Optimal Dynamic Tariffs for Flexible Ramp Market in the Presence of Wind Power Generation and Demand Response

Gerardo J. Osório, Miadreza Shafie-khah
C-MAST/UBI, Covilha, Portugal
miadreza@ubi.pt;
gjosilva@gmail.com

Nuno G. S. Soares
FEUP, Porto,
Portugal
ee12191@fe.up.pt

João P. S. Catalão
INESC TEC and FEUP, Porto, C-MAST/UBI,
Covilha, and INESC-ID/IST-IL, Lisbon
Portugal
catalao@fe.up.pt

***Abstract*—The uncertainty and variability as a consequence of modern utilization of wind power in the electrical system besides unpredicted contingencies of the system components can impose crucial challenges on the Independent System Operator's (ISO) performance. In such a situation, increasing operational flexibility is the main way to cover wind power unpredictability and to enable secure operation of the power system. To this end, this paper proposes a flexible security-constrained program to schedule supply-side and demand-side via an optimal pricing and incentive scheme. The considered demand response (DR) programs include time of use (TOU), real-time pricing (RTP), critical peak pricing (CPP), as well as emergency demand response program (EDRP). The study aims to find the most effective DR scheme among a set of DR programs to improve the efficiency of electricity markets while guaranteeing the security and environmental restrictions through minimization of two objective functions, the ISO's operational cost and pollutant emissions from generation units.**

Keywords—Air pollution, Demand response programs, Operation flexibility, Renewable energies, Stochastic programming, Wind integration

I. Nomenclature

A. Indexes

b, b'	Buses indexes.
i	Generation unit index.
j	Loads index.
h	Sub-hourly time periods index.
l	Transmission lines index.
m	Segment index.
p	Wind farm index.
s	Scenarios index.
t, t'	Hourly time periods indexes.

B. Parameters

$A_{i,t}, B_{i,t}$	Linearization of generation unit curve price.
$A(t)$	Incentive at hour *t* ($/MWh).
$B(t)$	Customer's income.
$C_i(m)$	Slope of the segment *m* regarding the cost of fuel of each generator *i* ($/MWh).
C_i^{FRU}/C_i^{FRD}	Offered cost of upward/downward ramp product ($/MWh).
C_i^{RU}/C_i^{RD}	Offered costs of up and down deployed reserves ($/MWh).
C_i^{SU}	Start-up cost of thermal units ($).
C_i^{UC}/C_i^{DC}	Offered costs of up and down capacity reserves ($/MWh).
C_p^{spill}	Cost of wind spillage ($/MWh).
$C_{p,t}^{wind}$	Cost of the wind power ($/MWh).
$d_0(t)'$	Initial electricity demand before DR (MW).
$\lambda_{i,t}$	Price of each generation unit ($).
Δ	Real-time slot.
$DFRD_{s,t,h}^{RT}$	Real-time downward ramp need (MW).
$DFRD_t^{ex}$	Expected nominal hourly downward ramp need (MW).
$DFRU_{s,t,h}^{RT}$	Real-time upward ramp need (MW).
$DFRU_t^{ex}$	Expected nominal upward ramp need at time *t* (MW).
DR^{max}	Maximum DR participation level (%).
η_A	Weight coefficient of the incentive.
MUT_i/MDT_i	Minimum up/down time (h).
$NB(t)$	Customer's net benefit.
NLC	Load with no cost.
$P_{i,t}^{min}, P_{i,t}^{max}$	Minimum/Maximum output of conventional units (MW).
P_p^{inst}	Power at each wind farm *p* (MW).
$P_{p,s,t,h}$	Real-time generation of wind farms (MWh).
$P_{p,t}^{wind}$	Forecasted wind generation (MWh).
R_l	Resistance of the transmission line *l* (Ω).
$\rho_0(t)$	Initial electricity tariff ($/MWh).
RU_i/RD_i	Ramp up and ramp down rates (MW/h).
$TP_{l,s,t}$	Power flow of branch *l* in scenario *s* at the hour *t* (MW).
$VOLL_j$	Value of lost load *j* ($/MWh).
w_s	Probability of each scenario *s*.

C. Variables

c_i^{RU}/c_i^{RD}	Cost of up/down real-time reserve ($/MWh).
$\Delta d(t)$	Changes in electrical demand (MW).

J.P.S. Catalão acknowledges the support 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, UID/EMS/00151/2013, 02/SAICT/2017 - POCI-01-0145-FEDER-029803, and also funding from the EU 7th Framework Programme FP7/2007-2013 under GA no. 309048.

