SCUC with Hourly Demand Response Considering Inter-temporal Load Characteristics

Amin Khodaei, *Member, IEEE,* Mohammad Shahidehpour, *Fellow, IEEE* and Shaghayegh Bahramirad, , *Member, IEEE*

***Abstract*— In this paper, the hourly demand response (DR) is incorporated into security-constrained unit commitment (SCUC). Unlike fixed hourly loads, responsive loads linked to hourly prices can be curtailed or shifted to other operating hours. The responsive loads are modeled with their inter-temporal characteristics. Numerical simulations in this paper exhibit the effectiveness of the proposed approach. The study results show that DR could shave the peak load, reduce the system operating cost, reduce fuel consumptions and carbon footprints, and reduce the transmission congestion by reshaping the hourly load profile.**

***Index Terms*—Demand response, Security constrained unit commitment, Real time prices**

Indices:

b	Index for bus
i	Index for unit
t	Index for time

Sets:

f	Superscript for fixed loads
r	Superscript for responsive loads

Parameters:

NB	Number of buses
NG	Number of units
NT	Number of time periods (hours)
$EX_b^{\max}$	Max curtailable daily load at bus b
D_{bt}^f	Fixed load at bus b at time t
$D_{bt}^{r,\max}$	Submitted responsive load at bus b at time t
$DX_{bt}^{\min}$	Min curtailable load at bus b at time t
DR_b	Drop off rate of load at bus b
UR_b	Pickup rate of load at bus b
UT_b	Min up time of load at bus b
DT_b	Min off time of load at bus b
X_{bt}^{on}	ON time of load at bus b and time t
X_{bt}^{off}	OFF time of load at bus b at time t

Variables:

CB_{bt}	Consumption benefit at bus b at time t
D_{bt}	Load at bus b at time t
D_{bt}^r	Responsive load at bus b at time t
GC_{it}	Generation cost of unit i at time t
I_{it}	Commitment state of unit i at time t
P_{it}	Generation of unit i at time t
v_{bt}	Curtailment state of load at bus b at time t
w_t	Power mismatch at time t
μ_{bt}, π_{it}	Dual variables

Symbols:

$\wedge$	Given variables

The authors are with Electrical and Computer Engineering Department, Illinois Institute of Technology, Chicago, IL 60616 USA (e-mail: akhodaei@iit.edu; ms@iit.edu).

I. Introduction

IN RESTRUCTURED power systems, the independent system operator (ISO) would schedule available system resources to satisfy the hourly system load and maintain the system security at the least operating cost [1]-[2]. The hourly system load could be fixed in the day-ahead scheduling. The participating generating companies would submit strategic bids to the ISO to supply the hourly load forecast [3]. The market clearing price would be set by the marginal price of the last scheduled generator for satisfying the hourly fixed load. Hence, the demand-side had no role in the market clearing and price setting. Some of drawbacks of the lack demand-side participation in power markets could include large price spikes, congested transmission lines, higher fuel consumption and carbon footprint, lack of sufficient generation resources in particular at peak hours, and exercise of market power [4]-[8].

Price spikes might occur when the demand-side has no role in setting electricity prices, so generators have no incentive to bid close to their marginal costs which could lead to bids that are much higher than actual generation costs. This behavior could lead to volatile market prices that are away from perfectly competitive prices. In addition, price spikes might happen when generation reserves are lower during peak demand hours. To compensate generation shortages at peak hours, generators with high marginal costs are installed to supply peak demands, which could result in a significant underutilization of such generators at off-peak periods.

Demand-side participation could be very effective in such circumstances. Demand-side participation may reduce the load at peak periods, which is a more economical way to respond to generation capacity constraints. The demand-side participation could also mitigate price manipulations which could lead to the market power exercise. The price manipulations could occur when the hourly generation dispatch is calculated by minimizing the total operating cost (without considering any demand-side participation.) An increase in the demand-side participation could benefit individual customers and ultimately the entire electricity market.

Demand-side participation would include distributed generation, on-site storage, and demand response (DR). DR is considered in this paper. DR includes the reduction or deferral of consumption in response to higher market prices or market incentives [4]-[5]. DR could include the emergency DR and the economic DR. Emergency DR will reduce the load temporarily in response to an emergency grid condition initiated by a request from system operators. This type of DR is not frequently used and not considered in this paper. Economic DR will reduce the load voluntarily by electricity customers and in response to market prices. In restructured power systems, nodal prices vary with time and location; so electricity customers could adjust their load profiles in response to electricity price volatilities. Customers could curtail loads in such circumstances. However, load curtailments are usually undesirable. Customers would rather shift less critical loads to hours with more moderate prices [9]-[13]. All customers would, however, benefit from lowered market prices as shifting five to eight percent of consumption to off-peak hours and shedding additional four to seven percent of peak demand could save U.S. customers about $15 billion a year [14].

