SR_{hts} + \rho_{or,ts} \cdot OR_{hts}] \\ & + \sum_{w=1}^{NW} \sum_{t=1}^{NT} [\rho_{g,ts} \cdot TP_{wts} + \rho_{sr,ts} \cdot SR_{wts} + \rho_{or,ts} \cdot OR_{wts}] + \sum_{z=1}^{NZ} R_{bc,z} \end{aligned} \tag{2}$$

and

$$\begin{aligned} COST_s = & \sum_{n=1}^{NGC} C_{ns} + \sum_{u=1}^{NGS} C_{us} + \sum_{j=1}^{NNG} \sum_{t=1}^{NT} [SU_{jts} + SD_{jts}] \\ & + \sum_{l=1}^{NCM} \sum_{h=1}^{NH_l} \sum_{t=1}^{NT} [SU_{hts} + SD_{hts}] + \sum_{z=1}^{NZ} C_{pen,zs} \end{aligned} \tag{3}$$

2.2. Unit constraints

The mathematical formulation for cascaded hydro, NG units, NG infrastructure constraints and wind units constraints are given as follows:

- Cascaded Hydro Constraints
  (a) Generator availability constraint.
  (b) Energy and ancillary services supplied.
  (c) Water-to-power conversion.
  (d) Operating regions (water discharge limits).
  (e) Reservoir volume limits.
  (f) Initial and terminal reservoir volumes.
  (g) Water balance constraint.
  (h) Minimum on/off time and ramping up/down constraints.
- NG Unit Constraints
  (a) Generator availability constraint.
  (b) Fuel consumption and emission allowance constraints for groups of NG units.
  (c) Energy and ancillary services supplied.
  (d) Minimum on/off time and ramping up/down constraints.
- NG Infrastructure Constraints

The hourly and yearly linear network flow models considering limits on pipelines, sub-areas, power plants, and units are adopted for the midterm stochastic model. The detailed description for the constraints regarding NG units, NG contracts, infrastructure and cascaded hydro units could be found in [5] and [13].

- Wind Unit Constraints

The nonlinear wind speed to power conversion curve is given in (4) and $P_{\psi,wts}$ is given as an input. The wind generation w is subject to (5)

$$P_{\psi,wts}(\psi_{wts}) = \begin{cases} 0 & \text{if } \psi_{wts} < \upsilon_{\mathrm{CI},w} \\ 0.5c_{\mathrm{p},w}\cdot\rho_{\mathrm{air},w}\cdot A_w\cdot(\psi_{wts})^3 & \text{if } \upsilon_{\mathrm{CI},w} \leqslant \psi_{wts} < \upsilon_{\mathrm{R},w} \\ P_{\mathrm{R},w} & \text{if } \upsilon_{\mathrm{R},w} \leqslant \psi_{wts} < \upsilon_{\mathrm{CO},w} \\ 0 & \text{if } \psi_{wts} \geqslant \upsilon_{\mathrm{CO},w} \end{cases} \quad \forall w,\ \forall s \tag{4}$$

$$I_{wts}\cdot P_{\min,w} \leqslant P_{wts} \leqslant I_{wts}\cdot P_{\psi,wts}(\psi_{wts}) \quad \forall k, \forall s \tag{5}$$

The auto-regressive moving average (ARMA) based approach [12] would provide wind energy scenarios forecasts. The wind power forecast errors are simulated using ARMA series. The series parameters are fitted via an optimization algorithm considering the difference between old hourly forecasts and actual realized values. The obtained ARMA series is sampled in order to obtain the forecast errors for each time step t for each scenario s. Finally, the wind power Monte-Carlo scenarios are taken to be the sum of the wind power forecasts and the sampled wind power forecast errors for the study horizon. The wind forecast and three Monte Carlo weekly wind power scenarios are depicted in Fig. 1.

