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# Optimal Emergency Demand Response Program Integrated with Multi-Objective Dynamic Economic Emission Dispatch Problem

E. Dehnavi, H. Abdi*, F. Mohammadi

Department of Electrical Engineering, Engineering Faculty, Razi University, Kermanshah, Iran

**ABSTRACT**

*Nowadays, demand response programs (DRPs) play an important role in price reduction and reliability improvement. In this paper, an optimal integrated model for the emergency demand response program (EDRP) and dynamic economic emission dispatch (DEED) problem has been developed. Customer's behavior is modeled based on the price elasticity matrix (PEM) by which the level of DRP is determined for a given type of customer. Valve-point loading effect, prohibited operating zones (POZs), and the other non-linear constraints make the DEED problem into a non-convex and non-smooth multi-objective optimization problem. In the proposed model, the fuel cost and emission are minimized and the optimal incentive is determined simultaneously. The imperialist competitive algorithm (ICA) has solved the combined problem. The proposed model is applied on a ten units test system and results indicate the practical benefits of the proposed model. Finally, depending on different policies, DRPs are prioritized by using strategy success indices.*

**KEYWORDS:** Emergency demand response program, Dynamic economic emission dispatch, Imperialist competitive algorithm, Optimal incentive, Strategy success indices.

## 1. INTRODUCTION

Determining the optimal incentive in the incentive-based demand response programs (DRPs) should be based on a feasible and economical approach. Otherwise, it may impose a high additional cost at the supply side, create new peak when DRP ends [1], and decrease the network reliability [2].1 Due to the natures of the emergency DRP (EDRP) and dynamic economic emission dispatch (DEED) problems which focus on the demand side and supply side respectively, for a more comprehensive and effective investigation, integrating these two problems seems very useful. In other words, in the combined model, the fuel cost and emission are minimized and the optimal incentive is determined simultaneously. Modeling the customer's behavior based on price elasticity matrix (PEM) is one of the most feasible and powerful methods in this field [3-6].

EDRP and direct load control (DLC) are both voluntary incentive-based DRPs and there is no difference between their modeling. In other words these two programs have a same modeling as will be developed in the part two in this paper. Actually the ways of implementing of these two programs by independent system operator (ISO) is the main difference between them. In DLC, ISO directly controls some special loads which have possibility of being controlled remotely and this is not possible for all kind of loads. In EDRP, ISO motivates customers to reduce, interrupt, or shift their loads and it is possible for all kind of loads. On the other hand when EDRP is implemented, people have more social welfare in comparison to DLC. For the time-based DRPs like time of use (TOU), real time pricing (RTP), and critical peak pricing (CPP), instead of the optimal incentive, the optimal electricity price is determined during different periods.

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*Corresponding author:
H. Abdi (hamdiabdi@razi.ac.ir).

A time-based DRP has been implemented in [7] to serve the power and heat demands of the customer with minimum cost. In the proposed DRP, the amount of responsive load can vary in different time intervals. The aim of the proposed DRP is to shift the load from high market price time intervals to the low market price time intervals. Actually they have presented the short-term hourly scheduling of industrial and commercial customers with cogeneration facilities, conventional power units, and heat-only units.

Real time pricing (RTP) program has been investigated in [8]. They have presented a combined scheduling and bidding algorithm for constructing the bidding curve of an electric utility that participated in the day-ahead energy markets.

In Ref. [9] EDRP and Interruptible/Curtail able (I/C) programs have been implemented in the unit commitment (UC) problem. Then, the effects of these two DRPs have been compared in the long-term UC problem with fuel constraints. The proposed methodology has been formulated as a mixed integer linear problem and implemented in GAMS environment.

A robust optimization approach has been proposed in Ref. [10] for decision making of electricity retailers. Meanwhile, considering the effect of DRP on total procurement cost, an optimal bidding strategy is proposed of electricity retailers with the time-based model of DRP in the electricity market. Also, it is considered that the consumers only participate in TOU programs. Moreover, rather than using the forecasted prices as inputs, the upper and lower limits of pool prices have been considered for the uncertainty modeling in their proposed model.

Up to now many works have been carried out based on the UC problem integrating with DRPs [11-15].

As mentioned above, the UC problem integrating with DRP has been investigated a lot. But, there are few works related to the economic dispatch problem integrating with the DRPs to appoint the optimal incentive or price and get the minimum generation cost. Y. Chen and J. Li [16] compared three formulations of the security constrained economic dispatch for facilitating participation of DRRs in the Midwest ISOs energy and the ancillary service market. They mainly focused on the interruptible loads [16]. A. Ashfaq et al. [17] presented a combined model of the economic dispatch problem integrating with demand side response. In their model, at the peak hours, the price signal is set by the generation company one hour ahead and sent to the residential area. They have neglected some constraints in the economic dispatch problem and like the pervious mentioned work the emission objective of the generating units has not been taken into account. Also, in their model just peak hours have been considered and it has not been applied to the whole day. N.I. Nwulu and X. Xia [18] investigated the game theory based DR integrating with the economic and environmental dispatch [18]. Game theory is the study of strategic decision making introduced by John von Neumann in 1928. Specifically, it is the study of mathematical models of conflict and cooperation between intelligent rational decision-makers. One of the main drawbacks of this theory is the difficulty of using it as a basis for estimation. In other words, after modeling, the model will not be so clear and in realistic systems may not be so helpful. Also, in Ref. [18] the valve-point loading effect and POZs have not been considered in their model. Also, their combined model is not so clear and by paying incentives to the customers, at the all hours of the operation, the demand is decreased which may not be always realistic, practical and economical. Also, this may not be based on the ISO point of view. In fact, customers who participate in DRPs can decrease or shift their demand during peak hours to off-peak hours. Actually they have neglected the shift-able loads.

Soft computing methods have higher capability of solving the non-linear multi-objective problems than the traditional methods and usually can optimally solve non-convex and non-smooth cost functions. Particle swarm optimization [19], gravitational search [20], artificial bee colony [21], harmony search [22], intelligent tuned harmony search (ITHS) [23], spiral [24], and imperialist competitive algorithm (ICA) [25-27] are some of these optimization algorithms. Among the mentioned optimization algorithms, ICA is a new one introduced in 2007 by E. A. Gargari [25]. It has a good performance in solving optimization problems in different areas such as DG planning, plate-fin heat exchangers design, template matching and electromagnetic problems [26, 27].

The major contributions of this paper are: (i) Integration of EDRP with the multi-objective DEED problem to schedule the online generators power output and determine the optimal incentive. (ii) The effectiveness of the final model is shown by applying it on the ten unit's test system in three different case studies. (iii) Investigation the effects of the EDRP-DEED model on the improvement of the load curve characteristics. (iv) Prioritizing of DRPs based on different policies by using the strategy success indices. Moreover, although valve point loading effect and POZ have been considered in DEED problem, but they have not been considered in an integrated model of DEED and DRPs. Actually addition of these constraints are the innovation of this paper.