978-1-5386-5186-5/18/$31.00 ©2018 IEEE

$\Delta FRU/\Delta FRD$	Real-time flexible up and down ramps (MW).
d_t	Electricity Demand (MW).
$F_{l,t}$	Energy flow in the line *l* at time *t* (A).
FRU/FRD	Hourly flexible up and down ramps (MW).
$L_{final}(t)$	Final load after DR.
$LS_{j,s,t}$	Load shedding (MWh).
$P_{i,t,m}$	Generation of segment *m* in linearized cost curve (MW).
$P_{i,s,t,h}$	Real-time generation of units (MW).
ρ_t	Electricity price (\$/MWh).
$\rho_t^{LTP\|OTP\|PTP}$	Tariffs of low-load, off-peak and peak periods in TOU program (\$/MWh).
$r_{s,i,t}^{RU}/r_{s,i,t}^{RD}$	Deployed up/down reserve (MWh).
$Spil_{p,s,t}^{wind}$	Wind power spillage (MWh).
SUC_i	Start-up cost of thermal generation unit (\$).
$U_{i,t}$	Binary variable to indicate on and off states.

II. INTRODUCTION

The increased penetration of green energy sources because of growing the environmental affairs boosts the inevitability of further flexibility resulted from supply unpredictability. Employing these green energy sources would even reduce the current flexibility level, because thermal units are replaced with the uncertain energy sources in power system dispatch as a result of giving the priority of generation to clean power plants. On this basis, thermal plants need to start-up, shut-down as well as ramp up and ramp down more frequently to retain the supply-demand balance in real-time [1].

For compensating the part of thermal power plants' loss and incentivizing these units to deliver upward/downward flexible ramps, a well-functioning market has been established so-called "flexiramp" in California ISO (CAISO) [2] and "ramp capability" in Midcontinent ISO (MISO) [3] accompanied by energy and reserve markets to guarantee the rampability of generation mix to handle the unexpected load variation.

Investigating real-world Demand Response (DR) experiences indicates that DR programs are the prospective measure to move towards flexible power system [4]. Thus, empowering end-users' potential by means of proper DR programs would open up an opportunity to improve the power system flexibility to overcome renewable energy inconsistency and contingencies. The uncertainties of renewable energy sources have been integrated with Security Constrained Unit Commitment (SCUC) in several reports [5].

DR has been considered in SCUC problems [6-8]. In [6], a stochastic SCUC framework is proposed where DR is modeled by considering DR providers who manage end-users' response and take part in the markets. Operation characteristics of aggregated DR e.g., bidding strategies, demand pattern, and intertemporal features are taken into account in [7]. In [8], a stochastic model is developed to find the optimal time of use (TOU) rate in an SCUC problem on the basis of system reliability index.

Moreover, the benefit of utilizing stochastic programming over deterministic approaches may be assessed by two values regarding the total cost, the expected perfect information and the stochastic solution. In two-stage SCUC models, there are day-ahead and real-time decisions. Due to various scenarios, the problem would be relatively large.

It should be noted that, in the second stage, the scenarios are not directly related to each other. Therefore, when the decisions of the first-stage are obtained, the second stage of every single scenario is individually treated; consequently it yields small groups of individual optimization problem. In Fig. 1 is represented a scenario tree for a two-stage problem adapted from [9].

References [5-8] address comprehensive model of SCUC, however, the uncertainty of wind generation, and environmental concerns have not taken into account. Providing a proper DR strategy enables the entire potential of demand-side and ensures the secure, economic and green power system operation.

To this end, this article proposes a flexible security-constrained program to schedule supply-side and demand-side via an optimal pricing and incentive scheme. The DR programs will be TOU, RTP, CPP, EDRP tariffs. The study is from the ISO's point of view, and the objective is to find the most effective DR scheme among DR programs to improve the efficiency of electricity markets while ensuring the security and environmental restrictions.

Hence, in this paper, an SCUC problem is presented taking DR and wind power generation into account. Several indices are measured for assessing the effectiveness of the markets, system security and pollutions. The indices are market prices, social welfare, load factor (peak to valley proportion), Lerner index, and air pollution.

To discover the most efficient DR program, a multi-objective problem is employed to study aforementioned indices [10], [11], considering the generation costs, pollutant emissions, losses of load, wind spillage costs, start-up, shut-down and reserve costs are also considered. The two proposed objective functions are the minimization of operational cost to the ISO and the minimization of the emissions of pollutant gases from generation units. The remaining paper is structured as follows. Section III provides the mathematical formulations, Section IV provides the case study and outcomes, and finally Section V provides the main conclusions.