2.3. Bilateral contracts and coordination

BC, transacted by external generating entities, can be either physical or financial. BC characteristics include:

(1) NZ: 52 weeks for a one year study;
(2) ρ_{pen}: BC penalty price ($/MW h) over the contract length.

A flexible $E_{bc,z}$ at period z given in (6) can be adjusted by a GENCO for enhancing its payoff.

$$E_{bc,\min} \leqslant E_{bc,z} \leqslant E_{bc,\max}, \quad \forall z \tag{6}$$

A flat case is represented by $E_{bc,min} = E_{bc,z} = E_{bc,max}$. Accordingly, the GENCO receives a payment of $R_{bc,z}$ as

$$R_{bc,z} = \rho_{bc}.E_{bc,z}, \quad \forall z \tag{7}$$

GENCOs can offer excess generation to the day-ahead market as shown in the first three terms of (2). The GENCO's penalty payment is represented by the last term of (3) if the GENCO defaults on its BC given in following equation:

$$E_{def,zs} = \max\{0, (E_{bc,z} - E_{del,zs})\}, \quad \forall z,\ \forall s \tag{8}$$

The MIP formulation of (8) would use an external binary variable W, where

$$0 \leqslant E_{def,zs} - [E_{bc,z} - E_{del,zs}] \leqslant M\cdot[1 - W_{zs}]$$

$$0 \leqslant E_{def,zs} \leqslant M\cdot W_{zs}, \quad \forall z,\ \forall s \tag{9}$$

Here M is a large positive number and W_{zs} is the binary index which is equal to 1 when $E_{bc,z} \geqslant E_{del,\,zs}$, and is 0 otherwise. The penalty $C_{pen,zs}$ is given as

$$C_{pen,zs} = \rho_{pen}.E_{def,zs}, \quad \forall z,\ \forall s \tag{10}$$

Since the penalty is considered in the objective function, (11) would replace (9) to simplify the presentation.

$$[E_{bc,z} - E_{del,zs}] \leqslant E_{def,zs}, 0 \leqslant E_{def,zs}, \quad \forall z,\ \forall s \tag{11}$$

At the optimal solution, one of the constraints in (11) is binding. Multiple generating units in a GENCO could be considered for satisfying BC as given in the following equation

$$\sum_{j\in SBC}\sum_{t\in ST_z} P_{bc,jts} + \sum_{h\in SBC}\sum_{t\in ST_z} P_{bc,hts} + \sum_{w\in SBC}\sum_{t\in ST_z} P_{bc,wts} = E_{del,zs}, \quad \forall z,\ \forall s \tag{12}$$

The BC coordination would be based on the level of uncertainty, i.e. a wind unit dispatch could be coordinated with NG units, which are also subject to NG interruption and NG price uncertainty. A typical generating unit dispatch (13) includes its BC supply and the energy offered to the day-ahead market at time t under contract period z and scenario s.

$$P_{bc,jts} + TP_{jts} = P_{jts}, \quad \forall z,\ \forall s,\ \forall t \in ST_z \tag{13}$$

2.4. Consideration of financial risk

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 may set a target payoff T_0 and the risk associated with its decision is measured by the failure to meet the target. 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 as

$$RISK_s = \max\{0, T_0 - PF_s\}, \quad \forall s \tag{14}$$

The expected downside risk should be lower than a target risk,

$$\sum_{s=1}^{NS} p_s.RISK_s \leqslant \overline{EDR} \tag{15}$$

subject to risk constraints given in [14].