The rest of this paper is organized as follows. In Section 2, the economic model of the price-based and incentive-based DRPs is developed based on PEM and the customer's benefit function. Formulation of the DEED problem is presented in Section 3. In Section 4 the optimal model through combining of DEED and EDRP including their constraints is developed. The characteristics of the test system are introduced in Section 5. Numerical simulation and results are presented in Section 6. Finlay, in Section 7 the conclusion is drawn.

## 2. ECONOMIC MODEL OF RESPONSIVE LOAD

To obtain the optimal consumption at the demand side, the elasticity is defined as the sensitivity of the demand respect to the price as Eq. (1) [2, 4, and 28].

$$E(t,t') = \frac{\rho_0(t')}{d_0(t)} \frac{\partial d(t)}{\partial \rho(t')} \quad \begin{cases} E(t,t') \le 0 \; if \; t = t' \\ E(t,t') \ge 0 \; if \; t \ne t' \end{cases} \tag{1}$$

where, $E$ is the elasticity, $d(t)$ and $d_0(t)$ are the customer demands after implementing DRP and before it, during period $t$, $\rho(t')$ and $\rho_0(t')$ are the elasticity price and the initial electricity price during period $t'$, respectively.

For 24 hours in a day, self and cross elasticity values can be given as a 24×24 matrix as Eq. (2).

$$\begin{bmatrix} \frac{\Delta d(1)}{d_0(1)} \\ \frac{\Delta d(2)}{d_0(2)} \\ \frac{\Delta d(3)}{d_0(3)} \\ \cdots \\ \frac{\Delta d(24)}{d_0(24)} \end{bmatrix} = \begin{bmatrix} E(1,1) & \cdots & E(1,24) \\ \vdots & \ddots & \vdots \\ E(24,1) & \cdots & E(24,24) \end{bmatrix} \times \begin{bmatrix} \frac{\Delta \rho(1)}{\rho_0(1)} \\ \frac{\Delta \rho(2)}{\rho_0(2)} \\ \frac{\Delta \rho(3)}{\rho_0(3)} \\ \cdots \\ \frac{\Delta \rho(24)}{\rho_0(24)} \end{bmatrix} \tag{2}$$

### 2.1. Modeling of single period elastic loads

In this case, the total revenue for the customers who participate in the DRPs will be calculated as Eq. (3) based on the hourly incentive rate. In other words, DRPs create a motivation for customers to reduce their consumption. The total payment given to the customers is as Eq. (3) [28].

$$INC(\Delta d(t)) = inc(t) \times [\Delta d(t)] \tag{3}$$

where, $inc(t)$ is the amount of the incentive for reducing the consumption per $MW.h$, $\Delta d(t)$ is the amount of the reduced load.

Some programs consider a penalty for the customers who promise to participate in the DRP, but they don't (Eq. (4)). Most of the DRPs like EDRP and DLC are implemented voluntary. So, customers' are not penalized if they don't participate in DRPs (if they don't reduce or cut their consumption during peak hours). But, a DRP can be implemented mand-atorily which means that if customers' don't reduce their consumption during peak hours they will be penalized by an additional cost in their electricity bill. Some examples of mandatory programs are capacity market program (CAP) and interruptible / curtail-able (I/C) service programs.

$$PEN(\Delta d(t)) = pen(t) \times \{IC(t) - [\Delta d(t)]\} \tag{4}$$

where, $IC(t)$ is the amount of the demand which the customer is responsive to reduce or shift.

Consumers who participate in DRP, increase their production benefit, decrease their consumption, and receive the reward from the system operator. Thus, the net-profit of the customer is as Eq. (5) which is related to the customer's income because of electricity consumption and producing their commodities.

$$NP(t) = B(d(t)) - d(t)\rho(t) + INC(\Delta d(t)) - PEN(\Delta d(t)) \tag{5}$$

where, $B$ is the profit which customers obtain by consuming power.

To maximize the customer benefit, the derivative of Eq. (5) should be zero.

$$\frac{\partial NP}{\partial d(t)}=\frac{\partial B(d(t))}{\partial d(t)}-\rho(t)+\frac{\partial INC}{\partial d(t)}-\frac{\partial PEN}{\partial d(t)}=0 \quad (6)$$

$$\frac{\partial B(d(t))}{\partial d(t)}=\rho(t)+inc(t)+pen(t) \quad (7)$$

As mentioned before, it is assumed that $B(d(t))$ is customer's benefit from the use of electricity during tth hour. Taylor series of $B$ is given by Eq. (8).

$$B(d(t))=B(d_0(t))+\frac{\partial B(d_0(t))}{\partial d(t)}[d(t)-d_0(t)]+\frac{1}{2}\frac{\partial^2 B(d_0(t))}{\partial d^2(t)}[d(t)-d_0(t)]^2 \quad (8)$$

To obtain the optimal consumption by which the customers get the maximum profit, from Eq. (8):

$$B(d(t))=B(d_0(t))+\rho_0(t)[d(t)-d_0(t)]+\frac{1}{2}\frac{\rho_0(t)}{E(t,t)d_0(t)}[d(t)-d_0(t)]^2 \quad (9)$$

Differentiating:

$$\frac{\partial B(d(t))}{\partial d(t)}=\rho_0(t)\left(1+\frac{d(t)-d_0(t)}{E(t,t)d_0(t)}\right) \quad (10)$$

By combining Eqs. (10) and (7), for the single-period model of the load can be obtained:

$$\mathrm{d}(\mathrm{t})=\mathrm{d}_0(\mathrm{t})\times\left(1+\frac{\rho(\mathrm{t})-\rho_0(\mathrm{t})+\mathrm{inc}(\mathrm{t})+\mathrm{pen}(\mathrm{t})}{\rho_0(\mathrm{t})}\mathrm{E}(\mathrm{t},\mathrm{t})\right) \quad (11)$$

### 2.2. Modeling of multi period elastic loads

Now, to consider shift-able loads in the, then we will have the multi period model as the following equation:

$$\mathrm{d}(\mathrm{t})=\mathrm{d}_0(\mathrm{t})\times\left\{1+\sum_{\substack{t'=1\\t'\neq t}}^{24}\mathrm{E}(\mathrm{t},\mathrm{t'})\times\frac{[\rho(\mathrm{t'})-\rho_0(\mathrm{t'})+\mathrm{inc}(\mathrm{t'})-\mathrm{pen}(\mathrm{t'})]}{\rho_0(\mathrm{t'})}\right\} \quad (12)$$

### 2.3. Load economic model

Finally, the combined model including the single and multi- period models of the load (considering curtail-able, interruptible, and shift-able loads) is given by Eq. (13).

$$\mathrm{d}(\mathrm{t})=\mathrm{d}_0(\mathrm{t})\times\left\{\begin{array}{l}1+\frac{\rho(\mathrm{t})-\rho_0(\mathrm{t})+\mathrm{inc}(\mathrm{t})-\mathrm{pen}(\mathrm{t})}{\rho_0(\mathrm{t})}\mathrm{E}(\mathrm{t},\mathrm{t})\\+\sum_{\substack{t'=1\\t'\neq t}}^{24}\mathrm{E}(\mathrm{t},\mathrm{t'})\times\frac{[\rho(\mathrm{t'})-\rho_0(\mathrm{t'})+\mathrm{inc}(\mathrm{t'})-\mathrm{pen}(\mathrm{t'})]}{\rho_0(\mathrm{t'})}\end{array}\right\} \quad (13)$$

Equation (11) is the single period elastic load model which considers just interruptible or curtail able (I/C) loads. Eq. (12) is for multi-period elastic load model which considers just shift-able loads. Eq. (13) is the combined model included both single and multi-periods models which consider both (I/C) and shift-able loads. In this paper the combined model is taken into account.