III. MATHEMATICAL FORMULATION

A. Electricity Market Model

Each participant of the electrical market is modeled as an agent whose main purpose is to maximize its own profits. In this sense the ISO gives the day-ahead market price using a SCUC [12]. The objective function of the problem corresponds to minimization of the ISO's cost (1), considering the unit's prices (2) and incentive's paid by the system operator to the clients (3):

$$Min \sum_{t=1}^{T} [(\lambda_{i,t}.P_{i,t}) + inc] \quad (1)$$

$$\lambda_{i,t} = P_{i,t}.A_{i,t} + U_{i,t}.B_{i,t} \quad (2)$$

$$inc = \sum_{t=12}^{T_{peak}} [\Delta d.A.\eta_A] \quad (3)$$

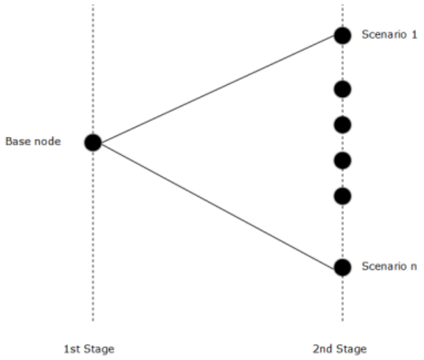

Fig. 1. Two-stage scenario tree example.

B. Electricity Market Model Constraints

The constraints related to the electricity market model are the following [13]:

$$P_{i,t}^{min}.U_{i,t} \le P_{i,t} \le P_{i,t}^{max}.U_{i,t} \tag{4}$$

$$\sum_{i=1}^{I} P_{i,t}^{max}.U_{i,t} \ge \sum_{i=1}^{I} d_{i,t} + R_{i,t} \tag{5}$$

$$P_{i,t} - P_{i,t-1} \le RU_i.U_{i,t} + P_i^{min}.(1 - U_{i,t}) \tag{6}$$

$$P_{i,t} - P_{i,t-1} \le RD_i.U_{i,t} + P_i^{min}.(1 - U_{i,t}) \tag{7}$$

$$Loss_{l,t} = F_{l,t}^2.R_l \tag{8}$$

$$Loss_{total} = \sum_l Loss_{l,t} \tag{9}$$

C. DR Programs Model

In order to model DR programs it is necessary to define the concept of elasticity of demand which represents the clients response to changes in electricity prices; which is the same as saying that if electricity prices are changed for different hours, the consumers react.

1) Objective Function

$$\begin{aligned} F_{cost} = \sum_t \Big\{ & \sum\nolimits_i \Big[NLC_i.U_{i,t} + C_i^{su} + \sum\nolimits_m P_{i,t}(m).C_i(m) \Big] \\ & + \sum\nolimits_i \big[C_i^{RU}.R_{i,t}^U + C_i^{RD}.R_{i,t}^D \\ & + C_i^{FRU}.FR_{i,t}^U + C_i^{FRD}.FR_{i,t}^D \big] \Big\} \\ + \sum_s \sum_t \sum_h w_s.\Delta.\Big\{ & \sum\nolimits_i \big[C_i^{RU}.r_{i,s,h,t}^{RU} - C_i^{RD}.r_{i,s,h,t}^{RU} \\ & + C_{i,h}^{FRU}.\Delta FRU_{i,s,h,t} \\ & + C_{i,h}^{FRD}.\Delta FRD_{i,s,h,t} \big] \Big\} \end{aligned} \tag{10}$$

2) Thermal Units' Constraints

The power output of conventional generation plants and their limits have already been denoted in (4). The operation range of thermal power plants including reserve and flexible ramps are shown in (11) and (12), respectively. The sum of total reserve and ramping capacities cannot surpass the ramping capability of generation plants as presented in (13) and (14). Furthermore, the deployed up/down reserve restrictions are presented by (15) and (16). The start-up cost is expressed in equation (17). Actual power generations of conventional plants utilizing flexible ramps are limited by equations (18) and (19) [14-16].

