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Optimal power dispatch for day-ahead power system operation considering demand elasticity

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ABSTRACT

This paper proposes the optimal power dispatch (OPD) considering price-based demand response (PDR). In the proposed framework, the nodal spot price (NSP) is use as a price signal to the consumers. In the proposed method, the optimal real power dispatch is solved by quadratic programming (QP) to minimize the total operating cost and obtain the NSP components. Consequently, demand elasticity (DE) is applied to estimate the system demand for more accurate day-ahead operations. In the DE matrix, the self-DEs represent the consumer consumption of hour *h* in response to the NSP of that hour. Meanwhile, the cross-DEs represent the response of consumer consumption of hour *h* to the NSP of other hours. The algorithm was tested with the IEEE 30-bus system with several cases of demand elasticity. The results show that the proposed algorithm can incorporate price elasticity of demand into day-ahead scheduling and effectively minimize total operating costs. The simulation study shown that, the operating cost can be reduced by 0.33-0.695% with self-DE of -0.1~-0.2, by reducing the consumption respected to the NSP. Meanwhile, when applying cross-DE, the operating cost can be reduced by 0.015% under the same daily consumption with the consumer's load shifting respected to NSP.

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NOMENCLATURE

a_i, b_i, c_i	: Generator cost coefficients
$a_{il,h}$	: The line flow sensitivity factor at bus *i* at hour *h*
EC^h	: Electricity cost at hour *h*
$\lvert f_{lm,h}\rvert$	: The MVA flow on the branch between bus *l* and *m* at hour *h*
$\lvert f_{lm}\rvert^{max}$	: The maximum MVA limit of the branch between bus *l* and *m*
$f_{l,h}^0$	: The initial real power flow at line *l* at hour *h*
$\Delta f_{l,h}$	: Change in power flow on line *l*
$FC_i(P_{Gi,h})$	: The fuel cost of the generator at bus *i* at hour *h*
NB	: The total number of buses
NG	: The total number of generators
$P_{Di,h}$	: The real power demand at bus i with demand response at hour *h*
$P_{Gi,h}$	: The real power generation at bus *i* at hour *h*
$P_{Gi,h}^{max}$	: The maximum real power generation at bus *i*

$P_{Gi,h}^{min}$	: The minimum real power generation at bus *i*
$P_{i,h}$	: The real injection power at bus *i* at hour *h*
$P_{Li,h}$	: The power demand at bus *i* at hour *h*
$P_{Li,h}^{0}$	: The initial power demands at hour *h*
$P_{Li,h}$	: The power demand at bus *i* at hour *h*
$P_{loss,h}$	: The power loss at bus *i* at hour *h*
$\Delta P_{i,h}$	: Change in real injection power at bus *i* at hour *h*
$\Delta P_{Li,h}$	: Change in power demand at bus *i* at hour *h*
$Q_{Di,h}$	: The reactive power demand at bus *i* at hour *h*
$Q_{Gi,h}$	: The reactive power generation at bus *i* at hour *h*
$Q_{Gi,h}^{max}$	: The maximum reactive power demand at bus *i*
$Q_{Gi,h}^{min}$	: The minimum reactive power demand at bus *i*
TFC	: The total system cost
$\lvert V_{i,h}\rvert$	: The voltage magnitude at bus *i* at hour *h*
$\lvert V_{j,h}\rvert$	: The voltage magnitude at bus *j* at hour *h*
$\lvert y_{ij}\rvert$	: The magnitude of the y_{ij} element of Y_{bus}
$\varepsilon_{i,h}$	: The demand elasticity matrix at bus *i* at hour *h*
$\varepsilon_{i,j}$	: Position in the demand elasticity matrix representing self and cross demand elasticity
$\Delta\sigma_{i,h}$	: Change in spot price at bus *i* at hour *h*
$\sigma_{i,h}$	: The spot price at bus *i* at hour *h*
$\eta_{L,ih}$	: The marginal transmission loss component at hour *h*
$\eta_{QS,ih}$	: The network quality of supply component at hour *h*
λ_h	: The system marginal price at hour *h*
θ_{ij}	: The angle of the y_{ij} element of Y_{bus}
$\delta_{ij,h}$	: The voltage angle between bus *i* and bus *j* at hour *h*

1. INTRODUCTION

Nowadays, the power system operation has created several techniques for increasing the market-based energy efficiency of electric infrastructure. Demand response (DR) is one of the effective tools for balancing unexpected electricity price spikes and decreases in customer energy use to satisfy electricity price incentives. These price signals lower peak power demand when the cost of production is very high. This process also increases the reliability of electricity both in the short and long term. Therefore, the system's performance can be enhanced with the DR plan, for instance, boosting power system dependability, efficiency, stability, and mobility, as well as cutting down on electricity costs. As a result, a variety of roadmaps and initiatives are available for the DR scheme. New options for power system operation are now possible because of the DR technology's continual development.

