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Impact of Demand Response on Unit Commitment in Microgrid Environment

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Demand response program (DRP) aims to reshape an inconsistent load demand and motivates the customers to reduce their energy consumption to get financial benefit. In this paper demand response based unit commitment (DRUC) model is used to study the impact of DRP on generation scheduling and total cost of the system. DRUC model describes the customer behavior for different incentive values and variation in the price elasticity matrix. The simulation study is carried out with a low voltage microgrid system with and without integration of solar and wind renewable sources (RS). It is found from the results that with the increase in incentive value and price elasticity matrix elements, customers tend to participate more in DRP which increases customer benefits and reduces total utility cost. It is also observed that integration of RS significantly reduces the total cost of the system.

Keywords: *Demand response program (DRP), Microgrid (MG), Unit commitment (UC), Price elasticity matrix (PEM), Renewable sources (RS).*

Nomenclature

A	Incentive offered to the customer
a_i, b_i, c_i	Fuel cost coefficients of unit i
$B(P_{L(h)})$	Customer's income during hour h
$B_{O(h)}$	Initial customer benefit
$C_{Benefit}$	Customer benefit in terms of incentive paid at hour h
c_cost	Cold start-up cost
CSH	Cold start hour
E	Price elasticity
EP	Electricity price
∂EP	Change in electricity price
$\partial EP_{(j)}$	Change in electricity price in jth period
EP_o	Initial electricity price
$FCi_{(h)}$	Fuel cost of unit i at hour h
Fmi	Fuel cost for minimum capacity of unit i
$G_{(h)}$	Solar radiation at particular hour h
h	Hour index
h_cost	Hot start-up cost
i	Thermal unit index
k	Segment index
MD	Minimum down time
MU	Minimum up time
N	Number of thermal units
Ns	Number of segments
PEM	Price elasticity matrix
$Pi_{(h)}$	Power output of unit i at hour h
P^{max}	Maximum generation capacity of a unit
P^{min}	Minimum generation capacity of a unit
Pki , Ski	Power and slope of kth segment of unit i
PL	Load demand after implementing DRP
PL_o	Initial load demand
∂P_L	Change in load demand
$\partial P_{L(h)}$	Change in load demand at hour h
PR	Rated power of wind turbine
$PS_{(h)}$	PV module power output at hour h

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$PW_{(h)}$	Wind turbine power output at hour h
SDC	Shut down cost
SUC	Start-up cost
SR	Spinning reserve
T	Total schedule period
TB	Total benefit of customer
TC	Total cost
T^{off}	Continuous OFF duration of a unit
T^{on}	Continuous ON duration of a unit
u_i	On/off status of unit i
$v_{(h)}$	Wind speed at particular hour
v_r, v_{ci}, v_{co}	Rated, cut-in and cut out speed of wind turbine respectively
χ	Area of pv module
Ψ	Customer participation in percentage
□	Efficiency of pv module

1.0 INTRODUCTION

Deregulation of power industries and emerging energy market permits all customers to decide their electricity usage along with the market price. Generally market price is high during peak load period and low during off-peak period. In demand response, customers tend to reduce their load demand during high energy price which in turn enhances the load profile and reduces the total cost of the system.

DR programs are mainly divided into two groups, namely, time based programs (TBP) and incentive based programs (IBP) [1]. The Time base DR program includes time-of-use (TOU) program, real time pricing program (RTP) and critical peak pricing (CPP) program. TBP inspires customers to shift their load from peak hours to low load or off- peak hours to reduce the load demand during peak hours. Incentive based DR program comprises direct load control (DLC), interruptible/curtailable (I/C) program, demand bidding/buyback (DB) program, emergency DR program (EDRP), capacity market program (CAP) and ancillary services (A/S) programs. In IBP, customers are entitled to money or discounts in bill for reducing their energy consumption during period of high electricity price [2].

Unit commitment (UC) is a significant concern of power industry due to the existence of two consecutive problems of on/off decision of generating unit (UC) and dispatching committed generators over a scheduled time horizon (Economic Load Dispatch) to minimize the operating cost while satisfying the load demand and multiple constraints. In recent years, many researchers have developed numerous numerical and meta-heuristics optimization approaches to solve unit commitment problem. The elementary numerical method involves priority list method (PL) [3], mixed integer programming (MIP) [4], branch and bound method (BB) [5], dynamic programming (DP) [6] and lagrangian relaxation (LR) [7] and meta-heuristics techniques includes genetic algorithm (GA) [8], artificial neural networks (ANNs) [9], simulated annealing (SA) [10], evolutionary programming (EP) [11], tabu search (TS)[12], particle swarm optimization (PSO) [13] , ant colony optimization (ACO) [14] and artificial bee colony algorithm (ABC) [15].

A few demand response based unit commitment (DRUC) models are reported in literature. A model of emergency demand response (EDRP) and interruptible load contracts (ILC) is proposed in UC problem to minimize the energy consumption during the critical or peak period of the day to diminish the cost of generation in [16]. The novel approach of calculating marginal cost of virtual generation resources from customer response with DR constraints is discussed in [17]. UC problem associated with DR program model (UCDR) to study the environment and economic effects of DR program is suggested in [18]. DR programming for emission reduction is described in [19]. Several case studies of customer behavior for DR program with different incentive and penalty are discussed in [20].

The main objectives of this paper are:

- To study the impact of DRP on UC and total cost of microgrid system with and without integration of solar and wind renewable sources.
- To study the customer behavior in the DRP for different test cases listed as:
    1. Different values of incentive offered

2. Use of different price elasticity matrix elements
3. Variation in incentive value and price elasticity matrix elements considering 10% reduction in load demand during peak hours.