3. Solution method

The objective function (1) is subject to constraints (2)-(15) as given above. The original problem is first relaxed from risk

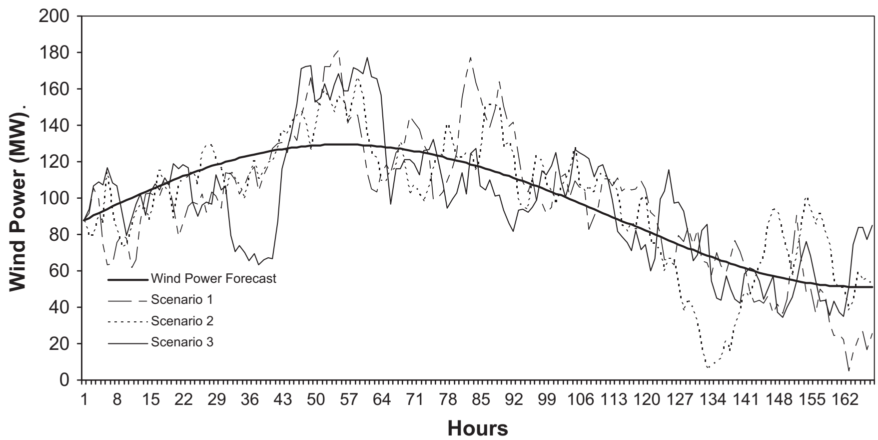

Fig. 1. Wind power forecasts and Monte Carlo simulations.

constraints using Lagrangian multipliers. Then, it is decomposed into subproblems for NG, hydro, and wind units [5]. The algorithm flowchart is shown in Fig. 2. The subproblems for NG, cascaded hydro, and wind 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. 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.

The GENCO's risk evaluation problem is solved by assuming an initial target payoff without considering risk constraints. The proposed solution would include the expected risk level. If the risk were not within the GENCO's tolerance, the GENCO would add the risk-constraints. The process will continue until the difference between the objective function values in two consecutive iterations is smaller than a predefined threshold. If the risk were still out of GENCO's tolerance, the GENCO would decrease its target payoff and repeat the process. The Lagrange multipliers of the risk-neutral solution are recorded and set at the beginning of risk-constrained algorithm to decrease the solution time of the risk-constrained case. Further discussions on the solution method is provided in [5].

4. Case studies

We first present a 3-h example to introduce the coordination for one wind and one NG unit. A more realistic example considering a GENCO with 8 NG, 4 cascaded hydro units, and 3 wind units will also be discussed.

4.1. Three-hour example

Consider a 3-h example of a GENCO with one wind and one NG unit. There are two scenarios with a 50% probability for each scenario. Assume wind forecasts of 100 MW, 150 MW, 170 MW at hours 1–3 in the first scenario, and 80 MW, 130 MW, 150 MW at hours 1–3 in the second scenario. The NG unit has a generation cost of \$19/MW h with min/max capacity of 55 MW and 200 MW, respectively. The day-ahead energy prices are \$20/MW h and \$15/MW h for scenarios 1 and 2, respectively. The following cases are studied:

Case 1: No coordination of generating units and no BC.
Case 2: Fixed BC without coordination of units.
Case 3: Wind-NG unit coordination with a fixed BC.
Case 4: Wind-NG unit coordination with an optimized BC.

