Framework for the incorporation of demand-side in a competitive electricity market

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Abstract: The paper discusses the importance of simultaneous plant production and demand reduction scheduling which is required for the establishment of a full electricity market where demand-side has opportunity to compete with generators, as is the case with the England & Wales Pool's demand-side bidding (DSB) scheme. It also emphasises that demand cannot be generally treated as negative generation because of the ability of demand to redistribute itself in response to price based load management activities. In that sense, an adequate scheduling methodology of available resources (from supply and demand-sides) is needed to facilitate the new market. However, traditional formulations of the plant scheduling problem are not valid when load reduction is available, as gross demand is not known in advance. For that purpose a composite model for optimal generation and demand reduction scheduling is presented in the paper. It is shown that this model can be used for a comprehensive evaluation of possible scenarios for the implementation of demand-side bidding into the electricity market and the assessment of the influence of DSB on total production costs, system marginal price (SMP) profile, capacity element payments and benefit allocation between producers and consumers.

1 Introduction

Since 1990 England & Wales (E & W) electricity industry has been operating in a competitive environment, where electricity is sold by generators and purchased by suppliers through the Pool. It was decided to use marginal price structure as a base for the trading arrangements [1].

However, it has been widely accepted that no strict distinction between generators and consumers need be made in a market driven environment. Electricity producers and consumers are simply treated as participants in the electricity market who wish to maximise their profits. Hence, any change in demand can be considered as a corresponding, symmetrically opposite, change in generation and *vice versa*. Along that line, the E & W electricity market has recently adopted a scheme called demand-side bidding (DSB) where large industrial consumers can offer their ability to reduce load directly to the Pool and receive a payment by making this reduction available. An improvement in competition for supply, reduction in total production costs and in system marginal price have been the principal expected benefits from the scheme.

On the other side, however, the relationship between demand and price has been studied from the individual consumer's point of view, where the phenomenon of migration of the load across time in response to variations in price has been highlighted [2–6]. The issue is that not only does load rise or fall in response to price (as with other commodities), but that consumption redistributes itself. Thus, in addition to a self elasticity effect, it is important to consider suppression of load at one time and its reappearance at another, through a cross elasticity effect [7], unless the reduction is created by local generation. This is particularly important because industrial customers, as prospective participants in the DSB scheme, cannot reduce their load on a regular daily basis without load recovery, otherwise their profits could suffer. Load management services based on plain load reduction can be offered to the power system operator for other purposes, such as to meet reserve requirements and to participate in load frequency control, but not to participate in determining the system marginal price on a regular basis. In other words, the demand-side may contribute to demand redistribution but not necessarily to energy reduction. Load reduction periods can be followed by load recovery periods, and that load increase has to be supplied by scheduled system generators. Hence, additional costs incurred in recovery periods unavoidably accompany demand redistribution. Therefore, demand and generation do not have to be necessarily opposite and symmetric to each other and this opens up important questions regarding a more adequate treatment and incorporation of DSB in available scheduling methodologies. Additionally, a more detailed specification of the terms in DSB bids is required for the practical implementation of the scheme.

In this paper a conceptual framework is developed for an evaluation of possible scenarios for the implementation of DSB into the electricity market. It

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includes an assessment of the influence of DSB on total production costs, SMP profile, capacity element payments and the benefit allocation between producers and consumers, using the Pool rules [1].

It is shown that a relatively small reduction in total production costs that might be achieved by a DSB scheme could be accompanied by a very significant change in benefit allocation between consumers and suppliers, because of the possible large difference between marginal prices for generation and the marginal benefit from load reduction.

2 Model for simultaneous generation and load reduction scheduling

The role of DSB in daily scheduling needs to be carefully analysed, as load reduction can be followed by load recovery which changes the load profile of the customer both before and after the exercise and therefore changes total electricity production costs. It should be noted that load reduction by a DSB is normally scheduled by GOAL [1]. For this study, an augmented plant scheduling formulation, capable of dealing with supply side and demand-side bidders simultaneously, has been developed.