The deployment of the rest of this paper is as follows:

The fundamental UC objective function using a piecewise linear model and a DR program model is presented in Section 2. Section 3 describes the formulation of DR based UC problem (DRUC) using solar and wind renewable sources. The simulation results for different cases are discussed and compared in Section 4. Finally conclusion is discussed in Section 5.

2.0 MODELING STRUCTURE OF UC AND DR

2.1 Unit commitment problem

UC problem performs optimal scheduling of generating units after appropriate on/off decision of units to attain minimum generation cost while handling load demand and power balance, spinning reserve, generation limit and minimum up/down constraints over a scheduled period of 24 hours. The objective function of UC problem to be minimized is specified as [21]:

$$\min TC = \sum_{i=1}^{N}\sum_{h=1}^{T} FC_{i(h)} + SUC_{i(h)} + SDC_{i(h)} \quad ....(1)$$

The fuel cost of generating unit in quadratic polynomial function of power generated is classically expressed as:

$$FC_{i(h)} = a_i + b_i P_{i(h)} + c_i P^2{}_{i(h)} \quad ....(2)$$

Fuel cost curve is typically nonlinear in nature and it can be linearized by using series of straight line blocks as shown in Figure.1.

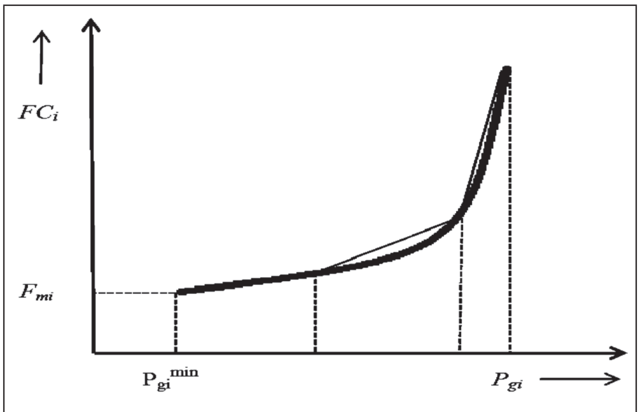

FIG. 1 PIECEWISE LINEAR MODEL OF FUEL COST CURVE

The analytical expression of fuel cost in piecewise linear model is given as [22]:

$$FC_i = F_{mi}u_i + \sum_{k=1}^{Ns} P_{ki}S_{ki} \quad ....(3)$$

The start-up cost depends on temperature of thermal unit and it is described in terms of hot start-up cost and cold start-up cost.

$$SUC_{i(h)} = h\_\cos t_{i(h)} \quad ....(4)$$

$$if \quad MD_{i(h)} \le T_i^{off} \le MD_{i(h)} + CSH_i$$

$$SUC_{i(h)} = c\_\cos t_{i(h)}$$

$$T_i^{off} > MD_{i(h)} + CSH_i$$

The shut-down cost is a constant value for individual generating unit and has negligible influence on generation scheduling and hence excluded in this study.

2.2. Demand response program

To comprehend the impact of customer participation in DR program, economic model of load demand based on price elasticity is essential to understand. Price elasticity is defined as a change in load demand according to the electricity price [20].

$$E = \frac{EP_o}{P_{Lo}} * \frac{\partial P_L}{\partial EP} \quad ....(5)$$

According to (5), price elasticity of the h[th] time with respect to j[th] period can be written as [20]:

$$E_{(h,j)} = \frac{EP_{o(j)}}{P_{Lo(h)}} * \frac{\partial P_{L(h)}}{\partial EP_{(j)}} \quad ....(6)$$

Price elasticity matrix (PEM) is a measure of customer behavior in response to DR program. PEM is a 24×24 matrix with self-elasticity coefficients as diagonal elements and cross elasticity coefficients as off-diagonal elements. There are basically two categories of customer behavior regarding the price variation, namely, single period loads and multi-period loads. The former is considered as stiff load which cannot shift to other periods and estimated by diagonal elements of price elasticity matrix called self-elasticity. The multi-period loads can shift their load from peak hours to off-peak hours and are estimated by off-diagonal elements of PEM called cross elasticity [20].

- **Single period loads**

In DR program participating customer changes their load demand according to the incentive value (*A*) offered to them. A customer benefit in terms of an incentive paid to the customer in h[th] period for reduction of each KWh load demand is given as [20]:

$$C_{Benefit} = A_{(h)}[P_{Lo(h)} - P_{L(h)}] \quad ....(7)$$

After implementation of DR program, the total benefit of the customer in h[th] hour can be written as [20]:

$$T_B = B(P_{L(h)}) - P_{L(h)} * EP_{(h)} + C_{Benefit} \quad ....(8)$$

Total maximum benefit can be attained by making $\partial T_B / \partial P_{L(h)} = 0$ which results in:

$$\frac{\partial B(P_{L(h)})}{\partial (P_{L(h)})} = EP_{(h)} + A_{(h)} \quad ....(9)$$

From [23], typical quadratic benefit function is written as:

$$B(P_{L(h)}) = B_{o(h)} + EP_{o(h)} \times [P_{L(h)} - P_{Lo(h)}]$$

$$\frac{\partial B(P_{L(h)})}{\partial (P_{L(h)})} = EP_{(h)} + A_{(h)} \quad ....(10)$$

