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Flexibility from the Demand Side

Daniel S. Kirschen, *Fellow, IEEE*, Angel Rosso,

Juan Ma, *Student Member, IEEE*, Luis F. Ochoa, *Member, IEEE*

Abstract – The stochastic nature of renewable energy sources such as wind and sun introduces a new form of uncertainty in power system operation. The standard answer to the concerns that this increase in uncertainty raises is that the system should become more “flexible”. However, there is as yet no agreement on exactly how much flexibility is needed or even a commonly accepted measure of flexibility. There is agreement however on the fact that flexibility has a cost and that this cost should be minimized in a way that does not affect reliability to facilitate the integration of these renewable energy sources.

This presentation will explore how flexibility from demand-side resources compares with the flexibility that fast ramping generating units can provide. In order to take into account the associated investment costs, this comparison relies on an extended unit commitment optimization that considers both short- and long-term aspects.

Index Terms— Flexibility, demand side management, integration of wind generation, long-term unit commitment, reserve requirements.

I. INTRODUCTION

POWER system operation has always been affected by uncertainty. In conventional power systems some of this uncertainty stems from unforeseen fluctuations in the load, but the largest source is unpredictable failures of generating units. To guard against the sudden imbalances that these failures cause, system operators procure a significant amount of spinning reserve capacity, which provides a preventive security margin. Renewable energy sources such as wind and solar generation introduce a different form of uncertainty, which typically results in smaller but more frequent imbalances. Since increasing the preventive security margin to cope with these imbalances would be quite costly, a significant amount of attention has been devoted recently to the concept of “flexibility” in power systems. However, there is as yet no agreement on exactly how much flexibility is needed or even a commonly accepted measure of flexibility. There is agreement however on the fact that flexibility has a cost and that this cost should be minimized in a way that does not affect reliability to facilitate the integration of these renewable energy sources.

Flexibility can be provided by generators that start and stop quickly, that have large up and down ramping rates, and low minimum up- and down-time. Interconnection with more

flexible systems is another conventional solution. However, relying solely on generators to provide flexibility is expensive because it often involves producing energy with more agile but less efficient generation units or operating plants below their maximum efficiency loading. It is thus important to know how much flexibility is actually needed in a given power system and how much flexibility can be provided in a cost-effective manner by new solutions such as demand side management or storage.

Optimizing the flexibility of a generation portfolio is a problem that has been considered for some time [1]. The liberalization of the electricity markets has made this issue more complex because the owners of the generating units must have an incentive to provide flexibility [2]. While there is obviously a need for “physical” flexibility, the operating practice and the market rules affect the amount of flexibility that is needed. Low cost “virtual” flexibility can be obtained by adjusting these practices. For example, when renewable generation represent a significant fraction of the installed capacity, periodic re-optimization based on improved wind generation forecasts (e.g. 6-hour rolling unit commitment) reduces the need for additional reserve margin [3]. While such techniques reduce the cost of operating expensive peaking units, it also reduces their utilization factor and thus makes their profitability even more marginal. These considerations, along with the availability of cheaper communication and control technologies, suggest that the provision of flexibility by the demand side might be a viable alternative [6]. Tyagi et al. showed that the optimal scheduling of DSM during critical price periods, particularly thermal loads, results in a significant reduction in the need for flexible generation units [7]. Kowli and Gross demonstrated using a security-constrained unit commitment that introducing DSM would reduce both load curtailment (and the corresponding losses of profit or comfort) and the need for investments in grid reinforcements [8]. A number of papers have also explored the interactions between renewables and DSM. Akmal et al. [9] compare two ways of managing under-floor heating from electrically operated heat pumps: for peak shaving and for charging/discharging following high/low wind periods. DSM reduces the number of occasions when peaking units have to be started or wind power production has to be curtailed. However, this approach does not optimize the overall operation of the generating units or the generation portfolio. Other strategies, such as real time pricing (RTP), have been shown to reduce load curtailment events and the need for additional reserve requirements [10].

