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Demand-Side Response in Pool- Based Day-Ahead Electricity Markets

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Abstract:- The active demand-side response in electricity market would produce benefits not only for individual consumers but also for the market as a whole. This paper proposes a method i.e. price responsive demand shift bidding of distribution companies to reduce congestion and peak locational marginal prices in the pool-based day-ahead electricity markets. The market dispatch problem is formulated as to maximize the social welfare of market participants subject to operational security constraints. This bidding mechanism is able to shift the price responsive demand from the periods of high price to the periods of low price in day-ahead electricity markets. The comparison of the price responsive demand shifting bids with conventional price taking bids is presented by solving hourly market dispatch problems on an IEEE 30-bus system for 24-h scheduling period. The effects of the proportion of demand-side participation on the price taking and price responsive consumer are also illustrated.

Keywords:- Congestion management, locational marginal price, price responsive demand shifting bidding, social welfare, effective cost.

I. INTRODUCTION

In many wholesale electricity markets, the demand-side is treated as a forecasted load to be served under all conditions and supply side is responsible for balancing between generation and load. This absence of demand-side participation results an increase in prices and exercise of market power which cause the end consumers to suffer. The demand-side participation is an economical way to design the electricity network to reduce system load at peak periods [1-5].

In a pool-based electricity market, the independent system operator (ISO) collects hourly/half-hourly benefit bids from distribution companies (DistCos) and supply bids from generator companies (GenCos) to develope day-ahead market dispatch generation and demand schedule. The locational marginal prices (LMPs) of real and reactive power at any bus and at any time interval are the marginal costs of supplying the real and reactive powers, respectively, at that bus and at that time and are the by-products of the solution of the market dispatch problem. The LMP varies over the system buses due to the losses and congestion in the system. Hence, LMP provides the economic signal regarding the delivery of power at that bus and that time. In other words, if LMPs are high at demand buses then system is said to be congested. [6-9].

Retailers purchase wholesale electricity at volatile rates from the pool market and resell them to end users at a fixed rate, thereby face a risk of revenue and retailers can minimize this risk by exposing some of their consumers to the wholesale pool prices. If these dynamic prices or pool prices are determined and made available to the demand-side before the day of the actual trade of electricity (*ex-ante*), the demand-side can adjust its activities and subsequently its demand profiles [10].

Kirschen and Strbac [11] demonstrated a realistic market-clearing mechanism in which demand-side bids are allowed. Borghetti *et al.* [12] developed an auction algorithm that implicitly allows demand shifting. However, in this algorithm the periods when the consumers can reduce their load or recover the energy that they did not consume are fixed so flexibility is reduced. Authors in Ref. [13] presented an alternative market-clearing tool for achieving maximum social welfare in a pool market. The consumers in this auction model are required to submit bids to purchase energy explicitly. This means that the consumers will contractually own the demand if the bids are accepted. Su and Kirschen [14] proposed the price responsive demand shifting bidding for market clearing mechanism of day-ahead electricity markets, in which some price sensitive consumers are able to shift the demand from periods of high LMP to the periods of low LMPs. However the mechanisms proposed in [14] do not take into account the operational and security constraints of transmission networks. Singh *et al.* [15] modified the price responsive shifting bidding mechanism as developed in [14] for congestion management and controlling peak LMPs in day-ahead electricity markets. The market dispatch problem is formulated as to maximize the social welfare subject to operational and security constraints.

II. BIDDING MECHANISM OF DISCOS

Follow ing are the various demand bids that are offered by the DisCos:

1. Price Taking Bids

It allows demand to purchase a certain amount of energy regardless of the market clearing prices. The bidder will receive a schedule of deliveries equal to the specified amount for all hours of the scheduling horizon. The major portion of the demand bid is price taking, which is required to meet essential daily services to residential, domestic and industrial loads.