A multitechnology production model is adopted, where the cost function for each generator can be decomposed into several piecewise linear curves, while start-up and no-load costs are spread over the running period. The plant scheduling problem is simplified to emphasise the specific role of the proposed demand model. The scheduling problem is formulated as

$$min \sum_{t=1}^{t=n} \sum_{i=1}^{i=I} C_i x_{ti} + \sum_{t=1}^{t=n} \sum_{j=1}^{j=J} B_j y_{tj} \qquad (1)$$

subject to

$$x_i^{min} \leq x_{ti} \leq x_i^{max} \qquad t = 1, n; i = 1, I$$

$$y_j^{min} \leq y_{tj} \leq y_j^{max} \qquad t = 1, n; j = 1, J$$

and a balance of generation and demand given by

$$q_{\Sigma t} + \sum_{j=1}^{j=J} \Delta q_{tj} = \sum_{i=1}^{i=I} x_{ti} \qquad t = 1, n \qquad (2)$$

where

$$\Delta q_{tj} = \sum_{k=1}^{k=n} \pi_{tk}^{j} y_{kj} \qquad j = 1, J$$

The total available energy reduction is to be limited by

$$\sum_{t=1}^{t=n} y_{tj} \leq Y_j \qquad j = 1, J$$

where

C_i = per unit price bid by generator i

B_j = per unit price bid by consumer j

I = the total number of supply side bidders

J = the total number of demand-side bidders

n = number of scheduling periods (e.g. 48 half-hour periods)

x_{ti} = output of generator i at time t

y_{tj} = load reduction of the consumer's j load at time t

x_i^{max} = maximum operating level of generating unit i

x_i^{min} = minimum operating level of generating unit i

y_j^{max} = maximum demand that can be reduced by DSB j over one reduction period

y_j^{min} = minimum demand that can be reduced by DSB j over one reduction period

$q_{\Sigma t}$ = expected gross demand at time t (without DSB)

Δq_{tj} = net change in the demand at time t as a result of the redistribution of the load by the demand-side bidders j

π^{j}_{tk} = elements of a square matrices Π, that describes the load redistribution of demand-side bidders j (see below)

Y_j = the total amount of energy that can be reduced by consumer j during the exercise period

The main difference between this formulation and traditional formulations lies in the fact that the final demand profile is not known in advance. In other words, it is not known when the DSBs are to be asked to exercise their bids nor the amount of optimal load reduction accompanied with load recovery. Therefore, gross demand to be supplied by the generators is not any more an exogenous parameter but rather an internal unknown variable which has to be determined.

To handle this new requirement a square matrix Π is introduced to model load redistribution. The structure of the matrix is depicted in Fig. 1. The number of rows and columns in this matrix depend on the scheduling periods being considered. Typically this may be 48 half-hour periods representing a day's operation. By this matrix, associated with each DSB, both load reduction and load recovery are explicitly modelled. Note that the structure of one column defines the structure of the whole matrix.

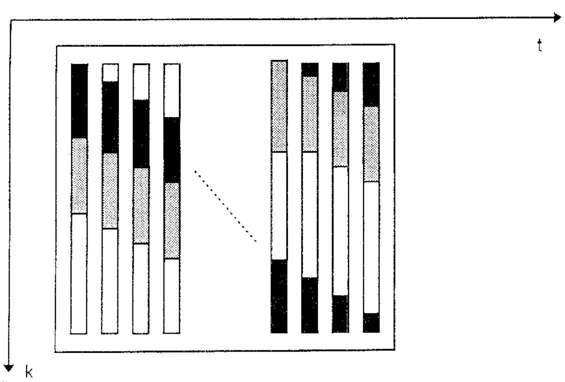

Fig. 1 *Structure of matrix Π_j that describes load redistribution possibilities for DSB_j*

Each column contains three different types of element. Black-shaded areas of the matrix correspond to possible periods when load reduction can be required by the operator of the DSB the corresponding elements are put to −1. Grey areas correspond to the pattern of the bidders' energy recovery process and entries will be put to a positive value corresponding to the proportion of load recovered in that period. Such recovery can occur both before and after the bid is exercised. All other entries are zero. This allows us to model all possible load redistribution patterns.

