Assessment of Ancillary Service Demand Response and Time of Use in a Market-Based Power System Through a Stochastic Security Constrained Unit Commitment

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Abstract. In this paper, the impacts of an incentive-based Demand Response, i.e., Ancillary Service DR (ASDR), and a price-based DR, i.e., Time of Use (ToU), are revealed in a restructured power system which has some wind farms. This network is designed based on the pre-emptive market which is a day-ahead market with a balancing market prognosis. It is a proper mechanism to deal with the stochastic nature of non-dispatchable and outage of all units of the network. With Monte Carlo Simulation (MCS) method, several scenarios are generated in order to tackle the variability and uncertainties of the wind farms generation. The impacts of merging ASDR and ToU are investigated through running a two-stage stochastic security constrained unit commitment (SCUC), separately .

Keywords: Ancillary service demand response · Security constrained unit commitment · Time of Use · Two-stage stochastic programming

1 Introduction

With the increasing of these renewable energy resources in the power systems, Independent System Operators (ISO) have been faced with new challenges, mainly related to the random and uncertain nature of wind speed [1, 2].

On the other hand, with growing the share of wind energy in power system's energy, novel methods have been proposed to improve the power consumption pattern of consumers [3]. Demand Response Programs (DRPs) are one of the most practical methods for this purpose.

With the expansion of smart meters, like Advanced Metering Infrastructure (AMI) and Internet of Things (IoT), in demand side of power systems, implementation of different methods of Demand Response (DR) is going to be much more applicable [4, 5]. A suitable DR method can not only decrease total operation cost but also provide security and safety of the network operation [6].

L.M. Camarinha-Matos et al. (Eds.): DoCEIS 2017, IFIP AICT 499, pp. 233–241, 2017.
DOI: 10.1007/978-3-319-56077-9_22

In [7], an approach is proposed for shifting suitable amount of load from peak hours to off-peak hours to facilitate effective use of wind generators, reduce possible contingencies in the network and nonnegative local marginal prices (LMP).

Transferring and load shifting has been performed for those loads that can be moved from peak hours to off-peak hours under the load control of Independent System Operator (ISO), while the total load over the planning horizon is completely fixed. Load shifting of the consumers from peak hours to off-peak hours has been conducted by implementing Incentive Based Demand Response (IBDR) programs where only one of the incentive demand response programs has been modeled. By implementing several programs of demand response programs and using time-based demand response programs, more reliable results will be presented.

In [8], wind resources have been used for the flexibility of supply side and their uncertainties have been considered. A flexible stochastic security-constrained shedding framework has been presented for simultaneous optimization of utilization in the supply and demand side aided a demand response plan or program named Time of Use (TOU) optimization tariff [9]. In [10–12], TOU tariffs have been optimized so that the flexibility potential of load side in confronting with the load uncertainty and large scale changes of generation side is maximized. In [13, 14], the impact of two important demand response strategies of Load curtailment and Load shifting on power systems with the wind generation has been investigated. In [15] the problem of constructing the bidding curve has been discussed for a retailer to offer in the pool market. The problem is formulated as a stochastic linear programming.

In this paper, the impacts of Ancillary Service DR (ASDR) and Time of Use (ToU) are studied. A day-ahead market with a balancing market is considered. With a Monte Carlo Simulation (MCS) method, several scenarios are generated in order to tackle the variability and uncertainties of wind generation. The impacts of merging ASDR and ToU are thoroughly investigated.

2 Relationship to Smart Systems

The various current facilities in smart grids either in terms of communication technology e.g. Home Area Networks (HAN) or smart meters e.g. advanced metering infrastructures (AMI) enable end-users to participate actively in electricity market in order to improve security, economy, efficiency and reliability of network operation [16]. The information flow in the smart grids can be classified based on power flow and power system sections. Accordingly, communication architecture for demand response is introduced. Home Area Networks/Business Area Networks/Industrial Area Networks (HANs/BANs/IANs) are communication technologies which are deployed in residential units, commercial buildings, and industrial plants in order for connecting multiple electrical appliances to smart meter through ZigBee, WiFi, or Power-line communication (PLC) [17].

On the other hands, Neighborhood Area Networks/Field Area networks (NANs/FANs) are designed for communication between different smart meters of power distribution system through Data aggregate Unit (DAU), WiFi, world-wide interoperability for microwave access (WiMax) or cellular networks like GPRS, 3G and LTE.