After differentiating (10) with respect to P_L *(h)* and substituting the result into (9), the expression obtained is:

$$EP_{(h)} + A_{(h)} = EP_{o(h)} \left\{ 1 + \frac{P_{L(h)} - P_{Lo(h)}}{E_{(h)} * P_{Lo(h)}} \right\} \quad ....(11)$$

Hence, participating customer's consumption will be described as [20]:

$$P_{L(h)} = P_{Lo(h)} \left\{ 1 + E_{(h,h)} * \frac{EP_{(h)} - EP_{o(h)} + A_{(h)}}{EP_{o(h)}} \right\} \quad ....(12)$$

- **Multi-period loads**

Assuming price elasticity as a constant value that is [23]:

$$\frac{\partial P_{L(h)}}{\partial EP_{(j)}} = \text{Constant for } h,$$

where $j = 1, 2 \ldots\ldots 24.$ ....(13)

By relating prices and demands linearly, multi-period load model obtained is:

$$P_{L(h)} = P_{Lo(h)} \left\{ 1 + \sum_{\substack{j=1 \\ j \neq h}}^{24} E_{(h,j)} * \frac{EP_{(j)} - EP_{o(j)} + A_{(j)}}{EP_{o(j)}} \right\} \quad ....(14)$$

- **Load economic model**

Combination of (12) and (14) results in load economic model as follows [20]:

$$P_{L(h)} = P_{Lo(h)} \begin{Bmatrix} 1 + E_{(h,h)} * \dfrac{EP_{(h)} - EP_{o(h)} + A_{(h)}}{EP_o(h)} \\ + \sum_{\substack{j=1 \\ j \neq h}}^{24} E_{(h,j)} * \dfrac{EP_{(j)} - EP_{o(j)} + A_{(j)}}{EP_{o(j)}} \end{Bmatrix} \quad ....(15)$$

3.0 PROBLEM FORMULATION

The mathematical expression of the DRUC model to minimize total cost of the microgrid system after incorporating DRP is described as:

$$\min TC = \sum_{i=1}^{N} \sum_{h=1}^{T} FC_{i(h)} + SUC_{i(h)} + C_{Benefit} \quad ....(16)$$

The execution of above DRUC model must satisfy several constraints listed below:

- *Power balance constraint:* This model incorporates the wind power and solar power for satisfying the power balance constraint of fundamental UC which means that total power generation must be equal to load demand as follows[24]:

$$P_{i(h)} = P_{L(h)} - P_{S(h)} - P_{W(h)} \quad ....(17)$$

The generated output power from wind turbine model is calculated as follows [25]:

$$P_{W(h)} = \begin{cases} q * v_{(h)}^{3} - z * P_R & v_{ci} < v_{(h)} < v_r \\ P_R & v_r < v_{(h)} < v_{co} \\ 0 & otherwise \end{cases} \quad ....(18)$$

where $q = P_R / (v_r^{3} - v_{ci}^{3})$ and

$$z = v_{ci}^{3} / (v_r^{3} - v_{ci}^{3})$$

The power output of photovoltaic module depends on area and efficiency of pv model and solar radiation is calculated as [26]:

$$P_{S(h)} = \chi * \eta * G_{(h)} \quad ....(19)$$

Assuming Ψ as a possible customer participation (in percentage) in DR program then (17) can be written as [18]:

$$P_{i(h)} = (1-\Psi) P_{Lo(h)} + \Psi P_{L(h)} - P_{S(h)} - P_{W(h)} \quad ....(20)$$

$$P_{i(h)} = (1-\Psi) P_{Lo(h)} + \Psi P_{Lo(h)} \times \begin{Bmatrix} 1 + E_{(h,h)} * \dfrac{EP_{(h)} - EP_{o(h)} + A_{(h)}}{EP_{o(h)}} + \\ \sum_{\substack{j=1 \\ j \neq h}}^{24} E_{(h,j)} * \dfrac{EP_{(j)} - EP_{o(j)} + A_{(j)}}{EP_{o(j)}} \end{Bmatrix} - P_{S(h)} - P_{W(h)} \quad ....(21)$$

- Generation limit constraint: Power generation of each unit must be within the prescribed limit for enhanced system operation.

$$P_i^{\min} \leq P_i \leq P_i^{\max} \quad ....(22)$$

- Spinning reserve constraint: Usually certain amount of spinning reserve (SR) is maintained for system reliability.

$$\sum_{i=1}^{N} P_i^{\max} * u_{i(h)} \geq P_{L(h)} + SR_{(h)} \quad ....(23)$$

- Minimum up/down time constraint: Each thermal unit must remain on/off for particular time duration before next transition occurs.

$$T_i^{on} \geq MU_i \qquad T_i^{off} \geq MD_i \quad ....(24)$$

- Initial status of each generating unit is considered before commencement of generation scheduling.

4. SIMULATION RESULT STUDY

The generation scheduling of microgrid with 12 thermal units, 3 wind turbines and a single solar system is carried out for simulation study in this paper. The microgrid system parameters, load demand and market price data extracted from [27] are listed in Table.1 and Table.2 respectively.