D S Kirschen is with the University of Washington, Seattle WA, USA. (e-mail: kirschen@uw.edu). A Rosso, J Ma and L F Ochoa are with the School of Electrical and Electronic Engineering at The University of Manchester, Manchester, UK. (e-mail: juan.ma@postgrad.manchester.ac.uk, luis_ochoa@ieee.org).

This presentation will present a technique for assessing the value of demand-side flexibility in a portfolio of flexibility resources taking into account not only the operational costs but also the investment costs. The proposed tool can also be used to assess the how flexibility affects the integration of wind generation.

II. METHODOLOGY

To assess the provision of flexibility from a combination of generating units and demand-side activities, one has to balance the additional cost of providing more flexible generating units (an investment cost) against the operational benefits that this flexibility provides (an operational cost). DSM is incorporated in the model by allowing part of the load to be curtailed and ‘recovered’ later in the same day. In other words, the available DSM is a fraction of the hourly demand that can be ‘shifted’ to another time later in the day. This concept is consistent with the expected mode of operation of smart appliances.

A. Unit Commitment

Assessing these benefits requires a model that adequately represents the operational constraints of the system (such as the need to follow the load profile while maintaining enough spinning reserve) as well as the operating limits of the generating units (e.g. ramp rate and minimum up- and down-time). Unit Commitment (UC) programs are typically used to enforce these constraints but such programs consider only the cost of running the generating units over an optimization horizon ranging from a day to a week. Several extensions are required to transform such a UC program into a tool capable of balancing the long- and short-term costs of providing flexibility:

- The objective function must include not only the operating cost but also the amortized investment cost of each generating unit
- The optimization must be able to decide not only when a particular generating unit is started-up and shutdown, but also whether building that unit is optimal or not
- The optimization horizon must be extended because the need for flexibility varies with the seasonal variations in load level, load profile and renewable generation.

B. Variable set of generating units

While a conventional UC optimizes the commitment of a fixed set of available generating units, the proposed model should have the opportunity to add or remove generating units from the available set to model the existence or non-existence of generating units providing flexibility in the commitment. To this end, another binary decision variable is introduced for each possible generating unit. This decision variable models the existence of the generating unit. If it takes the value “1”, the generating unit exists and can be committed. On the other hand, if its value is “0”, the unit does not exist and cannot be committed at any hour of the horizon.

C. Optimization horizon

The optimization horizon of a conventional UC ranges from one day to a week or slightly more. Such an horizon is not suitable for assessing investment decisions because the chosen week is unlikely to be representative of all the operating conditions that the system is likely to face. In particular, when considering the needs for flexibility, one should take into account the variations in demand level, demand profile and wind generation that occur naturally over the course of a year. Running the proposed optimization algorithm over a whole year with the one-hour resolution needed to model the flexibility needs would require an excessive amount of computing time. Instead, four weeks are used to represent a year. The load profile of each of these weeks is the average of the load profiles of all the weeks of a season. The load profiles of these four representative weeks are linked together to make up the 672 hours optimization horizon. Two aspects of this linkage must be emphasized. First, the existence decision variables should obviously run through all weeks otherwise a decision might be made to invest in a unit only for the winter. Second, as will be discussed below, the initialization of the commitment variables at the beginning of each week must be done carefully. In the objective function, the operating cost of each week is weighed by the number of weeks in the season. On this basis, the results of the optimization problem indicate how many generating units of each type are needed to minimize the total cost for an average year. However, one must consider the possibility that every few years there might be a week with extreme variations in load and renewable intermittent generation. The optimal amount of flexibility calculated on the basis of average representative weeks might not be sufficient to handle effectively such a situation. To take such a possibility into account, the optimization can be performed using a composite load profile consisting of the five average representative weeks plus one or more weeks representing extreme conditions. The relative weighting given in the objective function to these extreme weeks should reflect their rarity.