$$P_{i,t}R_{i,t}^{UC} + FRU_{i,t} \le P_i^{max}.U_{i,t} \tag{11}$$

$$P_{i,t}R_{i,t}^{DC} + FRD_{i,t} \ge P_i^{min}.U_{i,t} \tag{12}$$

$$0 \le R_{i,t}^{UC} + FRU_{i,t} \le RU_i.U_{i,t} \tag{13}$$

$$0 \le R_{i,t}^{DC} + FRD_{i,t} \le RD_i.U_{i,t} \tag{14}$$

$$0 \le r_{i,s,h,t}^{up} \le R_{i,t}^{UC} \tag{15}$$

$$0 \le r_{i,s,h,t}^{dn} \le R_{i,t}^{DC} \tag{16}$$

$$SUC_{i,t} \ge SC_i(U_{i,t} - U_{i,t-1}) \tag{17}$$

$$P_{i,s,t,h} + FRU_{i,t} + \Delta FRU_{i,s,t,h} \le P_i^{max}U_{i,t} \tag{18}$$

$$P_{i,s,t,h} + FRD_{i,t} + \Delta FRD_{i,s,t,h} \le P_i^{min}U_{i,t} \tag{19}$$

3) Load, Wind Generation and Network Constraints

The supply-demand balance in the day-ahead session is shown in (20). The DC power flow and network constraints are formulated by (21) and (22). It should be noted that, TOU is considered by the concept of price-demand elasticities. Moreover, as an assumption, ISOs develop ramp forecast tools for the required upward/downward flexible ramps to manage deviations of the demand, expressed in (23) and (24).

$$\sum_i P_{i,t} + \sum_p P_{p,t}^{wind,s} - \sum_j d_{j,t}^{DR} = \sum_l F_{l,t}^0 \tag{20}$$

$$F_{l,t}^0 = \frac{(\sigma_{b,t} - \sigma_{b',h})}{X_l} \tag{21}$$

$$-F_l^{max} \le F_{l,t}^0 \le F_l^{max} \tag{22}$$

$$\sum_i FRD_{i,t} \ge DFRU_t^{ex} \tag{23}$$

$$\sum_i FRD_{i,t} \ge DFRD_t^{ex} \tag{24}$$

D. Augmented ε-Constraint

The specified method is designed to discover the best points of the Pareto front based on the optimization of one of the objectives, while the other goal is considered as a constraint bound by a range of ε_{kz} values. The problem is solved repeatedly for different values of ε_{kz} to generate the whole set of Pareto. This can be expressed considering the Payoff table represented in Table I. Table I represents the problem solution for each of the objective functions, by taking the entire constraints into account.

IV. Case Study and Results

For this problem, the chosen solution was formed on IEEE 24 bus Reliability Test System, presented in Fig. 2, as it is very similar to real large-scale electrical grids that contain a variety of generation technologies. The six hydroelectric generation units at bus 22 were removed and the final modified grid is then defined with twenty-six generation units, six wind farms, thirty lines and seventeen loads [17,18].

TABLE I. Payoff Table Example

	F_{cost} **($)**	$F_{emission}$ **(kg)**
Min F_{cost}	F_{cost}^{min}	$F_{emission}^{max}$
Min $F_{emission}$	F_{cost}^{max}	$F_{emission}^{min}$

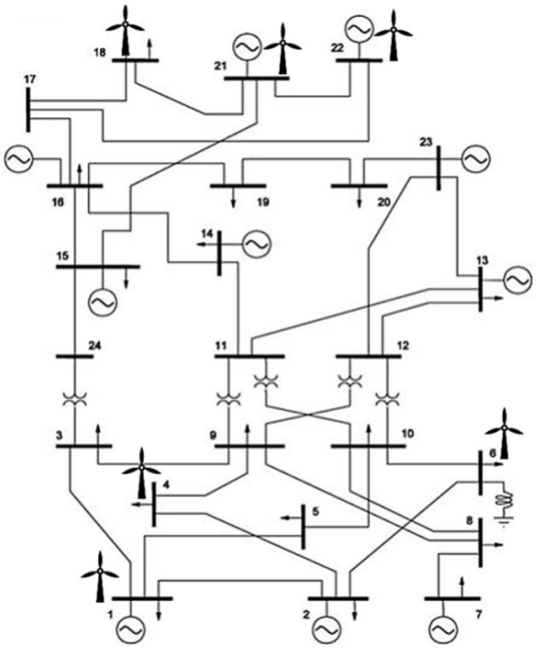

Fig. 2. Modified IEEE 24-Bus test system under study.

The generation plants are assumed to submit their offers in three different linear segments, amongst the minimum and maximum production capability, as it can be seen in Fig 3. The data regarding the Power of all the twenty-six generators is presented in Table II and each of its start-up cost is presented in Table III.