Meanwhile, for communication between bulk generation, transmission lines (Wide-Area Network) WANs is used through fiber-optic communication or microwave transmission.

3 Formulation

In this paper, two objective functions are introduced in order to deal with both priced-based demand response that is ToU and incentive-based demand response which is ASDR. In fact, for the earlier, a two-stage stochastic program is run for maximizing social welfare and the later, a two stage-stochastic program is run for minimizing total operation cost. Some amount of customers' consumption in ToU program are presented as load bidders. Hence, the objective is to maximize deference of end-user cost and operation cost. Accordingly, the objective function for ToU program and their constraints are shown as follows:

$$Max \sum_{t=1}^{T} \left\{ \begin{array}{l} \sum_{b=1}^{B} \{(Bid_{b,t} DisL_{b,t}) - \sum_{n=1}^{N} \left(P_{n,t} B_{n,t} + C_{n,t}^{Up} SR_{n,t}^{Up} + C_{n,t}^{Down} SR_{n,t}^{Down} + SU_n y_{n,t} + SD_n z_{n,t}\right) \\ \quad + \sum_{s=1}^{S} (\Pr_{t,s} \times (\sum_{n=1}^{N} r_{s,n,t}^{up} \times resC_n^{up} + r_{s,n,t}^{down} \times resC_n^{down}) + \sum_{b=1}^{B} VOLL \times Lshed_{s,b,t}) \end{array} \right\} \tag{1}$$

In this formulation, the first line is regarding first stage where $Bid_{b,t}$, is load bidding at hour t and bus b, $DisL_{b,t}$, is the dispatched load at hour t and bus b. Moreover, $P_{n,t}B_{n,t}$ is cost of scheduled power production of unit n at hour t. $C_{n,t}^{Up}SR_{n,t}^{Up}$, $C_{n,t}^{Down}SR_{n,t}^{Down}$ are cost of scheduled up-spinning reserve and down-spinning reserve of unit n at hour t, respectively. SU_n, SD_n are the start-up cost and shut-down cost of unit n, respectively. The second line is related to second stage which handles the balance market by different scenarios where $\Pr_{t,s}$, is the probability of scenario s at time t, $r_{s,n,t}^{up} \times resC_n^{up}$ is the cost of scheduled up-spinning reserve of unit n at scenario s, $r_{s,n,t}^{down} \times resC_n^{down}$ is the cost of scheduled down-spinning reserve of unit n at scenario s. The last term $VOLL \times Lshed_{s,n,t}$ is the cost of forced load curtailment at bus n and scenario s and hour t.

Subject to:

DC power flow equation

$$\sum_{n=1}^{N} P_{n,t} + W_{b,t}^{dispach} = \mu \sum_{b=1}^{B} Ld_{b,t} + \sum_{l=1}^{L} Pflow_{l,t} \tag{2}$$

where, $W_{b,t}^{dispach}$ is the real power usage from wind farm node n at hour t which should be less than $W_{b,t}^{\exp ect}$(the expected produced power from wind farm of node n at hour t), $Ld_{b,t}$ is the whole demand at bus b and hour t, μ is the percentage of the load which must be feed and are not placed in ToU program, $Pflow_{l,t}$ is real power flow in line l and hour t which is as follows:

$$Pflow_l = \frac{1}{X_l}(\delta_{ls} - \delta_{lr}) \tag{3}$$

where X_l is reactance of line l, δ_{ls} is voltage angle of sending-end bus of line l and δ_{lr} is voltage angle of receiving-end bus of line l and its constraint is as follows:

$$-Pflow_{l,t}^{\max} \le Pflow_{l,t} \le Pflow_{l,t}^{\max} \tag{4}$$

where $Pflow_{l,t}^{\max}$ is the maximum capacity of line l. And the real power generation constraints are as follows:

$$p_n^{\min}.u_{n,t} + SR_{n,t}^{Down} \le p_{n,t} \le p_n^{\max}.u_{n,t} - SR_{n,t}^{Up} \tag{5}$$

where $p_n^{\min}$,$p_n^{\max}$ are the minimum and maximum capacity of unit n, $u_{n,t}$ is the commitment state of unit n at hour t. Moreover, start-up and shut-down constraint of units are as follows:

$$\begin{aligned} u_{n,t} - u_{n,t-1} &= y_{n,t} - z_{n,t} \\ y_{n,t} + z_{n,t} &\le 1 \end{aligned} \tag{6}$$