Many DR's have planned the introduction of contemporary power supply responses to industrial needs. DR schemes have been proposed in various sources of literature [1]. DR systems can be specifically divided into three basic groups [2]. According to the kind of control mechanism, offered motivation, decision variable are provided to customers to lower their energy use. In general, programs can be categorized by their mechanism as shown in Figure 1 economically, DR can be classified into incentive base DR (IDR) [3], [4] and price-based DR (PDR) [5], [6]. In this article, we will focus on PDR.

PDR is a strategy used by energy providers to manage electricity demand during peak periods. The idea is to incentivize customers to reduce their energy consumption during times of high demand by offering them lower prices for their electricity usage [7]. Energy providers will offer different pricing tiers based on the time of day and the overall demand for electricity. During peak periods when electricity demand is highest, prices will be higher, while during off-peak periods, prices will be lower. This encourages customers to reduce their energy consumption during peak periods and shift their usage to off-peak periods.

PDR scheduling has lately been studied in [8]–[11]. In [8] and [9], the operational challenge takes into account demand shifting and peak shaving. In [10], the day-ahead unit commitment model treats curtailable and changing requests separately. Best practices for scheduling the hourly demand response taking renewable energy uncertainties into account in the day-ahead market [11].

The PDR consists of a time of use (TOU) program [12], [13], critical peak pricing (CPP) [14], [15], extreme day CPP (ED-CPP), extreme day pricing (EDP) [16] and real-time pricing (RTP) [17]–[19]. In [20] overview of two types of demand response, namely price-based and incentive-based, and gives examples of price-based responses. by focusing on the role of electricity companies in influencing consumer behavior to reduce the stress on the electricity grid. The mechanism behind these programs is electricity prices that change over time.

The fluctuation in the price of electricity reflects the cost of electricity production in each period. The main aim of the program is to make the power consumption curve smoothest by charging high prices during peak times and lower prices during off-peak periods. RTP programs, in the opinion of many economists, are the most direct and effective DR programs appropriate for competitive electricity markets and need to be the main focus of policymakers [19].

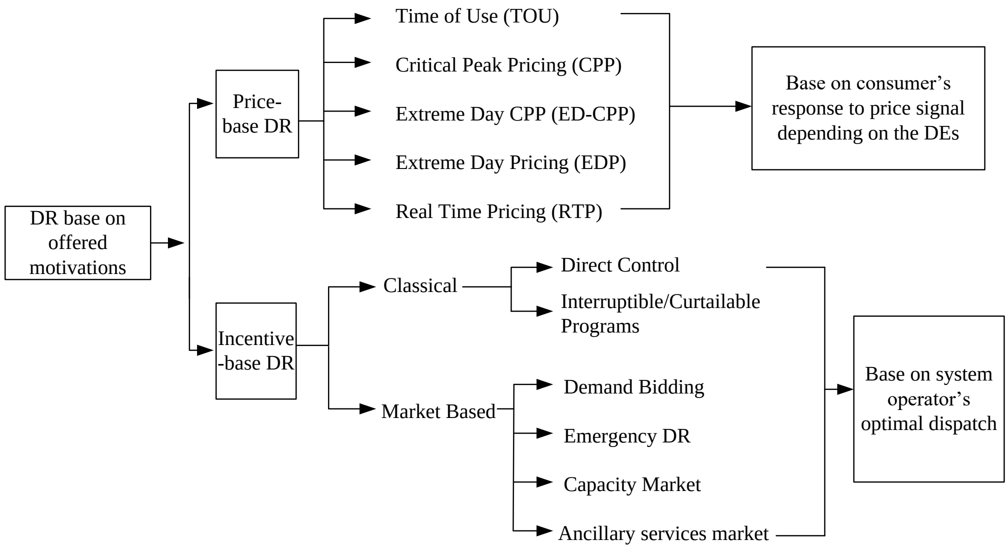


Figure 1. DR program

In this paper, demand elasticity (DE) is used to analyze the optimal power dispatch (OPD) for the PDR program using RTP. In the proposed RTP-PDR program the electricity users are informed of the day-ahead RTP prior to the dispatch day. Therefore, the electricity load forecast is adjusted according to the DE. Then, the system operator re-dispatch with the smoother load profile, leading to a lower electricity price.