The load profile is divided into three different time periods, Low-Load (01:00-08:00), Off-Peak (09:00-16:00) and Peak (17:00-24:00). For this system, its maximum load is 2850 MW. For this model the two most pollutants where considered, Nitrogen Oxides (NO_x) and Sulfur Dioxide (SO_2). The amount of emissions of each of these gases by generator is presented in Table IV.

Regarding the wind farms, in this model they were included in the grid at buses 1, 4, 6, 18, 21 and 22. Each one of these produces up to 150 MW, adding to a total of 900 MW of wind farms. To model the wind power generation, Weibull distribution was taken into account for wind speed. To enable the inconstancy of wind farms, several scenarios were generated by Roulette Wheel Mechanism.

Among several generated scenarios, only ten were employed to decrease computational complexity. These scenarios are illustrated in Fig. 4. It was also assumed that each scenario had the same probability of happening, 10%. The wind spillage cost was established at 40$/MWh. The value of VOLL was defined as 100$/MWh for each load, which means in exchange for 1 MWh loss, the system operator has to pay 100$ to the affected consumer. The electricity tariffs for the different cases are indicated in Table V.

To assess the efficiency of the proposed model, two different cases were defined as presented in Table V. It is important to note that when a percentage of DR participation is implemented the DR program modeled is TOU. Table VI shows the Payoff table considering the first case study, i.e., the problem with no DR and no flexiramp (FR) strategy. Moreover the Pareto front result for this case study is shown in Fig. 5.

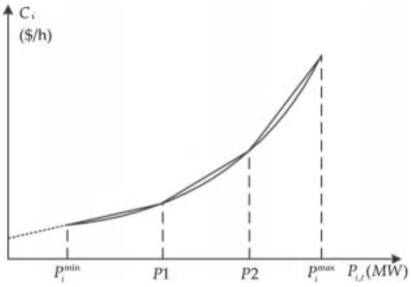

Fig. 3. Linearized cost by generators segment example.

TABLE II. POWER AND COST OF EACH GENERATOR

Gen. 1 - 5		Gen. 6 - 9		Gen. 10 - 13		Gen. 14 - 16	
P_i (MW)	C_i ($)	P_i (MW)	C_i ($)	P_i (MW)	C_i ($)	P_i (MW)	C_i ($)
2.40	23.41	15.80	29.58	15.20	11.46	25.00	18.60
6.00	23.78	16.00	30.42	38.00	11.96	50.00	20.03
9.60	26.84	19.80	42.82	60.80	13.89	80.00	21.97
12.00	30.40	20.00	43.28	76.00	15.97	100.00	22.72
Gen. 17 - 20		**Gen. 21 - 23**		**Gen. 24**		**Gen. 25 and 26**	
P_i (MW)	C_i ($)	P_i (MW)	C_i ($)	P_i (MW)	C_i ($)	P_i (MW)	C_i ($)
54.25	9.92	68.95	19.20	140.00	10.08	100.00	5.31
93.00	10.25	118.20	20.32	227.50	10.66	200.00	5.38
124.00	10.68	157.60	21.22	280.00	11.09	320.00	5.53
155.00	11.26	197.00	22.13	350.00	11.72	400.00	5.66

TABLE III. START UP COST OF EACH GENERATION UNIT ($)

Gen.	1-5	6-9	10-13	14-16	17-20	21-23	24	25-26
C_i^{SU}	87.40	15.00	715.20	575.00	312.00	1018.90	2298.00	0.00

TABLE IV. EMISSION OF EACH GENERATION UNIT (KG/MWH)

Gen.	1-5	6-9	10-13	14-16	17-20	21-23	24	25-26
NO_x	1.140	0.832	3.125	1.850	2.602	3.260	8.330	0.00
SO_2	0.456	0.330	1.250	0.740	1.041	1.304	3.330	0.00

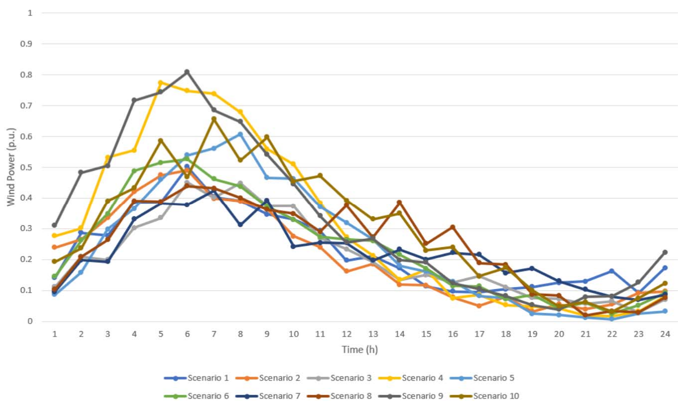

Fig. 4. Wind power scenarios considered.