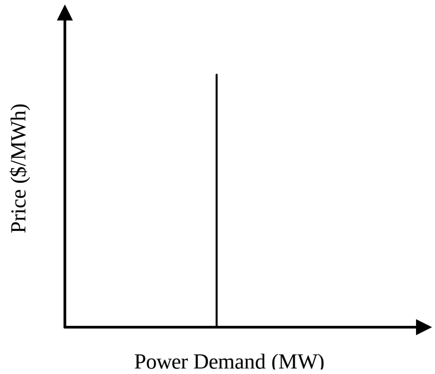

Fig. 1. Price Taking Bid

2. Price Responsive Demand Shifting Bids

In PRDS bids, an aggregator is capable to increase or decrease demands in response to the market clearing price as well as also able to shift its demand from periods where market price is higher to the periods where market price is comparatively lower. The bidder that submits a price responsive bid is also allowed to place a price taking bid (*e.g.* for meeting its inflexible demand) and vice versa.

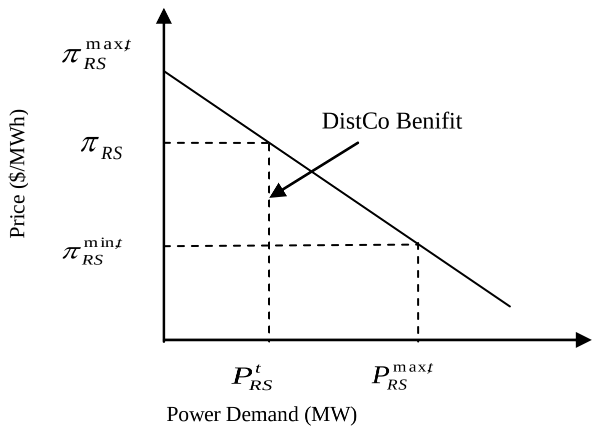

Fig. 2. Price Responsive Demand Shift Bid

Under PRDS bidding a DistCo specifies its maximum price bid $\pi_{RS}^{\max t}$, minimum price bid $\pi_{RS}^{\min t}$ and its corresponding maximum power demand $P_{RS}^{\max t}$, during a particular *t*th time period. The curve of price responsive demand shifting bid have negative slope so the bidder would purchase the amount of demand (P_{RS}^{t}) for which its willing price (π_{RS}^{t}) is less than or equal to market price. The demand that is lost during the periods of high market price can be recovered during other periods by extending the limit on price responsive demand.

The maximum price responsive demand is calculated by considering that all the energy consumed (E_{RS}) by the bidding DistCo during entire scheduling period can be consumed in a single time period at the maximum. It can be written as

$$P_{RS}^{\max t} = \frac{E_{RS}}{\Delta t}$$

III. PROBLEM FORMULATION

The day-ahead market dispatch problem is formulated as to maximize the social welfare *i.e.* the difference between benefits of DistCos due to price responsive demand and GenCos real and reactive power generation cost for the complete scheduling period of 24h, subjected to power balance equality constraints, Line flow inequality constraints and limits on variables, in each scheduling sub-interval. The objective function is

Max Social Welfare

$$= \sum_{t=1}^{24} \sum_{n=1}^{N} \left[\sum_{i=1}^{D} B_i^{n,t}(P_{RSi}^{n,t}) - \sum_{i=1}^{G} \left\{ C_i^{n,t}(P_{gi}^{n,t}) + C_i^{n,t}(Q_{gi}^{n,t}) \right\} \right] \tag{1}$$

The benefit function (or gross surplus) $B_i^{n,t}(P_{RSi}^{n,t})$ of DistCo is due to their P_{RS}^t consumption and the consumer gross surplus for price taking demand is assumed constant and hence taken out of the optimization. Thus benefit function can be determined from the PRDS curve

$$B_i^{n,t}(P_{RSi}^{n,t}) = \lambda_i^{\max t} P_{RSi}^{n,t} - 0.5a_{RSi}^t (P_{RSi}^{n,t})^2 \qquad (2)$$

