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# Robust Operation Planning With Participation of Flexibility Resources Both on Generation and Demand Sides Under Uncertainty of Wind-based Generation Units

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**Abstract:** In recent years, the increasing of non-dispatchable resources has posed severe challenges to the operation planning of power systems. Since these resources are random in nature, the issue of flexibility to cover their uncertainty and variability has become an important research topic. Therefore, having flexible resources to cover changes in the generation of these resources during their operation can play an essential role in eliminating node imbalances, system reliability, providing the required flexible ramping capacity, and reducing system operating costs. Among flexibility resources, there are quick-act generation units such as gas units that can play an important role in covering net load changes. Also, on the demand side, the optimal design of demand response programs as responsive resources to price and incentive signals, by modifying the system load factor can prevent severe ramps at net load, especially during peak load hours, and as a result, increase system flexibility while decreasing operational cost of the power system. In this paper, unlike the existing literature, the effect of the mentioned flexibility resources (both on the generation side and the demand side) in day-ahead operation planning under high penetration of wind generation units has been studied on the IEEE RTS 24-bus test system. Also, for this scheduling, a mixed-integer, two-stage, and tri-level adaptive robust optimization have been used, which is solved by column-and-constraint generation decomposition-based algorithm to clear the energy and ramping capacity reserve jointly.

**Keywords:** Adaptive Robust Optimization, Column-and-Constraint Generation, Flexibility Resources, Non-Dispatchable Resources.

## Nomenclature

### Sets and Indices

| | |
|---|---|
| $B$ | Set of bus indices. |
| $B^w$ | Set of buses indices in which the wind generation unit is located. |
| $B^{EDRP}$ | Set of selected buses to implementing EDRP. |
| $B^{TOU}$ | Set of selected buses to implementing the TOU program. |
| $b$ | Index of buses. |
| $I$ | Set of generation unit indices. |
| $I^{QA/NQA}$ | Set of quick-act/non-quick-act generation units indices. |
| $I_b$ | Set of indices of generation units located at bus $b$. |
| $i$ | Index of generation units. |
| $L$ | Set of indices in power transmission lines. |
| $l$ | Index of power transmission lines |
| $T$ | Set of indices of time periods. |
| $T^{EDRP}$ | Set of indices of time periods that EDRP is implemented. |
| $t$ | Indices of time periods. |
| $Lin$ | Set of linear segments for EDRP cost function. |
| $SG$ | Index of linear segments for EDRP cost function. |

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**Parameters**

$\Delta p_{bt}^{dn}$, $\Delta p_{bt}^{up}$ Maximum down/up fluctuation of wind generation in bus *b* and time *t* [MW].

$\Delta_{bt}^{SG}$ The length of each linearized interval in EDRP.

$C_{it}^{FRD}$, $C_{it}^{FRU}$ Downward/ Upward spinning flexible ramping reserve cost of unit *i* at time *t* [$/MW/h].

$C_{it}^{FRN}$ Non-spinning flexible ramping reserve cost of unit *i* at time *t* [$/MW/h].

$C_{it}^{su}$, $C_{it}^{sd}$ Start-up and shut-down cost of unit *i* at time *t* [$].

$c_i^f$, $c_i^v$ Fixed cost [$] and variable cost [$/MWh] of unit *i*.

$C_{bt}^{\min}$ The minimum cost of participating energy in EDRP [$].

$D_{bt}$ Forecasted demand bus *b* at time *t* [MW].

$E_{tt}$ / $E_{tt'}$ Self /Cross elasticity of demand.

$\overline{F_l}$ Maximum capacity of line *l* [MW].

$fr(l)$ Primary bus of line *l*.

$inc_{bt}^{\min/\max}$ Minimum/Maximum incentive at bus *b* and time *t* for EDRP.

$U$ Parameter related uncertainty budget.

$\underline{P_{it}}$, $\overline{P_{it}}$ Min/max generation capacity of unit *i* at time *t* [MW].

$P_{bt}^w$ Predicted output level of wind generation unit at bus *b* and time *t* [MW].

$pf$ Participation factor of DR programs implementation [%].

$P_t^0$ Initial price of energy before running DR programs in time *t* [$/MWh].

$RD_i$, $RU_i$ Ramp down/up unit *i*.

$SU_i$, $SD_i$ Start-up and shut-down ramp rate unit *i*.

$slp_{bt}^{SG}$ The slope of each linear segment of linearized cost function EDRP.

$to(l)$ End bus of line *l*.

$x_l$ Reactance of line *l*.

**Variables**

$a_{bt}^{up}$, $a_{bt}^{dn}$ Binary variables representing the worst case of wind generation level.

$\theta_{bt}^u$, $\theta_{bt}$ Voltage angle of bus b at time t under uncertainty/ base case.

$\Psi$ The value of power imbalance in the third level problem.

$\Psi^w$ Worst-case of system imbalance

$W_{bt}^{-u}$, $W_{bt}^{+u}$ Continuous variables indicating the value of power imbalance at bus *b* and time *t* under uncertainty condition.

$\delta_{bt}^{SG}$ The amount of incentive in each interval segment associated EDRP cost function.

$c_{it}^{sd}$, $c_{it}^{su}$ Cost of shut-down and start-up of unit *i* at time *t*.

$C_{bt}^{EDRP}$ Hourly cost of EDRP at bus *b*.

$d_{bt}^{dr}$ Demand after implementing DR programs in bus *b* and time *t*.

$inc_{bt}$ The amount of incentive paid to EDRP participants in bus *b* and time *t*.

$EDRP_{bt}$ Demand reduction by EDRP in bus *b* and time *t*.

$FRU_{it}$, $FRD_{it}$ Upward/downward spinning flexible ramping reserve provided by unit *i* at time *t*.

$FRN_{it}$ Non-spinning flexible ramping reserve provided by quick-act unit *i* at time *t*.

$f_{lt}^u$, $f_{lt}$ Power flow rate of line *l* at time *t* under uncertainty/base case.