As shown in Figure 2, in the fixed price strategy or without price signal to consumers, the demand curve is the vertical line. In other words, the buyers are willing to pay whatever price to meet the demand. But with price signals to the consumer, the customers' electricity usage habits will vary depending on the price at the time in according to DE. If the price is high, the demand will be less. If the price is low, the demand will be high. Then, it is estimating the consumer response to the price by elasticity price [21] and obtaining the price-corrected load forecast. Finally, the price-corrected optimal power dispatch is obtained. Accordingly, in this paper, the optimal real power dispatch algorithm for market-based power system operation incorporating demand price elasticity for day-ahead operation using quadratic programming (QP) is proposed. The nodal real-time spot price algorithm for a power system with loss sensitivity and the DC line flow method is determined. The proposed method was tested by using the IEEE 30-bus system and investigate the solution with different elasticity coefficients.

The contributions in this paper are summarized as follows:

– The optimal real power dispatch algorithm for market-based power system operation incorporating demand price elasticity for day-ahead operation using QP (for total cost minimization) is developed.
– The algorithm for the nodal real-time spot price of power system using loss sensitivity and DC line flow method is incorporated into the proposed optimal real power dispatch.
– Several different elasticity coefficients had been investigated and discussed.

The remainder of the paper is structured as follows. Section 2 focuses on the dynamic load economic model. The formulation of the proposed mathematical problem is described in section 3. Simulation results are in section 4. Section 5 serves as the paper's conclusion.

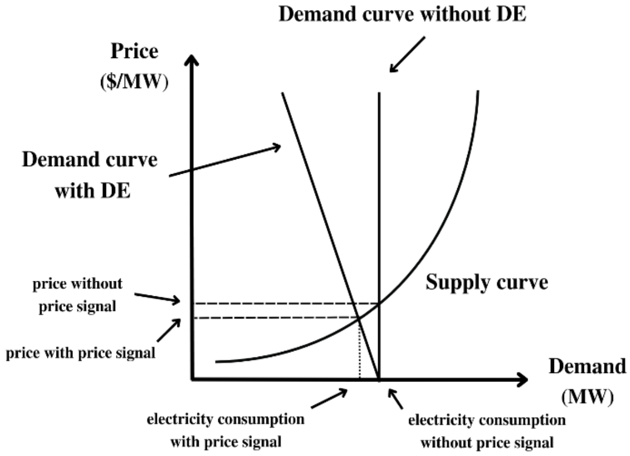


Figure 2. Bidding curve of demand

2. DAY-AHEAD ELASTIC LOAD MODEL

An economic load model that depicts the shifts in customer demand in response to changes in demand prices is needed to define client engagement in DR schemes. DE is used to represent the demand response behavior. The relative slope of the demand-price curve could be used to determine the demand-price elasticity as shown in Figure 2 This elasticity coefficient shows significantly a change in a commodity's price would alter the relative level of demand for that commodity. It shall be assumed throughout this paper that all prices and quantities have been normalized about a certain equilibrium.

The fixed-demand bids are inelastic to the market price in terms of demand. To represent the consumer's behaviors, the DE can be formulated by the matrix consisted of "self-elasticity" and "cross-elasticity". The self-elasticity represents the DE of the demand corresponding to the price in the same hour. Therefore, if the higher price leads to the lower demand and the self-elasticity is then negative. On the other hand, the higher price in hour *i* (that reduce the consumption in hour *j*. Therefore, the cross-elasticity is then negative. An elasticity matrix can be followed as (1)-(2).

$$\begin{bmatrix} \Delta P_{L1} \\ \Delta P_{L2} \\ \vdots \\ \Delta P_{L24} \end{bmatrix} = \begin{bmatrix} \varepsilon_{1,1} & \varepsilon_{1,2} & \cdots & \varepsilon_{1,24} \\ \varepsilon_{2,1} & \varepsilon_{2,2} & \cdots & \varepsilon_{2,24} \\ \vdots & \vdots & \ddots & \vdots \\ \varepsilon_{24,1} & \varepsilon_{24,2} & \cdots & \varepsilon_{24,24} \end{bmatrix} \begin{bmatrix} \Delta\sigma_1 \\ \Delta\sigma_2 \\ \vdots \\ \Delta\sigma_{24} \end{bmatrix} \tag{1}$$

$$\varepsilon_{i,j} \leq 0, \text{ if } i = j, \text{ and } \varepsilon_{i,j} \geq 0, \text{ if } i \neq j \tag{2}$$

As was previously noted, the period under consideration affects how customers respond to changes in power prices. In this paper, we will focus on the response "short-term", which refers to the period between the price announcement for the subsequent 24-hour period and the actual demand periods. Therefore, hourly demand changes can be followed as (3)-(4).

$$\Delta P_{Li,h} = \sum_{i=1}^{24} \varepsilon_{i,h} \Delta\sigma_{i,h}, \text{ and} \tag{3}$$

$$P_{Li,h} = P_{Li,h}^0 + \Delta P_{Li,h}, i = 1, \ldots, NB, h = 1, \ldots, 24. \tag{4}$$

The price of electricity each hour, taking into account the elasticity price can be followed as (5).