Up and down spinning reserve constraints are as follows:

$$\begin{aligned} 0 \le SR_{n,t}^{Up} &\le R_n^{up} \\ 0 \le SR_{n,t}^{Down} &\le R_n^{down} \end{aligned} \tag{7}$$

where R_n^{up} is ramp-up limitation for unit n and R_n^{down} is ramp-down limitation for unit n. Plus, ramp-up and -down constraints are as follows:

$$\begin{aligned} P_{n,t} - P_{n,t-1} &\le R_n^{down} \\ P_{n,t-1} - P_{n,t} &\le R_n^{up} \end{aligned} \tag{8}$$

Constraints of second stage include DC power flow equation which is as follows:

$$\sum_{n=1}^{N} us_{s,n,t} P_{n,t} + r_{s,n,t}^{up} - r_{s,n,t}^{down} + W_{s,b,t}^{scen} - W_{s,b,t}^{spill} = \mu \sum_{b=1}^{B} Ld_{b,t} + \sum_{l=1}^{L} Pflow_{s,l,t} - Lshed_{s,b,t} \tag{9}$$

where $us_{s,n,t}$ is the given state of unit n at scenario s and hour t, $W_{s,n,t}^{scen}$ is the amount of produced power by wind farm node b in scenario s and hour t, $W_{s,b,t}^{spill}$ is the spillage power of wind farm node b in scenario s and hour t, $Pflow_{s,l,t}$ is power flow of line l in scenario s and hour t which is as follows:

$$Pflow_{l,s} = \frac{1}{X_l}(\delta_{s,ls} - \delta_{s,lr}) \tag{10}$$

where $\delta_{s,ls}$ is voltage angle of sending-end bus of line l in scenario s and $\delta_{s,lr}$ is voltage angle of receiving-end bus of line l and its constraint is as follows:

$$-Pflow_{l,t}^{\max} \leq Pflow_{s,l,t} \leq Pflow_{l,t}^{\max} \tag{11}$$

The deployed up- and down-spinning reserve constraints are as follows:

$$\begin{aligned} 0 \leq sr_{s,n,t}^{Up} \leq us_{s,n,t}.SR_{n,t}^{Up} \\ 0 \leq sr_{s,n,t}^{Down} \leq us_{s,n,t}.SR_{n,t}^{Down} \end{aligned} \tag{12}$$

Finally, the maximum load that is participated in this demand response program should be specified as follows:

$$DisL_{b,t} \leq \lambda \times Ld_{b,t} \tag{13}$$

where λ is the percentage of the load at bus b that should be joined in DRP.

On the other hands, the objective function for ASDR and some constraints have a few differences compared with ToU. In this program, total operation cost will be minimized and demand response is scheduled as a reserve for the loads which participate in this program. the objective function is as follows:

$$Min \sum_{t=1}^{T} \left\{ \begin{aligned} & \left. \sum_{n=1}^{N} \left(P_{n,t} B_{n,t} + C_{n,t}^{Up} SR_{n,t}^{Up} + C_{n,t}^{Down} SR_{n,t}^{Down} + SU_n \times y_{n,t} + SD_n \times z_{n,t} \right) + \sum_{b=1}^{B} CDR_{b,t} \right) \\ & + \sum_{s=1}^{S} (\Pr_{t,s} (\sum_{n=1}^{N} r_{s,n,t}^{up}.resC_n^{up} + r_{s,n,t}^{down}.resC_n^{down}) + \sum_{b=1}^{B} EDRs_{s,b,t} + \sum_{b=1}^{B} VOLL.Lshed_{s,b,t}) \end{aligned} \right\} \tag{14}$$

where $CDR_{b,t}$ is the capacity cost of scheduled demand response reserve for load of bus b at hour t and $EDRs_{s,b,t}$ is the energy cost of scheduled demand response reserve for load of bus b in scenario s and at hour t which are defined as follows:

$$\begin{aligned} DR_{b,t} &= q_{b,t}^0 u_{b,t}^0 + \sum_{k=1}^{K} \lambda_{b,t}^k u_{b,t}^k \\ CDR_{b,t} &= cc_{b,t}^0 q_{b,t}^0 u_{b,t}^0 + \sum_{k=1}^{K} cc_{b,t}^k \lambda_{b,t}^k u_{b,t}^k \\ \lambda_{b,t}^k &= q_{b,t}^k - q_{b,t}^{k-1} \end{aligned} \tag{15}$$

