Assessing Impact of Demand Response in Emission-Constrained Environments

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Abstract—Reducing the emissions produced by the electric power production may be one of the most challenging problems of the electricity sector in the coming future. As one of the potential solutions, demand response (DR) can play an important role to reduce emissions and costs associated with emission reduction activities. This paper aims to assess the short-term impacts of running a DR program on a power system constrained by emissions caps. The DR program is designed to procure operating reserve from demand-side participants. A day-ahead network-constrained market clearing model with emission cap constraints is used as the assessment tool, where the DR program participants along with generating units are considered as available resources to provide reserve for the system. A model is also presented for reserve provided by DRPs and its associated cost function. The proposed approach is applied to the IEEE-RTS to illustrate the impacts of the DR program.

Index Terms—demand response, emission cap, operating reserve, market clearing, mixed-integer linear programming.

I. Nomenclature

i	Index of generating units
l	Index of transmission line
t	Index of time
b	Index of bus
a	Index of system areas
d	Index of DR program participants
e	Index of emission type
G	Set of generating units
D	Set of participants in the DR program
T	Set of scheduling hours
B	Set of buses
G_b	Set of generating units connected to bus b
G_a	Set of generating units located at system area a
L_b	Set of transmission lines connected to bus b
NN_i	Number of segments of piecewise linear cost function of generating unit i
NE_i	Number of segments of piecewise linear emission function of generating unit i
NQ_d	Number of discrete points of offer package of DRP d
SUC_{it}	Startup cost of unit i at time t
SUE_{it}^e	Startup emission of type e of unit i at time t
MC_i	Minimum production cost of unit i
ME_i^e	Minimum production emission of type e of unit i
I_{it}	Commitment state of unit i at time t
P_{it}	Real power generation of unit i at time t
P_{it}^n	Real power generation of unit i in segment n at time t
$P_i^{\min}$	Lower limit of real generation of unit i
$P_i^{\max}$	Upper limit of real generation of unit i
K_i	Startup cost of unit i
J_i^e	Startup emission of type e of unit i
SR_{it}	Scheduled up-spinning reserve of unit i at time t
RU_i	Ramp-up limit of unit i (MW/min)
RD_i	Ramp-down limit of unit i (MW/min)
T_i^{on}	Minimum up time of unit i
T_i^{off}	Minimum down time of unit i
X_{it}^{on}	On time of unit i at time t
X_{it}^{off}	Off time of unit i at time t
F_{lt}	Real power flow of line l at time t
$F_l^{\max}$	Maximum capacity of line l
X_l	Reactance of line l
δ_{ls}	Voltage angle of sending-end bus of line l
δ_{lr}	Voltage angle of receiving-end bus of line l
P_{bt}^D	Load demand of bus b at time t
DRR_{dt}	Scheduled reserve of DRP d at time t
$CDRP_{dt}$	Capacity cost function of reserve provided by DRP d at time t
u_{dt}^k	Binary variable associated with point k of DRP d at time t; 1 if the point is scheduled and 0 otherwise
μ_{nit}^f	Slope of segment n of the piecewise linear cost function of unit i at time t
μ_{nit}^e	Slope of segment n of the piecewise linear emission function of type e of unit i at time t
μ_{it}^{SR}	Offered capacity cost of unit i for providing

spinning reserve at time t

EMC^e Daily Emission cap of system for emission type e

$EMC^{e,a}$ Daily emission cap of system for emission type e in area a

II. Introduction

C LIMATE change mitigation may be one of the most challenging issues of our generation. In order to address the problem, emissions exhausted from industrial processes – identified as root cause of climate change – should be limited and reduced in an appropriate manner. The United Nations Framework Convention on Climate Change (UNFCCC) and its Kyoto Protocol [1] provide an international framework for mitigating climate change. The major feature of the Kyoto Protocol is that it sets binding targets for industrialized countries and the European community for reducing environmental emissions. These amount to an average of five percent against 1990 levels over the five-year commitment period 2008-2012. Like to the other emission source categories, emission caps are also applied to electricity sector. This means that the emissions produced by electricity generating units should not exceed the allocated emission allowance in a specified horizon. This, in turn, put a challenging constraint on the control and management of power system ranging from long-term resource planning activities to short-term generation scheduling to meet the power demand.