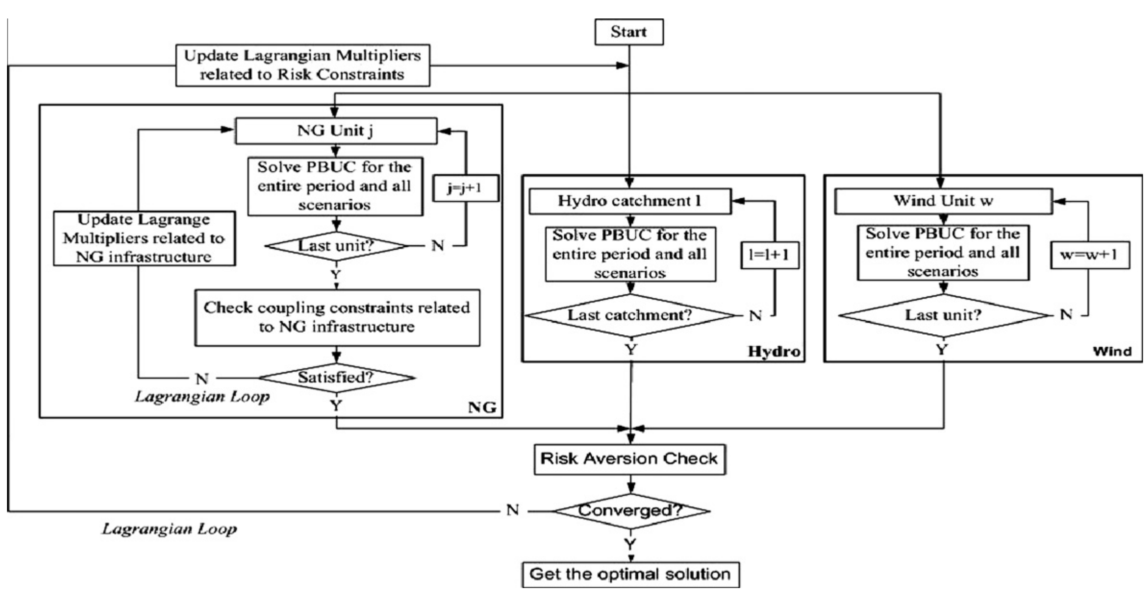

Fig. 2. Flowchart of the MIP solution method.

4.1.1. Case 1

This case serves as the base case. All available wind energy is utilized since the NG unit is profitable only in the first scenario when the given scenario day-ahead energy prices and NG unit generation cost is considered. The expected payoff is $6900 in Table 1 and the target payoff is the same as the expected payoff with a downside risk of $750. This target payoff is used in the following cases.

4.1.2. Case 2

A BC of 400 MW h with an energy price of $18/MW h and penalty price of $30/MW h is added. The hourly schedule based on PBUC is given in Table 2. The BC price is lower than that of energy in scenario 1 and higher in scenario 2. Since there is no coordination between wind and NG units, the GENCO uses the wind unit to supply BC and uses BC to hedge its expected payoff when the NG unit generation is offered to the day-ahead market. The available energy is 420 MW h in scenario 1 and 360 MW h in scenario 2. Since BC is 400 MW h, the excess 20 MW h in scenario 1 is offered to the day-ahead market, while a penalty is paid in scenario 2 for the 40 MW h deficiency. The expected payoff in Case 2 drops to $6800 due to the penalty payment, while the downside risk is lowered to $450 when BC is utilized so that the GENCO is not exposed to market volatilities in scenario 2.

4.1.3. Case 3

The NG and wind units are coordinated in Table 3. Here the NG unit provides a means of satisfying the BC energy when the availability of wind generation is uncertain. The expected payoff increases to $7090 and the downside risk is decreased to $260. The inexpensive wind unit is scheduled in both scenarios as in previous Cases. In Scenario 1, the NG unit is fully dispatched and offered to the day-ahead market since its generation cost is cheaper than the market price. In Scenario 2, the NG unit with a minimum capacity of 55 MW is committed at hour 1 to supply the deficient BC of 40 MW h, and its excess 15 MW h is offered to the day-ahead market.

4.1.4. Case 4

The potential BC energy is varied between 200 and 600 MW h and the optimal BC is calculated at 525 MW h. The expected payoff is $7132.5 while the downside risk is increased slightly to $292.5. The hourly unit schedules are given in Table 4. The NG unit is committed at all hours in coordination with the wind unit to satisfy BC and offer the excess energy to the day-ahead market. The NG unit is only profitable in Scenario 1. However, the additional energy required by BC would require the commitment of NG unit at hours 2 and 3 with a higher expected payoff than that in Case 3. A higher BC limit would increase the GENCO's expected payoff.