The real power generation cost function of each generator is modeled by a quadratic function where $a_{gi}^{n,t}$, $b_{gi}^{n,t}$ and $c_{gi}^{n,t}$ are predetermined coefficients

$$C_i^{n,t}(P_{gi}^{n,t}) = c_{gi}^t + b_{gi}^t P_{gi}^{n,t} + a_{gi}^t (P_{gi}^{n,t})^2 \qquad (3)$$

From the approximated capability curve, the reactive power cost of each GenCo can be modeled as

$$C_i^{n,t}(Q_{gi}^{n,t}) = k\left[C_i^{n,t}(P_{gi}^{\max}) - C_i^{n,t}\left(\sqrt{(P_{gi}^{\max})^2 - (Q_{gi}^{n,t})^2}\right)\right] \qquad (4)$$

where k is the profit rate of active power generation, usually lies between 5 to 10%.

Constraints

1. Power Flow Constraints: The power flow equations as determined by the kirchhoff's law, for all buses during all scheduling sub-intervals are given by

$$\sum_{i\in G_n} P_{gi}^{n,t} - \sum_{i\in D_n} P_{Ti}^{n,t} - \sum_{i\in D_n} P_{RSi}^{n,t} - \sum_{p\in N} V_n^t V_p^t Y_{np} \cos(\delta_n^t - \delta_p^t - \theta_{np}) = 0 \qquad (5)$$

$$\sum_{i\in G_n} Q_{gi}^{n,t} - \sum_{i\in D_n} Q_{Ti}^{n,t} - \sum_{i\in D_n} Q_{RSi}^{n,t} - \sum_{p\in N} V_n^t V_p^t Y_{np} \sin(\delta_n^t - \delta_p^t - \theta_{np}) = 0 \qquad (6)$$

2. Constraint on Constant power factor of consumers: The real and reactive power consumption at any bus *i*th DistCo at *n*th bus during *t*th sub-interval are tied together by constant power factor.

$$Q_{Ti}^{n,t} + Q_{RSi}^{n,t} = (P_{Ti}^{n,t} + P_{RSi}^{n,t}) \tan\alpha_i^t \qquad (7)$$

3. Constraint on Energy Consumed during Entire Scheduling Period under PRDS: Energy consumed by the PRDS demand at any *i*th DistCo during entire scheduling period should be less than the maximum specified value.

$$\sum_{t\in T} P_{RSi}^t \Delta t \le E_{RSi} \qquad (8)$$

4. Transmission Line Loading Limits: Transmission line flows are bounded by their thermal limits for short lines and stability limits for long lines

$$S_l^t(V_p^t, V_q^t, \delta_p^t, \delta_q^t) \le S_l^{\max} \qquad (9)$$

5. Limits on Variables: Real and reactive power of GenCo, price taking and PRDS demand of DistCo and voltage at various buses have their minimum and maximum limits

$$P_{gi}^{\min} \le P_{gi}^{n,t} \le P_{gi}^{\max}$$
$$Q_{gi}^{\min} \le Q_{gi}^{n,t} \le Q_{gi}^{\max}$$
$$0 \le P_{RSi}^{n,t} \le P_{RSi}^{\max t}$$
$$V_n^{\min} \le V_n^t \le V_n^{\max} \qquad (10)$$

6. Additional Constraint Due to Capability Curve: The apparent power generated by the GenCo should lie within the boundaries of capability curve and mathematically can be written as

$$(P_{gi}^{n,t})^2 + (Q_{gi}^{n,t})^2 \le (S_{gi}^{\max})^2 \qquad (11)$$

The proposed market dispatch problem with the objective functions of social welfare maximization and subject to operational and security constraint is a non-linear programming problem and is solved by using Sequential Quadratic Approach in AMPL.