TABLE 1

MICROGRID SYSTEM DATA

Unit	P^{max} (kW)	P^{min} (kW)	a (cts/h)	b (cts/kWh)	c (cts/kWh^2)	MU (h)	MD (h)	h_ cost (cts)	c_ cost (cts)	CSH (h)	IS (h)
U1	410	100	65	15.20	0.00052	5	5	550	1100	3	5
U2	410	100	60	15.30	0.00061	5	5	500	1000	3	5
U3	270	50	45	16.60	0.00210	3	3	450	900	2	3
U4	270	50	41	16.50	0.00211	3	3	460	920	2	3
U5	140	25	40	18.50	0.00420	2	2	800	1600	1	2
U6	140	25	38	18.76	0.00530	2	2	750	1500	1	-2
U7	90	20	38	26.70	0.00080	2	2	360	720	1	-2
U8	90	20	35	26.90	0.00120	2	2	350	700	1	-2
U9	65	15	30	29.71	0.00090	1	1	280	560	0	-1
U10	65	15	24	29.92	0.00130	1	1	285	570	0	-1
U11	45	10	18	26.20	0.00240	1	1	200	400	0	-1
U12	45	10	15	26.79	0.00310	1	1	205	410	0	-1

TABLE 2

HOURLY LOAD DEMAND AND MARKET ELECTRICITY PRICE

Hour	1	2	3	4	5	6	7	8	9	10	11	12
Demand (kW)	1000	1030	1050	1070	1090	1150	1300	1400	1640	1700	1870	1870
EP	29.8	29.9	30.0	30.1	30.2	30.3	30.4	30.5	30.6	30.7	30.8	30.9
Hour	13	14	15	16	17	18	19	20	21	22	23	24
Demand (kW)	1850	1800	1720	1700	1650	1630	1550	1450	1350	1200	1150	1050
EP	30.9	30.8	30.7	30.6	30.5	30.4	30.3	30.2	30.1	30.0	29.9	29.8

Load demand curve is divided in three major periods of the day, namely, low load period (1:00 hrs – 5:00 hrs), off-peak period (6:00 hrs – 9:00 hrs and 17:00 hrs – 24.00 hrs) and peak period (10:00 hrs – 16:00 hrs) as shown in Figure.2. The price elasticity matrix used for DRP is given in Table.3 which is collected form [18] with some modification.

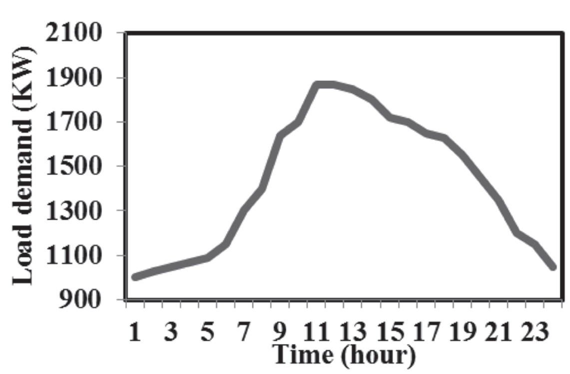

FIG. 2 LOAD DEMAND CURVE

TABLE 3

PRICE ELASTICITY MATRIX

	Low	Off-peak	Peak	Off-peak
Low	-0.08	0.03	0.034	0.03
Off-peak	0.03	-0.11	0.04	0.034
Peak	0.034	0.04	-0.11	0.04
Off-peak	0.03	0.034	0.04	-0.11

This paper mainly focuses on the effects of demand response program on unit commitment without and with renewable sources assuming 40% customer participation of total load demand. The fundamental scheduling is performed using piecewise linear model which splits the cost curves of thermal units into 20 linear segments between the minimum and maximum unit generation capacity. The spinning reserve requirement is assumed as 10% of the load. This study assumes the equal value of electricity price EP_o and EP before and after implementation of DRP [18]. The different cases considered for simulation study are listed in Table 4.

4.1 Test case-1

This test case involves generation scheduling without renewable sources (RS). The study comprises two cases without and with demand response (DR) program.

TABLE 4

DIFFERENT TEST CASES

cases	Incentive offered	Price elasticity	Load demand
Test case-1 (Without RS)			
1	-	-	Base load
2	4	As Table.3	
Test case-2 (With RS)			
3	-	-	Base load
4	4	As Table.3	
5	8	As Table.3	
6	2	As Table.3	
7	4	As double value of Table.3	
8	4	As half value of Table.3	
9	4	As Table.3	10% reduction in peak of base load
10	4	As half value of Table.3	
11	8	As half value of Table.3	

Case 1: This case is considered as a base case of unit commitment over a 24 hour scheduled period without employing DR program. The simulation is executed to solve the objective function given in (16) and generation scheduling with fuel cost, start- up cost and total generation cost is presented in Table.5. It is observed from the Table.5. that cheaper units U-1 to U-4 remains in ON condition for entire scheduled period of 24 hours. Generating units U-1 and U-2 generates power at their maximum generation capacity to share the major portion of the load demand. The utility cost including fuel cost and start-up cost in this case is 585564.50 cents.

TABLE 5

GENERATION SCHEDULING OF A BASE CASE

Hour	U1 (kW)	U2 (kW)	U3 (kW)	U4 (kW)	U5 (kW)	U6 (kW)	U7 (kW)	U8 (kW)	U9 (kW)	U10 (kW)	U11 (kW)	U12 (kW)	FC (cts)	SUC (cts)	TC (cts)
1	410.0	410.0	73.1	106.8	0	0	0	0	0	0	0	0	15918.6	0	15918.6
2	410.0	410.0	90.5	119.5	0	0	0	0	0	0	0	0	16427.3	0	16427.3
3	410.0	410.0	98.9	131.0	0	0	0	0	0	0	0	0	16767.6	0	16767.6
4	410.0	410.0	113.4	136.6	0	0	0	0	0	0	0	0	17108.6	0	17108.6
5	410.0	410.0	127.4	142.6	0	0	0	0	0	0	0	0	17450.7	0	17450.7
6	410.0	410.0	154.2	175.8	0	0	0	0	0	0	0	0	18481.5	0	18481.5
7	410.0	410.0	219.7	235.3	25.0	0	0	0	0	0	0	0	21158.7	1600	22758.7
8	410.0	410.0	260.0	270.0	25.0	25.0	0	0	0	0	0	0	22988.2	1500	24488.2
9	410.0	410.0	270.0	270.0	140.0	100.0	20.0	0	0	0	10.0	10.0	27964.9	1530	29494.9
10	410.0	410.0	270.0	270.0	140.0	140.0	20.0	20.0	0	0	10.0	10.0	29339.7	700	30039.7