Fig. 1 depicts the energy market operation in a restructured power system. Generation and transmission companies provide the ISO with the available generating unit and transmission line information. The load serving entity (LSE) which acts as an aggregator for customer loads provides the load data to the ISO. The customers do not directly participate in the DR programs and the curtailment service provider (CSP) acts on behalf of such customers. CSP obtains load curtailment data from customers and submits DR bids to the ISO. In addition, it provides customers with curtailment options and saving opportunities, in day-ahead and real-time markets, based on forecasted prices. Note that an LSE or electric distribution company (EDC) could act as a CSP. The ISO runs the day-ahead security-constrained unit commitment (SCUC) based on the prevailing constraints to find the optimal hourly schedule of generating units and loads.

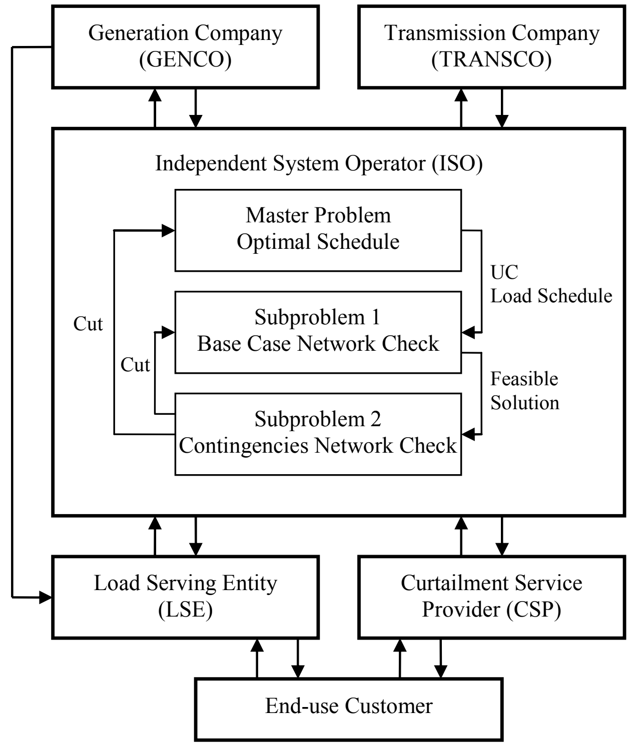


Fig. 1 Energy market components

The challenge here is to incorporate DR into the market clearing process to achieve the most efficient market dynamics [16]. [13] incorporated DR within auction rules using an iterative approach. An auction algorithm to implicitly allow DR is developed in [17], but the periods for reducing loads or recovering the saved energy are fixed. In [18] an alternative market-clearing tool is proposed for maximizing the social welfare in which customers submit bids for energy purchases. In [19] a multi-round auction algorithm is introduced in which market participants would modify their bids until an equilibrium is reached. The iterative algorithm may cause oscillations in market prices. In [20] load constraints are incorporated into day-ahead auctions using an hourly bidding mechanism. However, most of temporal constraints of loads and transmission constraints are disregarded. [21] quantifies the effect of DR on electricity markets in which the load shifting behavior of customers is considered in a centralized market-clearing mechanism. In [22] the elasticity of demand is incorporated in a centralized market clearing process. [23] further explored the approach proposed in [22] using a unit commitment (UC) instead of optimal power flow calculation for market clearing. The iterative process used in [22] integrates the market price computation with the elasticity of demand price. In [24] the iterative market clearing process proposed in [22]-[23] is revisited and convergence problems encountered in those approaches were alleviated.

In general, either a direct approach or an iterative approach was used when considering DR in market clearing processes. The iterative approaches use the elasticity of demand price to adjust the load demand. However, convergence problems may occur in the iterative process which would be time-consuming; it could also be difficult to guarantee the existence of a feasible solution. Direct methods do not accurately model the shifting of responsive loads which could have a significant impact on market clearing results. In addition, these approaches do not consider operating constraints of DR nor do they consider transmission constraints.

In this paper, we propose a DR model for market clearing. Responsive loads are considered which can be curtailed or shifted in time for economical reasons. The operating characteristics of loads including bids, hourly profile, and temporal characteristics, are considered which are submitted to the ISO. An hourly SCUC is applied for market clearing (see Fig. 1) in which the network feasibility in the base case and contingencies are taken into account. So the impact of DR on the hourly operation and control of constrained power systems is considered in the proposed approach.