$$EC_{i,h} = \sum_{i=1}^{NB} P_{Li,h} \cdot \sigma_{i,h}, i = 1, \ldots, NB, h = 1, \ldots, 24. \tag{5}$$

2.1. Spot pricing of electricity

The spot price applied in this scheme including the system marginal price, marginal transmission loss, and network quality of supply (line congestion premium) [22] which can be calculated by (6)-(8).

$$\sigma_{i,h} = \lambda_h + \eta_{L,ih} + \eta_{QS,ih}, i = 1,\ldots,NB, h = 1,\ldots,24, \tag{6}$$

$$\eta_{L,ih} = \lambda_h \cdot (-ITL_{i,h}) = \lambda_h \cdot (\frac{dP_{loss,h}}{dP_{i,h}}), i = 1,\ldots,NB, h = 1,\ldots,24, \text{ and} \tag{7}$$

$$\eta_{QS,ih} = -\sum_{l=1}^{NB} \mu_{l,h}(a_{li,h}), i = 1,\ldots,NB, h = 1,\ldots,24. \tag{8}$$

The $ITL_{i,h}$ is the change in total system loss due to the change in real injection power at bus i. The constraint incremental relaxation price or $\mu_{l,h}$ is defined as the reduction in supply cost or increase can be followed as (9).

$$ITL_{i,h} = \frac{dP_{loss,h}}{dP_{i,h}}. \tag{9}$$

The line flow sensitivity factors ($a_{li,h}$) of line l to change in real injection power at bus i is followed as (10), then $\Delta f_{l,h}$ is the change in power flow on line l when $\Delta P_{i,h} \neq 0$ and $\Delta P_{i,h}$ is the change in real injection power at bus i at hour h as (10).

$$a_{il,h} = \frac{\Delta f_{l,h}}{\Delta P_{i,h}}. \tag{10}$$

The change of real power flow at line l will be $\Delta f_{l,h}$ and the power flow at line l will be expressed as (11).

$$f_{l,h} = f_{l,h}^0 + a_{li,h}\Delta P_{i,h}. \tag{11}$$

3. PROBLEM FORMULATION

The conception of the paper can be shown in Figure 3. The primary optimal power dispatch provides the day-ahead hourly spot price and is announced prior to the dispatch day [23], [24]. The objective function is to minimize total operating cost considering demand response as (12).

$$\text{Minimize } TFC = \sum_{h=1}^{24} \sum_{i=1}^{NG} FC_i(P_{Gi,h}). \tag{12}$$

Where, the quadratic generator cost function has the form (13).

$$FC_i(P_{Gi,h}) = a_i + b_i P_{Gi,h} + c_i P_{Gi,h}^2 \text{ (\$/hr)}, i = 1,\ldots,NB, h = 1,\ldots,24. \tag{13}$$

Subjected to the power balance constraints in (14)-(15),

$$P_{Gi,h} - P_{Di,h} = \sum_{j=1}^{NB} |V_{i,h}||V_{j,h}||y_{ij}| \cos(\theta_{ij} - \delta_{ij,h}), i = 1,\ldots,NB, h = 1,\ldots,24, \tag{14}$$

$$Q_{Gi,h} - Q_{Di,h} = -\sum_{j=1}^{NB} |V_{i,h}||V_{j,h}||y_{ij}| \sin(\theta_{ij} - \delta_{ij,h}), i = 1,\ldots,NB, h = 1,\ldots,24, \tag{15}$$

and the generator operating limit constraints in (16)-(17),

$$P_{Gi,h}^{min} \leq P_{Gi,h} \leq P_{Gi,h}^{max}, i = 1,\ldots,NG, h = 1,\ldots,24, \tag{16}$$

$$Q_{Gi,h}^{min} \leq Q_{Gi,h} \leq Q_{Gi,h}^{max}, i = 1,\ldots,NG, h = 1,\ldots,24, \tag{17}$$

and line flow limit constraint in (18).

$$|f_{lm,h}| \leq |f_{lm,h}|^{max}, h = 1,\ldots,24. \tag{18}$$

The proposed method's computational process is as in Figure 4.