11	410.0	410.0	270.0	270.0	140.0	140.0	90.0	34.7	15.0	15.0	45.0	30.2	34028.2	1130	35158.2
12	410.0	410.0	270.0	270.0	140.0	140.0	90.0	34.7	15.0	15.0	45.0	30.2	34028.2	0	34028.2
13	410.0	410.0	270.0	270.0	140.0	140.0	90.0	20.0	15.0	15.0	45.0	25.0	33488.9	0	33488.9
14	410.0	410.0	270.0	270.0	140.0	140.0	55.0	20.0	15.0	15.0	45.0	10.0	32146.9	0	32146.9
15	410.0	410.0	270.0	270.0	140.0	140.0	20.0	20.0	0	0	30.0	10.0	29865.6	0	29865.6
16	410.0	410.0	270.0	270.0	140.0	140.0	20.0	20.0	0	0	10.0	10.0	29339.7	0	29339.7
17	410.0	410.0	270.0	270.0	140.0	110.0	20.0	0	0	0	10.0	10.0	28163.7	0	28163.7
18	410.0	410.0	270.0	270.0	140.0	90.0	20.0	0	0	0	10.0	10.0	27767.3	0	27767.3
19	410.0	410.0	270.0	270.0	103.7	56.3	20.0	0	0	0	10.0	0	26117.0	0	26117.0
20	410.0	410.0	270.0	270.0	65.0	25.0	0	0	0	0	0	0	23920.4	0	23920.4
21	410.0	410.0	246.6	258.4	25.0	0	0	0	0	0	0	0	22036.8	0	22036.8
22	410.0	410.0	179.5	200.5	0	0	0	0	0	0	0	0	19346.4	0	19346.4
23	410.0	410.0	154.2	175.8	0	0	0	0	0	0	0	0	18481.5	0	18481.5
24	410.0	410.0	98.9	131.0	0	0	0	0	0	0	0	0	16767.6	0	16767.6
												Total	**579104.3**	**6460**	**585564.3**

Case 2: In this case DR program is implemented with assumed 40 % customer participation considering 4 cents as a base incentive. The scheduling for this case is shown in Table 6. The load demand plot without and with DR is shown in Figure 3 which confirms that incorporation of demand response reduces the net load demand and hence the generation cost of a system.

TABLE 6

GENERATION SCHEDULING WITH DEMAND RESPONSE

Hour	**U1 (kW)**	**U2 (kW)**	**U3 (kW)**	**U4 (kW)**	**U5 (kW)**	**U6 (kW)**	**U7 (kW)**	**U8 (kW)**	**U9 (kW)**	**U10 (kW)**	**U11 (kW)**	**U12 (kW)**	**FC (cts)**	**SUC (cts)**	**TC (cts)**
1	410.0	410.0	96.3	120.2	0	0	0	0	0	0	0	0	16537.9	0	16537.9
2	410.0	410.0	112.1	135.3	0	0	0	0	0	0	0	0	17065.6	0	17065.6
3	410.0	410.0	125.4	142.6	0	0	0	0	0	0	0	0	17417.8	0	17417.8
4	410.0	410.0	134.5	154.2	0	0	0	0	0	0	0	0	17770.7	0	17770.7
5	410.0	410.0	143.5	165.8	0	0	0	0	0	0	0	0	18124.4	0	18124.4
6	410.0	410.0	156.9	177.3	0	0	0	0	0	0	0	0	18554.8	0	18554.8
7	410.0	410.0	223.7	236.1	25.0	0	0	0	0	0	0	0	21242.6	1600	22842.6
8	410.0	410.0	265.1	270.0	25.0	25.0	0	0	0	0	0	0	23079.2	1500	24579.2
9	410.0	410.0	270.0	270.0	140.0	106.0	20.0	0	0	0	10.0	10.0	28084.1	1120	29204.1
10	410.0	410.0	270.0	270.0	140.0	99.7	20.0	0	0	0	10.0	10.0	27960.0	0	27960.0
11	410.0	410.0	270.0	270.0	140.0	140.0	58.9	20.0	15.0	15.0	45.0	10.0	32252.5	1830	34082.5
12	410.0	410.0	270.0	270.0	140.0	140.0	59.1	20.0	15.0	15.0	45.0	10.0	32258.2	0	32258.2
13	410.0	410.0	270.0	270.0	140.0	140.0	54.8	20.0	15.0	0	45.0	10.0	31670.0	0	31670.0
14	410.0	410.0	270.0	270.0	140.0	140.0	20.0	20.0	15.0	0	31.4	10.0	30378.8	0	30378.8
15	410.0	410.0	270.0	270.0	140.0	99.4	20.0	20.0	0	0	10.0	10.0	28519.5	0	28519.5
16	410.0	410.0	270.0	270.0	140.0	99.6	20.0	0	0	0	10.0	10.0	27956.1	0	27956.1
17	410.0	410.0	270.0	270.0	123.4	73.4	20.0	0	0	0	10.0	0	26833.0	0	26833.0
18	410.0	410.0	270.0	270.0	110.0	67.4	20.0	0	0	0	10.0	0	26454.2	0	26454.2
19	410.0	410.0	270.0	270.0	87.1	43.1	0	0	0	0	0	0	24690.4	0	24690.4
20	410.0	410.0	253.9	270.0	25.0	25.0	0	0	0	0	0	0	22880.7	0	22880.7
21	410.0	410.0	217.3	235.2	25.0	0	0	0	0	0	0	0	21116.9	0	21116.9
22	410.0	410.0	155.9	177.4	0	0	0	0	0	0	0	0	18538.1	0	18538.1
23	410.0	410.0	131.0	154.0	0	0	0	0	0	0	0	0	17708.9	0	17708.9
24	410.0	410.0	80.9	107.9	0	0	0	0	0	0	0	0	16068.3	0	16068.3
												Total	**563163**	**6050**	**569213**