D. Objective function and constraints

The objective function (1) minimizes the sum of the generation and investment costs. The generation cost, $GC(i, t)$, includes the start up, no load, and production cost of each unit. This cost is multiplied by the corresponding weighting factor, $K(w)$, of each representative week. The investment cost, $AIC(i)$, accounts for the amortized investment cost of the generating units. $e(i)$, is a binary variable that indicates whether a unit i has been selected from the available portfolio of potential investments. The operating cost of a particular generating unit is zero if it has not been selected.

Because investments in wind generation rely heavily on various forms of subsidies or on mandates, they represent more a political than a technical decision. The construction of wind farms are therefore not taken into account in the investment costs of the system.

$$\min \left\{ \sum_{i=1}^I \left(\sum_{w=1}^{Weeks} K(w) * \sum_{t=t_0(w)}^{t_{end}(w)} GC(i, t) + AIC(i) * e(i) \right) \right\} \quad (1)$$

Equation (2) enforces the power balance constraint between generation, $G(i, t)$, demand, $D(t)$, and the committed aggregated capacity of DSM schemes, $DSM(t)$ is considered in (2), while Equation (3) enforces the reserve requirements.

$$D(t) - DSM(t) = \sum_{i=1}^I G(i, t) \quad \forall t \in 1, T \quad (2)$$

The generators' contribution to reserve is the difference between the maximum power available, $\overline{G(i)}$, and the actual power output, $G(i, t)$, of those units committed, $u_c(i, t)$, at instant t . The reserve-related contribution of DSM schemes is similar to the generation contribution: it is the DSM capacity still available, i.e. $\overline{DSM} - DSM(t)$, where $\overline{DSM}(t)$ is the maximum DSM capacity that can be used at instant t .

$$\sum_{i=1}^I u_c(i, t) * (\overline{G(i)} - G(i, t)) + (\overline{DSM}(t) - DSM(t)) \geq SR(t) \quad \forall t \in 1, T \quad (3)$$

The reserve requirements, $SR(t)$, include the possible loss of the largest generation unit and a factor that accounts for the uncertainties of wind generation. This reserve constraint has an important effect on the optimal amount of flexibility because it often forces the commitment of peaking units that are expensive to operate but relatively cheap to build.

As mentioned above, there is a maximum DSM capacity at every instant t . This limit is modelled as a fraction P of the actual demand, $D(t)$, during that period (4). Equation (5) ensures that energy that is shifted by DSM is recovered during the same day.

$$-\overline{DSM}(t) \leq DSM(t) \leq \overline{DSM}(t) \quad \forall t \in 1, T \quad (4)$$

$$\overline{DSM}(t) = P * D(t)$$

$$\sum_{t=t_0(d)}^{t_{end}(d)} DSM(t) = 0 \quad \forall d \in 1, Days \quad (5)$$

Conventional constraints on the operation of the generating units, such as limits on the ramp rates and the minimum working and cooling times are also considered.

III. 24-HOUR CASE STUDY

In order to evaluate the performance of the model and understand the impact of DSM on the demand-supply balance, this subsection presents a simple case study for 24 hours. The demand is modeled as a constant value modified by a sinusoid, i.e. $D(t) = 250 - 50 * \sin((t) * \pi/12)$ [MW]. This very well known shape makes it easier to visualize the impact of different DSM penetrations on the generation profile. The available DSM capacity is taken as a fraction of the scheduled demand of the corresponding hour. In addition, the committed DSM capacity is shifted from one period to another during the same day.

TABLE I
GENERATORS CHARACTERISTICS – TEST CASE

Unit	A	B
Min Power (MW)	60	60
Power elbow1 (MW)	236	150
Power elbow2 (MW)	240	240
Power elbow3 (MW)	244	360
Max Power (MW)	400	600
Variable Cost 1 (\$/MW)	8	25
Variable Cost 2 (\$/MW)	8.4	25.5
Variable Cost 3 (\$/MW)	8.8	26
Variable Cost 4 (\$/MW)	10	26.5
No Load Cost (\$)	200	25
Investment Cost (M\$)	20	10
Ramp Up/Down (MW/h)	50/200	50/60
Min time Up/Down (h)	8/5	1/1

The generation portfolio consists of only two units: Unit A is a base unit, with a low operating cost and slow ramp rates while Unit B has the opposite characteristics (see Table I).

