IEEE Access
Multidisciplinary : Rapid Review : Open Access Journal

Received December 3, 2017, accepted January 19, 2018, date of publication January 24, 2018, date of current version April 18, 2018.
Digital Object Identifier 10.1109/ACCESS.2018.2797272

Minimization of Network Losses With Financial Incentives in Voluntary Demand Response

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This work was supported by the Sichuan Province Youth Science and Technology Innovation Team under Grant 2017TD0009.

ABSTRACT This paper delivers a customer voluntary demand response (CVDR) program to help the load serving entity (LSE) curtail peak demand and cutoff carbon emission. LSE provides financial incentives to customers who are willing to curtail energy consumption during peak demand hours. A bilevel problem is proposed to determine the optimal power curtailment and financial incentives to achieve equivalent minimal cost for LSE and maximal utility function for customers simultaneously. The effects of the CVDR program are examined with two benchmark radial systems: 3-bus and the IEEE 8500-Node networks. All simulations are carried out with General Algebraic Modeling System and MATLAB. Numerical studies unveil that CVDR enhances customer's willingness in demand response program and achieve economic savings and peak shaving for LSE.

INDEX TERMS Customer voluntary demand response (CVDR), financial incentives, network losses (NLs), willingness.

I. INTRODUCTION

Demand Side Management (DSM) refers to a set of measures implemented by utility companies to motivate changes in electricity use at the customer side of the meter [1]. During the recent years, DSM has emerged as an effective means of regulating the available energy consumption, thus to defer the installing of power distribution components [2]. The implementation of DSM elevates emission reductions, mitigates dependency on the grid and conserves natural resources [3]. All DSM techniques should result in one of the following demand reduction scenarios as shown in Fig. 1. (1) Peak clipping, in Fig. 1(a), prevents the load from exceeding the supply capacity of distribution substations, or the thermal limit of transformers and feeders. (2) Valley filling, in Fig. 1(b), aims at promoting off-peak energy consumption through energy storage devices, such as battery energy storage system (BESS) and plug-in hybrid electric vehicles (PHEVs) [4]. (3) Load shifting, in Fig. 1(c), targets to reduce demand from the peak and increase demand on the off-peak periods. Load shifting assembles peak clipping and valley filling scenarios without reducing the users' total energy consumption within a day [5]. (4) Energy conservation, in Fig. 1(d), denotes that energy consumption of consumers is reduced at all times. The well-known technology in this category is conservation voltage reduction (CVR) [6], [7]. CVR is implemented via the voltage reduction on the feeders that run from the substation to consumers. Since this paper focuses on scenarios when the Load Serving Entity (LSE) encounters Locational Marginal Pricing (LMP) spikes, peak clipping is utilized to reduce the network losses (NLs) of LSEs.

DSM techniques are implemented alongside electronic control, metering, and monitoring of the customers' energy consumption characteristics. Amongst those techniques, the most frequently employed one is demand response (DR) [8], [9]. Li *et al.* [10], Zhong *et al.* [11], Fang *et al.* [12], Fang *et al.* [13], and Vivekananthan *et al.* [14] proffered coupon induced demand response (CIDR) programs in transmission and distribution systems. CIDR attempts to boost flexibility for customers on a voluntary basis, in which coupon values can be optimized. Compared with fluctuating real-time pricing (RTP) which imposes on customers, CIDR maintains a flat rate on the consumers and offers coupon incentives to the DR end users. However, the coupon rebates paid to customers usually have a pre-determined fixed value, which cannot satisfy different operating conditions. Traditional CIDR program mentioned above does not consider customers' participation willingness factor. In this paper, the effects of incorporating an elastic and customer voluntary demand response (CVDR) program is proposed. The objective of CVDR is to promote reduced electricity consumption during increased LMP tariffs [15]. Simultaneously, a bilevel problem (BP) is projected to ascertain the LSE-customer demand dispatch optimality. Recently, many