## 3. DYNAMIC ECONOMIC EMISSION DISPATCH FORMULATION

When the valve-point, loading effect is taken into account, the total fuel cost over the whole dispatch period is as follows.

$$\min\sum_{t=1}^{T}\sum_{i=1}^{Ng}F_i(P_{i,t}) \quad (14)$$

$$F_i(P_{i,t})=a_i+b_iP_{i,t}+c_iP_{i,t}^2+\left|d_i\sin\left(e_i\left(P_i^{min}-P_{i,t}\right)\right)\right| \quad (15)$$

where, $a_i$, $b_i$, $c_i$, $d_i$ and $e_i$ are the fuel cost coefficients of the ith unit, $P_i^{min}$ is the minimum power generation, $P_{i,t}$ is the power output of the ith unit during the $t$-th time interval, $N_g$ and $T$ are the number of the generating units and the dispatch interval, respectively.

The atmospheric pollution caused by the fossil-fired generator contains carbon dioxide $CO_2$, nitrogen oxides $NO_x$, sulfur oxides $SO_x$, etc. The environmental objective is as follows.

$$\min\sum_{t=1}^{T}\sum_{i=1}^{Ng}E_i(P_{i,t}) \quad (16)$$

$$E_i(P_{i,t})=\alpha_i+\beta_iP_{i,t}+\gamma_iP_{i,t}^2+\eta_i\exp(\delta_iP_{i,t}) \quad (17)$$

where, $\alpha_i,\beta_i,\gamma_i,\eta_i$, and $\delta_i$ are coefficients of the emission issue for the $i$-th unit.

## 4. THE COMBINED MODEL OF EDRP INTEGRATED WITH THE DEED PROBLEM

The cost of implementing EDRP is as Eq. (18).

$$C_{EDRP}(t)=(d_0(t)-d(t))inc(t) \quad (18)$$

The multi-objective optimization problem can be changed to a single objective function using a penalty factor as follows:

$$\min TOF\left(P_{i,t}\right)= \sum_{t=1}^{T}\left\{\begin{array}{l}\omega_F \times\left[\sum_{i=1}^{N_g}\left\{\begin{array}{l}a_i+b_i P_{i,t}+c_i\left(P_{i,t}\right)^2 \\ +\left|d_i \sin\left(e_i\left(P_i^{min}-P_{i,t}\right)\right)\right|\end{array}\right\}\right] \\ +\omega_F \times C_{EDRP}(t) \\ +\omega_E \times \sum_{i=1}^{N_g}\left[pff(i) *\left(\begin{array}{l}\alpha_i+\beta_i P_{i,t}+ \\ \gamma_i\left(P_{i,t}\right)^2+\eta_i \exp\left(\delta_i P_{i,t}\right)\end{array}\right)\right]\end{array}\right\} \quad (19)$$

where,

$$\omega_F+\omega_E=1 \quad (20)$$

The first and second terms in Eq. (19) are cost functions ($) and the third term is emission (Ib). Therefore, to have same unit for cost and emission i.e. in dollar, the third term's unit should be changed from Ib to $. Therefore, that is why a price penalty factor (*pff*) is used. In other words, *pff* changes the unit of third term in Eq. (19) from Ib to $ [29].

$$pff(i)=\frac{F_i\left(P_i^{max}\right)}{E_i\left(P_i^{max}\right)} =\frac{a_i+b_i P_i^{max}+c_i\left(P_i^{max}\right)^2+\left|d_i \sin\left(e_i\left(P_i^{min}-P_i^{max}\right)\right)\right|}{\alpha_i+\beta_i P_i^{max}+\gamma_i\left(P_i^{max}\right)^2+\eta_i \exp\left(\delta_i P_i^{max}\right)} \quad (21)$$

## 4.1. Constraints

The DEED problem should satisfy the following equality and inequality constraints.

### 4.1.1. Power balance constraint

The total power output should be equal to the predicted load demand plus the total losses.

$$\sum_{i=1}^{N_g} P_i(t)=d(t)+P_L(t); t=1,\ldots T \quad (22)$$

where, $d(t)$ and $P_L(t)$ are the load demand and the power loss of transmission line at the $t$-th time interval. Generally $P_L(t)$ is calculated by Kron's loss formula, which can be given as Eq. (23).

$$P_L(t)=\sum_{i=1}^{N_g}\sum_{j=1}^{N_g} P_i(t) B_{ij} P_j(t) \quad (23)$$

where, $B_{i,j}$ is the power loss coefficient of the transmission network.

### 4.1.2. Incentive limits

For EDRP program, the incentives paid to the customers should be in a feasible range.

$$inc(t)^{min} \leq inc(t) \leq inc(t)^{max} \quad (24)$$

Referring to [32] $inc(t)^{min}$ and $inc(t)^{max}$ are usually considered to be $0.1\times\rho_0(t)$ and $10\times\rho_0(t)$, respectively.

### 4.1.3. Power generation limits

Generators power output is limited by its upper and lower generation limits.

$$P_i^{min} \leq P_{i,t} \leq P_i^{max} \quad i=1,2\ldots N_g \quad (25)$$

where, $P_i^{min}$ and $P_i^{max}$ are the lower and upper generation limits for the ith unit.

### 4.1.4. Prohibited operation zones constraint

In practice, generators should not work in some POZs. The main reason of this limitation is the vibration of the shaft bearing. So, generators should work in the feasible operating zones as given by Eq. (26).

$$\begin{cases} P_i^{min} \leq P_i^t \leq P_{i,1}^{\,l} \\ P_{i,k-1}^{\,u} \leq P_i^t \leq P_{i,k}^{\,l}; i=1,\ldots,Ng; t=1,\ldots,T \\ P_{i,M}^{\,u} \leq P_i^t \leq P_i^{max} \end{cases} \quad (26)$$

where, $P^l_{i,k}$ and $P^u_{i,k}$ are the lower and upper limits of the $k$th POZ respectively, $M$ is the number of POZs for the $i$th unit.

### 4.1.5. Generator ramp rate limits

Generator longevity is effectively influenced by the thermal stress. The increase and decrease rates of the generator power output are usually called the ramp-up and ramp-down, respectively. So, the operating range of the $i$-th unit is as Eq. (27).

$$\begin{cases} P_i^t-P_i^{t-1} \leq UR_i \\ P_i^{t-1}-P_i^t \leq DR_i \end{cases} \quad (27)$$

where, $UR_i$ and $DR_i$ are the up-ramp and down-ramp limits of the $i$-th unit, respectively and are usually expressed in MW/h.