IV. QUANTIFYING THE IMPACT OF DEMAND-SIDE PARTICIPATION

The modeling of consumer's bidding behavior depends upon the concept of price elasticity of demand.

$$\because P_D = P_T + P_{RS}$$

P_T Price taking demand and

P_{RS} Price responsive demand

The proportion of the demand that responds to prices affects the shape of the demand curve. Considering the parameters of the demand curve shown on this figure, the load participation factor is defined as the ratio of the price responsive demand to the total possible demand

$$LPF = \frac{P_{RS}}{P_D} \qquad (12)$$

The price elasticity of demand (ε) provides a quantitative measurement of the sensitivity of demand to changes in electricity prices.

$$\varepsilon = -\frac{\pi}{P} \cdot \frac{\Delta P}{\Delta \pi} \qquad (13)$$

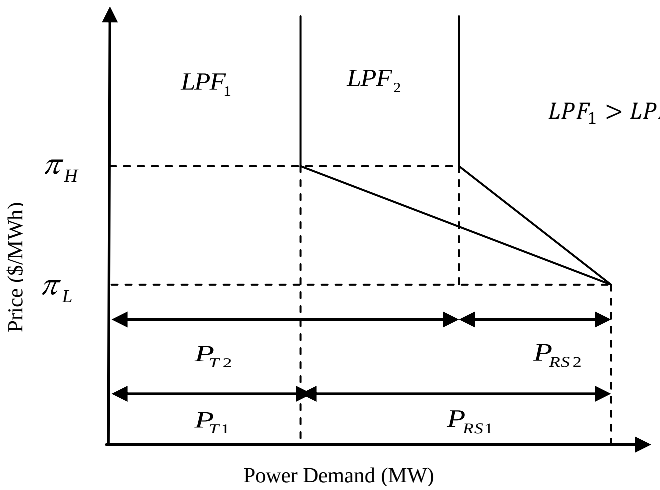

Fig. 3. Relationship between LPF and deamnd

Assume that P_{RS} is linearly and inversely proportional to electricity price. Then, the price elasticity (ε) of P_{RS} can be represented as:

$$\varepsilon = -\frac{\pi_L}{P_D} \cdot \frac{P_D - P_T}{\pi_H - \pi_L} \qquad (14)$$

Then, substituting eq. (12) into (14) gives

$$\varepsilon = -LPF \cdot \frac{\pi_L}{\pi_H - \pi_L} \qquad (15)$$

Hence, increased elasticity can be model by increasing LPF.

PERFORMANCE MEASURE: The weighted average cost per 1 MWh of energy to the demand shifting bidder can be given as

$$\mu_R = \frac{\sum_{t=1}^{T} \pi^t \cdot P_{RS}^{n,t}}{\sum_{t=1}^{T} P_{RS}^{n,t}} \qquad (16)$$

The benefit that demand-side response creates for price responsive consumer can be measured by taking the difference between the weighted average price without and with demand-side response. The relative saving for price-responsive bidder can be written as

$$\lambda_R(LPF) = \mu(LPF = 0) - \mu_R(LPF) \qquad (17)$$

V. RESULTS

The methodology described above has been applied on an IEEE 30-bus system, to develope day-ahead generation and demand schedule of 24 hr considering scheduling sub-interval of 1hr. Generators are located at buses 1, 2, 5, 8, 11, and 13 and their real power generation cost functions are considered to be same during entire scheduling period as given in [16]. Lower and upper bus voltage limits are considered to be 0.94 p.u. and 1.06 p.u. The reactive power generation cost of generators are modeled using eq. (4) by taking k = 10%. The limits on maximum and minimum reactive power generation are taken from [16]. Apparent power flow limit of line 1-3, 4-12, and 28-27 is considered to be 65 MVA, 30 MVA and 17 MVA, and the limit of all other lines is taken to be 180 MVA. The maximum real and reactive power demand of DistCos at buses 2, 5, 7, 8, 12, 21 and 30 are varied during the entire scheduling period of 24 hr. The day-ahead power generation and demand schedule is developed under two cases

Case 1: The DistCo at all buses offers price taking bid in each hour (no price responsive bid)

Case 2: The DistCo at all buses offers price taking bid in each hour except that at bus 30. The DistCo at bus 30 is bidding 98% of the total demand with price taking bid and remaining 2% demand with PRDS bid in each hour. For PRDS bid of DistCo at bus 30,