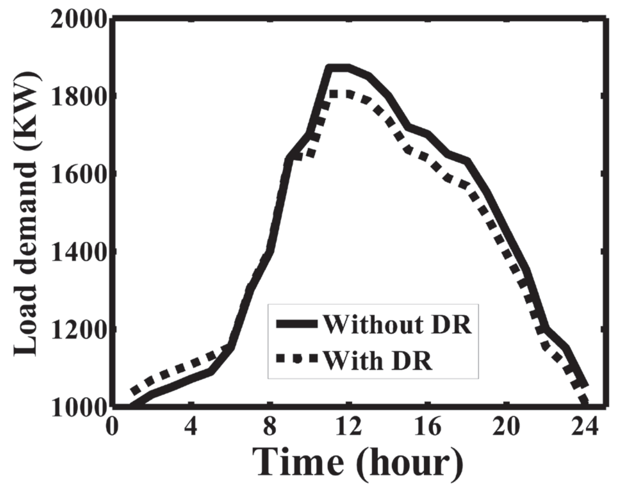

FIG. 3 LOAD DEMAND WITH AND WITHOUT DEMAND RESPONSE

The utility cost including generation cost and incentives is 569213.0 cents which causes a net profit of 13715.9 cents to utility and benefit of 2635.6 cents to the customer. This case yields 2.34% reduction in total cost as compared with Case 1.

4.2 Test case-2

This test case considers the effect of solar and wind renewable sources (RS) in unit commitment without and with DR program. The solar and wind data used for analysis are received from NREL's data center [28]. Solar radiation and wind speed for normal sunny day for 24 hours are shown in Figure.4 and Figure.5 respectively. In this test case, wind and solar power are calculated using (18) and (19) respectively. The parameters required for RS are given in Table.7.

TABLE 7

SOLAR AND WIND PARAMETERS

PV system (1×360kWp)		**Wind Plant (3×140kWp)**	
χ	1659×870 mm	P_R = 140 kW	v_{ci} = 3 m/sec
η	15 %	v_r = 12 m/sec	v_{co} = 25 m/sec

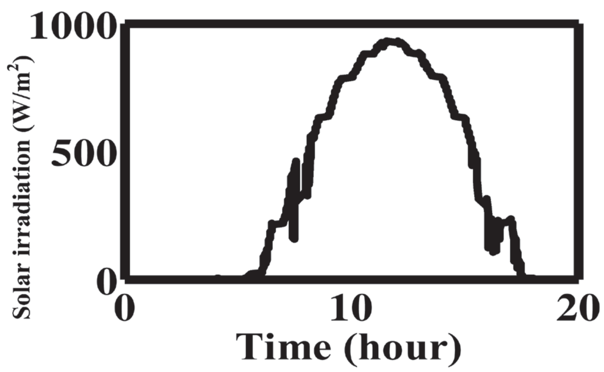

FIG. 4 SOLAR RADIATION OF A NORMAL SUNNY DAY

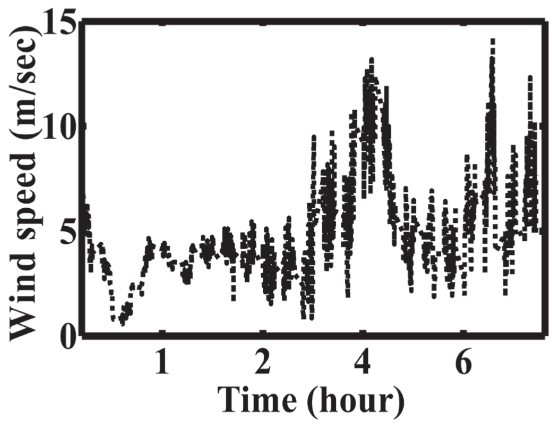

FIG. 5 WIND SPEED OF A NORMAL DAY

Case 3: This case involves the fundamental unit commitment with renewable sources (RS) without DR program. The load demand reduction due to integration of RS from the original demand is presented in Figure 6. The generation scheduling for this case is given in Table 8. It is observed that the presence of RS results in 12.17% cost reduction compared to Case 1.