## 4.2. Solving the DEED-EDRP problem

In this part a general procedure for solving the DEED-EDRP problem by the population-based meta-heuristic algorithms is presented. In fact, the population includes some possible solutions of the optimization problem. The population size is determined by the number of possible solutions. The possible solutions in ICA are called countries, in PSO particles, in ABC artificial bees, etc. Also, every possible solution is called a candidate. In DEED-EDRP, every scheduled generating unit output at each hour comprises a component of the population. In other words, it is a candidate for DEED-EDRP optimization problem at each hour. The $k$th candidate ($PG_k$) at each hour is defined as Eq. (28).

$$PG_k = \left[P_{k,1}, P_{k,2}, \ldots, P_{k,j}, \ldots, P_{k,N_g}\right], k = 1,2..M' \qquad (28)$$

where, $PG_k$ is the current position of the $k$th vector, $N_g$ is the number of generation units, $M'$ is the population size, $j$ is the generator number, and $P_{k,j}$ is the power output of the jth generation unit.

Constraint Eq. (22) can be handled by using a penalty term in Eq. (29). Thus, the evaluation function used in DEED-EDRP can be written as Eq. (29).

$$EF\left(P_{i,t}\right) = \sum_{t=1}^{T} \left\{ \begin{array}{c} \sum_{i=1}^{N_g} TOF\left(P_{i,t}\right) + \\ K_n .abs\left(\sum_{i=1}^{N_g} P_{i,t} - P_{D,t} - P_{L,t}\right) \end{array} \right\} \qquad (29)$$

where, $K_n$ is the penalty factor, which is a positive real number. The amount of $K_n$ at each hour increases with the algorithm iterations. If the constraint Eq. (22) is nonzero, the amount of the second term in Eq. (29) will be nonzero, too. In other words, a candidate which doesn't meet the constraint Eq. (22) will have a large evaluation function and more likely will be discarded. On the other hand, a candidate which meets the constraint Eq. (22) will have a relatively small evaluation function and consequently will be kept. $K_n$ can be written as Eq. (30).

$$K_n = 1000 \times \sqrt{n}\,; n = 1, \ldots N_{iter} \qquad (30)$$

where, $N_{iter}$ is the maximum number of iterations at each hour.

To ensure meeting of constraints Eqs. (25) - (27), before calculating the evaluation function of each candidate by Eq. (29), the power generation outputs of each candidate should be in the acceptable ranges specified by constraints Eqs. (25) - (27). If a candidate meets the constraints Eqs. (25) - (27), its evaluation function will be determined by Eq. (29). Otherwise, its evaluation function will be penalized by a large number. For more information about ICA, refer to [25-27]. The solution method for EDRP-DEED problem can be summarized in some steps as following.

Step 1: Defining technical units' data, daily load demand, $\rho_0(t)$ , PEM, load model, participation percentage ($\mu$), and initial incentive (is set to zero by ISO). Moreover, in ICA optimization, the initial population which is a set of possible solutions of the EDRP-DED problem, is defined based on the pervious section.

Step 2: Increasing the amount of incentive by ISO and determining the hourly demand and total incentive. Also, generation costs are determined by the supply side in this step.

Step 3: Solving the EDRP-DED problem by ICA and determining the optimal generation power outputs which are announced to the supply side.

Step 4: Continuing the process from step 2 until the minimum cost of generation units is obtained and the optimal incentive is determined by ISO.

## 5. TEST SYSTEM

To show the correctness, features, and practical benefits of the proposed model, it is applied on the ten unit's test system. The test system is taken from [30, 31] with some modifications. The characteristics of the test system are given as Table 1-2. Also, the elements of PEM are like Table 3. The daily load curve is divided into the peak period (9 A.M. - 14 P.M. & 19 P.M. - 24 P.M.), the off-peak period (5 A.M. - 9 A.M. & 14 P.M. - 19 P.M), and the valley period (0 A.M.-5 A.M.). DR implementation potential ($\mu$) is considered 20%. It means that 20 percent of the customers participate in the DRP. The initial electricity price ($\rho_0$)is as Fig. 1 [32]. Also, the transmission line losses coefficients of the ten-unit test system are as Eq. (31).

$$B = \begin{bmatrix} 49 & 14 & 15 & 15 & 16 & 17 & 17 & 18 & 19 & 20 \\ 14 & 45 & 16 & 16 & 17 & 15 & 15 & 16 & 18 & 18 \\ 15 & 16 & 39 & 10 & 12 & 12 & 14 & 14 & 16 & 16 \\ 15 & 16 & 10 & 40 & 14 & 10 & 11 & 12 & 14 & 15 \\ 16 & 17 & 12 & 14 & 35 & 11 & 13 & 13 & 15 & 16 \\ 17 & 15 & 12 & 10 & 11 & 36 & 12 & 12 & 14 & 15 \\ 17 & 15 & 14 & 11 & 13 & 12 & 38 & 16 & 16 & 18 \\ 18 & 16 & 14 & 12 & 13 & 12 & 38 & 16 & 16 & 18 \\ 19 & 18 & 16 & 14 & 15 & 14 & 16 & 15 & 42 & 19 \\ 20 & 18 & 16 & 15 & 16 & 15 & 18 & 16 & 19 & 44 \end{bmatrix} \times 10^{-6} \qquad (31)$$

**Table 1.** Ten-unit test system characteristics (a)

| **Units** | $P_{max}$ (MW) | $P_{min}$ (MW) | $a_i$ (\$/h) | $b_i$ (\$/MWh) | $c_i$ (\$/$(Mh)^2h$) |
|---|---|---|---|---|---|
| 1 | 455 | 150 | 1000 | 16.19 | 0.00084 |

| | | | | | |
|---|---|---|---|---|---|
| 2 | 455 | 150 | 970 | 17.26 | 0.00031 |
| 3 | 130 | 20 | 700 | 16.6 | 0.002 |
| 4 | 130 | 20 | 680 | 16.5 | 0.00211 |
| 5 | 162 | 25 | 450 | 19.7 | 0.00398 |
| 6 | 80 | 20 | 370 | 22.26 | 0.00712 |
| 7 | 85 | 25 | 480 | 27.74 | 0.00079 |
| 8 | 55 | 10 | 660 | 25.92 | 0.00413 |
| 9 | 55 | 10 | 665 | 27.27 | 0.00222 |
| 10 | 55 | 10 | 670 | 27.79 | 0.00173 |
| **Units** | $d_i$ (\$/h) | $e_i$ (rad/MW) | ***POZs*** (MW) | | |
| 1 | 40 | 0.0141 | — | | |
| 2 | 60 | 0.0136 | [185-210], [275-305], [410-420] | | |
| 3 | 30 | 0.0128 | — | | |
| 4 | 20 | 0.0152 | [25-40], [55-70], [75-85] | | |
| 5 | 20 | 0.0163 | — | | |
| 6 | 30 | 0.0148 | [30-45] , [50-65] | | |
| 7 | 30 | 0.0168 | [35-50] , [55-70] | | |
| 8 | 32 | 0.0162 | [15-25] , [35-45] | | |
| 9 | 25 | 0.0178 | — | | |
| 10 | 33 | 0.0174 | — | | |