Generally speaking, demand response (DR) is a tariff or program established to motivate changes in electric consumption by end-use customers in response to changes in the price of electricity over time. Developments in real-time telemetry systems have enabled the system operators to design different DR programs and utilize them in their markets. The DR programs can be divided into two major programs: time-based DR programs, and incentive-based DR programs. Both types of DR are currently under operation in many ISO's around the world [2]. The time-based DR programs are established to overcome flat or averaged electricity pricing flaws. Many types of these programs are designed in different ISOs, but time-of-use tariffs, critical-peak-pricing, and real-time-pricing are three well-known programs. The incentive-based DR programs offer payments for customers to reduce their electricity usage during periods of system need or stress. The incentive-based DR programs substantially have market-based structures, and can be offered in both retail and wholesale markets. The incentive-based DR programs can be offered in energy market as well as ancillary service markets to address system reliability issues.

DR programs provide power systems with many potential benefits [3]. Among these potential benefits, helping to reduce the environmental issues may be one of the most interesting benefits from the public policy point of view. In a recent project sponsored by the U.S. environmental protection agency (EPA), DR along with energy efficiency and clean distributed generation are introduced as the potential solutions to reduce the emissions produced by generating units [4].

Holland and Mansur analyzed the short-term environmental impacts of real-time pricing (RTP) program by estimating the effect of load variation on emissions [5]. They argued that the impacts of a reduction in load variance due to the RTP program are different for different regions in U.S. In particular, they emphasized that contrary to the conventional wisdom, RTP may actually increase emissions in some regions [5]. Reference [6] assesses the emissions impacts of expanding economic DR programs in New England. It concludes that significant emission reductions could result from additional DR capacity in New England, if that capacity were used to meet operating reserve requirements. Similar to [5], the authors of [6] also emphasize that the finding are specific to New England, and it is needed to study the potential impacts of DR programs on a region-by-region basis.

This paper presents a model to assess the short-term impacts of DR on the power systems constrained by emission caps. The model is a network-constrained day-ahead market clearing tool which is used to schedule generation facilities to meet the anticipated demand of the next day. In the proposed model, ISO also runs a DR program to procure operating reserve from the program participants at load buses [7]. Naturally, the reserve provided by DRPs is different from that of generating units. A model for reserve provided by DRPs and its associated cost function is presented in this paper, and its mixed-integer linear representation is developed to be used in the proposed model.

The rest of this paper is organized as follows. Section III presents the structure of the DR program and the proposed model for it. Section IV presents the proposed model to assess the short-term impacts of DR on the power systems constrained by emission caps. The implementation of the model on the IEEE-RTS is presented in Section V. Conclusions are given in Section VI.

III. Demand Response Program Model

The structure of the DR program is described here. The purpose of the DR program is to procure operating reserve from participants in the day-ahead market. Qualified large individual customers as well as DR providers (DRPs) are permitted to participate in the program. DRPs register smaller customers, aggregate their offers, and submit the aggregated offers on behalf of them in the DR program [7]. The interactions between participants in the DR program are depicted in Fig. 1. It can be seen in this figure that DRPs act as a medium between ISO and small customers and enable the participation of small customers in the DR program. ISO sends program information to participants and invite them to submit their offers to participate in the DR program. A typical bid-quantity offer package is shown in Fig. 2 [7]. DRPs will aggregate discrete retail customer responses to construct such an offer.