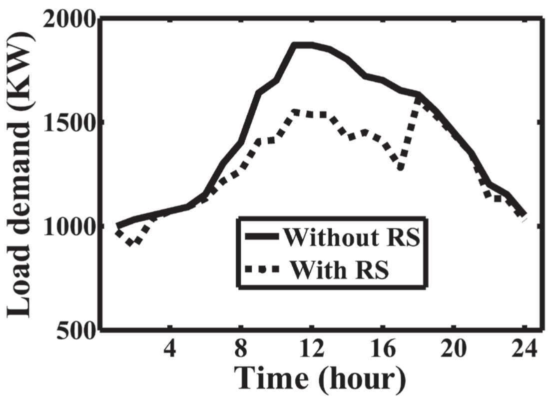

FIG. 6 LOAD DEMAND WITH AND WITHOUT RENEWABLES

TABLE 8

GENERATION SCHEDULING WITH RENEWABLE SOURCES

Hour	U1 (kW)	U2 (kW)	U3 (kW)	U4 (kW)	U5 (kW)	U6 (kW)	U7 (kW)	U8 (kW)	U9 (kW)	U10 (kW)	U11 (kW)	U12 (kW)	FC (cts)	SUC (cts)	TC (cts)
1	410.0	410.0	0	152.0	0	0	0	0	0	0	0	0	15418.4	0	15418.4
2	410.0	410.0	0	79.5	0	0	0	0	0	0	0	0	14186.5	0	14186.5
3	410.0	410.0	0	191.0	25.0	0	0	0	0	0	0	0	16595.0	800	17395.0
4	410.0	410.0	0	225.0	25.0	0	0	0	0	0	0	0	17185.4	0	17185.4
5	410.0	410.0	127.4	142.6	0	0	0	0	0	0	0	0	17450.7	450	17900.7
6	410.0	410.0	146.8	165.8	0	0	0	0	0	0	0	0	18180.9	0	18180.9
7	410.0	410.0	188.9	208.6	0	0	0	0	0	0	0	0	19652.1	0	19652.1
8	410.0	410.0	200.5	217.8	25.0	0	0	0	0	0	0	0	20518.1	800	21318.1
9	410.0	410.0	263.4	270.0	25.0	25.0	0	0	0	0	0	0	23047.6	1500	24547.6
10	410.0	410.0	270.0	270.0	27.8	25.0	0	0	0	0	0	0	23219.0	0	23219.0
11	410.0	410.0	270.0	270.0	100.4	55.2	20.0	0	0	0	10.0	0	26034.2	1120	27154.2
12	410.0	410.0	270.0	270.0	97.8	55.2	20.0	0	0	0	0	0	25702.5	0	25702.5
13	410.0	410.0	270.0	270.0	93.8	49.2	20.0	0	0	0	10.0	0	25788.9	200	25988.9
14	410.0	410.0	270.0	270.0	35.3	25.0	0	0	0	0	0	0	23358.4	0	23358.4
15	410.0	410.0	270.0	270.0	66.4	25.0	0	0	0	0	0	0	23947.6	0	23947.6
16	410.0	410.0	270.0	270.0	25.2	25.0	0	0	0	0	0	0	23169.6	0	23169.6
17	410.0	410.0	212.1	223.9	25.0	0	0	0	0	0	0	0	20826.7	0	20826.7
18	410.0	410.0	270.0	270.0	140.0	0	31.5	20.0	0	0	45.0	10.0	27800.6	2230	30030.6
19	410.0	410.0	270.0	270.0	89.0	43.1	20.0	20.0	0	0	0	0	25872.9	750	26622.9
20	410.0	410.0	270.0	270.0	56.9	25.0	0	0	0	0	0	0	23765.8	0	23765.8
21	410.0	410.0	246.6	258.4	25.0	0	0	0	0	0	0	0	22036.8	0	22036.8
22	410.0	410.0	147.3	165.8	0	0	0	0	0	0	0	0	18189.4	0	18189.4
23	410.0	410.0	143.3	165.8	0	0	0	0	0	0	0	0	18121.2	0	18121.2
24	410.0	410.0	86.5	119.5	0	0	0	0	0	0	0	0	16359.8	0	16359.8
												Total	**506428.5**	**7850**	**514278.5**

Case 4, 5, 6: In these cases, different incentive values of price elasticity matrix of Table.3 are used to analyze the consumer behavior towards DR program. Initially for Case 4 the base incentive is considered as 4 cents. Then in Case -5 the incentive value is doubled the base value (8 cents) and Case-6 deals with half the value (2 cents) of base incentive value. The incentives paid to the customers for their load demand reduction in these three cases are 2274.6 cents, 9098.0 cents and 568.62 cents respectively. It is clear that the customer's behavior in DRP is highly influenced by the incentive value. Customers tend to reduce more load demand for higher incentive value and less reduction in load demand for lower incentive value. These cases result in 12.91%, 14.12% and 13.26% reduction in total cost respectively compared to Case 1.

Case 7, 8: To realize the influence of price elasticity matrix PEM over unit commitment with base incentive, all the matrix elements given in Table.3 are multiplied by 2 in Case 7 and divided by 2 in Case 8. In Case 7 utility cost is 502846.2 cents including generation cost and incentive offered, which gives 82718.3 cents net utility profit and 14.12% reduction in total cost compared to Case 1 while for Case 8 net utility profit is 77687.5 cents and 13.26% reduction in total cost. The customers benefit for Case 7 is 9098.0 cents which reveals that the customer has more flexibility to shift their load from peak to off-peak hours. Similarly, the customer benefit in Case 8 is 568.62 cents which indicates the customer's stiffness towards load shifting for low value of price elasticity matrix elements.