TABLE V. EMISSION OF EACH GENERATION UNIT (KG/MWH)

	Low-Load 01:00-08:00h	Off-Peak 09:00-16:00h	Peak 17:00-24:00h
No DR + no FR	10.60	10.60	10.60
10% DR + FR	12.53	14.31	14.31

As it can be seen from Fig. 5, the optimal solution is the point indicated with a green color and its coordinates correspond to $F_{emission}$ =139,653kg and F_{cost} = 410,524.60\$. Moreover, the load characteristics are expressed on Table VII. It is possible to note that for the base case study, i.e., without DR and FR the results are acceptable.

Hence, Fig. 6 shows the hourly load in MW considering the first case study, i.e., no DR, no FR during the 24 hours under analysis, while Fig. 7 shows the marginal prices results on the where the minimum price was noticed in hour 1 with 5.53 \$/MWh and the highest price was reached in hour 20 with 20.10 \$/MWh.

For the second case study, i.e., a 10% of DR and FR integration, the Payoff table results is described in Table VIII. Moreover, as the first case study, the Pareto front result is shown in Fig. 8, where the optimal solution is the point indicated with green color and its coordinates correspond to $F_{emission}$ = 145,385.91kg and F_{cost} = 429,530.43\$. Hence, the load characteristics are expressed on Table IX.

In Fig. 9 is expressed the hourly load in MW considering integration of 10% of DR and FR along the whole 24 hours of scheduling. In Fig. 10 is shown the marginal prices considering the same case study under analysis, i.e., 10% of DR and FR program. Table X expresses the optimal solution for each case study.

Moreover, in Table XI presents the load characteristics for both cases studies under analysis. As can be observed the flexiramp strategy has no effect on load, which means that the load characteristics for the cases with and without DR it will be the same.

From the results previously described, as the final load is calculated from the original load, the original tariff, the elasticity matrix and the DR tariffs, flexiramp has no effect on it. Since the load does not change, the electricity price will have insignificant changes. The marginal prices (i.e., the marginal day-ahead prices) with and without FR are not exactly the same (based on the results that prove the correctness of the model) but the changes are not considerable.

TABLE VI. NO DR + NO FR PAYOFF TABLE

	F_{cost} (\$)	$F_{emission}$ (kg)
***MinF**$_{cost}$*	410,510	143,650
***MinF**$_{emission}$*	785,560	103,680

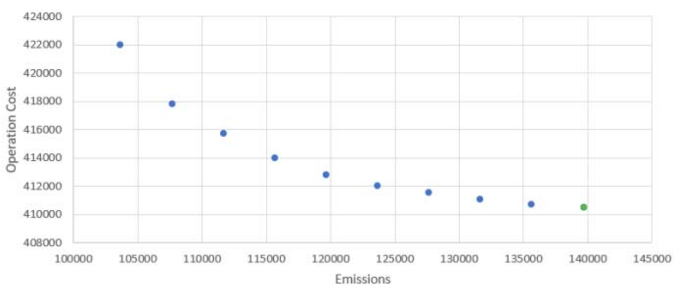

Fig. 5. No DR + No FR Pareto front results.

TABLE VII. LOAD CHARACTERISTICS WITH NO DR + NO FR

Load Factor	L_{max} (MW)	L_{avg} (kg)
81.52%	2503.10	2040.47

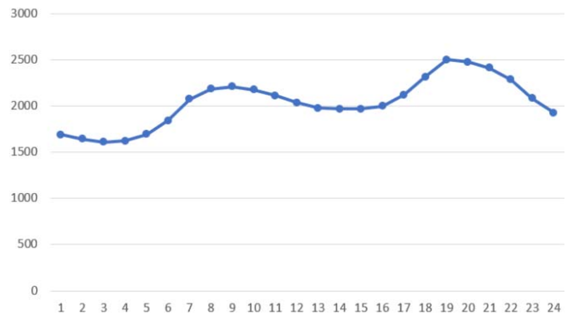

Fig. 6. No DR + No FR hourly load.