The rest of the paper is organized as follows. Section II outlines the proposed day-ahead market clearing model, while Section III formulates the problem. The numerical studies are provided in Section IV, the observations are listed in Section V and the paper is concluded in Section VI.

II. Day-Ahead Market Clearing Model

The proposed market clearing process with DR is presented in this section.

A. Market clearing process

We assume both generators and loads could submit complex offers and bids to the ISO. Complex load bids include multiple bid sections with inter-temporal load constraints. When considering simple generation offers and load bids, the market clearing price is the cross section of aggregated load and generation quantities. The hourly SCUC schedule for complex bids shows the optimal commitment and dispatch of generating units and the hourly DR based on submitted offers and bids. In our approach, transmission constraints are considered in base case and contingencies. The objective would be to maximize the social welfare, i.e. consumption payments minus generation costs.

B. Load bids

DR bids include hourly fixed and responsive load bids. Fixed loads are price-takers which are satisfied at the market clearing price. The responsive load price would drop with increasing the load quantity. A responsive load bid consists of hourly quantity and price of load which are subject to the following constraints [25]-[26]:

- Minimum up/down time limits
- Load pickup/drop rates
- Minimum hourly curtailment
- Maximum daily curtailment

Minimum up time defines the number of consecutive hours that the load would have to be supplied once it is restored. Minimum down time represents the minimum number of consecutive hours that a load would be off once curtailed. Load pickup/drop rates represent the ramping capability for restoring/curtailing loads. These rates identify the rate at which a customer would change its consumption. The minimum hourly curtailment defines the lower limit for the allowable hourly curtailment. The minimum load curtailment may either reflect physical load limits or be imposed by system operators whereby smaller responsive loads could not participate in markets. The maximum daily curtailment would restrict the total load curtailment in the scheduling horizon. These physical constraints would calculate a feasible hourly schedule for responsive loads.

C. Hourly SCUC Solution with DR

The proposed flowchart is depicted in Fig. 1. The solution of the master problem consists of optimal day-ahead commitment and dispatch schedule of generating units and loads. The solution of the master problem is used in the subproblem 1 to check the feasibility of the system when considering the base case transmission system constraints. In the case of violations, hourly Benders cuts are generated and added to the master problem for the next iteration. This iterative process will continue until an optimal base case solution is achieved. The solution of the master problem is further used in the subproblem 2 to check the system feasibility in the case of contingencies. In the case of violations, Benders cut is added to the next iteration of the master problem. This iterative process will continue until the system security constraints are satisfied. The Benders cuts in this problem would include one additional variable, i.e. load quantity, as we solve the SCUC problem [27]-[31].

III. Formulation of SCUC with DR

The SCUC formulation in the master problem and two subproblems is presented in the following.

A. Master Problem

The objective of the master problem is to determine the day-ahead schedule of generating units and loads in order to maximize the system social welfare while satisfying the prevailing unit, load and system constraints. The objective is shown in (1):

$$Max \sum_{t=1}^{NT}\sum_{b=1}^{NB} CB_{bt}(D_{bt}) - \sum_{t=1}^{NT}\sum_{i=1}^{NG} GC_{it}(P_{it}) \tag{1}$$

The objective is to maximize the system social welfare, which is consumption benefit minus generation cost. This objective is subject to power balance constraint (2)

$$\sum_{i=1}^{NG} P_{it} - \sum_{b=1}^{NB} D_{bt} = 0 \qquad (t = 1,..., NT) \tag{2}$$

In (2), both generation and load are considered as variables. Other system constraints include system spinning/operating reserve requirements, system fuel limits, and system emission limits. Unit constraints include unit output limits, unit spinning/operating reserve limit, ramp up/down rate limits, min up/down time limits, fuel limits, and emission limits.

The bus load consists of fixed and responsive terms (3). The fixed load term should be fully satisfied. The responsive load term can be curtailed or shifted to another operating hour when the electricity price is cheaper. No price is associated with the fixed load. Therefore, the objective function of SCUC would only include responsive load bids.

$$D_{bt} = D_{bt}^{f} + D_{bt}^{r} \qquad (b = 1,..., NB)(t = 1,..., NT) \tag{3}$$

A typical DR bid curve is depicted in Fig. 2 which includes fixed and step-wise responsive load bids. The amount of fixed load, the minimum load curtailment and the maximum responsive load submitted to the ISO are represented in Fig. 2 by *A*, *B* and *C*, respectively. The responsive load constraints are formulated as follows.