Fig. 1 clearly shows that with higher penetration of DSM, the final energy profile flattens. It is important to mention that the piecewise linear approximation of generation costs has an impact on the final shape of the profiles. Since the cost function is a linear approximation, any load point between two elbows of the piecewise linear curve has the same final value on the objective function. Since, this is a demonstration case, the location of the elbows of the piecewise linear approximation was selected so the final profile with no limit on DSM would give a result of a flat profile.

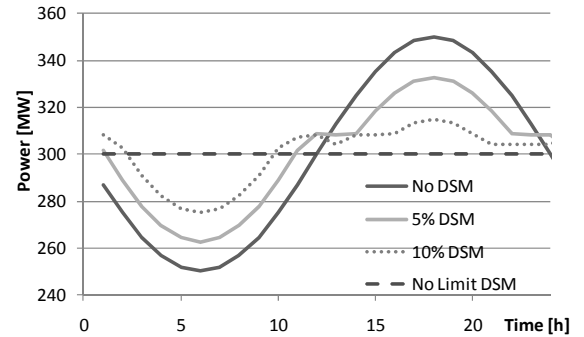


Fig. 1 Progressive impact on the generation profile of DSM.

Since Unit A is cheaper than Unit B, this unit should be committed at its maximum capacity before any other. However, in order to cope with the reserve requirements of the system, Unit B must be synchronized and operated at its technical minimum (Fig 3). DSM could improve the performance of the system reducing the necessity of keeping peaking units online to provide spinning reserves. In systems with a wider portfolio, some of the peaking units would not need to be committed.

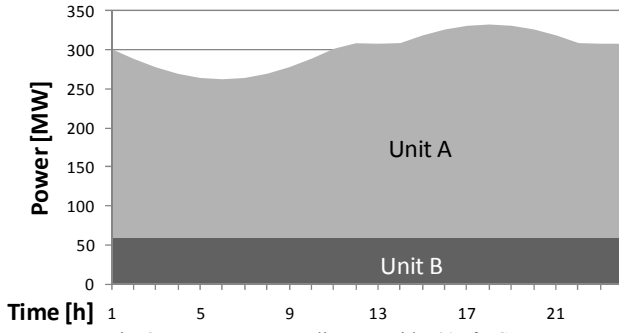


Fig. 2 Energy coverage diagram with 5% of DSM.

IV. CASE STUDY: IEEE RTS

In this section, the proposed methodology is applied using an adapted version of the IEEE Reliability Test System (RTS-96) [12] and hourly demand and wind power data for central Scotland in 2003 [13]. The optimization problem was solved using the Xpress optimization engine [14]. The demand is modeled by the factors showed on table I. The effect of wind generation on the demand for the considered winter week is illustrated in Fig. 3. Here, wind power is considered deterministically, (i.e. modeled by just one profile) given that its variability is taken into account by the reserve constraint. A more formal approach would model wind stochastically. Using this renewable resource affects the demand and reduces the need for power from conventional generating units.

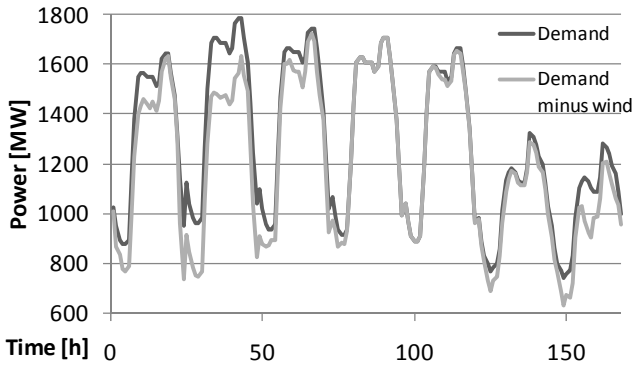


Fig. 3 Demand and the effect of wind power.