$of$ The value of the objective function related the minimum operating cost.

$P_{it}^u$, $P_{it}$ Generation level of unit *i* at time *t* under uncertainty/base case.

$P_{it}^{wu}$ Level of wind power generation under uncertainty.

$P^{val/off/pk}$ Valley/ off-peak/ peak energy tariffs in TOU program.

$TOU_{bt}$ Demand reduction by TOU program.

$v_{it}$ Binary variable indicating the scheduling status of generation units in base case.

$v_{it}^{st}$, $v_{it}^{sd}$ Binary variables indicating on/off status of quick-act units under uncertainty conditions.

$v_{bt}^{SG}$ Binary variable indicating participation status of load in bus *b* and time *t* for EDRP.

## 1 Introduction

IN recent years, the maximum use of renewable energy resources as a principle not only in the planning of future power systems, but also as an essential factor in promoting security and energy independence of communities, has been considered by power system operators. In such a way that many governments are looking to get more than half of their electricity needs from these resources within the next ten years [1]. Therefore, the traditional operation of power systems will not meet the high penetration of renewable resources; because, in the operation of power systems with high capacity of these resources, in addition to the uncertainty in power generation, their high variability, the short-term operation will face serious problems. It should be noted that uncertainty indicates prediction error, and variability refers to changes in time-variable generation of these resources. Thus, the main problem is the existence of sufficient generation capacity along with the lack of ramping capacity, which leads to imbalance of load and generation, and shutdown or operation of thermal units outside the optimal operation point, which has made the short-term flexibility as an important issue in power system day-ahead operation planning. For this purpose, in the ancillary services market, the flexible ramping product (FRP) was introduced to cover the random generation of renewable energy resources [2]. Conventional generation resources are among the providers of this type of reserve, which according to their technical and economic characteristics, including generation capacity, ramping rate, minimum up time and minimum down time and the costs of energy and reserve, start-up and shutdown, participate in power system day-ahead scheduling [3, 4]. For day-ahead scheduling, independent system operators schedule the system by solving a unit commitment (UC) problem, which results in the optimal generation scheduling [2]. Also, increasing the penetration of renewable energy resources, in the generation side has created an opportunity for flexible and quick-act resources such as gas generation units and diesel turbines in wholesale electricity markets so that in addition to non-quick-act units, the potential of such resources in day-ahead generation scheduling can provide the required flexibility of the power system.

On the other hand, Demand Response Programs (DRPs) on the demand side can convert demand-side resources, which are the consumers of electricity, into active and responsive resources to price and incentive signals, which can lead to significant correction of the system load factor that can increase the ability of the system to respond to the uncertainties of renewable resources and ramp events, while significantly reducing the cost of operating the system [5, 6]. Demand response can be in the form of reductions, changes in energy consumption, or both, depending on the price elasticity of consumer's demand for electricity. Also, the capacity provided by demand response resources, particularly during peak periods, can be used as an alternative to expensive power plants with high ramping capacity, which will naturally increase social welfare and reduce electricity prices. Demand response programs can be classified into two categories: Incentive-Based Programs (IBPs) and Time-Based Programs (TBPs). Incentive programs are divided into three main subgroups, including voluntary, mandatory, and market clearing programs. Also, in time-based programs, the price of electricity will change at different intervals in proportion to the price of electricity supply. These programs do not provide any penalties or incentives [7].

According to what was provided, some of the contributions of this article about day-ahead operation planning are:

- Separating generation resources in the form of quick and non-quick-act generation units, based on their speed response to make optimal use of their ramping capacity.
- The optimal design of demand response programs in day-ahead scheduling as flexibility resources in demand side for enhancing system flexibility, including incentive and time-based programs.
- Using two-stage and tri-level adaptive robust optimization based on the column-and-constraint generation (CCG) decomposition method for mentioned day-ahead scheduling problem, which, due to the existence of optimality primal cuts of the problem type, has a high convergence speed.

Accordingly, the rest of this paper is organized as follows: Section 2 provides the tri-level robust operation planning model. In Section 3, the problem-solving approach is proposed. Section 4 is allocated to a comprehensive case study. Numerical results and conclusions will be presented in Sections 5 and 6, respectively.

## 2 Problem Formulation

Problem formulation in this paper is tri-level Mixed Integer Programming (MIP). In the following, each level of the problem formulation will be introduced.

### 2.1 First Level Problem

$$of = \min \left\{ \sum_{i\in I}\sum_{t\in T} \begin{bmatrix} c_i^f v_{it} + c_i^v p_{it} + c_{it}^{su} \\ + c_{it}^{sd} + C_{it}^{FRU} FRU_{it} \\ + C_{it}^{FRD} FRD_{it} \end{bmatrix} + \sum_{i\in I^{QA}}\sum_{t\in T} C_{it}^{FRN} FRN_{it} + \sum_{b\in \mathrm{B}^{EDRP}}\sum_{t\in T^{EDRP}} C_{bt}^{EDRP} \right\} \quad (1)$$

$$\sum_{i\in I_b} p_{it} + \sum_{l\in L|to(l)=b} f_{lt} - \sum_{l\in L|fr(l)=b} f_{lt} = d_{bt}^{dr} - p_{bt}^{w};\ \forall b\in \mathrm{B}, \forall t\in T \quad (2)$$

$$f_{lt} = \frac{1}{x_l}\left(\theta_{fr(l)t} - \theta_{to(l)t}\right);\ \forall l\in L, \forall t\in T \quad (3)$$

$$-\bar{F}_l \le f_{lt} \le \bar{F}_l; \forall l\in L, \forall t\in T \quad (4)$$

$$v_{it}^{st} \le 1 - v_{it}; \forall i\in I^{QA}, \forall t\in T \quad (5)$$

$$v_{it}^{sd} \le v_{it}; \forall i\in I^{QA}, \forall t\in T \quad (6)$$

$$\underline{p}_{it} v_{it} \le p_{it} \le \bar{p}_{it} v_{it}; \forall i\in I, \forall t\in T \quad (7)$$