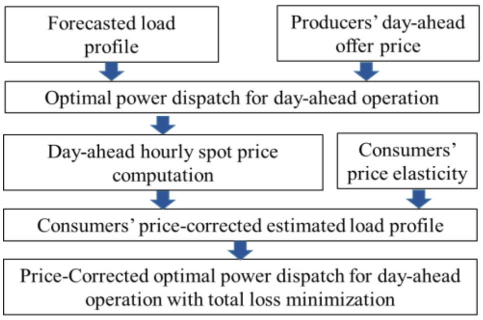


Figure 3. The conception of the proposed framework

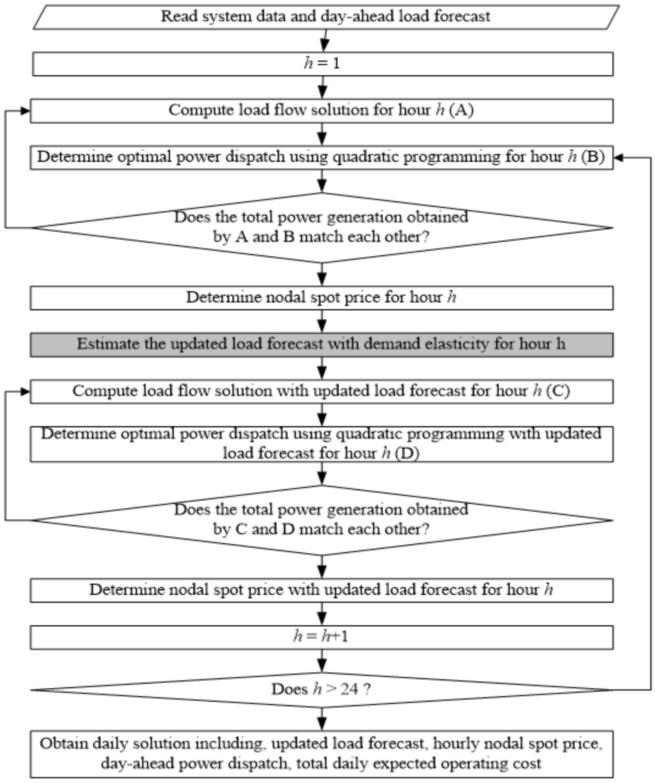


Figure 4. Computational procedures

4. SIMULATIONS RESULT AND DISCUSSION

This section examines the proposed method by using the IEEE 30-bus test system. The IEEE 30-bus system used in this simulation. Table 1 lists the quadratic cost functions for each generator in the IEEE 30-bus system according to [25]. To analyze the effects on different facets of the electricity system while incorporating price-elastic demand bids, the simulation for of 24 hours is used. The six generators are situated at buses 1, 2, 5, 8, 11, and 13 in the IEEE 30-bus system. Bus 1 has been designated as the slack bus.

Table 1. Generator data for the IEEE 30-bus system [25]

BUS	P_{min} (MW)	P_{max} (MW)	Q_{min} (MVar)	Q_{max} (MVA)	Cost coefficient		
					a_i	b_i	c_i
1	50	200	-20	250	0	2.00	0.00375
2	20	80	-20	100	0	1.75	0.01750
5	15	50	-15	80	0	1.00	0.06250
8	10	35	-15	60	0	3.25	0.00834
11	10	30	-10	50	0	3.00	0.02500
13	12	40	-15	60	0	3.00	0.02500

The system's daily load profile in the summer peak day of Thailand 2018, which peaks of 20340.70 MW at hour 20 and light-load of 13681.76 MW at hour 8, as shown in Figure 5 is used. The peak in demand occurs between 7:00 p.m. and 12:00 a.m., which is when there could be a significant need for power because of human activity.

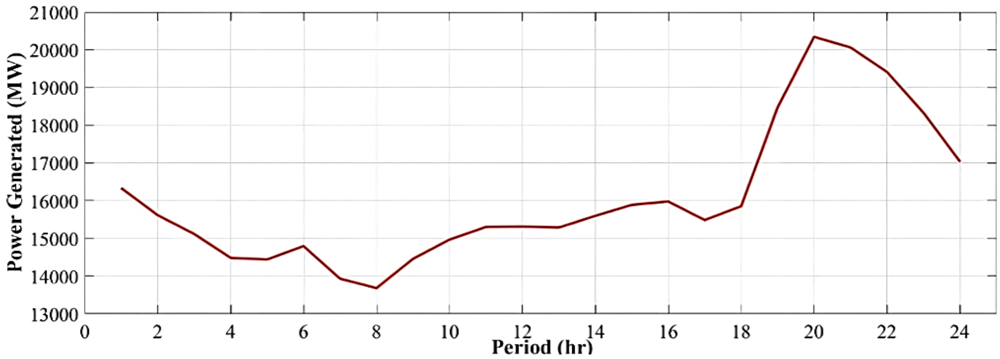


Figure 5. System daily load curve

The simulation study includes:

- Case I: Base case. In this case, the price signal is not applied.
- Case II: Self-elasticity -0.1 without cross-elasticity. In this case, DE is considered for all buses in the system. The demand is changed after considering demand price-elasticity.
- Case III: Self-elasticity -0.2 without cross-elasticity. In this case, DE is considered for all buses in the system. The demand curve with DE is the same as in case II, but a price elasticity is set to -0.2.
- Case IV: Self-elasticity -0.23 and cross-elasticity 0.01. In this case, DE is considered for all buses in the system. The demand curve with DE has, a self-elasticity of -0.23 and a cross-elasticity of 0.01. We use this to represent the changes in the price of one hour affect the demand for another.