For this particular network it was assumed that a maximum 5% of the demand is available for demand side management, i.e. $\overline{DSM}(t) = 0.05 * D(t)$. As the results will show, even such a relatively small fraction of the demand can have a significant impact on the optimal generation portfolio. Other penetration levels of DSM can also be considered [8].

Table II and Table IV show respectively the economic and technical specifications of the generation portfolio considered for this case study. Units 1 to 9 are peaking units (low constraints on minimum up and down times, and large ramp rates) and units 24 to 26 are base units (lowest incremental costs). The other units are intermediate. Fig. 4 shows how demand is affected by the introduction of DSM.

TABLE II
PRODUCTION COSTS SIMPLIFIED RTS SYSTEM

Unit	Technology	Min Power (MW)	Power elbow1 (MW)	Power elbow2 (MW)	Max Power (MW)	inc. Cost 1 (\$/MW)	inc. Cost 2 (\$/MW)	inc. Cost 3 (\$/MW)	No Load Cost (\$)	Start Up Cost (\$)
1-5	Fossil_Oil_1	2,4	5,6	8,8	12	25,75	25,91	26,07	24,0	68
6-9	Combustible_Oil	4	9,3	14,7	20	37,71	37,84	37,97	117,3	5
10-13	Fossil_Coal_1	15,2	35,5	55,7	76	13,77	14,13	14,48	76,4	656
14-16	Fossil_Oil_2	25	50	75	100	18,47	18,78	19,09	210,1	566
17-20	Fossil_Coal_2	54,2	87,8	121,4	155	11,35	11,66	11,97	120,7	1048
21-23	Fossil_Oil_3	69	111,6	154,3	197	23,47	23,69	23,91	239,2	775
24	Fossil_Coal_3	140	210	280	350	11,40	11,61	11,83	132,1	4468
25-26	Nuclear_1	100	200	300	400	8,07	8,46	8,85	221,2	0

TABLE III
DYNAMIC PARAMETERS SIMPLIFIED RTS SYSTEM

Unit	Technology	Investment Cost (\$/MW)	Ramp Up (MW/h)	Ramp Down (MW/h)	Minimum time Up (h)	Minimum time down (h)
1-5	Fossil_Oil_1	214400	48	60	1	1
6-9	Combustible_Oil	272666	31	70	1	1
10-13	Fossil_Coal_1	2923469	39	80	3	2
14-16	Fossil_Oil_2	1786670	51	74	4	2
17-20	Fossil_Coal_2	5962339	55	78	5	3
21-23	Fossil_Oil_3	3519740	55	99	5	4
24	Fossil_Coal_3	13463345	70	220	8	5
25-26	Nuclear_1	21170000	55	200	8	5

As expected, the final demand (*demand with DSM*) to be supplied by the conventional generators is flattened compared to the un-modified demand. This is particularly significant during peak periods. Since the proportion of available DSM capacity is not very high (5%), the overall impact is (visually) relatively small. Wind power moves the load duration curve down during the peak hours (Figure 6) and up during the off-peak hours (Figure 7).

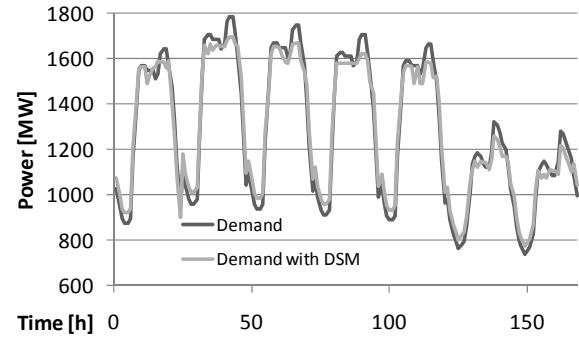


Fig. 4 Influence of DSM on demand to be fed by the generation portfolio.