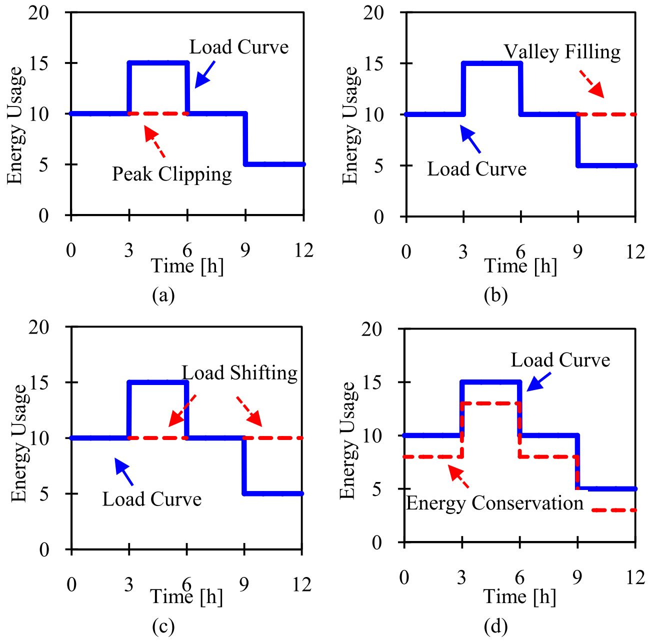

FIGURE 1. Four typical DSM scenarios: (a) peak clipping; (b) valley filling; (c) load shifting; (d) energy conservation.

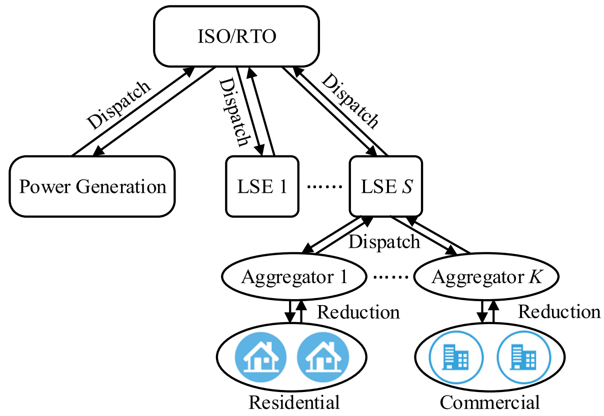

FIGURE 2. System model illustration of ISO/RTO, LSEs, and customers.

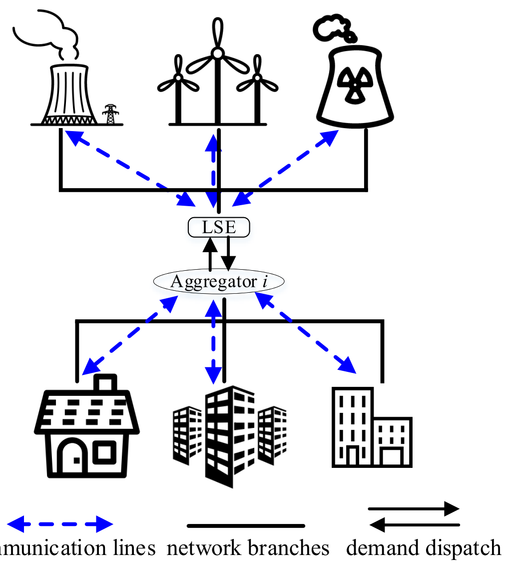

FIGURE 3. Aggregators participation in CVDR program to dispatch load.

complementary models consisting of mathematical programs with equilibrium constraints (MPECs) were implemented for strategic interactions between two levels of decision-making [16]. MPECs are currently implemented to model various scenarios, such as optimal active and reactive power dispatch [17], vulnerability analysis under multiple contingencies [18], transmission expansion planning to achieve maximal average social welfare [19], and BESS profitable planning [20].

The main contribution of this paper are two folders: (1) Bilevel CVDR program with financial incentives mechanism is developed to minimize the NLs of LSE and achieve customers' utility function (CUF) simultaneously. (2) An efficiency incentives allocation algorithm is proposed. The computational complexity of this CVDR program grows linearly with the number of financial incentives intervals.

This paper is organized as follows. Section II outlines the bilevel problems and defines the Karush-Kuhn-Tucker optimality condition. Meanwhile, CVDR optimal demand allocation algorithm is given to distribute incentives among aggregators in CVDR program. In Section III, a 3-bus and the IEEE 8500-Node radial systems are studied to demonstrate the benefits of the proposed model. All simulations are carried out with General Algebraic Modeling System (GAMS) and MATLAB via GDXMRW. Section IV illustrates the benefits of the CVDR program. Section IV concludes the contributions in this research and discusses possible future work.