To illustrate how load redistribution is modelled, let us consider a simple situation in which it is assumed that a reduction of one unit of energy in the gross demand over any period of one hour (two settlement periods) requires an increase in demand over the following two hours (four settlement periods), such that the total energy consumed (over, say, a day) remains constant. This determines the structure of the matrix: black-shaded areas have length of two half-hour periods with entries equal to –1, while the four elements immediately below these have values 0.5, and all the other elements are zero. The sum of the elements in each column is equal to zero, as the total energy consumed remains unchanged by the assumption. If the amount of load reduction is required in two successive periods, the total change is the sum of the individual load changes A and B, which is depicted in Fig. 2 (A and B could be thought of as two DSBs). It is important to note that the total individually reduced demand of 4 units has resulted in the net reduction of only 3.5 units in gross demand, as a result of the overlap of load reduction of B and load recovery of A. This overlap may be required when it is desirable to postpone a recovery period further (i.e. when peak periods are relatively long), which can be achieved by a new exercise of, say, another available DSB (B in Fig. 2). This effect is taken into account in the proposed formulation by the load balance equation.

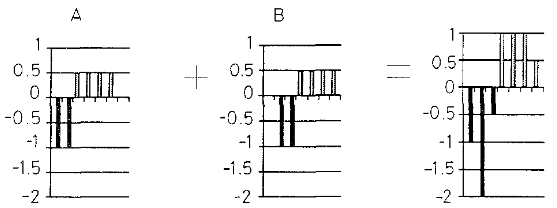

Fig. 2 *Total change in demand as a result of two equal successive load reduction exercises with an overlap in load reduction and load recovery*
■ load reduction
□ load recovery

Generally, however, not all of the energy reduced has necessarily to be recovered, and the proposed model is capable of handling this situation also. The proportion of energy that will not be recovered, if DSB is called, could be obtained from any column (e.g. column t) of the matrix Π and is given by

$$e^j = \frac{\left|\sum\limits_{k \in black} \pi^j_{tk}\right| - \sum\limits_{k \in grey} \pi^j_{tk}}{\left|\sum\limits_{k \in black} \pi^j_{tk}\right|} \qquad j = 1, J \qquad (3)$$

The unrecovered energy is zero when the total energy that is reduced (at times marked by the black areas) will be recovered at some other time (marked by the grey areas). It should be noticed that if $e = 1$, then the reduced energy by exercise of DSB is completely unrecovered for that particular day.

From the above discussion it can be concluded that demand should not be treated as negative generation in scheduling formulations, as is currently the case in the E & W Pool. Furthermore, any demand reduction cannot be as effective as equivalent generation, from the total cost point of view. Moreover, the case with an overlap in load reduction of one DSB and load recovery of another DSB, reduces the total usefulness (value) of the load reduction, as the sum of individual reductions are generally lower than the net reduction seen by the system. Presumably, each DSB would be paid for with respect to its individual reduction (2 units each in the above example) while the system, in fact, experiences a lower reduction (3.5 units). Therefore, the per unit value of the reduction decreases in this case. It is, therefore, reasonable to expect that in order for DSB to compete with generators on a total production costs basis, DSB has to offer a price which is competitive (low) enough to compensate for the cost associated with the very nature of the load redistribution process.

Furthermore, demand-side bids, in addition to the cost and amount of MW available for reduction, should also take into consideration the duration of the exercise (or the total amount of energy that can be reduced, expressed by the last term in the set of constraints (eqn. 2)), and the estimated shape of the energy restoration pattern, which determines the structure and values of the columns in the matrix Π.

3 Application

The above discussion and the proposed combined plant scheduling formulation is illustrated on the IEEE test system [2], slightly modified (Table 1).