$\pi_{RS}^{\max t} = 45.0\text{\$/MWh}$, $a_R^t = 0.2\text{\$/MW}^2 h$ and $P_{RS}^{\max t} = 3.936\, MW$

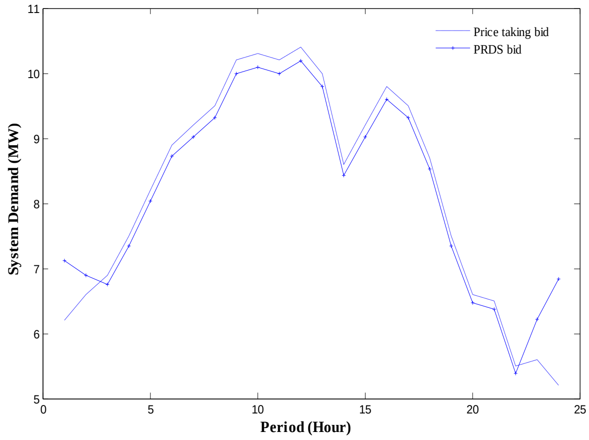

Fig. 4. System Demand at bus 30

Fig.4 shows the variation of scheduled real power consumption at bus 30 under two cases. In Case 1, all the demand at bus 30 is price taking, hence power consumption at bus 30 is equal to the maximum values in each hour irrespective of its locational marginal price. In Case 2, the PRDS demand at bus 30 is scheduled to be consumed in off-peak hours (1, 2, 23, 24) where LMPs are low. During remaining hours, only price taking demand is scheduled to be consumed.

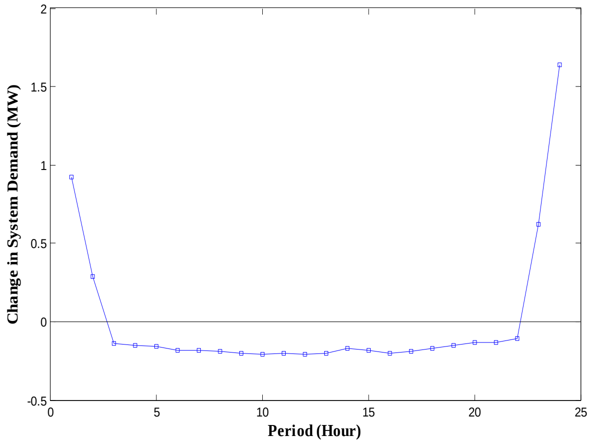

Fig. 5. Change in system demand under PRDS bid

Fig. 5 shows that change in system demand with respect to maximum demand in each hour of the scheduling period is positive during off-peak periods and negative during peak periods.

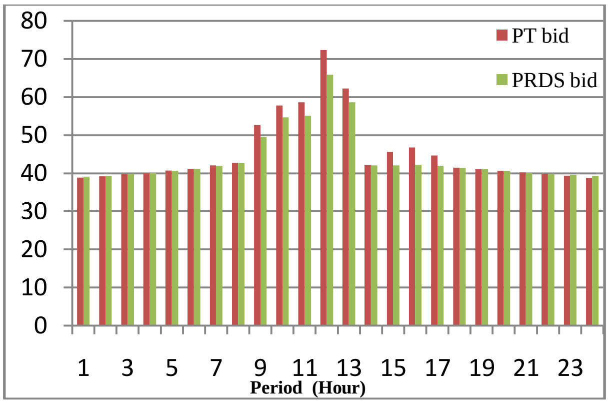

Fig. 6. LMP of real power at bus 30 under two cases

Figs. 6 and 7 show that variations in LMP are highest in Case 1, where all demand is price taking. In Case 2, some consumers reduce their energy consumption during the periods when LMPs are high and the energy that is not consumed can be consumed in off-peak periods. Thereby PRDS bid normalizes LMPs by reducing peak values and increasing off-peak values.

The methodology given above is applied for varying LPF ranging from 0.02 to 0.10. By using the formula given in (16), the weighted average cost per 1 MWh of energy to the demand shifting bidder for the various LPF is calculated.