$$[D_{bt}^{r,\max} - DX_{bt}^{\min} - D_{bt}^{r}]v_{bt} \ge 0 \quad (b=1,...,NB)(t=1,...,NT) \quad (4)$$

$$D_{bt}^{r} v_{bt} \ge 0 \quad (b=1,...,NB)(t=1,...,NT) \quad (5)$$

$$[D_{bt}^{r} - D_{bt}^{r,\max}][1 - v_{bt}] \ge 0 \quad (b=1,...,NB)(t=1,...,NT) \quad (6)$$

$$D_{bt}^{r} - D_{b(t-1)}^{r} \le UR_b \quad (b=1,...,NB)(t=1,...,NT) \quad (7)$$

$$D_{b(t-1)}^{r} - D_{bt}^{r} \le DR_b \quad (b=1,...,NB)(t=1,...,NT) \quad (8)$$

$$[X_{b(t-1)}^{on} - UT_b][v_{b(t-1)} - v_{bt}] \ge 0 \quad (b=1,...,NB)(t=1,...,NT) \quad (9)$$

$$[X_{b(t-1)}^{off} - DT_b][v_{bt} - v_{b(t-1)}] \ge 0 \quad (b=1,...,NB)(t=1,...,NT) \quad (10)$$

$$\sum_{t=1}^{NT}(D_{bt}^{r,\max} - D_{bt}^{r}) \le EX_b^{\max} \quad (b=1,...,NB) \quad (11)$$

In this formulation, the responsive load, i.e. D_{bt}^{r}, and the curtailment state of load, i.e. v_{bt}, are variables. The curtailment state is 1 when the load is curtailed and is 0 otherwise. The curtailed load is the difference between the maximum and the scheduled responsive loads. The curtailed load would be larger than the minimum load curtailment. Since the curtailed load is not directly considered in the formulation, its associated constraints are presented using responsive load. The possible cases are as follows:

- The proposed curtailed load is less than the minimum load curtailment: in this case the minimum load curtailment constraint (4) would be imposed. The scheduled responsive load would be the submitted responsive load minus the minimum load curtailment.
- The proposed curtailed load is larger than the minimum load curtailment: in this case, constraint (5) would ensure that the scheduled responsive load is nonnegative.
- Load is not curtailed: in this case the submitted responsive load will be scheduled. Constraint (6) would be enforced and loads will be shifted to this hour.

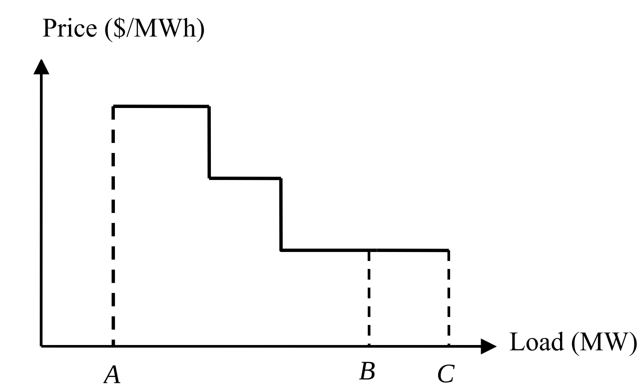


Fig. 2 DR bid curve

The hourly load pickup/drop rates constraints (7)-(8) would limit the rate of load changes between any two successive hours. The minimum load up/down time constraints (9)-(10) indicate that the minimum number of hours when the load cannot be curtailed/restored. Constraint (11) restricts the total daily load curtailment. The hourly load curtailment is the difference between the submitted responsive load and the scheduled responsive load. This term is positive when the load is curtailed, negative when the load is shifted to that hour, and zero when there is no load curtailment or shifting at that hour. Using this constraint, responsive loads may be shifted or curtailed.

B. SCUC Subproblems

The solution of the master problem, i.e. the hourly unit commitment and dispatch as well as load schedule, is used in the base case and contingencies network check subproblems to examine the feasibility of the master solution for satisfying the network security. The objective of the subproblems is to minimize power mismatches in all system buses. In the case of violations, hourly cuts (12) are provided to the UC problem as

$$\hat{w}_t + \sum_{i=1}^{NG}\pi_{it}(P_{it}I_{it} - \hat{P}_{it}\hat{I}_{it}) + \sum_{b=1}^{NB}\mu_{bt}(D_{bt} - \hat{D}_{bt}) \le 0 \quad (12)$$

The $\hat{w}_t$ denotes the current bus power mismatch in the base case. The π_{it} and μ_{bt} are respectively dual variables of the hourly unit dispatch and load balance equations. The second and third terms respectively represent the change in the objective value (power mismatch) when the unit schedule and load schedule are changed. The cut indicates that current violations in the base case can be mitigated by recalculating the schedule of units and loads.