Table 1: Loading capabilities of system generators and their bid prices

Generator	Generator capacity MW	Marginal cost \$/MWh
1	300	0
2	400	6
3	400	6
4	350	12
5	310	12
6	155	14
7	155	14
8	152	16
9	152	16
10	591	23
11	360	30
12	35	43

The system is supplied by 12 generators, and a daily schedule that corresponds to the load profile is depicted in Fig. 3 (seven generators that provide base load are grouped into one in this Figure). The merit order is determined by the linear programming formulation (eqns. 1–2). In this case it is assumed that system reserves are also scheduled through part loaded generators but these are not included in the example for clarity.

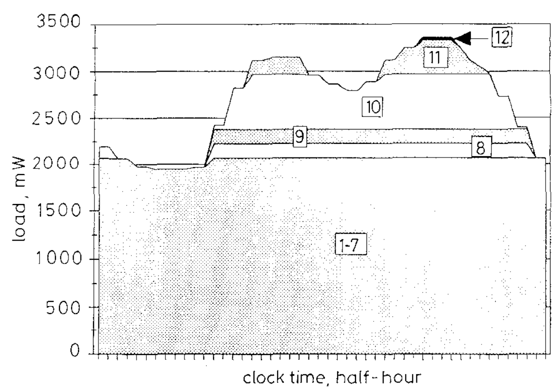

Fig. 3 *Gross demand profile of the IEEE system and generation scheduling without DSB*

To support the above discussion and to study the efficiency of DSB, the simplest case, with only one large industrial customer participating in the scheme, is analysed. It is assumed that

(i) the DSB can reduce load equal to the maximum output of the marginal generator (35MW) that supplies the peak period (black-shaded area in Fig. 3)

(ii) the maximum energy that can be reduced is equivalent to the energy produced by the peak generator in four half-hour periods (70MWH)

(iii) energy that is reduced during the exercise period will be recovered by increased consumption over an assumed recovery period (4h before and 4h after the exercise)

(iv) the total energy not produced at peak is recovered. In this case, matrix Π has the following structure: the lengths of the black-shaded bars is 4 with elements -1 (peak generator is in service for four half-hour periods), while the lengths of the grey bars, that correspond to the recovery periods, below and above the black ones, are 8, with elements 0.25. All other elements are zero. This makes $e = 0$ as $4 \times (-1) + 16 \times 0.25 = 0$.

Combined linear programming was used to optimise eqns. 1 and 2, giving the schedule for the generators and the optimal times and levels of load reduction simultaneously. In practice, however, a more realistic integer based optimisation would be used.

To evaluate the effectiveness of the available load management services, the bid price of the DSB was gradually decreased from the bid price of the peak generator (generator 12) until the DSB replaced the generator. This occurred when the DSB bid price was at least 2.65 times lower than the bid price of the peak generator, thereby indicating the highest price the customer can bid to get called and eliminate the peak generator from the order.

In Fig. 4 the optimal composite generation production and load redistribution schedule is given, where the ability of the customer to reduce load is used to remove the marginal generator completely from the merit order. For the sake of clarity, the Figure shows the period of interest only, particularly indicating the load redistribution process.

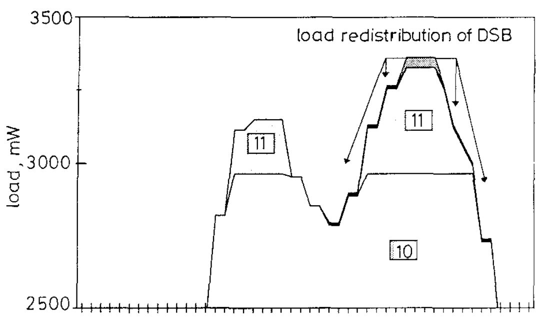

Fig. 4 *Composite generation production and load redistribution schedule*

It can be seen from Fig. 4, that there is an increase in the demand over the energy recovery periods, and called generators have to generate more at those times, so an increase of the total cost at those times is unavoidable. Strictly speaking, redistribution of DSB's consumption might increase system marginal price during the recovery period, but this is not very likely to happen as, in practice, load recovery periods are normally expected to be considerably longer than load reduction periods and not to coincide with peak prices.