Case 9, 10, 11: These cases assume 10% reduction in load demand during peak hours. Case 9 is considered with base incentive and original PEM which gives 97806.8 cents as a net utility profit. Load reduction during peak hour results in 16.7% decrease in total cost compared to Case 1. Then the PEM elements are assumed half with base incentive in Case 10 which yields an increase in total cost of a system. Half PEM elements results in less incentive benefit to the customer compared to Case 9 which shows that the customers are stiffer to adopt changes in load demand because of half the PEM elements. Then the incentive value is kept double with half the PEM elements in Case 11. The results obtained in Case 11 are analogous to Case 9.

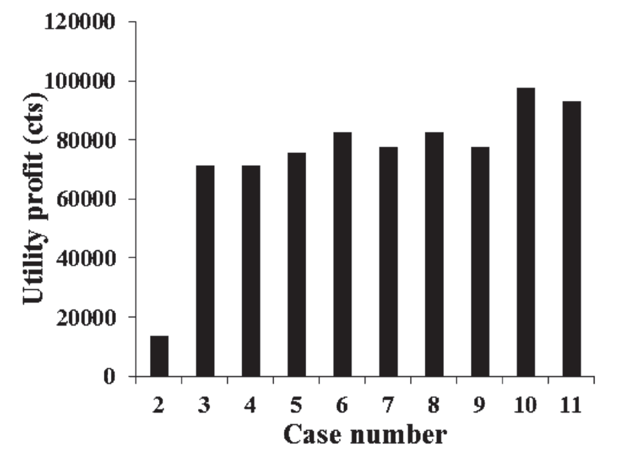

FIG. 8 FIGURE 8 NET UTILITY PROFIT FOR DIFFERENT CASES

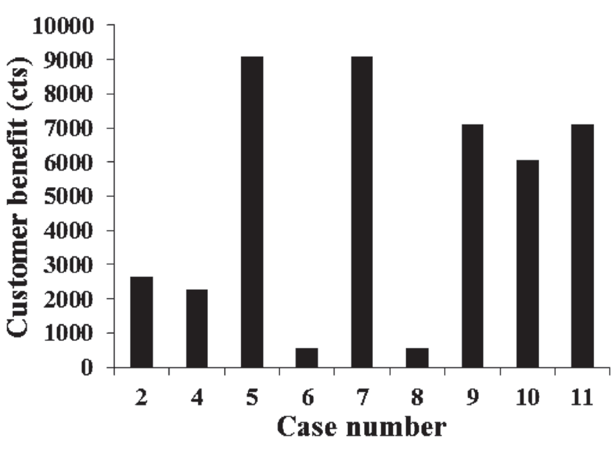

FIG. 7 INCENTIVES PAID TO THE CUSTOMER FOR DIFFERENT CASES

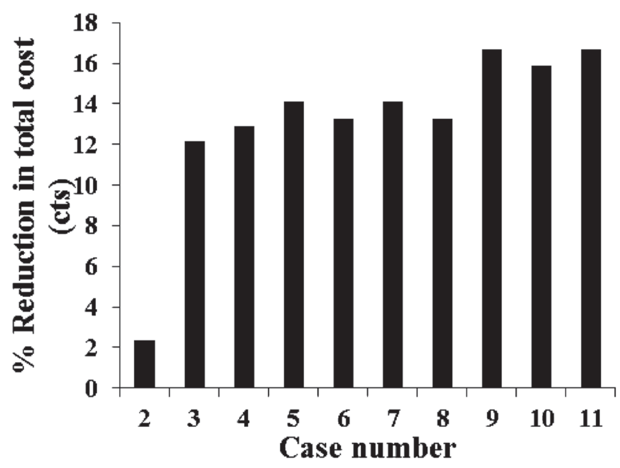

FIG. 9 REDUCTION IN COST FOR DIFFERENT CASES

TABLE 9

COST COMPARISON OF DIFFERENT CASES

cases	Generation cost (cents)	customer benefit (cents)	Utility cost (cents)	Net utility Profit (cents)	% reduction in cost
Test case-1 (Without RS)					
1	585564.5	-	585564.5	-	-
2	569213.0	2635.6	571848.6	13715.9	2.34
Test case-2 (With RS)					
3	514278.5	-	514278.5	71286.0	12.17
4	507691.6	2274.6	509966.2	75598.3	12.91
5	493748.2	9098.0	502846.2	82718.3	14.12
6	507308.4	568.62	507877.0	77687.5	13.26
7	493748.2	9098.0	502846.2	82718.3	14.12
8	507308.4	568.62	507877.0	77687.5	13.26
9	480656.1	7101.68	487757.7	97806.8	16.70
10	486415.7	6052.92	492468.6	93095.9	15.89
11	480656.1	7101.68	487757.7	97806.8	16.70

Figure 7 Cost comparison of different cases is summarized in Table.9. The summarized plots of customer benefit, net utility profit and percentage reduction in total cost are shown in Figure.7, Figure.8 and Figure.9 respectively. From these plots, it is concluded that the customer benefit is highest in Case 5 and Case 7 while utility profit and % reduction in total cost are highest in Case 9 and Case 10 respectively.

6.0 CONCLUSION

Demand response plays a significant role to uniform the load demand curve thereby shifting demand from peak hours to low load and off-peak periods. In this paper, the demand response based unit commitment (DRUC) model with integration of wind and solar renewable sources is considered to study the impact of DR on unit commitment and total cost of a system. In DR, customer behavior for different incentive value and variation in price elasticity matrix elements are also studied. This study shows that the customer benefit is amplified for the higher value of incentive and price elasticity matrix elements. This model also confirms that the net utility profit is increased by decreasing load demand during peak hours. The simulation results conclude that the utility cost is reduced after implementing DR program which further decreases with the incorporation of wind and solar renewable sources.

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