In the case of contingencies, corrective actions are introduced by generation redispatch. Accordingly, contingent lines and units are removed from the network. In case of violations, the hourly cuts for the UC problem are

$$\hat{w}_t + \sum_{i=1}^{NG}(\overline{\pi}_{it} - \underline{\pi}_{it})(P_{it} - \hat{P}_{it}) + \sum_{b=1}^{NB}\mu_{bt}(D_{bt} - \hat{D}_{bt}) \le 0 \quad (13)$$

The $\overline{\pi}_{it}$ and $\underline{\pi}_{it}$ are dual variables of the hourly generation redispatch constraints and μ_{bt} is the dual variable of the load balance equation. The $\hat{w}_t$ denotes the current bus power mismatch in the case of contingencies and the second and third terms respectively represent the change in the objective value (power mismatch) when the unit dispatch and load schedule are changed.

The iterative process between the master problem and subproblems continues until all contingencies are handled properly and the security of the system in base case and contingencies is satisfied [25].

IV. Numerical Simulation and Discussions

A modified IEEE 118-bus system is analyzed to illustrate the performance of the proposed method. The proposed method was implemented on a 2.4-GHz personal computer using CPLEX 11.0 [32]. The system has 118 buses, 54 units and 186 branches. The data for this system is given in motor.ece.iit.edu/data/SCUC_118test.xls. To analyze the effect of DR in SCUC the following cases are considered.

A. DR considered at a single bus

Bus 59 is considered as the bus with DR. 10% of the total load in this bus is considered as responsive while the rest is fixed. A single-step consumption bid of 20$/MWh is considered for the responsive load. The minimum and maximum hourly load curtailment of 5 MW and 150 MW are considered for this load. The minimum up and down times are 4 hours and the load pickup and drop rates are considered large enough to allow any load changes in successive hours. The following cases are considered:

Case 0: Base case SCUC with no DR
Case 1: Consider DR in Case 0 (with load curtailment)
Case 2: Consider DR in Case 0 (with load shifting)

Case 0: We assume that the load is fixed (DR is not considered) in SCUC. The calculated total operating cost in this case is $1,046,785.81. Forty five units are committed and the load at bus 59 is fully satisfied.

Case 1: In this case, 10% of the hourly load at bus 59 is considered as responsive load. Assume that this load can only be curtailed (cannot be shifted.) Accordingly, the operating cost is dropped to $1,042,325.48 (i.e., 0.43% decrease in the operating cost.) The actual and curtailed loads at bus 59 are depicted in Fig. 3. The load curtailment occurs at hours 14-19. The curtailment at hour 14 is 14.4 MW. At hours 15-19, the curtailed load is 26.9, 27.7, 27.7, 26.7 and 26.6 MW, respectively, which are equal to maximum hourly curtailable loads, and the total load curtailment is equal to the daily curtailment limit of 150 MW. The hourly load curtailment occurs near the peak hour which changes the scheduled unit commitment when units 2 and 9 are turned off. The total saving at bus 59 is $16,265.50 with a 4460.33 MBtu saving in fuel consumption.

Case 2: Fig. 4 depicts the application load shifting at bus 59. The load at hours 12-19 is shifted. However, the total energy consumption at bus 59 is not changed. The minimum load of 5 MW was shifted at hour 12. Load shifting changes the unit commitment schedule when nine expensive units are no longer committed at the peak hour. The total operating cost is $1,044,998.12 (i.e., 0.17% decrease) which is larger than that of Case 1 when the load was curtailed. The total saving in load consumption at bus 59 is $10378.15 with a 1787.69 MBtu saving in fuel consumption.

In Cases 1 and 2, the average system LMP is decreased in four hours. The average system LMP in Cases 0 and 1 are compared in Fig. 5. The hourly LMP in the entire scheduling horizon is affected, although the load curtailment is at hours 14-19. Here, a less congested network flows would result in lower LMPs. The average system LMP in Case 2 is fairly similar to that of Case 1, while the LMP at hours 21 and 22 is slightly higher. The load shifting could mitigate price spikes and lower the average system LMP as efficiently as load curtailment.