4 Cost analysis and changes in benefit allocation

The developed composite model can be used for comprehensive evaluation of possible scenarios for the implementation of DSB into the electricity market and the assessment of the influence of DSB on total production costs, SMP profile, capacity element payments and benefit allocation between producers and consumers.

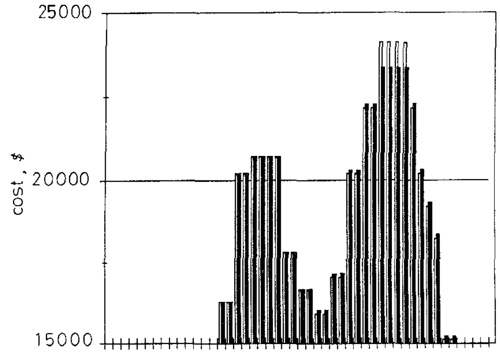

Fig. 5 *Production cost with and without DSB over the exercise and recovery periods*
□ no DSB
■ with DSB

Production costs, with and without DSB, over a 24h period, are depicted in Fig. 5, under the assumption that the DSB does not require any payment for the service. The difference in the total production cost is \$1134 or 0.15%, as a result of the load redistribution. The value of DSB is, therefore, \$1134, which is the maximum amount that the DSB could save for being called, judged from the reduced production cost point of view.

As the total reduced energy over the 2h period is 70MWh, the value of the reduction is 16.2\$/MWh, if the DSB bid price is zero. In this particular case, if the DSB bid below 16.2\$/MWh, the bidder would be called to replace the marginal generator, whose bid price is 43\$/MWh. The total net saving in production cost would be $(16.2 - B) \times 70$, where B is bid price of the DSB in \$/MWh.

For the implementation of the scheme, however, a mechanism for the payment allocation to DSB needs to be defined. In this paper, a possible scenario is suggested, according to which DSBS would be paid their bid prices. In the Pool concept, the payment would be collected from the other customers, by a corresponding increase in uplift over the period of the exercise, while SMP would remain to be determined by marginal generators. In this particular case, during the peak period, SMP would be 30\$/MWh as generator 12 would not be called to generate, while the increase in uplift necessary to cover DSB if the bid price is 16.2\$/MWh would be 0. 17\$/MWh over two hours.

In Fig. 6, SMP profiles are depicted for the cases with and without DSB.

The major change in the benefit allocation comes from the change in SMP, as generators make the largest proportion of their profit during peak periods. This situation is depicted in Fig. 7. The total change in the profit, as a result of DSB being exercised, is \$86450, or almost 10% in this particular case, which is significantly larger than the reduction in production costs (0.15%). From the demand-side point of view, the value of DSB would be \$86450, which gives the marginal benefit of 1235\$/MWh for the exercise.