$$p_{it} + FRU_{it} \le \bar{p}_{it} v_{it}; \forall i\in I, \forall t\in T \quad (8)$$

$$p_{it} - FRD_{it} \ge \underline{p}_{it} v_{it}; \forall i\in I^{NQA}, \forall t\in T \quad (9)$$

$$\underline{p}_{it}\left(v_{it} - v_{it}^{sd}\right) \le p_{it} - FRD_{it} \le \bar{p}_{it}(v_{it} - v_{it}^{sd});\ \forall i\in I^{QA}, \forall t\in T \quad (10)$$

$$0 \le FRN_{it} \le SU_i v_{it}^{st};\ \forall i\in I^{QA}, \forall t\in T \quad (11)$$

$$FRD_{it} \le SD_i + \bar{p}_{it}(1 - v_{it}^{sd});\ \forall i\in I^{QA}, \forall t\in T \quad (12)$$

$$p_{it} + FRU_{it} - \left(p_{it-1} - FRD_{it-1}\right) \le RU_i v_{it-1} + SU_i\left(v_{it} - v_{it-1}\right) + \bar{p}_{it}(1 - v_{it});\ \forall i\in I^{NQA}, \forall t\in T \quad (13)$$

$$p_{it-1} + FRU_{it-1} - \left(p_{it} - FRD_{it}\right) \le RD_i v_{it} + SD_i\left(v_{it-1} - v_{it}\right) + \bar{p}_{it}(1 - v_{it-1});\ \forall i\in I^{NQA}, \forall t\in T \quad (14)$$

$$p_{it} + FRU_{it} + FRN_{it} - \left(p_{it-1} - FRD_{it-1} + FRN_{it-1}\right) \le RU_i\left(v_{it-1} + v_{it-1}^{st} - v_{it-1}^{sd}\right) + \bar{p}_{it}(1 - v_{it-1} - v_{it-1}^{st} + v_{it-1}^{sd});\ \forall i\in I^{QA}, \forall t\in T \quad (15)$$

$$p_{it-1} + FRU_{it-1} + FRN_{it-1} - \left(p_{it} - FRD_{it} + FRN_{it}\right) \le RD_i\left(v_{it} + v_{it}^{st} - v_{it}^{sd}\right) + \bar{p}_{it}(1 - v_{it} - v_{it}^{st} + v_{it}^{sd});\ \forall i\in I^{QA}, \forall t\in T \quad (16)$$

$$p_{it} + FRU_{it} + FRN_{it} \le SU_i \left(1 - v_{it-1} + v_{it-1}^{sd} - v_{it-1}^{st}\right) + \overline{p}_{it}(v_{it-1} - v_{it-1}^{sd} + v_{it-1}^{st}); \quad \forall i \in I^{QA}, \forall t \in T \tag{17}$$

$$p_{it-1} + FRU_{it-1} + FRN_{it-1} \le SD_i \left(1 - v_{it} + v_{it}^{sd} - v_{it}^{st}\right) + \overline{p}_{it}(v_{it} - v_{it}^{sd} + v_{it}^{st}); \quad \forall i \in I^{QA}, \forall t \in T \tag{18}$$

$$TOU_{bt} = D_{bt}\left( E_{tt} \frac{\left(pr^{val/off/pk} - pr_t^0\right)}{pr_t^0} + \sum_{\substack{t'=1 \\ t' \ne t}}^{24} E_{tt'} \frac{\left(pr^{val/off/pk} - pr_{t'}^0\right)}{pr_{t'}^0} \right); \quad \forall b \in \mathrm{B}^{TOU}, \forall t \in \mathrm{T} \tag{19}$$

$$0.5 pr_t^0 \le pr^{val} \le pr_t^0 ; \forall t \in T^{val} \tag{20}$$

$$pr_t^{val} \le pr^{off} \le pr_t^{pk} ; \forall t \in T^{off} \tag{21}$$

$$pr^{pk} \ge pr_t^0 ; \forall t \in T^{pk} \tag{22}$$

$$TOU_{bt} \le pfD_{bt} ; \forall b \in \mathrm{B}^{TOU}, \forall t \in \mathrm{T} \tag{23}$$

$$TOU_{bt} \ge -pfD_{bt} ; \forall b \in \mathrm{B}^{TOU}, \forall t \in \mathrm{T} \tag{24}$$

$$\sum_{t \in T} TOU_{bt} = 0; \forall \mathrm{b} \in \mathrm{B}^{TOU} \tag{25}$$

$$inc_{bt}^{min} \le inc_{bt} \le inc_{bt}^{max} ; \forall b \in \mathrm{B}^{EDRP}, \forall t \in T^{EDRP} \tag{26}$$

$$C_{bt}^{EDRP} = C_{bt}^{min} v_{bt}^1 + \sum_{SG \in Lin} slp_{bt}^{SG} \delta_{bt}^{SG} ; \forall b \in \mathrm{B}^{EDRP}, \forall t \in T^{EDRP} \tag{27}$$

$$inc_{bt} = inc_{bt}^{min} v_{bt}^1 + \sum_{SG \in Lin} \delta_{bt}^{SG} ; \forall b \in \mathrm{B}^{EDRP}, \forall t \in T^{EDRP} \tag{28}$$

$$0 \le \delta_{bt}^{SG} \le \Delta_{bt}^{SG} v_{bt}^{SG} ; \forall b \in \mathrm{B}^{EDRP}, \forall t \in T^{EDRP}, \forall SG \in Lin \tag{29}$$

$$EDRP_{bt} = D_{bt}\left( E_{tt} \frac{inc_{bt}}{pr_t^0} + \sum_{\substack{t'=1 \\ t' \ne t}}^{24} E_{tt'} \frac{inc_{bt'}}{pr_{t'}^0} \right); \forall b \in \mathrm{B}^{EDRP}, \forall t \in T \tag{30}$$

$$EDRP_{bt} \le pfD_{bt} ; \forall b \in \mathrm{B}^{EDRP}, \forall t \in \mathrm{T} \tag{31}$$