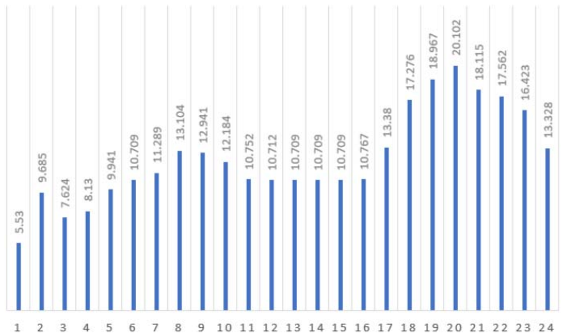

Fig. 7. No DR + No FR marginal prices.

TABLE VIII. 10% DR + FR PAYOFF TABLE

	F_{cost} (\$)	$F_{emission}$ (kg)
***MinF**$_{cost}$*	429,520.00	150,960.00
***MinF**$_{emission}$*	1,113300.00	96119.10

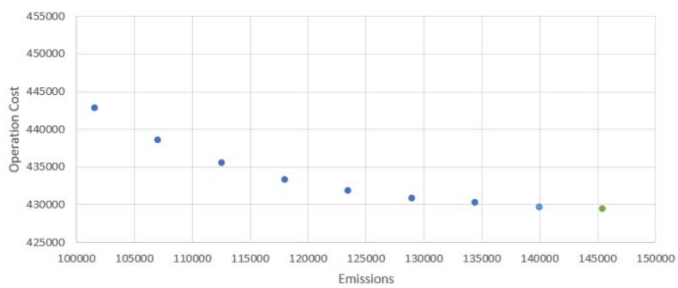

Fig. 8. 10% DR + FR Pareto front results.

TABLE IX. LOAD CHARACTERISTICS WITH 10% DR + FR

Load Factor	L_{max} (MW)	L_{avg} (kg)
84.96%	2252.79	1914.00

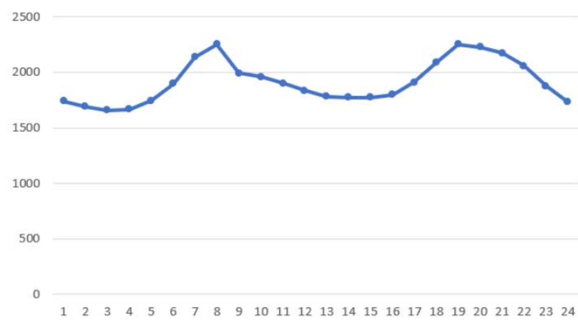

Fig. 9. 10% DR + FR hourly load.

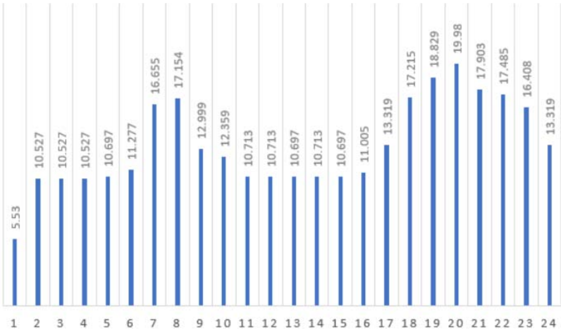

Fig. 10. 10% DR + FR marginal prices.

TABLE X. OPTIMAL SOLUTION FOR EACH CASE STUDY

	Emission (kg)	**Cost ($)**
No DR + No FR	139,653.00	410,524.60
10% DR + FR	145,395.91	429,530.43

TABLE XI. LOAD CHARACTERISTICS FOR EACH CASE STUDY

	Load Factor	L_{max}	L_{avg}
No DR + No FR	81.52%	2503.10	2040.47
10% DR + FR	84.96%	2252.79	1914.00

From all the results above shown, when the DR participation level increases, a decrease in electrical demand at peak periods and a consequent load recovery at low-load periods to balance the load profile is verified. Along with this, it is verified that the implementation of a flexiramp market has no impact on the final load as the final load is calculated from the original load, the original tariff, the elasticity matrix and the DR tariffs. Moreover, since the load does not change, the electricity price will as well have insignificant changes. The proposed model was implemented on a PC equipped with an Intel Core i3-6100 @2.30GHz with 8GB of RAM, and the solution to each case took in average 8h to be obtained. All proposed model was implemented in General Algebraic Modeling System (GAMS) [19] and all data obtained was checked on EmEditor [20].