**Table 2.** Ten-unit test system characteristics (b)

| Units | $\alpha_i$ (lb/h) | $\beta_i$ (lb/MWh) | $\gamma_i$ (lb/$(Mh)^2h$) | $\eta_i$ (lb/h) |
|---|---|---|---|---|
| 1 | 42.8955 | -0.5112 | 0.00460 | 0.25470 |
| 2 | 42.8955 | -0.5112 | 0.00460 | 0.25470 |
| 3 | 40.2669 | -0.5455 | 0.00680 | 0.24990 |
| 4 | 40.2669 | -0.5455 | 0.00680 | 0.24800 |
| 5 | 13.8593 | 0.3277 | 0.00420 | 0.24970 |
| 6 | 13.8593 | 0.3277 | 0.00420 | 0.24970 |
| 7 | 330.0056 | -3.9023 | 0.04652 | 0.25163 |
| 8 | 330.0056 | -3.9023 | 0.04652 | 0.25163 |
| 9 | 350.0056 | -3.9524 | 0.04652 | 0.25475 |
| 10 | 360.0012 | -3.9864 | 0.04702 | 0.25475 |
| Units | $\delta_i$ **(1/MW)** | ***UR* (MW/h)** | ***DR* (MW/h)** | |
| 1 | 0.01234 | 80 | 80 | |
| 2 | 0.01234 | 80 | 80 | |
| 3 | 0.01203 | 50 | 50 | |
| 4 | 0.01290 | 50 | 50 | |
| 5 | 0.01200 | 50 | 50 | |
| 6 | 0.01200 | 30 | 30 | |
| 7 | 0.01215 | 30 | 30 | |
| 8 | 0.01215 | 30 | 30 | |
| 9 | 0.01234 | 30 | 30 | |
| 10 | 0.01234 | 30 | 30 | |

**Table 3.** Self and cross elasticity values.

| | **Peak** | **Off-peak** | **Valley** |
|---|---|---|---|
| **Peak** | -0.10 | 0.016 | 0.012 |
| **Off-peak** | 0.016 | -0.10 | 0.01 |
| **Valley** | 0.012 | 0.01 | -0.10 |

## 6. NUMERICAL SIMULATION AND RESULTS

In this paper, the cost based, emission based, and cost-emission based DEED integrated with EDRP through three different case studies are investigated. On the other hand, the effects of the elasticity values and incentives on the results are evaluated. The initial daily load demand is as Fig. 2.

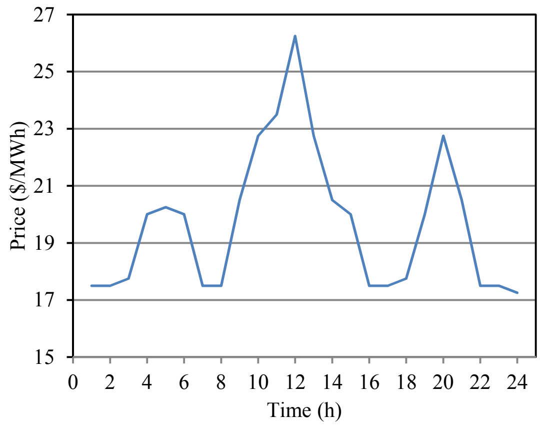



**Fig. 1.** Initial electricity price ($/MWh)

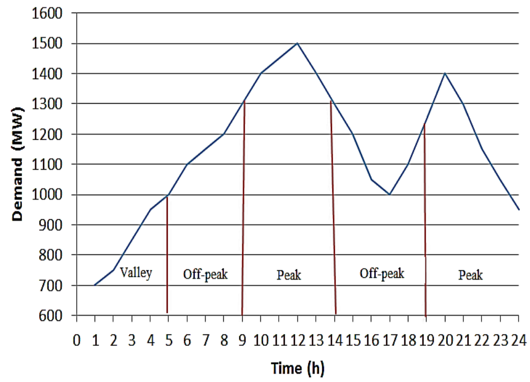



**Fig. 2.** Daily load curve

Three different groups with different values of PEM have been taken into account. In each case study, ten scenarios have been defined with different PEMs and incentives. Scenario 1 is the base case without implementing EDRP, scenarios 2-4 (group one with a PEM equals to E as Table 2) have incentives 4, 8, and 12 $/MWh, scenarios 5-7 (group two with PEM equals to 0.5× *E*) have incentives 4, 8, and 12 $/MWh, scenarios 8-10 (group three with PEM equals to 2×*E*) have incentives 4, 8, and 12 $/MWh, respectively.

To investigate the impacts of implementing EDRP on the load curve characteristics, some factors are defined as following. To evaluate the smoothness of the load curve, the load factor is defined as Eq. (32). Ideally, it is 100% which implies that at all hours of the operation the amount of demand is constant and does not change throughout the day.

$$Load-factor\% = 100 \times \left( \frac{\sum_{t=1}^{T} d(t)}{T \times d^{max}(t)} \right) \tag{32}$$

Peak-to-valley, peak-compensate, and deviation-of-peak-to-valley are the other important factors which are defined as Eqs. (33) - (35).

$$Peak-to-valley\% = 100 \times \left( \frac{d^{\max}(t) - d^{\min}(t)}{d^{\max}ax(t)} \right) \tag{33}$$

$$Peak-compensate\% = 100 \times \left( \frac{d_0^{max}(t) - d^{max}(t)}{d_0^{max}(t)} \right) \tag{34}$$

$$Deviation-of-peak-to-valley\% = 100 \times \left( 1 - \frac{d^{max}(t) - d^{min}(t)}{d_0^{max}(t) - d_0^{min}(t)} \right) \tag{35}$$

DRPs are usually prioritized by ISO to compare the performance value of the DR strategies. Therefore, in this paper to prioritize scenarios, the strategy index (SI) and strategy success index (SSI) are defined as Eqs. (36) and (37), respectively.

$$SI = \sum_{t=1}^{24} \left(St_1(t)\right)^{w_1} \times \left(St_2(t)\right)^{w_2} \times \ldots \left(St_k(t)\right)^{w_k} \tag{36}$$

$$SSI = \frac{\sum_{i=1}^{N} SI(i)}{\sum_{i=1}^{N} SI(max)} \times 100 \tag{37}$$

where, $S_t(t)$ is the performance value of the scenario in the period $t$, $W_k$ is the weighting for the $k$-th attribute, $N$ is the total days of DRPs implementation, and SSI represents the normalized value of SI. The higher SSI represents the better profit.

### 6.1. Case study one: cost based DEED integrated with EDRP

In this case, the effects of implementing EDRP on the overall cost of the generation units are evaluated. So, $\omega_F$ and $\omega_E$ are considered to be 1 and 0, respectively. Results are shown in Table 4. In all scenarios, after implementing EDRP, the total cost reduces. Implanting EDRP imposes an additional cost ($C_{EDRP}$) which is paid as the incentive to the customers. But, the total cost which is sum of the cost of the generating units and the total incentive, reduces. Scenario 9 has the most reduction of the total cost by 17411.0128$ (679111.1848-661700.1720) and scenario 5 has the least one by 4014.4215 $ (679111.1848-675096.7633). On the other hand, the customer's benefit in each group increases with the incentive value and PEM and decreases with the generation cost of units. For example, scenario 10 has the most total incentive (35839.3653 $) and scenario 5 has the least one (995.5379$).