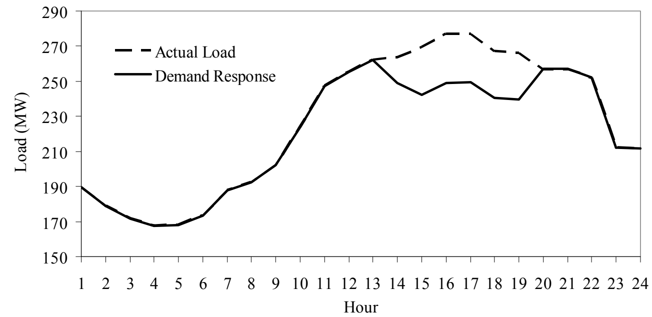


Fig. 3 Load at bus 59 with load curtailment

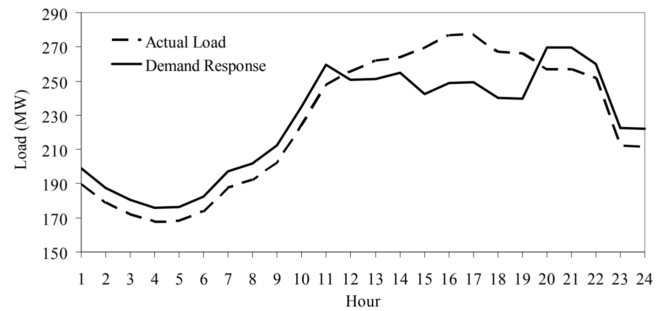


Fig. 4 Load at bus 59 with load shifting

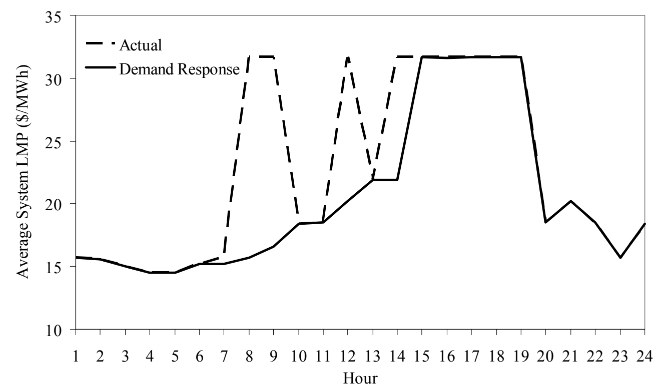


Fig. 5 Average system LMP

B. DR considered at all buses

In this case, DR (load shifting) is considered at all buses when calculating the hourly SCUC. The load is shifted from 0% to 20% with steps of 5%. Here, 20% means that one fifth of the hourly load may be shifted. Four cases are considered as follows:

Case 0: SCUC solution with DR
Case 1: SCED solution with DR
Case 2: Effect of contingencies on Case 0
Case 3: Effect of load pickup/drop rates on Case 0

Case 0: In Table I, the number of committed units and the total operating cost are reduced as we shift more loads away from peak hours. In Table I, the largest cost drop occurs during the first 5% step with a 1.32% reduction in the cost.

TABLE I
SCUC RESULTS WITH A VARIETY OF DR

Responsive load (%)	Total operating cost ($)	Number of committed units	Hourly load average	Hourly load standard deviation
0	1,046,785.89	45	3,048.10	537.67
5	1,033,506.86	33	3,048.10	346.68
10	1,030,887.89	29	3,048.10	200.31
15	1,030,191.46	25	3,048.10	70.86
20	1,030,018.28	23	3,048.10	22.09

Without any load shifts, 44 units are committed with 15 units operating as base units. With a 5% DR, the number of committed units is decreased to 34 with 16 units operating as base units. The number of committed units would decrease progressively in this case with more units operating as base unit.

The hourly load average (total daily load divided by 24) is fixed as curtailment is not considered. However the standard deviation is reduced as we shift more loads which would result in a flatter load profile (i.e., hourly system load gets closer to the average load.)

In Fig. 6, the 20% load shift is compared with the actual system load. The small change at hour 7 is due to the commitment of unit 19, which is the latest committed unit. The total shifted load is 5,711 MW which is shifted from hours 11-22 to hours 1-10 and 23-24. With a flat load profile, there will be no need to commit expensive units at peak hours. Here, by shifting loads to off-peak hours, line flows decrease at peak hours (i.e., less congestion) and increase at off-peak hours. The average LMP depicted in Fig. 7 which is much more flat with possible load shifts. The reduction in fuel consumption is shown in Fig. 8.

Case 1: In Case 0, there was an iterative process in the SCUC solution in which the UC solution was modified in each iteration in order to optimize the DR solution. Here, we fix the base case UC results in Table 1 and utilize an SCED with the 20% DR. Accordingly, a unit dispatch is obtained with a total operating cost of $1,039,343.61 which is 0.9% higher than that of the SCUC result. The standard deviation is 400 MW with a total load shift of 1,529 MW. Here the cost is higher because the fixed UC solution would restrict the load shifts and the DR benefits presented in Case 0.