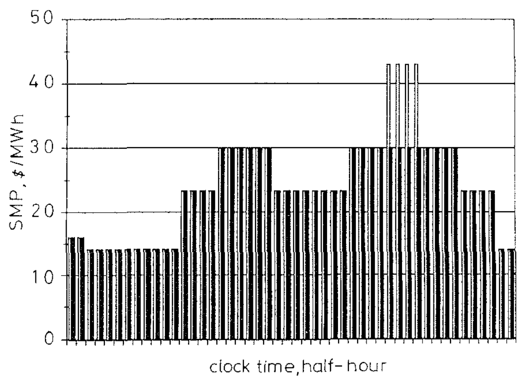

Fig. 6 *SMP profile with and without DSB*
▨ no DSB
■ with DSB

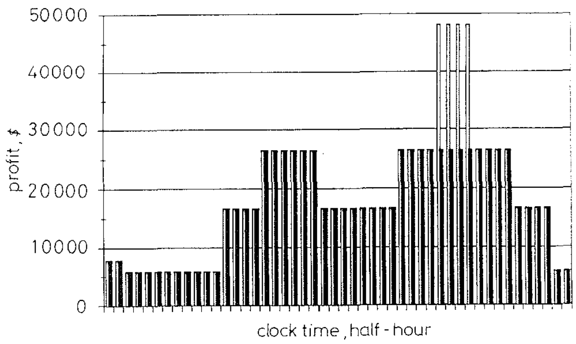

Fig. 7 *Supply side profit with and without DSB*
▨ no DSB
■ with DSB

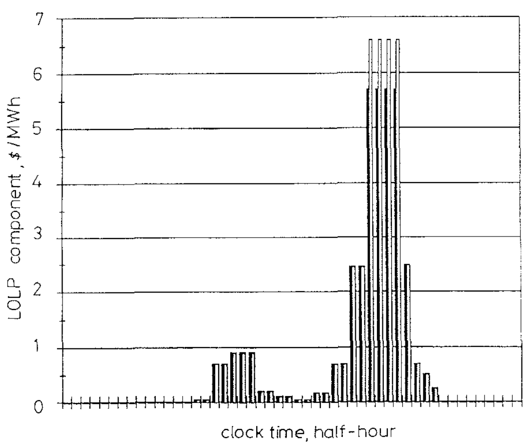

Fig. 8 *Capacity payments with and without DSB*
▨ no DSB
■ with DSB

It is interesting to note that capacity payments [1] will be changed as a result of DSB activities. Using a standard two-state generator availability model [9], LOLP components are calculated and depicted in Fig. 8. As all offered generators are used to calculate the LOLP [1], it is expected that the DSB, if called, could reduce the risk (and corresponding payment) of the system being unable to supply the demand over the load reduction period. However, because of the increase in the demand over the recovery period, corresponding risk could increase. When the energy recovery period is considerably longer than the load reduction period, it is reasonable to expect that this increase would not normally be significant. In this example no change in LOLP is observed over the recovery period.

The total revenue lost, from the supply side point of view, and gained from the demand-side point of view, as a result of LOLP reduction at peak, amounts to 0.87\$/MWh, or \$5846 in total. This is even more than the reduction in production cost, as all customers pay for the capacity element. The value of DSB, judging from the LOLP reduction only, would be therefore 83.5\$/MWh. The reduction in the LOLP component, caused by the DSB exercise, is relatively large as the eliminated peak generator is used in this calculation, which is in line with the Pool rules [1]. A debate over the appropriateness of the adopted LOLP calculation scheme can be found in [9].

Summing SMP and LOLP components appropriately in time, Pool purchase prices without and with DSB can be easily obtained. The marginal value of DSB from the change in Pool purchase price is 1318.5\$/MWh in total.

It is interesting to underline the difference between production marginal price (43\$/MWh) and load reduction marginal benefit (1318.5\$/MWh) at peak. It is important to emphasise that the marginal benefit depends on the absolute value of gross demand: the greater the demand, the larger the marginal benefit. In that respect, a buyer who purchases a significant amount of energy from the Pool, could find it very profitable to provide an incentive to his customers to reduce their load at peak times. It is important to recognise that such a buyer could afford to pay more to a prospective demand-side bidder than the demand-side bidder could get paid through bidding directly into the Pool. This is because the buyer could purchase the energy from the Pool at a cheaper rate, resulting from the SMP reduction caused by the exercise of his DSBs. In the above example, and under the assumption that the energy is purchased from the Pool by only one buyer (monopoly in supply), the buyer could afford to pay up to 1318.5\$/MWh to the DSB, while the DSB would only be paid up to 16.5\$/MWh by bidding directly into the Pool.

5 Conclusions

In this paper a framework is developed for a comprehensive evaluation of possible scenarios for the implementation of DSB into the electricity market and the assessment of the influence of DSB on total production costs, SMP profile, capacity element payments and benefit allocation between producers and consumers. The proposed composite model is capable of dealing with supply and demand-side bidders simultaneously. For the practical implementation of the full market, a suitable philosophy has to be developed. The presence of large differences between SMP and load reduction marginal benefits has to be adequately addressed, requiring that both short-term and long-term implications should be investigated further.

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