$$EDRP_{bt} \ge -pfD_{bt} ; \forall b \in \mathrm{B}^{EDRP}, \forall t \in \mathrm{T} \tag{32}$$

$$\sum_{b \in \mathrm{B}} TOU_{bt} + EDRP_{bt} \le pf \sum_{b \in \mathrm{B}} D_{bt} ; \forall t \in \mathrm{T} \tag{33}$$

$$\sum_{b \in \mathrm{B}} TOU_{bt} + EDRP_{bt} \ge -pf \sum_{b \in \mathrm{B}} D_{bt} ; \forall t \in \mathrm{T} \tag{34}$$

$$d_{bt}^{dr} = D_{bt} + TOU_{bt} + EDRP_{bt} ; \forall b \in \mathrm{B}, \forall t \in T \tag{35}$$

$$\left\{c_{it}^{su}\right\}_{t \in T}, \left\{c_{it}^{sd}\right\}_{t \in T}, \left\{v_{it}\right\}_{t \in T} ; \forall i \in I \tag{36}$$

$$FRU_{it} \ge 0, FRD_{it} \ge 0, FRN_{it} \ge 0; \; \forall i \in I, \forall t \in T \tag{37}$$

In the first level problem, the objective function (1) and constraints (2)-(37) include the dispatch and scheduling of energy and flexible ramping capacity reserve and optimal DRPs implementation with the minimum cost of reliable operation under the uncertainty of wind generation units. In the objective function (1), the costs related to generation costs in the base case, start-up, and shut-down of generation units, as well as the costs related to scheduling under uncertainty including upward and downward spinning ramping capacity reserve costs of the non-quick-act and quick-act units and non-spinning ramping capacity reserve cost of quick-act units and cost of optimal incentive-based DRP, are minimized. Constraints (2)-(4) represent the limitations of the transmission network in the base case, i.e. the amount of predicted net load. Constraint (2) relates to nodal power balance. Constraints (3) and (4) also represent the DC power flow and transmission lines capacity, respectively. Due to the ability of quick-act units to provide ramping capacity around their power output in a short period of time, constraints (5) and (6), including start-up binary variables ( $v_{it}^{st}$ ) and shut-down binary variables ( $v_{it}^{sd}$ ), have been presented. Constraint (7) indicates the power generation limits in the base case. Constraints (8)-(10) are related to the spinning ramping capacity reserve, which can be provided by non-quick and quick-act generation units according to their allowed generation limits ($FRU_{it}$, $FRD_{it}$). In addition, constraint (10) indicates that if a quick-act unit is scheduled as shut-down in uncertainty realization condition, it must be able to provide a downward ramping capacity within its power output limit. Constraint (11) states that if the quick-act unit had been scheduled off in the base case, it can provide a ramping capacity equal to its start-up ramp rate in operation condition ($FRN_{it}$). Constraint (12) represents that if due to the uncertainty realization, it is needed for the shut-down quick-act unit, it can provide ramping capacity to its shut-down ramp rate. Constraints (13)-(18) are related to the ability to change the power between two consecutive times by non-quick and quick-act units in the base case and operation condition due to their ramping constraints, which can be provided by them. As mentioned, demand response programs can play an essential role in increasing system flexibility by modifying the system load factor and preventing severe ramps in net load. Therefore, in this paper, Time of Use (TOU) and Emergency Demand Response Program (EDRP) as time-based and incentive-based DR programs, respectively, have been considered. Constraints (19)-(34), Express the use of EDRP and TOU programs together. It should be noted that the EDRP program is voluntary and free of charge in which participants reduce their consumption in exchange for optimal amounts of incentives. Also, in the TOU program, based on energy consumption tariffs in at least three periods, including valley, off-peak, and peak periods, consumers will change their consumption patterns. Constraints (19)-(25) refer to the economic model of the TOU program. Constraint (19) represents the changes in the system load according to the approved price signals in three different periods, including the valley, off-peak, and peak period that consumers change their consumption pattern following these signals, self and cross elasticity. Constrains (20)-(22) refer to the pricing policy adopted in the TOU program. In constraints (23) and (24), the maximum amount of participation considered for the TOU program has been presented, either to reduce or increase the load. Constraint (25) states that any amount of reduced load in each time period must be compensated in other periods; In other words, in the TOU program, the amount of energy consumed in the 24-hour scheduling period must be constant. Constraints (26)-(32) indicate the use of EDRP. According to constrain (38) in this program, the amount of load reduction (LR) by consumers in each time is proportional to the amount of incentives paid for them:

$$LR_{bt} = E_{tt}\frac{inc_{bt}}{pr_t^0}; \quad \forall b \in \mathrm{B}^{EDRP}, \forall t \in T^{EDRP} \tag{38}$$

Therefore, the cost of participation is obtained by multiplying the reduced load and the amount of incentive considered for each MWh of energy, which can be seen in constraint (39):

$$C_{bt}^{EDRP} = E_{tt}\frac{{inc_{bt}}^2}{pr_t^0}; \quad \forall b \in \mathrm{B}^{EDRP}, \forall t \in T^{EDRP} \tag{39}$$

So constraints (26)-(29) represent the piecewise linearization technique based on [25] for cost function in constraint (39). Constraint (30) represents the changes in the system load according to the incentive signals, self, and cross elasticity. In constraints (31) and (32), the maximum amount of participation considered for EDRP has been presented, either to reduce or increase the load. Constraints (33) and (34) also indicate that the amount of participation considered for demand response programs (TOU and EDRP) totally per hour should not exceed the predetermined amount, either to increasing or decreasing in load goes beyond. Constraint (35) indicates the amount of system load after implementing demand response programs, including TOU and EDRP programs. Constraint (36) indicates the minimum up/downtime, and start-up and shut-down costs of generation units, and related details are provided in Appendix [26]. Constraint (37) indicates that the variables related to spinning and non-spinning ramping reserve capacity are non-negative.