Case 2: Three possible contingencies including the outages of unit 10 and line 120 at peak hour and the outage of unit 19 at hour 5 are considered. Accordingly, the original unit commitment is adjusted and loads are shifted as preventive actions. However, possible corrective actions would be handled by the hourly generation dispatch and load curtailments. If we do not shift any loads, 48 units are committed to satisfy the load with a total operating cost of $1,060,349.50. When we consider a 20% load shift, the total operating cost is reduced to $1,035,364.42 in which only 25 units are committed. The hourly load standard deviation is 60 MW, which is larger than that of Case 0. This is due to the commitment of additional units at hours with contingency. Unit 23 is committed at hours 15-19 to handle the outage of unit 10; also unit 16 is committed at the entire scheduling horizon. Accordingly the dispatch of units and load shifts are modified. In UC, units 10, 19, and 23 are partially committed while the other committed units are always on. By shifting loads, the partially committed units will be loaded additionally and, as shown in Fig. 9, the load profile will not be as flat.

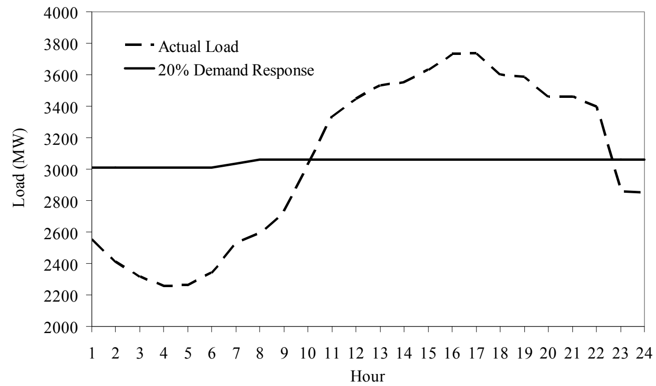


Fig. 6 Actual and shifted system loads

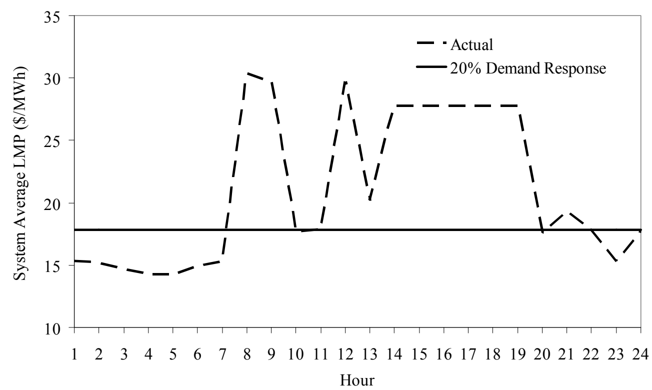


Fig. 7 Average system LMP

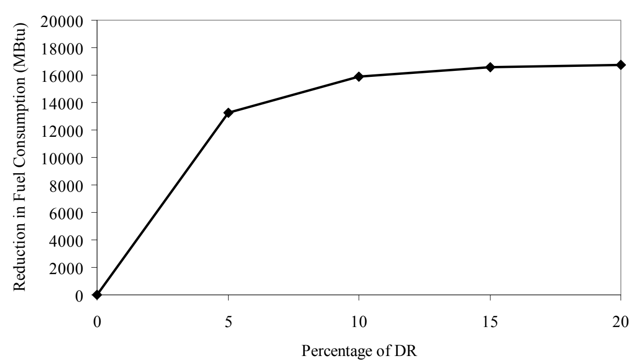


Fig. 8 Reduction in fuel consumption

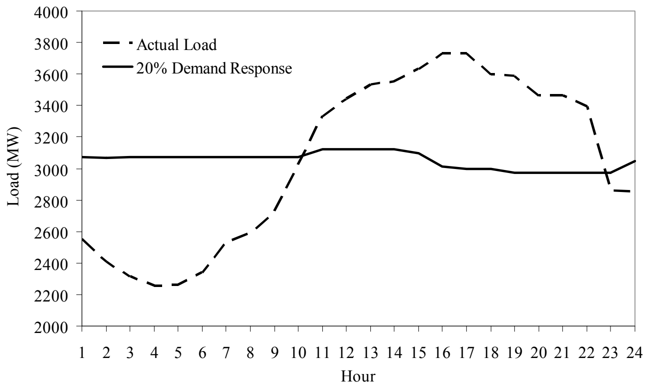


Fig. 9 Actual and shifted system load in the case of contingencies

Case 3: In this case load pickup/drop rates of 0.5 MW/min are considered. The SCUC with 20% DR is solved. The load pickup/drop rates would reduce the responsiveness of loads in seventeen buses as compared to Case 0. Accordingly, the load schedule in the entire system is changed to compensate the reduced load shifting capability of affected buses. The total operating cost is slightly increased as the total savings for loads subject to pickup/drop rates are decreased. This decrease in savings is due to fewer load shifting. Fig. 10 shows the DR solution which is compared with the actual system load. In Fig. 11, the responsive load of bus 54 could change much faster when load pickup/drop rates are not considered. The load changes are as high as 59 MW (between hours 11 and 12 and hours 12 and 13). However when considering the load pickup and drop rates, the responsive load would only change 30 MW from hour 8 to hour 9 and from hour 9 to hour 10.