The discrete DR reserve quantities at time t are labeled as q_{dt}^k in Fig. 2 with the associated cost of c_{dt}^k. Here, q_{dt}^0 should be greater than the minimum curtailment level of the DR

program specified by ISO. A mixed-integer representation of the bid-quantity is shown in (1)-(3).

$$DRR_{dt} = q_{dt}^0 u_{dt}^0 + \sum_{k=1}^{NQ_d} \lambda_{dt}^k u_{dt}^k \qquad (1)$$

$$CDRP_{dt} = c_{dt}^0 q_{dt}^0 u_{dt}^0 + \sum_{k=1}^{NQ_d} c_{dt}^k \lambda_{dt}^k u_{dt}^k \qquad (2)$$

$$\lambda_{dt}^k = q_{dt}^k - q_{dt}^{k-1} \qquad (3)$$

In the above formulation, u_{dt}^k is binary variable associated with the kth discrete point of the offer package, which takes one if the point is scheduled by the ISO, and otherwise takes zero. Here, it is assumed that the demand response increases as prices increase and c_{dt}^k is constrained to increase monotonically [8].
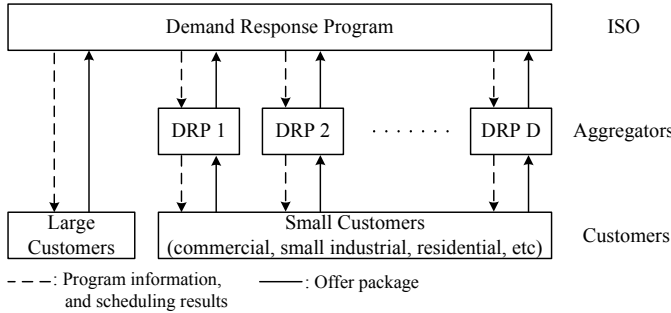

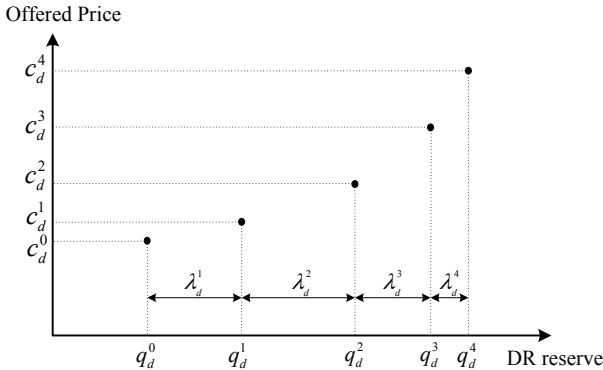Fig. 1. Interactions between participants in the DR program

Fig. 2. DRP's bid-quantity offer package

IV. THE PROPOSED MODEL DESCRIPTION AND FORMULATION

This section presents the proposed model to assess the short-term impacts of DR on the power systems constrained by emission caps. A day-ahead market is considered which is executed by the ISO to schedule the available resources to meet the anticipated demand of the next day. The ISO receives bid-quantity offers from GENCOs to provide energy and spinning reserve services, as well as offers of the DR program participants to provide reserve. ISO will also receive hourly load demands from DISCOs. It clears energy and spinning reserve markets and schedules the reserve provided by DR program participants by applying the following market clearing tool.

A. The Market Clearing Formulation

The formulation of the day-ahead market clearing tool is presented here. The problem is formulated in a mixed-integer linear programming (MILP) format. The objective function of the proposed method is to minimize the system total cost which is formulated as follows:

$$\sum_{t \in T} \left\{ \sum_{i \in G} \left(MC_i I_{it} + \sum_{n=1}^{NF_i} \mu_{nit}^f P_{it}^n + SUC_{it} \right) \right. $$
$$\left. + \sum_{i \in G} \left(\mu_{it}^{SR} SR_{it} \right) + \sum_{d \in D} \left(CDRP_{dt} \right) \right\} \qquad (4)$$

where the first line is cost of energy production by thermal generating units including startup cost, and the second line encompasses capacity cost of scheduling spinning reserve provided by generating units and participants of the DR program, respectively. The capacity cost function of the DR participants is defined by (2) in section III. The objective function (4) is subjected to the prevailing thermal generating units operating constraints, spinning reserve requirement of the system, system and area emission constraints, and DC power flow constraints which are used in this paper to model the transmission network. The problem constraints are as follows:

Real power generation of thermal generating units

$$P_{it} = P_i^{\min} I_{it} + \sum_{n=1}^{NN_i} P_{it}^n \qquad \forall i, \forall t \qquad (5)$$

$$0 \le P_{it}^n \le P_i^{n,\max} \qquad \forall n, \forall i, \forall t \qquad (6)$$