### 2.2 Second Level Problem

$$\Psi^w = \max \ \Psi \tag{40}$$

Subject to:

$$a_{bt}^{up} + a_{bt}^{dn} \le 1; \forall b \in \mathrm{B}^w, \forall t \in T \tag{41}$$

$$p_{bt}^w - \Delta p_{bt}^{dn} a_{bt}^{dn} \le p_{bt}^{wu} \le p_{bt}^w + \Delta p_{bt}^{up} a_{bt}^{up}; \forall b \in \mathrm{B}^w, \forall t \in T \tag{42}$$

$$\sum_{b \in \mathrm{B}^w}\left[\frac{\max\left\{0, p_{bt}^{wu} - p_{bt}^w\right\}}{\Delta p_{bt}^{up}} + \frac{\max\left\{0, p_{bt}^w - p_{bt}^{wu}\right\}}{\Delta p_{bt}^{dn}}\right] \le U; \quad \forall t \in T \tag{43}$$

The objective function (40) and constraints (41)-(43) represent the second-level problem. The objective function (40) identifies the worst-case for nodal power imbalance concerning the decisions made in the first level problem. Constraints (41)-(43) represent the use of budget-constrained polyhedral uncertainty set in which parameter $U$ represents the uncertainty budget and indicates the number of buses that simultaneously experience fluctuations in the wind power output and is determined based on the predicted uncertainty. Binary variables $a_{bt}^{up}$ and $a_{bt}^{dn}$ are presented to assess the worst-case scenario for up/ down fluctuations of wind generation units due to the uncertainty budget. Since a wind unit cannot experience both up and down fluctuations simultaneously, constraint (41) has been represented.

### 2.3 Third Level Problem

$$\Psi = \min \sum_{b \in \mathrm{B}}\sum_{t \in T} W_{bt}^{-u} + W_{bt}^{+u} \tag{44}$$

Subject to:

$$\sum_{i \in I_b} p_{it}^u + \sum_{l \in L|to(l)=b} f_{lt}^u - \sum_{l \in L|fr(l)=b} f_{lt}^u = d_{bt}^{dr} - p_{bt}^w - \Delta p_{bt}^{up} a_{bt}^{up} + \Delta p_{bt}^{dn} a_{bt}^{dn} + \mathrm{W}_{bt}^{-u} - \mathrm{W}_{bt}^{+u}; \ \forall b \in \mathrm{B}, \forall t \in T \tag{45}$$

$$f_{lt}^u = \frac{1}{x_l}\left(\theta_{fr(l)t}^u - \theta_{to(l)t}^u\right); \ \forall l \in L, \forall t \in T \tag{46}$$

$$-\overline{F}_l \le f_{lt}^u \le \overline{F}_l; \forall l \in L, \forall t \in T \tag{47}$$

$$p_{it} - FRD_{it} \le p_{it}^u \le p_{it} + FRU_{it}; \ \forall i \in I^{NQA}, \forall t \in T \tag{48}$$

$$p_{it} - FRD_{it} \le p_{it}^u \le p_{it} + FRU_{it} + FRN_{it}; \ \forall i \in I^{QA}, \forall t \in T \tag{49}$$

$$W_{bt}^{-u} \ge 0, W_{bt}^{+u} \ge 0; \forall b \in \mathrm{B}, \forall t \in T \tag{50}$$

In objective function (44), the variables of nodal power imbalance under uncertainty realization conditions are minimized according to the decisions made in the first and second level problem. Constraints (45)-(47) represent the nodal power balance, power flow, and transmission lines capacity under uncertainty conditions, respectively. Constraints (48) and (49) indicate the level of power generation of non-quick and quick-act units under uncertainty realization conditions and decisions made in the first level problem. Constraint (50) also shows that the nodal power imbalance variables are non-negative.

### 2.4 Master Problem

The master problem is the relaxed version of the problem (1)-(50). The master problem refers to the first stage in which, for iterations $k > 1$, a set of constraints related to operating conditions is added and is equivalent to constraints (45)-(49). It should be noted that these constraints are parameterized by the sub-problem solved in the previous iteration. Therefore, the master problem in iteration $k$ is as follows:

$$\text{Objective Function } (1) \quad (51)$$

Subject to:

$$\text{Constraints } (2)\text{-}(37) \quad (52)$$

$$\sum_{i\in I_b} p_{it}^m + \sum_{l\in L|to(l)=b} f_{lt}^m - \sum_{l\in L|fr(l)=b} f_{lt}^m = d_{bt}^{dr} - p_{bt}^w$$
$$-\Delta p_{bt}^{up} a_{bt}^{up(m)} + \Delta p_{bt}^{dn} a_{bt}^{dn(m)}; \quad \forall b\in \mathrm{B}, \forall t\in T,$$
$$m = 1,\ldots,k-1 \quad (53)$$

$$f_{lt}^m = \frac{1}{x_l}\left(\theta_{fr(l)t}^m - \theta_{to(l)t}^m\right); \ \forall l\in L, \forall t\in T,$$
$$m = 1,\ldots,k-1 \quad (54)$$

$$-\bar{F}_l \le f_{lt}^m \le \bar{F}_l; \forall l\in L, \forall t\in T, m=1,\ldots,k-1 \quad (55)$$

$$p_{it} - FRD_{it} \le p_{it}^m \le p_{it} + FRU_{it}; \quad \forall i\in I^{NQA}, \forall t\in T,$$
$$m = 1,\ldots,k-1 \quad (56)$$

$$p_{it} - FRD_{it} \le p_{it}^m \le p_{it} + FRU_{it} + FRN_{it}; \quad \forall i\in I^{QA},$$
$$\forall t\in T, m=1,\ldots,k-1 \quad (57)$$

### 2.5 Subproblem

The sub-problem refers to the second stage and includes the max-min model of the second and third level problems, which is converted to the single level maximization model using dual theory and represents the realized uncertainties that lead to the maximum imbalance in the system according to the decision made in the master problem. It should be noted that in each iteration $k$, the outputs of the master problem including $p_{it}^{(k)}$, $FRD_{it}^{(k)}$, $FRU_{it}^{(k)}$, $FRN_{it}^{(k)}$, and $d_{bt}^{dr(k)}$ enter the sub-problem where the worst-case of nodal power imbalance is determined by binary variables $a_{bt}^{up}$ and $a_{bt}^{dn}$, these binary variables return to the master problem for the next iteration.