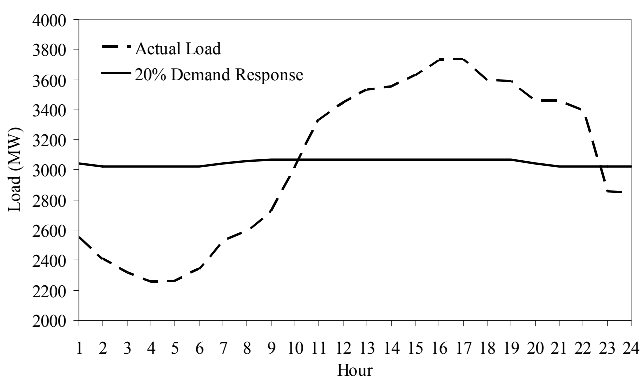
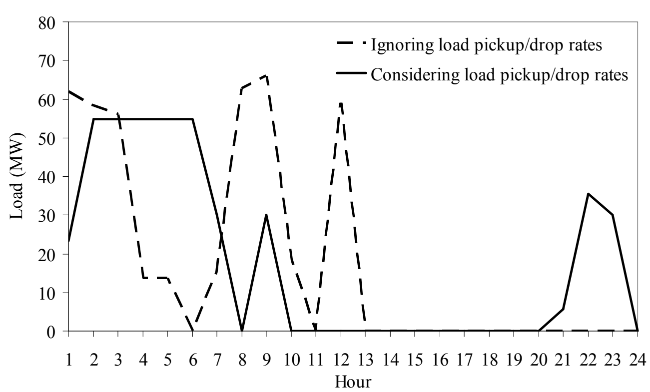


Fig. 10 Actual and shifted system load with load pickup/drop rates



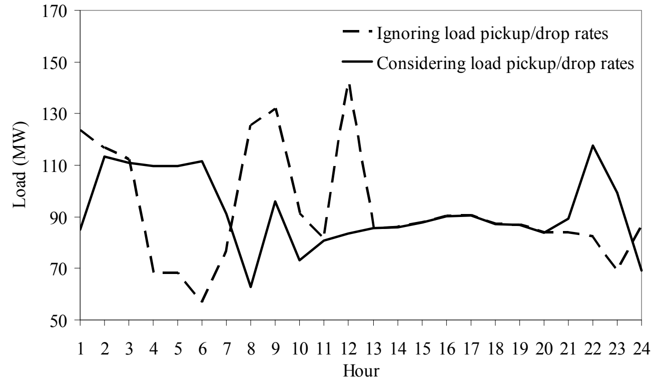


Fig. 11 Effect of load pickup/drop rates on responsive load at bus 54

V. Observations

Using the studied cases, we list the DR advantages as follows:

- Peak demand reduction. This reduction was by either curtailing peak demands or shifting peak demands to off-peak hours. The peak load reduction would mitigate price spikes and enhanced economical dispatch.
- Reduction in the average system LMP. Changes in DR-based hourly load profile could modify the hourly unit commitment and power flows, and accordingly reduce bus LMPs.
- Social benefits of DR. Any DR applications to a fraction of buses could provide benefits to the entire power system and all market participants.
- DR in day-ahead. DR application was more beneficial to SCUC than to SCED. The corresponding adjustments to SCUC would enhance the flexibility and the efficiency of market operations.
- Higher DR. Additional level of DR would lead to better SCUC results and a more flat hourly load profile. However, merits of very large DR were not as significant.
- Impact of DR on power system operation. A higher DR would lead to lower fuel consumptions and reduced carbon footprint in power systems.

VI. Conclusions

The ability to curtail or shift loads at peak periods could reduce the energy cost and require few on/off commitment of generating units. In this paper a comprehensive formulation is proposed to model the DR in the clearing process of electricity markets. The application of DR to SCUC would effectively incorporate responsive loads in the day-ahead market operations. Physical constraints of responsive loads along with generation units and transmission lines were considered. Such constraints were considered in base case and contingency operations of the system. The benefits of DR were demonstrated as viable options for managing the load growth in electric power systems.

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