Table 2 shows the spot prices for the peak and light-load hours of bus 5. Bus 5 is the highest-demand bus. The hourly price of each bus in cases I-IV are shown in Figures 6(a)-(d), respectively. The results of the fuel cost comparison in case I is served as a base case, with simulations indicating that the cost is higher in all scenarios as shown in Figure 6(a). In Figure 6(b), the result of case II, self-elasticity is applied with a value of -0.1. It is observed that the cost has slightly decreased in comparison to the base case. Figure 6(c) shows the result of case III, the self-elasticity is -0.2. Note that in this case, the total generation cost is the lowest. Finally, Figure 6(d) shows the result of case IV, self-elasticity is -0.23 and cross-elasticity is also applied at 0.01.

The optimal total power generator for all cases is shown in Table 3, representing the effect of price elasticity on the system demand. Comparing the experimental results in each case, it can be seen that in case III, the demand is 5503.423 MW per day, which is the least. Moreover, due to the cross-elasticity, the light-load demand, is higher, resulting in a better system load factor, as shown in Figure 7. In case III, self-elasticity is utilized with a value of -0.2 resulting in the case with the lowest cost. Additionally, case IV takes into account the impact of changes to one product on the cost of another product, as illustrated in Table 4.

As shown in Figure 8(a), the hourly price during peak hour of case III is the lowest due to only self-elasticity is applied. In case IV, the total power generation is the same as in case I, but the demands in peak hours are lower as well as the demands in light-load hours are higher, leading to the lower total cost under the same total consumption as shown in Figure 8(b).

Table 2. Spot price at bus 5

	Hour	Price ($/MWh)	
Peak hour	20	Case I	3.6946
		Case II	3.6881
		Case III	3.6818
		Case IV	3.6853
Light-load hour	8	Case I	3.0417
		Case II	3.0417
		Case III	3.0417
		Case IV	3.0508