## 3 Solution Methodology

Fig. 1 shows the problem-solving procedure according to the iterative method based on column and constraint generation (CCG) algorithm. In this method, in each iteration, the master problem is solved based on the worst-case of nodal power imbalance, under uncertainty budget $U$ obtained by sub-problem in the previous iteration ($k$–1), and co-optimization energy and ramping reserve capacity including fixed and variable generation costs, start-up and shut-down costs and ramping capacity reserve of non-quick and quick-act generation units to cover changes in the net load of the system with considering DRPs and optimal EDRP incentives in the minimum operation cost are done.

A worth point in the problem-solving process is the addition of primal optimality cuts for iteration $k > 1$, including constraints (53)-(57) to the master problem. According to Fig. 1, the problem is repeated until the decision made in the master problem, even in the worst-case scenario, leads to nodal power balance. Therefore, in this case, with the achievement of global optimality, the problem solving process will stop.

## 4 Case Study

To evaluate the effectiveness of non-quick and quick-act generation separation approach along with DRPs in providing the required flexibility of the power system as well as the performance of the proposed solution method, a modified 24-bus IEEE Reliability Test System in [18] is employed which includes 26 thermal generation units, 24 buses, 38 power transmission lines, six wind power generation units, each with 160MW capacity in buses 3, 5, 7, 16, 21, and 23, the maximum system load of 3498.66 MW, and uncertainty of wind power characterized by a ±20% fluctuation around the forecast generation level. Among the 26 thermal units in this test system, six quick-act units, including units 6, 7, 8, 9, 28, and 26, whose non-spinning ramping capacity reserve price has been considered twice the upward spinning ramping capacity reserve price. Assuming the existence of 6 wind generation units, which are the resources of uncertainty, the budget of uncertainty $U$ can have a range of change from 0 to 6; $U$ = 0 and $U$ = 6 indicate the base case and the worst-case of uncertainty realization in the system, respectively. Also, for implementing demand response programs, the power consumption period according to system demand is divided into three periods including valley (00:00-6:00), off-peak (6:00-16:00 and 20:00-24:00), and peak (16:00-20:00), which is based on the electricity consumption tariffs and incentive signals approved by

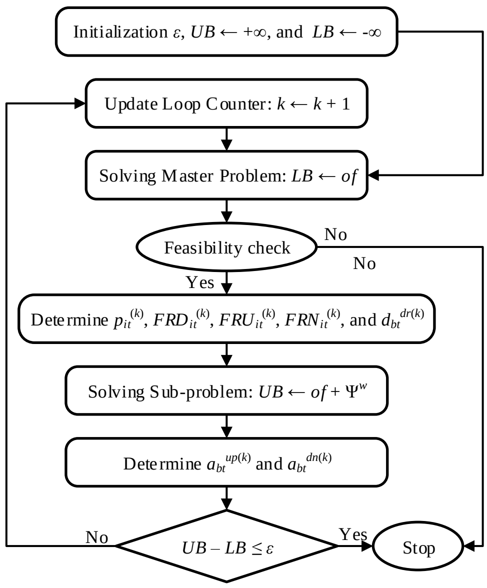


**Fig. 1** CCG problem-solving flowchart.

**Table 1** Price elasticity of demand.

| | Hours | 1-6 | 7-16 | 17-20 | 21-24 |
|---|---|---|---|---|---|
| Valley | 1-6 | -0.1 | 0.01 | 0.012 | 0.01 |
| Off-peak | 7-16 | 0.01 | -0.1 | 0.016 | 0.01 |
| Peak | 17-20 | 0.012 | 0.016 | -0.1 | 0.016 |
| Off-peak | 21-24 | 0.01 | 0.01 | 0.016 | -0.1 |

ISO and also self and cross elasticity, consumers trying to improve their electricity consumption. The price elasticity of the demand according to [7] has been considered as listed in Table 1.

To evaluate the performance of flexible resources, the following scenarios are considered:

1) Non-separating generation units based on their speed of response.
2) Separating generation units based on their speed of response.
3) Implementation scenario 2 using flexible resources on demand side including responsive consumers to TOU and EDRP.

## 5 Numeral Results

In this section, to evaluate the impact of flexibility resources in day-ahead scheduling to providing required flexibility, we first examine scheduling only by considering flexible resources on the generation side and then by considering flexibility resources both on generation and demand sides. MIP optimizations are performed by GAMS software package with CPLEX 12.0 solver on a personal computer powered by a Core i5 CPU processor and 4 GB of RAM. Also, in performed simulations, the optimum accuracy of the master problem and the sub-problem are set to $10^{-3}$ and zero, respectively.

### 5.1 Impact of Quick-Act Generation Resources

In this section, the effectiveness of classifying generation resources in non-quick and quick-act categories on mentioned test system has been investigated. According to Tables 2 and 3, which respectively are related to the unit commitment results in the worst case of uncertainty realization (i.e., $U = 6$) in scenarios 1 and 2, It can be seen that in the scenario of separation generation resources due to their response speed under uncertainty, the need for expensive units such as units 1, 2, 6, 8, and 9, to be online ($v_{it} = 1$) to use their spinning ramping capacity reserve, will decrease since quick-act units with the ability to change the status from off to on and vice versa in a short period of time and providing non-spinning ramping capacity reserve, significantly reduced operating costs. A significant part of these lowered costs is related to fixed and variable costs of generation units. As stated, simulation results show the reduction in operating costs for different amounts of uncertainty budget.