V. CONCLUSIONS

In response to the necessity of higher flexibility due to the high penetration of wind power generation, a new DR program considering flexiramp, in consort with energy and reserve markets was modeled. The proposed model was solved using a test network with 24 buses including 6 wind farms. Also, a multi-objective stochastic approach was employed to schedule sources and deploy flexible ramp products to tackle the deviations of wind and load. Moreover, both the operation cost to the ISO and the reduction of emissions of pollutant gases were minimized. However, these objectives conflict since the cheapest generation units are the ones which have more pollutant features. For this reason, the augmented ε-constraint method was used.

REFERENCES

[1] N. Troy, et al., "Unit commitment with dynamic cycling costs," IEEE Trans. Power Syst., vol. 27, no. 4, pp. 2196-2205, 2012.

[2] Technical bulletin-flexible ramp constraint. URL: https://www.caiso.com/; [last accessed 2018-03].

[3] Ramp capability product design for miso markets. URL: https://www.misoenergy.org/; [last accessed 2018-03].

[4] H. Holttinen, A. Tuohy, et al., "The flexibility workout: managing variable resources and assessing the need for power system modification," IEEE Power Energy Mag., vol. 11, no. 6, pp. 53-62, 2013.

[5] D. Pozo, J. Contreras, "A chance-constrained unit commitment with an n-k security criterion and significant wind generation," IEEE Trans. Power Syst., vol. 28, no. 3, pp. 2842-2851, 2013.

[6] M. Parvania, M. Fotuhi-Firuzabad, "Demand response scheduling by stochastic SCUC," IEEE Trans. Smart Grid, vol. 1, no. 1, pp. 89-98, 2010.

[7] A. Khodaei, M. Shahidehpour, S. Bahramirad, "SCUC with hourly demand response considering intertemporal load characteristics," IEEE Trans. Smart Grid, vol. 2, no. 3, pp. 564-571, 2011.

[8] M. Nikzad, B. Mozafari, et al., "Designing time-of-use program based on stochastic security constrained unit commitment considering reliability index," Energy, vol. 41, no. 1, 541-548, 2012.

[9] Q. Wang, Y. Guan, J. Wang, "A chance-constrained two-stage stochastic program for unit commitment with uncertain wind power output," IEEE Trans. Power Syst., vol. 27, no. 1, pp. 206-2015, 2012.

[10] E. Heydarian-Forushani, et al., "A stochastic framework for the grid integration of wind power using flexible load approach," Energy Conv. Manag., vol. 88, no. C, pp. 985-998, 2014.

[11] E. Heydarian-Forushani, et al., "Optimal operation of emerging flexible resources considering sub-hourly flexible ramp product," IEEE Trans. Sust. Energy, vol. 9, no. 2, pp. 916-829, 2018.

[12] H. Wu, et al, "Thermal generation flexibility with ramping costs and hourly demand response in stochastic security-constrained scheduling of variable energy sources," IEEE Trans. Power Syst., vol. 30, no. 6, pp. 2955-2964, 2015.

[13] B. Wang, B. F. Hobbs, "Real-time markets for flexiramp: A stochastic unit commitment based analysis," IEEE Trans. Power Syst., vol. 31, no. 2, pp. 846-860, 2016.

[14] M. I. Alizadeh, M. Parsa Moghaddam, N. Amjady, "Multi-stage multi-resolution robust unit commitment with non-deterministic flexible ramp considering load and wind variabilities," IEEE Trans. Sust. Energy, vol. 9, no. 2, pp. 872-883, 2018.

[15] P. Siano, D. Sarno, "Assessing the benefits of residential demand response in a real time distribution energy market," Appl. Energy, vol. 161, no. C, pp. 53-551, 2016.

[16] H. Wu, et al., "Thermal generation flexibility with ramping costs and hourly demand response in stochastic security-constrained scheduling of variable energy sources," IEEE Trans. Power Syst., vol. 30, no. 6, pp. 2955-2964, 2015.

[17] E. Heydarian-Forushani, et al., "Optimal operation of emerging flexible resources considering sub-hourly flexible ramp product," IEEE Trans. Sust. Energy, vol. 9, no. 9, pp. 916-929, 2018.

[18] E. Nasrolahpour, H. Ghasemi, "A stochastic security constrained unit commitment model for reconfigurable networks with high wind power penetration," Elect. Power Syst. Res., vol. 121, no. C, pp. 341–350, 2015.

[19] General Algebraic Modeling System (GAMS) URL: https://www.gams.com/; [last accessed 2017-11].

[20] Text Editor for Windows (EmEditor) URL: https://www.emeditor.com/; [last accessed 2018-01]