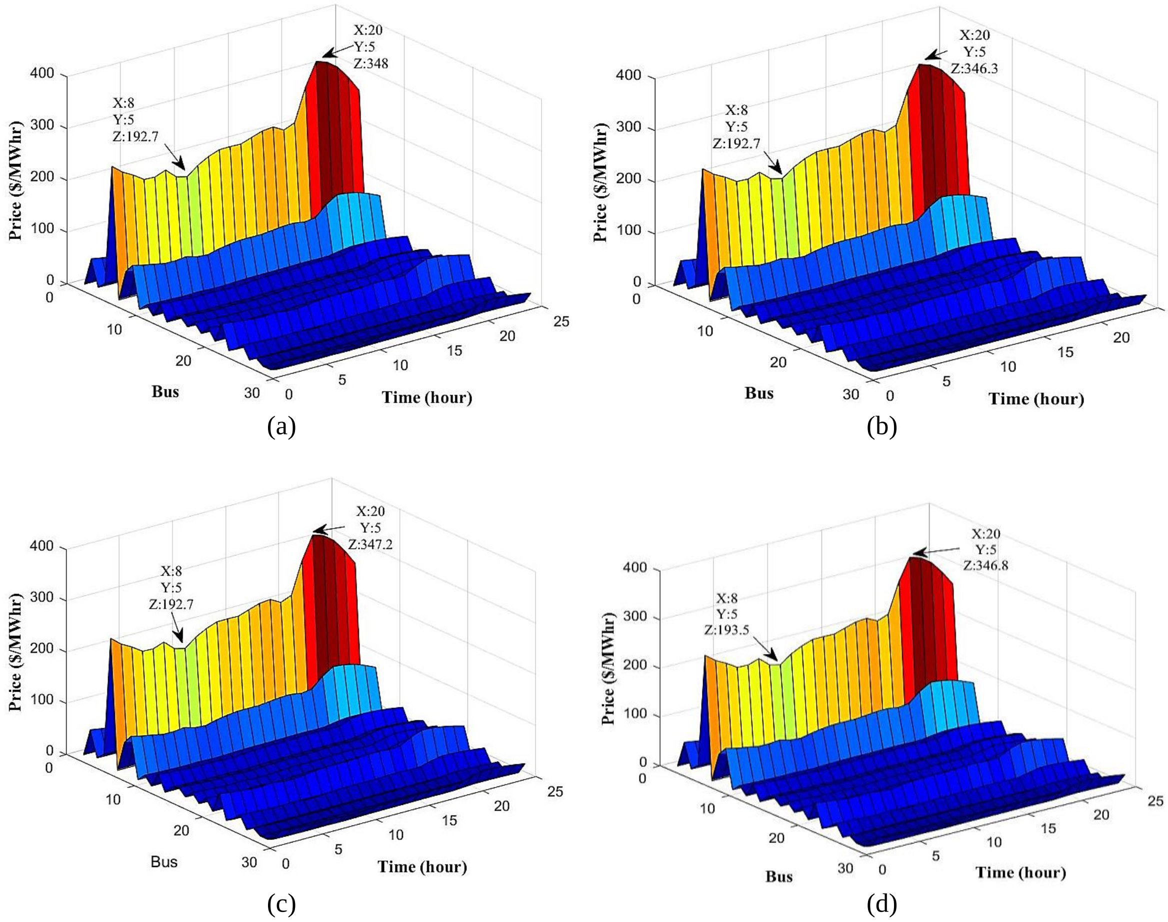


Figure 6. Fuel cost (a) case I, (b) case II, (c) case III, and (d) case IV

Table 3. Comparison of the results of the generator in a 30-bus system

Hour	Case I (MW)	Case II (MW)	Case III (MW)	Case IV (MW)
1	234.0324	233.3893	232.7466	233.8191
2	223.3372	222.8731	222.4092	223.5481
3	215.9894	215.6468	215.3042	216.4881
4	206.6524	206.4622	206.2721	207.5125
5	205.9933	205.8138	205.6344	206.8787
6	211.2119	210.9475	210.6831	211.8960
7	198.5118	198.4531	198.3943	199.6833
8	194.8387	194.8387	194.8387	196.1496
9	206.2330	206.0496	205.8663	207.1092
10	213.7649	213.4587	213.1526	214.3500
11	218.7275	218.3397	217.9521	219.1192
12	218.8779	218.4877	218.0975	219.2638
13	218.4868	218.1030	217.7193	218.8880
14	223.0959	222.6359	222.1759	223.3163
15	227.4109	226.8790	226.3473	227.4610
16	228.7400	228.1852	227.6313	228.7368
17	221.4381	221.0056	220.5731	221.7237
18	226.8976	226.3743	225.8511	226.9680
19	265.7107	264.6265	263.5428	264.4245
20	293.2090	291.8292	290.4499	291.2146
21	289.0740	287.7390	286.4045	287.1861
22	279.4950	278.2635	277.0325	277.8532
23	263.6143	262.5552	261.4962	262.3873
24	244.4869	243.6671	242.8478	243.8539
All day	5529.830	5516.624	5503.423	5529.831

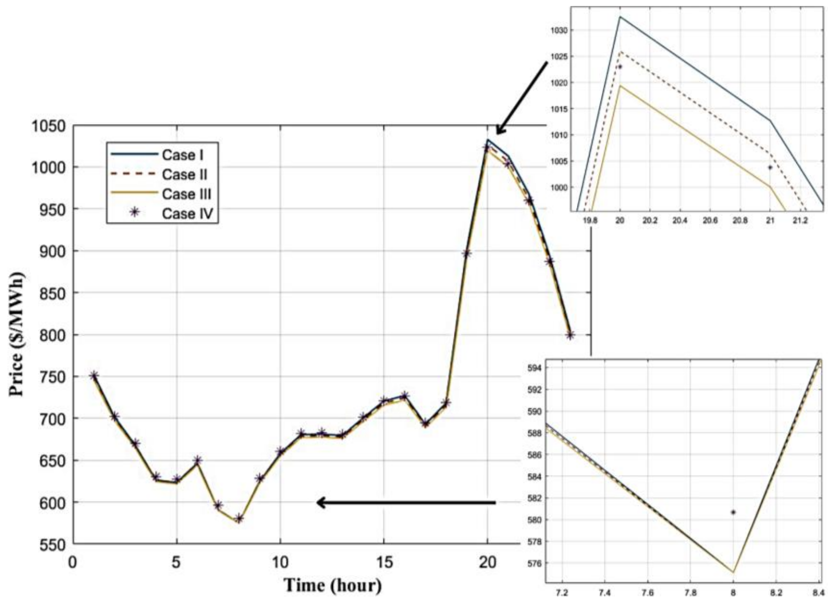
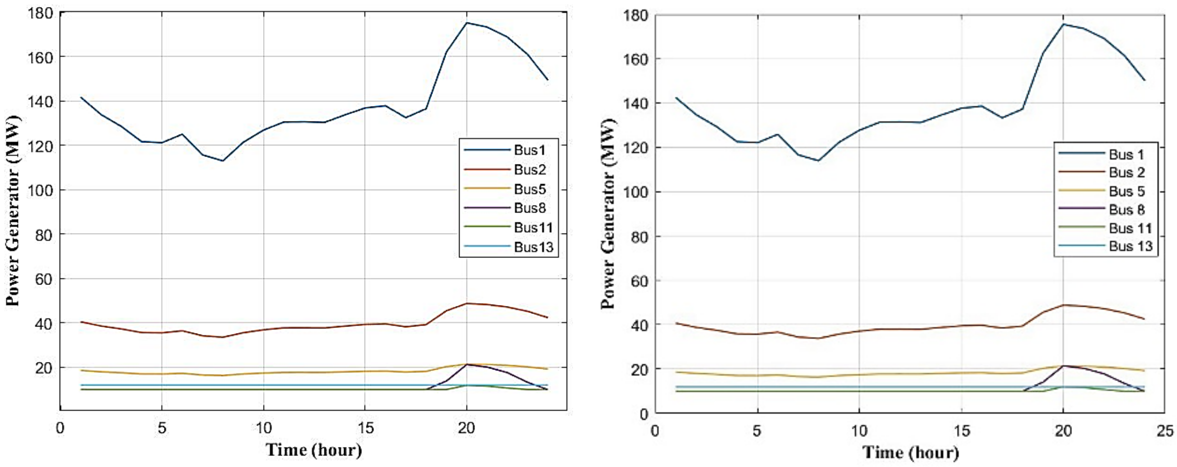