Based on the simulation results, for scenarios 1 and 2, as the uncertainty budget increases, so does the operating cost since there is a need to deploy more ramping capacity reserve to cover changes in the power output of wind units. On the other hand, if we take full advantage of the potential of the ramping capacity of quick-act resources, we will see a reduction in operating costs for different amounts of uncertainty budget; for example, in the worst-case scenario, operating costs were reduced by \$6786.6 or 0.85%. It is worth mentioning that under the worst-case scenario, the robustness cost in the first scenario was (\$803546.9-\$784333.2)/ \$784333.2 = 2.45% which in the second scenario, it decreased to (\$796760.3-\$784333.2)/\$784333.2 = 1.58%. Also, as an example for $U = 6$, Fig. 2 shows the vital role of quick-act resources in the operation time horizon such as peak periods to provide the required flexibility of the power system.

**Table 2** Unit commitment in the first scenario.

| | Number of units | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Hour | 1 | 2 | 3 | 4 | 5 | 6 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 |
| t0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 |
| t1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 0 | 1 |
| t2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 0 | 1 |
| t3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 0 | 1 |
| t4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 0 | 1 |
| t5 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 0 | 1 |
| t6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 0 | 1 |
| t7 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 |
| t8 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 1 | 1 | 1 |
| t9 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t10 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t11 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t12 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t14 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t15 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t16 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t17 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t18 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t19 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t20 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 1 |
| t21 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 1 |
| t22 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 |
| t23 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 |
| t24 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 0 | 1 |

### 5.2 Impact Flexibility Resources both on Generation and Demand sides

In this section, the impact of DRPs as flexible resources in day-ahead scheduling has been discussed. In fact, participants in DRPs act as a responsive

**Table 3** Unit commitment in the second scenario.

| | Number of units | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Hour | 3 | 4 | 5 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 |
| t0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 |
| t1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 0 | 1 |
| t2 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 0 | 1 |
| t3 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 0 | 0 |
| t4 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 0 | 0 |
| t5 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 0 | 0 |
| t6 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 0 | 0 |
| t7 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 |
| t8 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 1 | 1 | 1 |
| t9 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t10 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t11 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t12 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t13 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t14 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t15 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t16 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t17 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t18 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t19 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t20 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 1 |
| t21 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 1 |
| t22 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 |
| t23 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 0 |
| t24 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 0 | 0 |

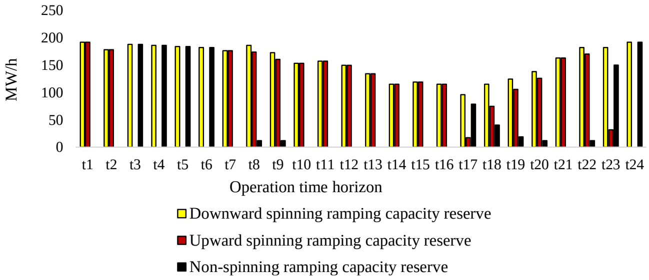


**Fig. 2** Participation of spinning and non-spinning ramping capacity reserve per hour for $U$ = 6.

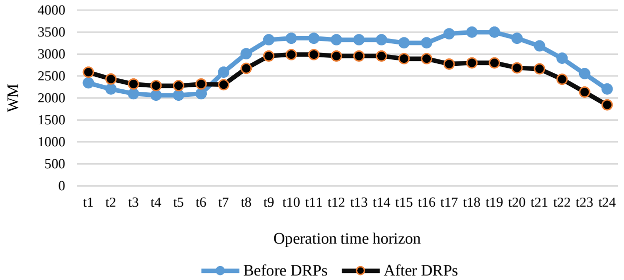


**Fig. 3** Demand curve before and after DRPs.

**Table 5** The effectiveness of each DRPs during peak hours.

| Hour | Reduced load by TOU [MW] | Reduced load by EDRP [MW] |
|---|---|---|
| t17 | 398.58 | 294.16 |
| t18 | 402.6 | 297.13 |
| t19 | 402.6 | 297.13 |
| t20 | 386.5 | 285.24 |

**Table 4** TOU prices.

| Period | Energy price [$/MWh] |
|---|---|
| **Valley** | 11.05 |
| **Off-peak** | 20.9 |
| **Peak** | 36.2 |

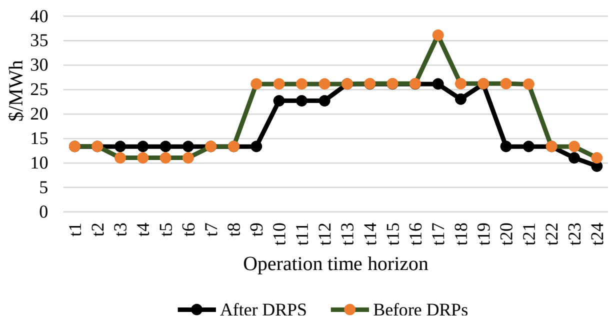


**Fig. 4** Market clearing price before and after DRPs.

**Table 6** Unit commitment in the third scenario.

| | Number of units | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| hour | 1 | 3 | 4 | 5 | 10 | 11 | 12 | 13 | 15 | 17 | 18 | 19 | 20 | 23 | 24 | 25 | 26 |
| t0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 |
| t1 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 0 |
| t2 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 0 |
| t3 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 0 |
| t4 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 0 |
| t5 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 0 |
| t6 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 0 |
| t7 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 0 |
| t8 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 0 |
| t9 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t10 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t11 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t12 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t13 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t14 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t15 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t16 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t17 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t18 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t19 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| t20 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 |
| t21 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 |
| t22 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 0 |
| t23 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 0 | 0 |
| t24 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 0 | 1 | 0 | 0 |

resource to pricing and incentive signals. EDRP and TOU program based on 20% participation factor for each DR program and total participation of DRPs in corresponding load bus have been used simultaneously. EDRP runs from 7:00 a.m. to 8:00 p.m., with an incentive between 0 and 10 $/MWh, depending on optimal scheduling conditions. ISO sends optimal incentive signals to consumers for reducing their load during these hours. By solving the problem under the pricing and the incentive policies presented, for the approved prices at the time of use in Table 4 and total $5706.18 incentive costs for different amounts of uncertainty budget, the system load change is as shown in Fig. 3.