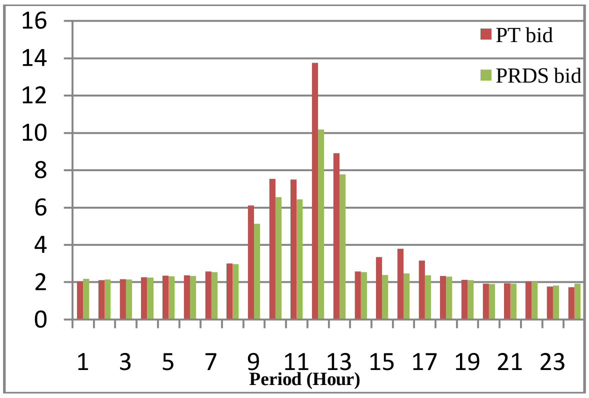

Fig. 7. LMP of reactive power at bus 30 under two cases

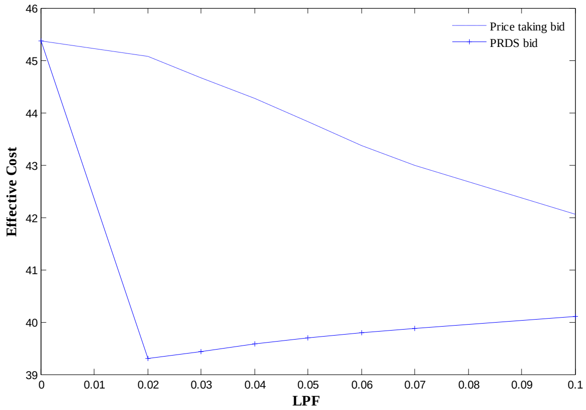

Fig. 8. Effective costs for PT and PRDS demand

Fig. 8 uses the weighted averages to summarize the effective costs for both the price taking and shifting price responsive bidders. When LPF is zero, effective cost for price responsive and price taking bidders is same, when small number of consumers become price responsive (at LPF=0.02), there is a significant decrease in effective cost of consumption for price responsive demand shift bidders but when LPF increases, then effective cost of consumption starts to increase for PRDS bidders.

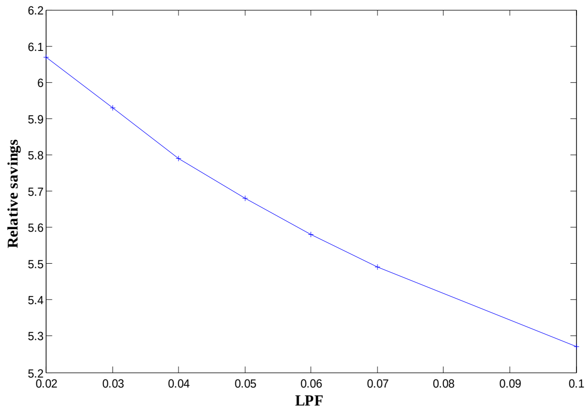

Fig. 9. Savings for PRDS demand

Fig. 9 shows that when LPF is low, relative saving of the price responsive bidders is more but it reduces as the size of the demand-shifting bid increases (i.e., as LPF increases). Therefore, the effect of the demand-side participation in the electricity market is limited.

VI. CONCLUSION

A significant penetration of demand-side participation at electricity markets would have impact on the electricity prices. In this paper the price responsive demand shifting bidding mechanism of DistCo has been presented that maximize the social welfare. This bidding mechanism offers consumer the opportunity to reduce their energy cost by submitting a shifting bid, provided they are flexible with the timing of their consumption. The study on IEEE-30 bus system show that peak locational marginal price tends to reduce with an increasing level of demand shifting, which benefits all bidders even if they do not participate in shifting activities, thereby helpful in managing congestion. Bus as more consumers become sensitive to prices than effective costs to serve the demand start to increase. Therefore, the the effect of the demand-side participation in the electricity market is limited.

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