4.1.5. Discussions

The expected payoffs and risks are summarized in Table 5. The available wind energy is utilized in all 4 Cases. The NG unit is not scheduled in Cases 1 and 2 since it is not profitable. The NG unit is coordinated with the wind unit in Scenario 2 of Case 3 to prevent penalty payments. The NG unit is committed at all hours in Case 4 for supplying the additional BC. The expected payoff is the highest in Case 4 for introducing a higher BC. The downside risk is increased in Case 4 since the GENCO makes a lower payoff in Scenario 2 to boost the payoff in Scenario 1 and increase the expected payoff. The risk could be reduced in Case 4 by introducing additional risk constraints. The wind-NG coordination and the corresponding BC optimization increase the expected payoff and decrease the expected risk by preventing the GENCO from exposure to volatile day-ahead market prices.

4.2. One-year example

A GENCO with 8 NG, 4 cascaded hydro and 3 wind units is analyzed to demonstrate the results. The units are hourly scheduled for the whole one-year period using the proposed algorithm. The forecast errors of day-ahead market prices, natural water inflows, and wind speed are considered. It is assumed that there are no transmission constraints and all units are subject to uniform hourly market prices. The NG infrastructure is shown in Fig. 3. The NG units fed by Pipeline 1 are located in two zones. The yearly NG supply from Zone 1 is limited to 37,200 MMCF. NG contracts are shown in Table 6. The yearly constraint for Pipeline 1 is 155,000 MMCF. The detailed generating unit data, and market prices for energy and ancillary services are given in http://motor.ece.iit.edu/data/WindBCPBUC. The Monte Carlo method is used to initially generate 100 scenarios, which are reduced to 12 final scenarios since the objective function does not change much based on this number of scenarios [15]. A 2% of the nominal power of wind unit (i.e., 4 MW) is used in scenarios as the standard deviation of wind forecast error. The study cases are listed in Table 7.

In Cases 2 and 3, the weekly BC energy is fixed at 50,750 MW h. In Case 4, BC energy is varied between 28,000 and 58,500 MW h for calculating the optimal weekly BC. The BC energy price is 46 $/MW h and the penalty price for deficient energy is 200 $/MW h. The risk neutral algorithm without the risk constraints is run first for each case. If the financial risk value is greater than zero for a specific case, the risk constrained algorithm is run to reduce the risk.

4.2.1. Case 1

The PBUC algorithm is applied to schedule the GENCO units considering hourly market prices, natural water inflows, and available wind generation. There is no BC and coordination in this case which means that all of the GENCO's units are separately scheduled considering only the hourly energy market price forecasts. When the risk-neutral algorithm is considered, the expected payoff is $312,025,369 and the downside risk is $5335,124 with a probability of 0.46. The individual payoff of NG, hydro, and wind units are calculated as $102,843,689, $98,896,229 and $110,285,448, respectively. When the downside risk is considered as constraint, the downside risk is decreased by 3.97% to $5123,521. The expected payoff would drop by 0.09% to decrease the expected downside risk.

Table 1
Optimal schedule with No BCs and no coordination.

	Hours	$t = 1$	$t = 2$	$t = 3$
Scenario 1	Available Wind Power	100	150	170
	NG unit dispatch	0	0	0
Scenario 2	Available Wind Power	80	130	150
	NG unit dispatch	0	0	0
Expected payoff		$6900 = 20 * 420 * 50% + 15 * 360 * 50%		

Table 2
Optimal schedule with 400 MW h BC and no coordination.

	Hours	t = 1	t = 2	t = 3
Scenario 1	Available Wind Power	100	150	170
	NG unit dispatch	0	0	0
Scenario 2	Available Wind Power	80	130	150
	NG unit dispatch	0	0	0
BC (MW)		400		
Expected payoff		\$6800 = (400 * 18 + 20 * 20) * 50% + (400 * 18–30 * 40) * 50%		

Table 3
Optimal schedule of 400 MW h BC with wind-NG coordination.