As shown in Fig. 3, during peak hours when the price of electricity is high, consumers are willing to shift their load to the valley and off-peak periods. On the other hand, the presence of the EDRP program is an influential factor in reducing the level of load during these hours. Therefore, according to Fig. 4, this change in the pattern of electricity consumption, while modifying the load factor from 0.83 to 0.88, can have a significant impact on the market-clearing price. It should be noted that an essential part of load factor correction is related to changing the consumption pattern in the peak period, that Table 5 shows the impact of each DRPs on load reduction during peak hours. According to this table, the TOU program with 58% influential, and EDRP program with a 42% influential rate, play a role in load reduction in the peak period, which results indicate the high importance of the TOU program in this period. According to Fig. 4, 20% participation of DRPs due to the change of marginal units, especially during off-peak, and peak hours and reducing the need for expensive units, prevents market price spikes, and consumers will pay less for energy consumption, especially during off-peak and peak hours.

According to Table 6, the use of flexible resources on the generation side and on the demand side in the worst-case of uncertainty realization, i.e. $U$ = 6 can significantly reduce the need for ramping capacity of expensive generation units like units 21 and 22 to be online to supply system load and cover the uncertainty of wind generation. According to this table, we can see a decrease in the number of online units from 354 cases in Table 2 and 335 in Table 3 to 295 in Table 6.

**Table 7** Operating cost of each mentioned scenarios.

| Uncertainty budget | Scenario1 [$] | Scenario2 [$] | Scenario3 [$] |
|---|---|---|---|
| $U = 0$ | 784333.2 | 784333.2 | 585237.6 |
| $U = 1$ | 786999.6 | 786015.6 | 586487.5 |
| $U = 2$ | 790221.8 | 787839 | 587864.1 |
| $U = 3$ | 793183.8 | 789544.7 | 589625.5 |
| $U = 4$ | 797507.6 | 791670.5 | 591710 |
| $U = 5$ | 799543.1 | 794270.3 | 594258 |
| $U = 6$ | 803546.9 | 796760.3 | 596814.9 |

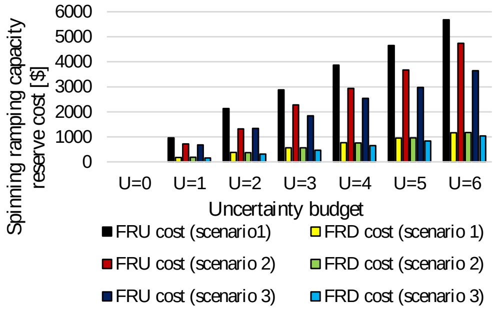


**Fig. 5** Spinning ramping capacity reserve cost in different scenarios.

It should be noted that with the implementation of the third scenario, according to Fig. 5, on average for different amounts of uncertainty budget, we see a reduction in the cost of upward and downward spinning ramping capacity reserves by %24.6 and %13.7 compared to scenarios 1 and 2, respectively, because in the third scenario due to the performance of responsive resources on the demand side by modifying the load factor of the system, severe ramps are prevented, which reduces the need to use the spinning ramping capacity reserve of expensive units.

Table 7 shows the operating costs for different scenarios. It is worth mention that in the case of implementation of scenario 3, respectively, on average for different amounts of uncertainty budget, we see a decrease of 25.6% and 25.3% in the cost of operating the system compared to scenario 1 and scenario 2, which shows the vital role of scenario 3 in reducing operating costs.

It should be noted that the use of adaptive robust optimization based on column and constraint generation algorithm along with the proposed model to provide the required ramping capacity of the system, including separation generation resources approach based on response speed and changing their status to cover fluctuations of wind power output and also using the demand response programs including EDRP and TOU program for increasing system flexibility, has an efficient convergence speed where the problem has been converged in maximum three iterations with an average computational time equal to 87s for different amounts of uncertainty budget. To evaluate the proposed model under operating conditions, the out-of-sample method [26] was used in which, by using a uniform probability distribution, 10,000 scenarios related to the production of wind units in the mentioned generation fluctuation interval were generated. By setting power imbalances and insufficient ramping penalty to $10M, the results showed an imbalance in the system to 0 MW for different scenarios that indicate the system is robust against any degree of uncertainty realizations within the pre-specified uncertainty set.

## 6 Conclusion

In this paper, the approach of separating generation units into non-quick and quick-act resources to provide the required flexibility was used. On the other hand, demand response programs as demand side resources for enhancing system flexibility, including optimal planning for TOU and EDRP was used. The results show the effectiveness of the use of flexible resources on demand and generation sides in the form of the proposed model for day-ahead operation planning problem under high penetration of wind generation units (about 27%), in a way that for different amounts of uncertainty budget, an average operating and robustness costs were reduced to 25.6% and 0.52%, respectively. Also, using an adaptive robust approach with column and constraint centration algorithm had an acceptable efficiency in problem-solving speed; the problem was solved and converged in maximum three iterations with an average calculation time of 87s for deferent amounts of uncertainty budget.

## Intellectual Property

The authors confirm that they have given due consideration to the protection of intellectual property associated with this work and that there are no impediments to publication, including the timing of publication, with respect to intellectual property.


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## CRediT Authorship Contribution Statement

**A. Mansoori:** Idea and conceptualization, Methodology, Software and simulation, Original draft preparation. **A. Sheikhi Fini:** Analysis, Revise and Editing, Supervision. **M. Parsa Moghaddam:** Data curation, Verification.

## Declaration of Competing Interest

The authors hereby confirm that the submitted manuscript is an original work and has not been published so far, is not under consideration for publication by any other journal and will not be submitted to any other journal until the decision will be made by this journal. All authors have approved the manuscript and agree with its submission to "Iranian Journal of Electrical and Electronic Engineering".

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