In this program, several demand response discrete points k is determined as $q_{b,t}^k$ for bus b and hour t and each discrete point k has a capacity cost $cc_{b,t}^k$. The first k is separated and the difference of next k and previous one is assigned as $\lambda_{b,t}^k$ with specific price of $cc_{b,t}^k$. Each level can be selected by the objective function based on profitability. The state of which level k at bus b and hour t is being deployed is determined as $u_{b,t}^k$. This program is almost the same in second stage which is as follows:

$$0 \le dr_{s,b,t} \le DR_{b,t}$$
$$dr_{s,b,t} = q^0_{b,t} uk^0_{s,b,t} + \sum_{k=1}^{K} \lambda^k_{s,b,t} uk^k_{s,b,t} \tag{16}$$
$$EDRs_{s,b,t} = ec^0_{b,t} q^0_{b,t} uk^0_{s,b,t} + \sum_{k=1}^{K} ec^k_{b,t} \lambda^k_{b,t} uk^k_{s,b,t}$$

where $ec^k_{b,t}$ is the energy cost of demand response reserve in scenarios and $uk^k_{s,b,t}$ is the state of which level k at bus b and hour t in scenario s is being deployed. $dr_{s,b,t}$ is scheduled demand response reserve of bus b in scenario s at hour t. Some of the constraints are different from the ToU program that are as follows:

$$\sum_{n=1}^{N} P_{n,t} + W^{dispach}_{b,t} = \sum_{b=1}^{B} Ld_{b,t} + \sum_{l=1}^{L} Pflow_{l,t}$$
$$\sum_{n=1}^{N} us_{s,n,t} P_{n,t} + r^{up}_{s,n,t} - r^{down}_{s,n,t} + W^{scen}_{s,b,t} - W^{spill}_{s,b,t} + \sum_{b=1}^{B} dr_{s,b,t} = \sum_{b=1}^{B} Ld_{b,t} + \sum_{l=1}^{L} Pflow_{s,l,t} - Lshed_{s,b,t} \tag{17}$$

4 Case Study

The 14-bus IEEE power system is used in this study. The slack bus of system is node1. Two wind farms are connected to the power system at Node 5 and Node8. The capacity of each one is equal to 100 MW. Here are several scenarios that each trajectory is the sum of power production of two nodes. There are four cases to assess running ToU and ASDR and compare them in terms of efficiency. First case is running a stochastic SCUC to maximize social welfare without participating loads as ToU DRP and with a constant tariff for load bidding $Bid_{b,t}$. The second case is similar to first one with difference of considering 20% of loads for joining ToU DRP with different tariffs $Bid_{b,t}$. The third case is running a stochastic SCUC to minimize total operation cost without considering ASDR. The fourth case is similar the third one with considering 20% of loads to join ASDR program. In the first case, it is assumed that load bidding is 50$/MWh for all hours. In the second case, two tariff levels are defined for ToU. For peak hours e.g. 13–20 and 28–45, tariff is 40 $/MWh and for others tariff is 70 $/MWh. Accordingly, social welfare for each hour is obtained and it is shown in Fig. 1. As can be seen, in case 2 where the ToU is used the social welfare is mostly higher than case 1, especially in peak times. Moreover, in Fig. 2 which shows the amount of DR participated loads that are supplied. As can be seen, some of loads at peak hours are not supplied in order to get higher social welfare. For the third and fourth cases, demand response is applied just for node 3 and 4. Furthermore, information of ASDR is shown in Table 1. As can be seen in Fig. 3, the operation cost of forth case at hours 34–38 and hour 42 is lower than the case without ASDR. Because, demand response is just scheduled for load in node 4 at hour 34–38 and hour 42. Therefore, the operation cost at these hours are less than operation cost without considering ASDR. Table 2 shows cost of reserve-up, reserve-down, power production units, and security cost which is related to balancing market for all four case studies. The total cost case 1 which is social welfare is lower than case 2 because of using ToU in second one. Finally, total operation cost for case 4 is lower than case 3 because of using ASDR in fourth case.