Generating units startup cost constraint

$$SUC_{it} \ge K_i \left(I_{it} - I_{i(t-1)} \right) \qquad \forall i, \forall t \qquad (7)$$

Minimum up and down time constraints

$$\left[X_{i(t-1)}^{on} - T_i^{on} \right] \left(I_{i(t-1)} - I_{it} \right) \ge 0 \qquad \forall i, \forall t \qquad (8)$$

$$\left[X_{i(t-1)}^{off} - T_i^{off} \right] \left(I_{it} - I_{i(t-1)} \right) \ge 0 \qquad \forall i, \forall t \qquad (9)$$

Ramping up and down constraints

$$P_{it} - P_{i(t-1)} \le \left[1 - I_{it} \left(1 - I_{i(t-1)} \right) \right] RU_i $$
$$+ I_{it} \left(1 - I_{i(t-1)} \right) P_i^{\min} \qquad \forall i, \forall t \qquad (10)$$

$$P_{i(t-1)} - P_{it} \le \left[1 - I_{i(t-1)} \left(1 - I_{it} \right) \right] RD_i $$
$$+ I_{i(t-1)} \left(1 - I_{it} \right) P_i^{\min} \qquad \forall i, \forall t \qquad (11)$$

Minimum and maximum real power generation of units

$$P_{it} \le P_i^{\max} I_{it} - SR_{it} \qquad \forall i, \forall t \qquad (12)$$

$$P_{it} \ge P_i^{\min} I_{it} \qquad \forall i, \forall t \qquad (13)$$

Spinning reserve requirement of the system

$$\sum_{i \in G} SR_{it} + \sum_{d \in D} DRR_{dt} \ge SRR_t \qquad \forall t \qquad (14)$$

System and area emission constraints

$$\sum_{i \in G} \sum_{t \in T} E_{it}^e \left(P_{it}, I_{it} \right) \le EMC^e \qquad \forall e \qquad (15)$$

$$\sum_{i \in G_a} \sum_{t \in T} E_{it}^e \left(P_{it}, I_{it} \right) \le EMC^{e,a} \qquad \forall e, \forall a \qquad (16)$$

DC power flow equation

$$\sum_{i \in G_b} P_{it} - P_{bt}^D = \sum_{l \in L_b} F_{lt} \qquad \forall b, \forall t \qquad (17)$$

Transmission lines flow equation and limits

$$F_{lt} = \frac{1}{X_l}\left(\delta_{ls} - \delta_{lr}\right) \qquad \forall l, \forall t \qquad (18)$$

$$-F_{lt}^{\max} \le F_{lt} \le F_{lt}^{\max} \qquad \forall l, \forall t \qquad (19)$$

In (14), reserves provided by generating units and the DR program participants are considered as the available resources to meet the spinning reserve requirements of the system. The reserve provided by DR program participants, DRR_{dt} is modeled by (1) in section III. The system and area-wide emission caps constraints are presented by (15) and (16), respectively. Typically, emissions produced by generating units are presented as functions of their power production [9], [10]. Two primary generating units' emissions are sulfur dioxide (SO_2) and nitrogen oxides (NO_x) which can be modeled by either quadratic or linear emission functions. To be consistent with MILP nature of the market clearing model, the following mixed-integer linear representation is used in this paper to model the emission function of generating units [11]:

$$E_{it}^e\left(P_{it}, I_{it}\right) = ME_i^e I_{it} + \sum_{n=1}^{NE_i} \mu_{nit}^e P_{it}^n + SUE_{it}^e \qquad (20)$$

where SUE_{it}^e is the startup emission of generating units which should satisfy the following constraint:

$$SUE_{it}^e \ge J_i^e\left(I_{it} - I_{i(t-1)}\right) \qquad \forall e, \forall i, \forall t \qquad (21)$$

Altogether, (4)-(21) presents the proposed model to assess the short-term impacts of DR on emission-constrained power systems. The proposed model, which is in the format of a standard MILP model, can be solved using any commercial MILP solvers.