Figure 7. Hourly fuel cost of IEEE 30-bus system

Table 4. Comparison of the results of the fuel cost the in the 30-bus system

Hour	Case I ($)	Case II ($)	Case III ($)	Case IV ($)
1	752.0372	748.9733	745.9161	751.0208
2	701.6643	699.5204	697.3800	702.6396
3	667.9710	666.4220	664.8750	670.2279
4	626.2246	625.3890	624.5540	630.0104
5	623.3228	622.5357	621.7492	627.2123
6	646.4610	645.2830	644.1061	649.5141
7	590.8004	590.5485	590.2967	595.8300
8	575.1123	575.1123	575.1123	580.6763
9	624.3773	623.5726	622.7684	628.2292
10	657.9165	656.5418	655.1686	660.5477
11	680.4396	678.6725	676.9078	682.2271
12	681.1278	679.3486	677.5718	682.8893
13	679.3396	677.5917	675.8463	681.1686
14	700.5464	698.4225	696.3021	701.5649
15	720.6651	718.1784	715.6963	720.8995
16	726.9135	724.3103	721.7148	726.8990
17	692.8850	690.8978	688.9135	694.1982
18	718.2583	715.8153	713.3767	718.5873
19	902.8454	897.8075	892.7829	896.8698
20	1032.560	1025.962	1019.385	1023.029
21	1012.679	1006.344	1000.028	1003.725
22	967.2195	961.4796	955.7555	959.5699
23	893.0503	888.1496	883.2608	887.3733
24	802.8380	798.8120	794.7972	799.7273
All day	17677.25	17615.69	17554.26	17674.63

The power produced in each case shown in Table 3 has the same trend as the cost in Table 4, in which case III has the least power output. Figure 8 address the hourly power generation of cases III and IV, respectively. Meanwhile, Table 5 shows the comparison of total cost for all cases. In case II, the total daily consumption was reduced from 5529.83 MW to 5516.624 MW, due to the consumer response to the nodal spot price (NSP) with self-DE, leading to the reduction in total daily operating cost from $17677.25 to $17615.69. Similarly, in case III the total daily consumption and total daily operating cost were reduced to 5503.423 MW and $17554.26, respectively, with the consideration of larger self-DE of -0.2. Meanwhile, with the balance seif- and cross- DEs, the total daily operating cost can be reduced to $17674.63 under the same total daily consumption of base case, due to the consumers' load shifting in response to the NSP. Accordingly, self-elasticity and cross-elasticity are both important measures of price elasticity in the electricity market. Self-elasticity measures the responsiveness of quantity demanded to changes in electricity use according to the NSP, while cross-elasticity measures the responsiveness of quantity demanded to changes in the price of other time intervals. Both measures provide different types of information about the responsiveness of demand to changes in NSP and are important in making informed decisions about power system operation and planning. More specifically, In the electricity market, self-elasticity is important for understanding how changes in the price of electricity affect the quantity demanded, while cross-elasticity is important for understanding how changes in the prices of related goods or services affect the demand for electricity.



(a) (b)

Figure 8. Hourly power generator (a) case III and (b) case IV

Table 5. Total cost for different price elasticity

Case	Case I	Case II	Case III	Case IV
Total daily operating cost ($)	17677.25	17615.69	17554.26	17674.63
Saving		0.35%	0.696%	0.015%

5. CONCLUSION

An integrated OPD with DE model was proposed in this paper. The spot pricing concept has been successfully incorporated into the power system operation plan by using DE with self-elasticity and cross-elasticity. The effectiveness of the proposed methodology has been comparatively tested and validated on the IEEE 30-bus system. The results showed that the proposed method can lower the total system cost.

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