**Table 4.** Scenarios' performance in the case one

| Scenario | Total generation cost ($) | Total incentive ($) | Total cost ($) |
|---|---|---|---|
| 1 | 679111.1848 | — | 679111.1848 |
| 2 | 669700.6678 | 1991.0758 | 671691.7437 |
| 3 | 660272.7458 | 7964.3034 | 668237.0492 |
| 4 | 651999.4772 | 17919.6826 | 669919.1599 |
| 5 | 674101.2254 | 995.5379 | 675096.7633 |
| 6 | 669686.4824 | 3982.1517 | 673668.6341 |
| 7 | 665398.5145 | 8959.8413 | 674358.3558 |
| 8 | 661476.1561 | 3982.1517 | 665458.3078 |
| 9 | 645771.5652 | 15928.6068 | 661700.1720 |
| 10 | 635583.916 | 35839.3653 | 671423.2813 |

The optimal incentives for three different groups are determined as shown in Table 5. Also, in all scenarios total losses decreases, too. All characteristics of the load curve are improved for three groups as shown in Table 6.

**Table 5.** Groups' performance for the optimal incentives in the case one

| Group | Optimal incentive ($/MWh) | Total generation cost ($) | Total incentive ($) |
|---|---|---|---|
| Base case | — | 679111.1848 | — |
| One | 7.75 | 660626.9668 | 7474.3121 |
| Two | 10.32 | 665495.0939 | 6623.0299 |
| Three | 5.87 | 652631.6164 | 8590.4034 |
| Group | Total cost ($) | Total power losses(MW) | — |
| Base case | 679111.1848 | 769.7731 | |
| One | 668101.2789 | 739.4306 | |
| Two | 672118.1237 | 740.8757 | |
| Three | 661222.0198 | 693.7434 | |

**Table 6.** Load curve's characteristics in the case one

| Group | Load factor | Peak to valley | Peak compensate | Deviation of peak to valley |
|---|---|---|---|---|
| Base case | 76.39 | 53.33 | — | — |
| One | 80.15 | 49.11 | 7.48 | 14.80 |
| Two | 78.10 | 51.41 | 3.55 | 7.03 |
| Three | 81.33 | 46.46 | 11.34 | 22.77 |

The load curves before and after implementing EDRP for three different groups (for their optimal incentives) are shown in Fig. 3. Customers with the highest PEM have more willingness to reduce or shift their consumption during peak hours (group three of the customers) and vice versa (group two of the customers). Actually, by implementing the EDRP, the load curve smoothens which improves the network reliability.

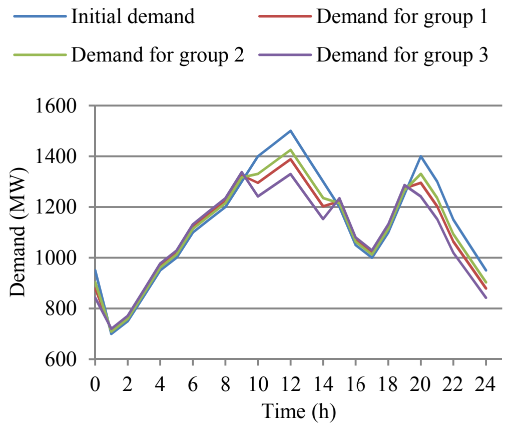



**Fig. 3.** The load curve before and after implementing EDRP for three different groups

### 6.2. Case study 2: emission-based DEED integrated with EDRP

In this case, the impact of implementing EDRP on reducing the emission is considered. It should be noted that in this case, the objective of implementing EDRP is 10 percent reduction of the initial emission. The initial emission before implementing EDRP is 49352.0551 Ib and in this case, the objective is to reduce it to 44416.8496 Ib. In this regard, $\omega_F$ and $\omega_E$ are considered to be 0 and 1, respectively. Results are shown in Table 7. Determining the optimal incentive is necessary from ISO point of view. From Table 7, it can be seen that the emission level of the generation units is decreased proportional to the elasticity of demand and the value of the incentive. For example, scenario 10 with larger PEM and incentive (2×E and 12 \$/MWh, respectively) has the most emission reduction by 11.05 % among the other ones.

### 6.3. Case study three: cost-emission based DEED integrated with EDRP

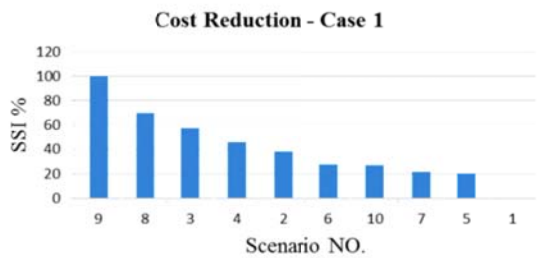
In this case, the cost-emission based DEED integrated with EDRP is investigated. Thus, there is a trade-off between the cost and the emission. In other words, $\omega_F$ and $\omega_E$ are both considered to be 0.5. But, depending on the system operator, different weights can be assigned too. Results are shown in Table 8. The objective function for the group three of customers reduces more. It is because of the fact that they have larger PEM which means that they have more willingness to reduce their consumption during the peak period or shift it to the valley or off-peak periods.

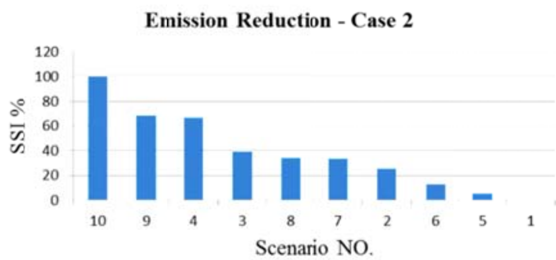
**Table 7.** Scenarios' performance in the case two

| Sce. | Total emission (Ib) | Emission reduction% | Optimal incentive for 10 % emission reduction ($/MWh) | Total incentive ($) for 10 % emission reduction ($/MWh) |
|---|---|---|---|---|
| 1 | 49352.0551 | — | — | — |
| 2 | 47892.3518 | 2.96 | 16.27 | 32941.4664 |
| 3 | 47203.6674 | 4.35 | | |
| 4 | 45796.2286 | 7.21 | | |
| 5 | 48956.6215 | 0.8 | 35.76 | 79566.9749 |
| 6 | 48528.7325 | 1.66 | | |
| 7 | 47495.8976 | 3.76 | | |
| 8 | 47294.4441 | 4.17 | 11.46 | 32686.3971 |
| 9 | 45554.8574 | 7.69 | | |
| 10 | 43901.3077 | 11.05 | | |

### 6.4. Prioritizing scenarios

Comparing the performance value of the scenarios using SSI coefficient is investigated in this part. For the best scenario, SSI is considered to be 100 % and for the other ones, it is calculated using Eqs. (36) and (37). Prioritizing of different scenarios based on different policies has been shown in Fig. 4. Here, reducing the total cost, emission, and objective function (case 1-3), energy reduction, load factor, and peak compensate are assumed as the important policies. As it is shown in Fig. 4, different policies have different priorities. In practice when there are some restrictions in implementing a higher priority scenario, ISO can choose another one with lower priority.