	Hours	t = 1	t = 2	t = 3
Scenario 1	Available wind power	100	150	170
	NG unit dispatch	200	0	0
Scenario 2	Available wind power	80	130	150
	NG unit dispatch	55	0	0
BC (MW)		400		
Expected payoff		\$7090 = (400 * 18 + 220 * 20 + 200 * (−19)) * 50% + (400 * 18 + 15 * 15–55 * 19) * 50%		

Table 4
Optimal schedule of BC with wind-NG coordination.

	Hours	t = 1	t = 2	t = 3
Scenario 1	Available Wind Power	100	150	170
	NG unit dispatch	200	200	200
Scenario 2	Available Wind Power	80	130	150
	NG unit dispatch	55	55	55
BC (MW)		400		
Expected payoff		\$7132.5 = (525 * 18 + 495 * 20–200 * 3 * 19) * 50% + (525 * 18–55 * 3 * 19) * 50%		

Table 5
Three hours payoff and risk summary.

Cases	Expected payoff (\$)	Expected risk (\$)
1: No wind-NG coordination and No BC	6900	750
2: No Wind-NG coordination with fixed BC	6800	450
3: Wind-NG coordination with fixed BC	7090	260
4: Wind-NG coordination with optimized BC	7132.5	292.5

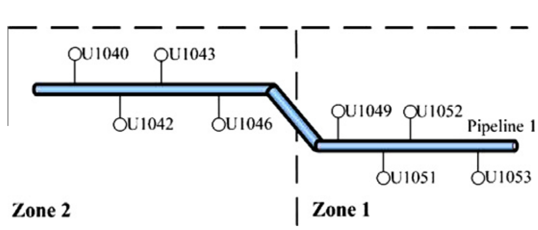

Fig. 3. NG infrastructure.

4.2.2. Case 2

The hydro units are considered for supplying the weekly BC in 1 year. The GENCO makes penalty payments at certain weeks when water inflows are lower. This condition leads to a negative payoff of \$69,913,914 for hydro units. The expected payoff drops by 54% to \$143,215,223 in comparison to that in Case 1. The downside risk increases to \$168,784,777 that is due to penalty payments. The hydro units are supposed to deliver 2639 GW h of BC energy in 52 weeks. However, due to water shortages the GENCO is subject to penalty payments. When hydro units supply BC, the expected payoff drops as compared to that in Case 1 and scenario payoffs are below the target. The risk constraints are not considered since the expected payoff is well below the target.

Table 6
NG Contracts.

Pipeline #	Contract #	Type	Amount (MMCF)	Cost or price
1	1	Firm	36,000	\$70,200,000
1	2	Interruptible	117,500	\$2170/MMCF

4.2.3. Case 3

One NG unit is coordinated with cascaded hydro units for delivering a fixed weekly BC. The expected payoffs for NG and hydro units are calculated as \$106,080,484 and \$98,984,802, while the wind schedule remains unchanged when the risk neutral case is considered. The hydro unit payoff increases by \$168,898,716 when one NG unit is considered additionally to satisfy BC and prevent penalty payments. The added NG would relax the reliance on uncertain water inflows for supplying BC. The total NG units payoff increases by \$3236,795; however, the payoff of individual NG units could decrease based on day-ahead and BC prices as in the 3-h example. The coordination of NG and hydro units would decrease

Table 7
1 Year study cases.

Case	Coordination of units	BC Energy
1	–	None
2	4 Hydro	Fixed
3	4 Hydro + 1 NG	Fixed
4	4 Hydro + 1 NG + 3 Wind	Fixed
5	4 Hydro + 1 NG + 3 Wind	Optimized

the risk by 49.4% to $2702,192 as compared to that in Case 1 when a risk-neutral algorithm is considered. This case indicates that the BC's constant price and energy would reduce the GENCO's financial risk when NG units with given fuel conditions is added to the BC coordination. The NG unit would supply BCs in the case of water shortages. The risk could be further decreased by considering risk as a constraint in the formulation as will be shown in Table 8.