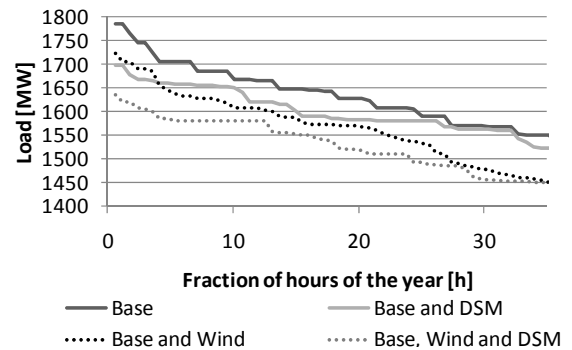


Fig. 5 Load duration curve – peak hours.

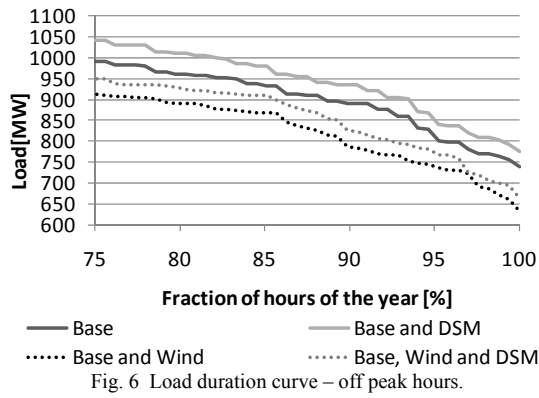


Fig. 6 Load duration curve – off peak hours.

Table IV shows the number of units of different types that would provide an optimal generation portfolio for the different scenarios considered. The introduction of DSM reduces the need for peaking units while the integration of wind power increases the need for such units. Fig. 7 gives the corresponding cost breakdown for all the studied cases. The obvious effect is that wind power reduces the demand and thus the overall operating costs. As mentioned earlier, the cost of investments in wind farms are not taken into account in this analysis. The introduction of DSM reduces both the operating and the investment costs for the base case and the case with wind generation. DSM has a marginal effect on the investment cost in the case with wind generation. However, the introduction of DSM reduces significantly the requirements of peaking units. In a sense, DSM is able to provide some of the flexibility that is usually provided by peaking units.

V. CONCLUSIONS

This paper has proposed an expanded methodology to consider both the short- and long-term operational and investment costs of providing flexibility. This technique is a powerful tool to analyze how demand-side management can be used to meet some of the requirements for flexibility in power systems. Results from its application to the simplified RTS system show that as wind is introduced in the generation mix, more flexibility is required. Provided the corresponding real-time monitoring and control infrastructure is in place, demand side management schemes, such as the aggregation of smart appliances, would not only improve the performance of the system but would also allow the cost effective integration of more renewable energy resources. However, since electricity is an essential good, DSM will be limited. Therefore, in the future, other sources of flexibility, such as storage, will also need to be part of the solution.

Further analyses should consider the stochasticity of wind generation, the uncertainty on the provision of reserve by the demand and the need for occasional load shedding. The study of other flexible resources such as interconnections with other systems and the introduction of storage will be considered in further work.

TABLE IV
NUMBER OF GENERATING UNITS IN THE OPTIMAL GENERATION PORTFOLIO

Unit types	Base Case	Base & DSM	Base & Wind	Base, wind & DSM
Peaking	8	5	9 (all)	6
Base	3	3	3	3
Intermediate	10	7	6	7

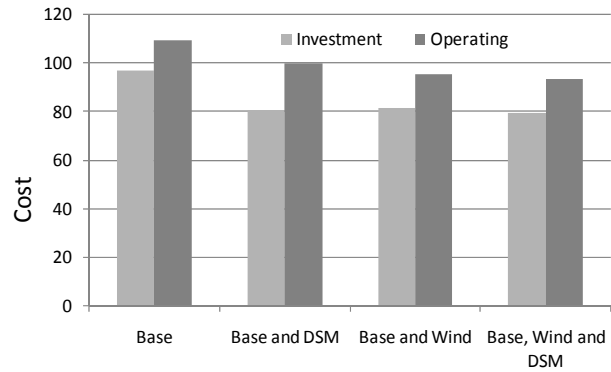


Fig. 7 Investment and generation costs for the various scenarios considered

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