V. CASE STUDY

The proposed model is demonstrated in this section on the IEEE-RTS [12] including hydro units. The one-line diagram of the IEEE-RTS is shown in Fig. 3. As shown in Fig. 3, the system consists of two distinct geographical areas [10]. Buses B1-B12 and B24, as well as generating units G1-G11 belong to Area 1, while the other buses and units are located in Area 2. It is assumed that generating units submit their offers for energy at the incremental heat rates given in [12]. Also, generating units offer capacity cost of spinning reserve at the rate of 40% of their highest incremental cost of energy. All other data for the system, including startup cost, upper and lower limits on power generation, ramp rates, minimum up and down times, etc, are directly extracted from [12]. The emission function slopes and the startup emission of generating units are the same as those for corresponding unit fuel cost curves, all multiplied by conversion factors of 0.2 and 0.5 for SO_2 and NO_x emission, respectively. The spinning reserve requirement of the system is assumed to be equal to 14% of the system load in each hour.

It is assumed that one DRP exists in each load bus which aggregates local customers and offers a package to participate in the DR program. The offer packages which is in the format of the package presented in section III, is presented in Table I. The proposed model is applied over a 24-hour scheduling horizon, while the hourly demand data corresponds to a weekday in summer and the peak load of the day is 2850 MW. Three difference cases are conducted on the IEEE-RTS as follows. All the cases are solved using the MILP solver CPLEX 12.1.0 [13], on a computer equipped with a 2.2 GHz dual-core processor and 2 GBs of RAM. The computation time of all the cases was about 10 seconds, while the upper bound on the duality gap is set to be zero.
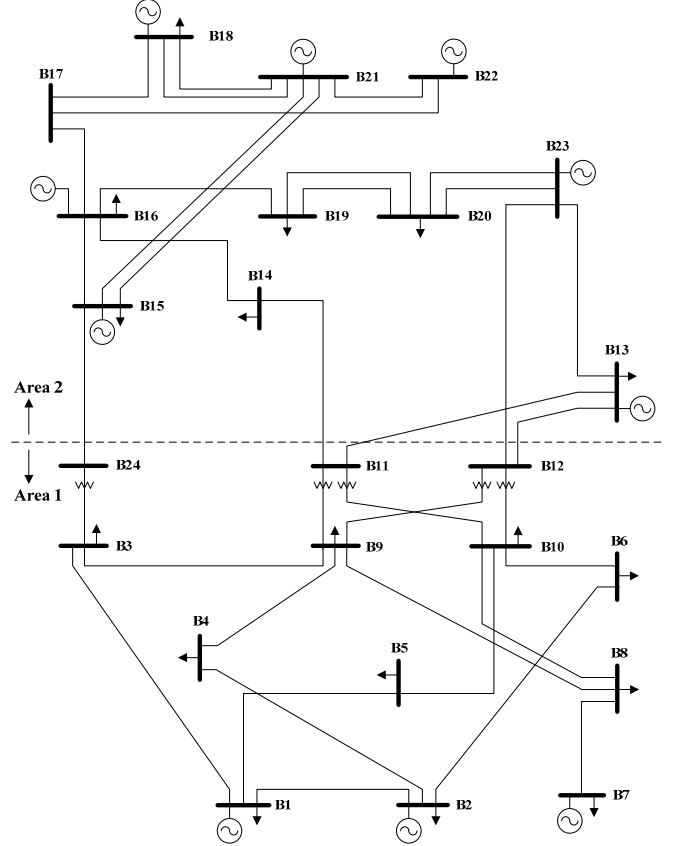
Fig. 3. IEEE-RTS one-line diagram

TABLE I
DRP OFFERS

k	0	1	2
q_{dt}^k (MW)	33% of total response	66% of total response	100% of total response
c_{dt}^k ($/MW)	11	12	13

TABLE II
THE COSTS OF THE IEEE-RTS

Case	Total Cost ($)	Energy Cost ($)	Spinning Reserve Scheduling Cost ($)	DR Reserve Scheduling Cost ($)
Case1	587181.4	521895.5	65285.91	-
Case2	604543.9	528478.7	76065.16	-
Case3	599464.3	520812.8	59406.91	19244.62

In Case1, the base case operation of the system is considered, where DR program is not utilized and no constraints are considered on the emission produced by generating units. The total NO_x emission of the system in Case1 over the 24-hour scheduling horizon is 146741.14 *lbs*. The total NO_x emission in Areas 1 and 2 are 31529.8 *lbs* and 115211.3 *lbs*, respectively.