4.2.4. Case 4

Wind units are further added to the coordination of 4 cascaded hydro and 1 NG unit. The expected payoff increases to $333,540,888. The payoffs for NG, hydro, and wind units are $110,038,248, $102,830,699,and $120,671,941, respectively. The wind units would increase payoffs by supplying BC and offering energy to the day-ahead market. Hence, the coordination would enhance the GENCO's midterm scheduling and lead to higher payoffs and lower risks.

Fig. 4 shows that the wind forecast error has a crucial impact on a GENCO's financial risk. Here, the target payoff is updated to $333,000,000 since the coordination has increased the expected payoff in Case 4. In Fig. 4, the financial risk is $ 2954,180 when wind forecast error is taken zero. In this case, the uncertainty of water inflow and market price is considered. The risk increases as a nonlinear response to the higher uncertainty. The lowest achievable downside risk is $11,584,835 for a 5% standard deviation. In Fig. 4, if the number of coordinated NG units is increased to 5, the downside risk would be lower. Here, the additional NG units would increase the chance of mitigating financial risks pertaining to wind units. The lowest achievable downside risk is reduced to $5619,520. Moreover, the NG schedule is analyzed as we increase the wind uncertainty in the 4 Hydro, 1 Wind, and 5 NG case.

Fig. 5 depicts the NG utilization as a function of wind forecast error. The figure shows that there is higher utilization as wind uncertainty increases. It becomes more profitable to schedule the additional NG in order to satisfy BC and maximize the payoff. In addition, NG utilization is lowered for a fixed 1% standard deviation of wind forecast error in order to minimize the risk in the risk-constrained case. However, reduction in NG utilization is less significant as we increase the wind uncertainty, since the

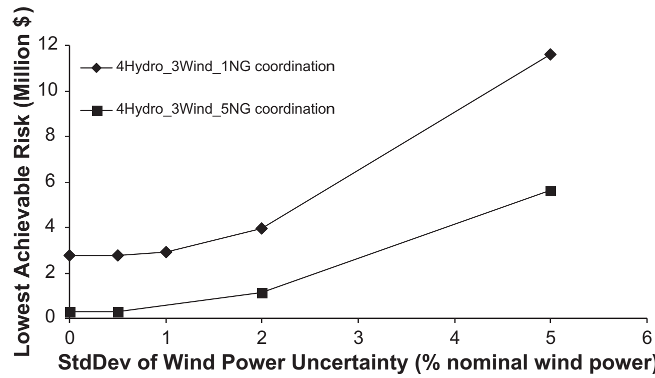

Fig. 4. Financial risks versus wind forecast errors for coordination cases.

additional NG units cannot lower the risk effectively. Consequently, GENCO would have to update its target payoff. A higher level of NG is utilized for 10% uncertainty as compared with the 1% case even though the total delivered energy is lower. This is because the NG units are committed at additional hours in the 10% case but produce less energy resulting in a lower total energy.

4.2.5. Case 5

In addition to the coordination in Case 4, the weekly BC energy is varied here between 28,000 and 58,500 MW h. The expected payoff increases to $334,308,722. Fig. 6 shows the optimal weekly BC energy in which the BC is higher (lower) in weeks with lower (higher) day-ahead energy price forecasts.

4.2.6. Discussions

The results are summarized in Table 8. In Case 1, the generation is offered only to the day-ahead market with a target payoff of

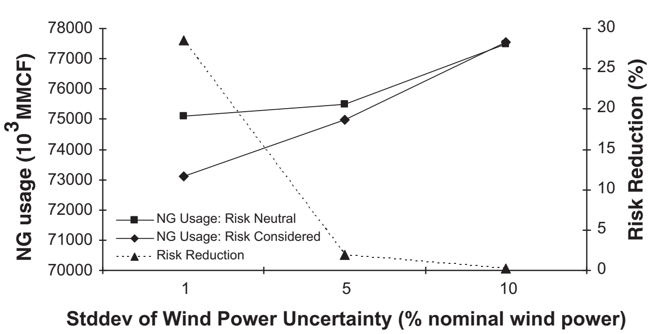

Fig. 5. Total NG utilization versus wind forecast errors.