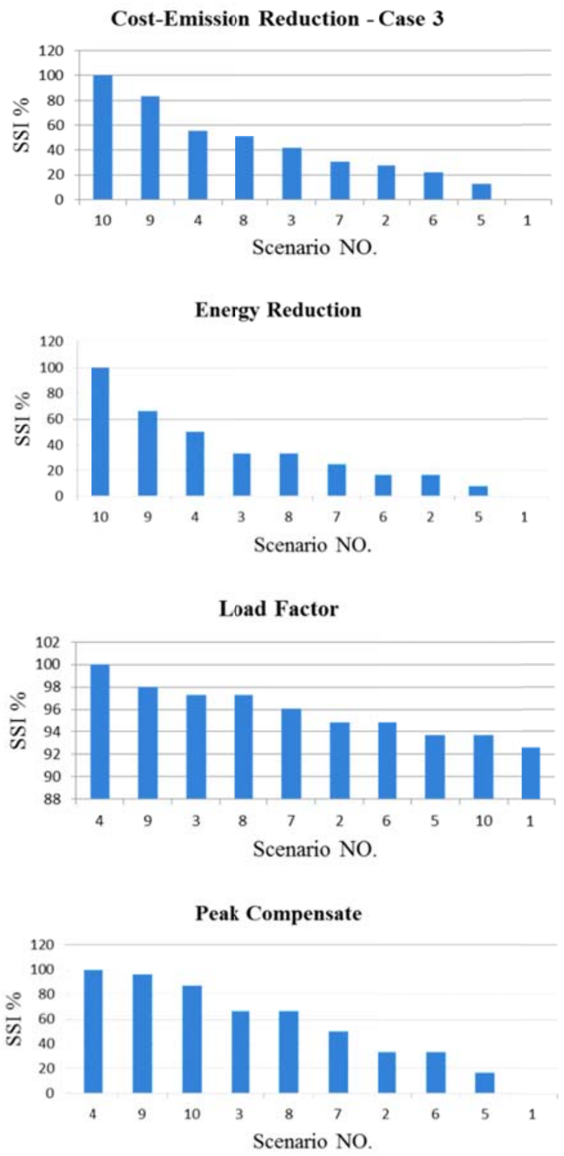



**Fig. 4.** Prioritizing of different scenarios based on different policies

**Table 8.** Scenarios' performance in the case three

| Scenario | Total generation cost ($) | Total emission (lb) | Total incentive ($) |
|---|---|---|---|
| 1 | 704386.6962 | 50752.9645 | — |
| 2 | 696378.1907 | 48965.6393 | 1991.0758 |
| 3 | 689097.4902 | 48083.3675 | 7964.3034 |
| 4 | 680312.5354 | 47426.8710 | 17919.6826 |
| 5 | 700936.9077 | 49775.3354 | 995.5379 |
| 6 | 695982.5925 | 49333.6351 | 3982.1517 |
| 7 | 691859.4736 | 48648.8467 | 8959.8413 |
| 8 | 689319.6233 | 48194.3079 | 3982.1517 |
| 9 | 673854.3426 | 46561.6077 | 15928.6068 |
| 10 | 655339.0089 | 45418.4736 | 35839.3653 |
| **Scenario** | **Objective function** | **Optimal incentive ($/MWh)** | |
| 1 | 638283.5824 | — | |
| 2 | 627284.3415 | | |
| 3 | 621368.4799 | 16.44 | |
| 4 | 615560.2359 | | |
| 5 | 633206.8812 | | |
| 6 | 629264.0664 | 22.03 | |
| 7 | 625897.6729 | | |
| 8 | 618088.7175 | | |
| 9 | 604602.4641 | 12.53 | |
| 10 | 597376.9502 | | |

## 7. CONCLUSION

DRPs' capabilities such as the cost reduction and reliability improvement have made them into important priorities for the electricity markets. In this paper EDRP was integrated to the DEED problem to minimize the fuel cost and emission and appoint the optimal incentive simultaneously.

In fact, the combined model is a win-win situation for both the customers and the generation companies. It is because of the fact that implementing DRPs not only decreases the total generation cost and emission but also increases the customer's benefit and network reliability. By applying the proposed model on the ten-unit system, some analyses were carried out to investigate the impacts of some important factors such as the elasticity values and incentives on the results. Also, prioritizing of different scenarios based on different policies was presented by using strategy success indices. Results showed the effectiveness and practical benefits of the proposed model. In the future work, the price-based DRPs such as the time of use (TOU) program will be integrated with the DEED problem. In this model instead of the optimal incentive, the optimal price during different periods is determined.

## APPENDIX A

Generators' optimal scheduling for case 1 (before and after implementing EDRP).

## ACKNOWLEDGMENT

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**Table 9.** Optimal generators power output (case 1, without implementing EDRP)