TABLE III
COMMITMENT STATES OF GENERATING UNITS – CASE1

Unit	Scheduling hours (1-24)
G1-G2	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
G3-G4	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
G5-G6	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
G7-G9	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
G10-G11	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0
G12	0 0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0
G13	0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0
G14	0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0
G15-G19	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
G20-G32	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1

TABLE IV
COMMITMENT STATES OF GENERATING UNITS – CASE2

Unit	Scheduling hours (1-24)
G1-G2	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
G3	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
G4	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0
G5-G6	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
G7-G11	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
G12-G13	0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0
G14	0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0
G15-G17	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
G18-G19	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0
G20-G32	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1

TABLE V
COMMITMENT STATES OF GENERATING UNITS – CASE3

Unit	Scheduling hours (1-24)
G1-G2	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
G3-G4	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
G5-G6	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
G7-G10	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
G11	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
G12	0 0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0
G13-G14	0 0 0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0
G15-G19	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
G20-G32	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1

In Case2, the daily NO_x emission cap of the whole system is assumed to be 140000 *lbs*. Besides the system-wide emission constraint, it is also assumed that the daily NO_x emission of Area 1 should be less than 20000 *lbs*. No DR program is utilized in Case2. In Case3, the emission caps are the same as those of Case2, while the DR program is also utilized to procure operating reserve from participants. It is assumed that 10% of customers are participated in each bus in the DR program. Table II presents the costs of the IEEE-RTS associated with the three case studies. It can be seen in this table that imposing the emission constraints to the system in Case2, considerably increases the total cost of the system by more than 17300$ in the 24-hour scheduling horizon. Also, it can be seen that utilizing the DR program in the emission-constrained system of Case2 reduces the total cost of the system by 5080$, while meeting the applied emission caps. The reason for the costs changes can be found by investigating the detailed schedules of the system in the three cases. Tables III, IV and V present the commitment states of generating units in Cases 1, 2 and 3, respectively. Also, scheduled spinning reserves for units over the 24-hour scheduling horizon are provided in Tables VI, VII and VIII. It

has to be noted that units which spinning reserve is not scheduled for them, are omitted in Tables VI-VIII.

TABLE VI
SCHEDULED SPINNING RESERVE FOR GENERATING UNITS (MW) – CASE1

Unit	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
G3	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
G4	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
G7	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
G8	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
G9	0	0	0	0	0	0	0	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
G10	0	0	0	0	0	0	0	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	0
G11	0	0	0	0	0	0	0	19	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	0
G12	0	0	0	0	0	0	0	0	0	30	30	30	30	30	30	30	30	30	30	30	30	30	30	0
G13	0	0	0	0	0	0	0	0	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	0
G14	0	0	0	0	0	0	0	0	30	30	30	30	30	30	30	30	30	30	30	30	30	30	0	0
G20	30	30	30	30	30	30	30	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9	30
G21	30	30	30	30	30	30	30	30	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30
G22	80	80	80	80	80	80	80	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	80
G23	79	79	79	79	79	79	79	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9
G30	30	30	30	30	30	30	30	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30
G31	30	30	30	30	30	30	30	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30
G32	40	40	40	40	40	40	40	40	40	18	18	18	18	18	18	18	18	18	18	18	18	18	40	40

TABLE VII
SCHEDULED SPINNING RESERVE FOR GENERATING UNITS (MW) – CASE2

Unit	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
G3	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
G4	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	0
G7	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
G8	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
G9	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
G10	19	19	19	17	17	19	19	35	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	60
G11	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
G12	0	0	0	0	0	0	0	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	0
G13	0	0	0	0	0	0	0	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	0
G14	0	0	0	0	0	0	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	0
G18	0	0	0	0	0	0	0	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	0	0
G19	0	0	0	0	0	0	0	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	0	0
G20	30	30	30	30	30	30	30	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30
G21	30	30	30	30	30	30	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30
G30	30	30	30	30	30	30	30	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8
G31	30	30	30	30	30	30	30	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30
G32	40	40	40	40	40	40	40	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0	19	40