Table 8
Comparison of cases 1–5 results (Target Payoff ıs $312,000,000).

Coordination of units	Risk neutral results ($)		Risk constrained results ($)	
	Expected payoff	Downside risk	Expected payoff	Downside risk
1: No Coordination and No BC	312,025,369	5335,124	311,752,084	5123,521
2: 4 Hydro	143,215,223	168,784,777	–	–
3: 4 Hydro + 1 NG	315,350,734	2702,192	315,077,937	2529,455
4: 4 Hydro + 1 NG + 3 Wind	333,540,888	0	333,540,888	0
5: 4 Hydro + 1 NG + 3 Wind, Variable BC	334,308,722	0	334,308,722	0

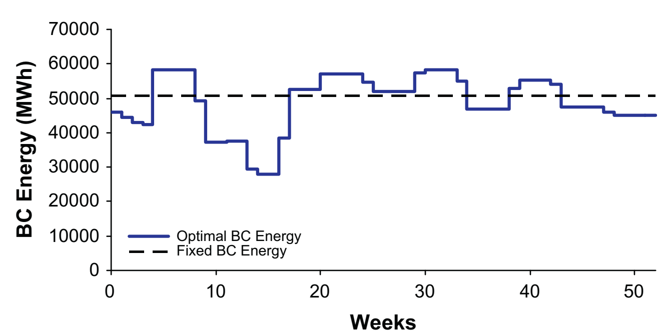

Fig. 6. Optimal BC energy.

$312,000,000. When hydro units are committed to satisfy the BC in Case 2, the expected payoff decreases since water inflow resources are insufficient, and the GENCO is subject to penalty payments if NG and wind unit schedules are the same as those in Case 1. One NG unit is coordinated with cascaded hydro units in Case 3 when the expected payoff is higher than that in Case 1 with a lower financial risk. The coordination will avoid penalty payments and offer energy to the day-ahead market when it is profitable. The wind units are also coordinated in Case 4 which increases the flexibility to satisfy the BC energy and leads to a higher expected payoff and zero downside risk. In Case 5, the weekly BC energy is optimized in one year. Table 8 shows that the BC coordination will reduce risks and increase expected payoffs when compared to Case 1. Notice that all of the GENCO's units are scheduled in each case, the difference between cases is the units considered in BC coordination. These units are given in "Coordination of Units" column of Table 8.

5. Conclusions

A small system demonstration is included to introduce the concept of coordination. Case studies show that BCs could adversely affect the expected payoff and financial risk of the GENCO when only hydro units with uncertain water inflows are considered. The expected payoff increases and the financial risk decreases with the addition of NG and wind units to the coordination. The observations are given as follows:

- Wind forecast uncertainty has a major impact on the midterm operation of power systems. A GENCO should utilize accurate forecasting tools to obtain a sound financial perspective since the financial risk increases nonlinearly with increments in wind power forecast uncertainty.
- Forward BCs could hedge GENCOs' risks when GENCOs are subject to volatile market prices.
- NG units would add flexibility for satisfying BCs in the midterm operation planning.
- A GENCO could utilize the proposed PBUC algorithm in a volatile environment to calculate its highest expected payoff in coordination with BCs.
- NG utilization increases in the risk-neutral case as the wind uncertainty increases. In the risk-constrained case, when the wind uncertainty is lower, the NG utilization is decreased in order to decrease the financial risk. However, a lower NG is not utilized when wind uncertainties are higher. GENCO should determine its target payoff carefully when the wind uncertainty is higher.
- GENCOs can use the proposed algorithm for the midterm planning of generating assets and bidding strategies.

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