| *Hour* | $P_1$(MW) | $P_2$(MW) | $P_3$(MW) | $P_4$(MW) | $P_5$(MW) | $P_6$(MW) | $P_7$(MW) | $P_8$(MW) | $P_9$(MW) | $P_{10}$(MW) |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 198.3231 | 241.684 | 31.63968 | 94.59544 | 27.19408 | 25.49634 | 26.8687 | 45 | 10.26797 | 10 |
| 2 | 150 | 247.7146 | 49.83891 | 110.7146 | 34.63525 | 65 | 27.30336 | 45 | 21.64562 | 10 |
| 3 | 230 | 167.7146 | 99.51208 | 110.4738 | 83.34554 | 65 | 53.15977 | 28.24109 | 16.64621 | 10.49327 |
| 4 | 310 | 222.6107 | 68.41978 | 85 | 101.9436 | 77.48763 | 33.43801 | 45 | 15.70465 | 10 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 5 | 390 | 267.0335 | 52.33952 | 85 | 101.6804 | 47.48763 | 30.61284 | 15 | 10.19548 | 24.39218 |
| 6 | 433.8736 | 347.0335 | 50.11793 | 92.06238 | 56.89958 | 28.54348 | 33.46109 | 45 | 27.28848 | 15.57493 |
| 7 | 446.6911 | 345.5086 | 75.58416 | 112.9852 | 56.08574 | 26.88016 | 32.65191 | 31.60081 | 40.43256 | 13.77038 |
| 8 | 366.6911 | 425.5086 | 98.37808 | 103.086 | 106.0857 | 65 | 29.89463 | 13.56929 | 15.49595 | 10 |
| 9 | 367.0852 | 430.1813 | 118.431 | 89.70195 | 156.0857 | 68.29093 | 29.53957 | 45 | 10 | 24.07745 |
| 10 | 447.0852 | 420.5234 | 128.4045 | 123.2035 | 133.2943 | 65 | 70 | 30.52909 | 10 | 16.76485 |
| 11 | 455 | 443.6234 | 130 | 111.8638 | 136.884 | 65 | 70 | 12.54559 | 33.12652 | 40.32668 |
| 12 | 455 | 449.4167 | 130 | 126.3022 | 162 | 65.24816 | 71.82764 | 45 | 35.87504 | 10.32668 |
| 13 | 452.9055 | 389.4062 | 129.8111 | 119.1658 | 125.3109 | 65 | 76.56733 | 50.54382 | 13.80363 | 21.79765 |
| 14 | 455 | 400.4528 | 114.9359 | 85 | 80.23671 | 65 | 70.1974 | 34.32804 | 10 | 24.65694 |
| 15 | 375 | 442.6851 | 64.9359 | 122.8244 | 50.6497 | 73.36889 | 52.6237 | 12.72644 | 15.00224 | 24.50812 |
| 16 | 301.8589 | 377.1026 | 114.9359 | 85.98152 | 35.88778 | 65 | 30.40196 | 32.65795 | 19.08779 | 12.50596 |
| 17 | 381.8589 | 329.3905 | 64.9359 | 70.42312 | 29.41574 | 65 | 30.78129 | 12.12719 | 19.96428 | 20.55156 |
| 18 | 405.0488 | 394.5353 | 95.00446 | 46.83145 | 26.91788 | 69.63742 | 51.6138 | 13.84193 | 13.9593 | 12.51913 |
| 19 | 455 | 436.1718 | 46.09915 | 96.83145 | 76.91788 | 65 | 70 | 12.6892 | 18.38966 | 11.26751 |
| 20 | 455 | 437.4784 | 96.09915 | 124.533 | 116.9341 | 77.66695 | 70 | 45 | 10 | 12.62963 |
| 21 | 455 | 394.2677 | 94.5559 | 102.0265 | 79.42167 | 74.46078 | 70 | 15 | 12.40555 | 42.62963 |
| 22 | 375.745 | 397.9068 | 74.50345 | 89.71224 | 77.12804 | 49.73815 | 70 | 10.98237 | 12.08122 | 23.45051 |
| 23 | 392.2455 | 374.1333 | 62.13671 | 46.03439 | 78.53448 | 25.33387 | 50.02141 | 26.8977 | 10.26565 | 11.73639 |
| 24 | 312.2455 | 307.1181 | 108.4851 | 72.7076 | 28.53448 | 65 | 30.08306 | 11.00563 | 11.13948 | 24.57502 |

**Table 10.** Optimal generators power output (case 1, group 1, incentive 7.75 $/MWh, after implementing EDRP)

| ***Hour*** | $P_1$**(MW)** | $P_2$**(MW)** | $P_3$**(MW)** | $P_4$**(MW)** | $P_5$**(MW)** | $P_6$**(MW)** | $P_7$**(MW)** | $P_8$**(MW)** | $P_9$**(MW)** | $P_{10}$**(MW)** |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 159.8035 | 226.6205 | 85.82839 | 48.51468 | 57.2006 | 22.95584 | 26.69639 | 46.18369 | 21.64581 | 21.47983 |
| 2 | 239.8035 | 179.4035 | 60.54318 | 85 | 44.8248 | 29.9754 | 29.40787 | 53.08889 | 18.88343 | 28.18016 |
| 3 | 299.2614 | 259.4035 | 31.77494 | 85 | 43.34917 | 27.70434 | 50.01592 | 30.67103 | 36.29844 | 11.24974 |
| 4 | 379.2614 | 182.563 | 64.44217 | 85 | 93.34917 | 49.67918 | 34.08422 | 45.07673 | 23.30656 | 22.96594 |
| 5 | 299.2614 | 262.563 | 114.4422 | 85 | 125.3316 | 24.51648 | 32.31975 | 50.47622 | 22.14551 | 15.03279 |
| 6 | 379.2614 | 320.7022 | 70.89777 | 108.1699 | 75.33159 | 65 | 26.909 | 31.35368 | 48.05633 | 15.96953 |
| 7 | 371.5328 | 400.7022 | 50.6717 | 99.26182 | 84.44543 | 65 | 32.46259 | 49.30955 | 27.98502 | 14.20571 |
| 8 | 426.4736 | 382.9169 | 51.28612 | 110.4204 | 96.25642 | 65 | 25.51265 | 45 | 30.0347 | 16.4447 |
| 9 | 455 | 452.0681 | 101.2861 | 98.48865 | 46.25642 | 65 | 27.24451 | 32.80284 | 55 | 24.35663 |
| 10 | 455 | 425.0122 | 102.4829 | 85 | 96.25642 | 46.83228 | 31.781 | 34.70053 | 25.72526 | 32.87751 |
| 11 | 417.6214 | 400.1585 | 112.6041 | 127.3472 | 146.2564 | 65 | 30.68051 | 52.05293 | 20.68154 | 10.01162 |
| 12 | 430.0328 | 422.7976 | 127.0438 | 97.44613 | 142.8555 | 66.77055 | 27.93882 | 49.91953 | 31.27763 | 35.84971 |
| 13 | 350.0328 | 408.3643 | 129.9616 | 111.1635 | 162 | 65 | 28.89328 | 45 | 12.19888 | 20.03089 |
| 14 | 430.0328 | 328.3643 | 97.95841 | 93.85765 | 112 | 72.77545 | 31.50753 | 15 | 21.81147 | 33.06842 |
| 15 | 357.5289 | 408.3643 | 125.3128 | 102.6092 | 72.24709 | 69.51408 | 34.69267 | 45 | 21.79396 | 10.99171 |
| 16 | 323.6045 | 375.7817 | 116.0473 | 85 | 27.09675 | 65 | 32.01686 | 15 | 20.62362 | 28.75407 |
| 17 | 271.9672 | 438.765 | 56.47937 | 85.94941 | 34.48164 | 46.23864 | 54.02472 | 11.16455 | 17.65936 | 20.58893 |
| 18 | 351.9672 | 358.765 | 106.4794 | 104.2435 | 84.48164 | 28.46595 | 31.19196 | 45 | 21.08438 | 10 |
| 19 | 389.0167 | 438.765 | 126.9681 | 107.086 | 44.83316 | 65 | 70 | 15 | 31.66874 | 13.99587 |
| 20 | 455 | 430.5116 | 89.23892 | 119.4467 | 25.21213 | 65 | 84.02351 | 26.13844 | 31.05067 | 10 |
| 21 | 420.2483 | 355.867 | 107.5968 | 124.5094 | 75.21213 | 46.34431 | 70 | 14.22062 | 10.2291 | 12.23036 |
| 22 | 384.2155 | 349.7336 | 108.9581 | 74.50942 | 25.21213 | 21.9332 | 52.42813 | 30.218 | 17.73097 | 26.37444 |
| 23 | 304.2155 | 269.7336 | 97.37275 | 112.9782 | 75.21213 | 24.17103 | 34.51549 | 14.37614 | 39.02653 | 20.92095 |
| 24 | 224.2155 | 234.2253 | 79.80722 | 122.3652 | 125.2121 | 24.19863 | 28.64941 | 27.8196 | 17.39608 | 11.38794 |

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