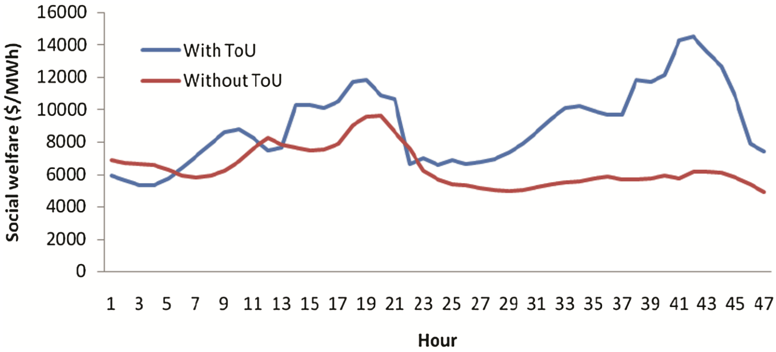

Fig. 1. social welfare for case 1 and 2 at each hour

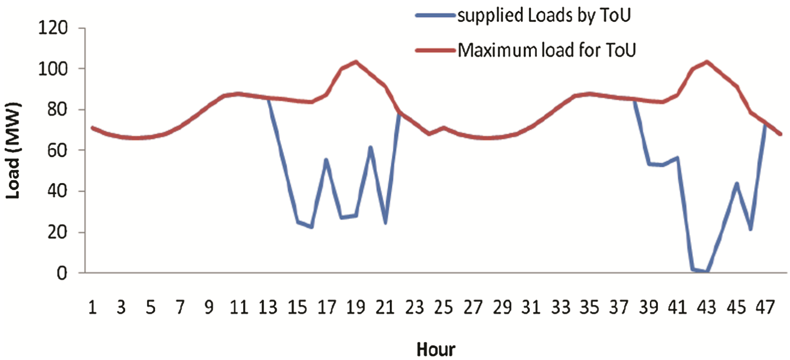

Fig. 2. Maximum load for joining ToU and the amount of supplied loads within ToU program

Table 1. ASDR data

k	0	1	2	3
$q_t^k(MW)$	20	30	40	50
$cc_t^k(\$/MWh)$	10	12.5	15	17.5
$ec_t^k(\$/MWh)$	20	22.5	25	27.5

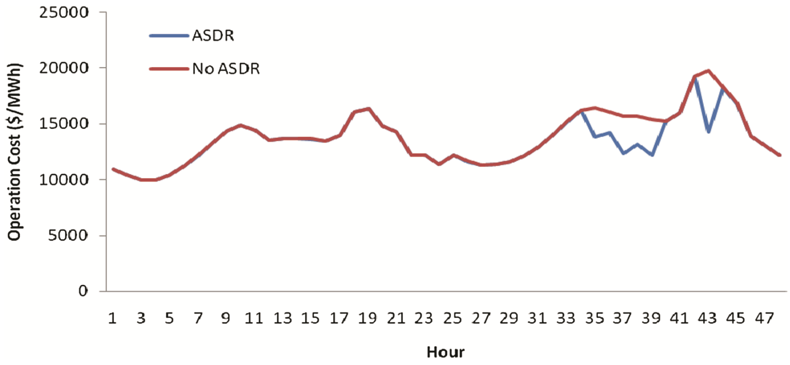

Fig. 3. Hourly operation cost for case 3 and 4

Table 2. Different costs of 4 case studies

	Case1 - base ToU	Case2 - ToU	Case3 - base ASDR	Case4 - ASDR
Reserve up($)	0	0	0	0
Reserve down($)	34627	34521.700	34627.000	40031.820
Production($)	669670	628490	669670	651300
Security($)	42380	42270	42380	48270
Total($)	306880	429770	661920	651080

5 Conclusions

In this paper, the impacts of Ancillary Service DR (ASDR) and Time of Use (ToU) were studied. A day-ahead market with a balancing market was considered. With a Monte Carlo Simulation (MCS) method, several scenarios were generated in order to tackle the variability and uncertainties of wind generation. The impacts of merging ASDR and ToU were thoroughly investigated. The results of this program demonstrate that using demand response program leads to not only compensate wind generators uncertainties but also increase operator benefits. In peak hours, volume of supplied loads will be dropped in both DR programs and social welfare will be higher which means both of operator and customer are more satisfied.

Acknowledgment. This work was supported by FEDER funds through COMPETE 2020 and by Portuguese funds through FCT, under Projects SAICT-PAC/0004/2015 - POCI-01-0145-FEDER-016434, POCI-01-0145-FEDER-006961, UID/EEA/50014/2013, UID/CEC/50021/2013, and UID/EMS/00151/2013. Also, the research leading to these results has received funding from the EU Seventh Framework Programme FP7/2007-2013 under grant agreement no. 309048.

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