TABLE VIII
SCHEDULED SPINNING RESERVE FOR GENERATING UNITS (MW) – CASE3

Unit	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
G3	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
G4	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
G7	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
G8	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
G9	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
G10	70	70	70	70	70	70	70	36	70	69	70	70	70	70	70	70	70	70	70	70	70	70	70	70
G12	0	0	0	0	0	0	0	30	30	30	30	30	18	30	30	30	30	30	30	30	30	30	30	0
G13	0	0	0	0	0	0	30	30	30	0	0	0	0	0	30	30	30	30	30	30	30	30	30	0
G14	0	0	0	0	0	0	30	30	30	29	0	21	30	5	30	30	30	30	30	30	30	30	30	0
G20	30	30	30	30	30	30	30	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
G21	30	30	30	30	30	30	30	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	29
G30	30	30	30	30	30	30	30	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30
G31	30	30	30	30	30	30	30	23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30
G32	40	40	40	40	40	40	40	40	6	0	0	0	0	0	0	0	0	0	0	0	0	0	4	40

It can be observed from Table IV that in addition to the units committed in Case1 (see Table III), two 12MW units

G18 and G19 are also committed in Case2. These units are loaded in their lowest capacity, and just are committed to provide spinning reserve for the system. Investigating Table VII proves this statement. It can be seen in Table VI that two nuclear units G22 and G23 provide considerable amount of spinning reserve in off-peak hours (hours 1-7 and 24) in Case1. But, Table VII shows that no spinning reserve is scheduled for the units in Case2. The reason for this can be explained regarding the fact that the nuclear units produce no NO_x emission in the system. So, in the emission-constrained system of Case2, they are forced to be energized at their maximum capacity in all hours of the day. It can be seen in Table VI that, instead of the units G22 and G23, the more expensive 100MW units G9-G11 are used in Case2 to provide spinning reserve in the off-peak hours. All the above mentioned deviations from the economically optimal dispatches of Case1 resulted in increase in much higher scheduling cost of Case2.

Now let us explore the scheduling results to find out how utilization of the DR program in the emission-constrained system of Case2 is eventuated in lower scheduling costs in Case3. It can be observed from Table V that the 12MW units which are committed in Case2 are not further committed in Case3. Also, one of the 100MW units (unit G11) which is committed in Case1 is not committed in Case3. The reason for this is that there are other sources of reserve in Case3, namely, the DR program participants, which can be utilized to provide reserve in Case3, and it is not required to commit other units to provide reserve while addressing the emission constraints of the system. The total amount of reserve which is scheduled for DR program participants in Case3 is presented in Table IX. Although utilization of DR reserve in Case3 imposes additional cost to the system in Table II, but it simultaneously cause a reduction in both energy and spinning reserve scheduling costs of the system, such that the total scheduling cost reduces by about 5080$ comparing to Case2.

TABLE IX
TOTAL SCHEDULED DR RESERVE IN EACH SCHEDULING HOUR (MW) – CASE3

Hour	1	2	3	4	5	6	7	8	9	10	11	12
Total Scheduled DR Reserve	19	19	19	19	19	19	19	0	83	90	120	149
Hour	13	14	15	16	17	18	19	20	21	22	23	24
Total Scheduled DR Reserve	128	131	144	89	89	89	88	87	87	88	85	50

VI. CONCLUSIONS

In this paper, a model to assess the short-term impacts of utilizing a DR program in a power system constrained by emission caps has been presented. The DR program is designed to procure operating reserve from demand-side participants in the electricity market. The proposed model is a day-ahead network-constrained market clearing model which simultaneously clears the energy and spinning reserve markets. It also schedules the reserve provided by DR resources. The proposed model has been demonstrated on the IEEE-RTS. The results show that the DR program can significantly reduce the costs associated with the emission-constrained power systems, while satisfying the emission caps constraints.

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