II. PROBLEM FORMULATION

Load flow and monetary interactions among wholesale market, LSE and customers are shown in Fig. 2. LSE collects demand reduction from its consumers and adjusts power procurement from the wholesale market. This bilateral process is denoted with a bilevel interaction between LSE and customers in Fig. 3. LSEs purchase electricity from the wholesale market at price $\lambda_{t,b}$, which is modeled as an upper-level (UL) problem. Meanwhile, LSEs provide electricity service to customers with a retail rate $\xi_{t,b}$. When customers agree to curtail demand $X_{t,b}$, in the lower-level (LL), LSEs provide financial incentive $R_{t,b}$ to customers. Accordingly, the incentive value represents the levels of customers willingness to curtail. To enhance the readability of this paper, the adopted notations are tabulated in Table 1.

A bilevel expression of CVDR program is organized. The general formulation of a bilevel optimization problem is the following:

$$\min_{x\in\mathcal{X}} \; F\left(x, y(x)\right) \tag{1}$$

$$s.t. \; G\left(x, y(x)\right) \leq 0 \tag{2}$$

$$H\left(x, y\left(x\right)\right) = 0 \tag{3}$$

TABLE 1. Nomenclature.

$D_{t,b}$	customer demand at bus b at time t, MW
$D_{t,b}^{base}$	base demand at bus b at time t, MW
$D_{min/max}$	demand lower and upper bound of aggregator i, MW
D_b^*	optimal demand at bus b in CVDR program
$F_{t,l}$	power flow in branch l at time t, MW
$F_l^{min/max}$	power flow lower and upper bound in branch l, MW
$G_{t,b}$	demand contract with wholesale at bus b at time t, MW
$G_{min/max}$	load demand lower and upper bound at bus b from the wholesale market, MW
$M_{1,2,3}$	sufficiently large positive number
Q^k	base electricity demand of aggregator k, MW
P^k	base retail rate price of aggregator k, \$/MW
ΔQ^k	deviation of the electricity demand of aggregator k, MW
ΔP^k	deviation of retail rate price of aggregator k, \$/MW
$Q_{t,b}$	customers demand at bus b at time t, it represents an alternative variable of $D_{t,b}$
$R_{t,b}$	financial incentives at bus b at time t, \$/MW
$\tilde{R}_{t,b,j}$	financial incentives at bus b with the jth rebate index at time t, \$/MW
R_{step}	financial incentives iteration value, \$/MW
$R_{t,b}^{ini}$	initial financial incentives at bus b at time t, \$/MW
$R^{min/max}$	financial incentives lower and upper bound, \$/MW
R_b^*	optimal incentives at bus b in CVDR program
S_b^*	optimal strategy at bus b in CVDR program
$X_{t,b}$	load reduction at bus b at time t after customers participate in CVDR program, MW
$\lambda_{t,b}$	locational marginal pricing (LMP) at bus b at time t, \$/MWh
$\xi_{t,b}$	retail rate at bus b at time t, \$/MWh
$\theta_{t,b}$	voltage angle at bus b during time interval t, rad
$v_{t,b,j}$	binary variable to the financial incentives decision at bus b with the jth rebate segment at time t, \$/MW
$\rho_{t,b}^{min/max}$	Lagrange multiplier of min/max load demand at bus b at time t
$u_{t,b}^{min/max}$	binary variable to min/max load demand at bus b at time t
x_l	reactance of transmission line l, ohms
ω^k	coefficient of demand of aggregator k
β^k	price elasticity of aggregator k
$\varphi(\{b\})$	minimal network losses determined at bus b
x	decision variables in UL problem
y	decision variables in LL problem
$\mathcal{X}$	decision variables set of UL problem
$\mathcal{Y}$	Decision variables set of LL problem
$F(\cdot)$	UL objective function
$f(\cdot)$	LL objective function
$G(\cdot)$	inequality constraint function at the UL
$g(\cdot)$	inequality constraint function at the LL
$H(\cdot)$	equality constraint function at the UL
$h(\cdot)$	equality constraint function at the LL
$\mathcal{L}(\cdot)$	Lagrangian expression of LL problem
B	*set of buses, indexed by b.*
K	*set of aggregators, indexed by k.*
L	set of transmission lines, indexed by l
N	set of financial incentives segment, indexed by j.
S	*set of LSE, indexed by s.*
T	*set of time intervals, indexed by t.*
Ξ_{UL}	set of upper-level (UL) decision variables
Ξ_{LL}	set of primal lower-level (LL) decision variables
$o(l)$	indices of sending buses of transmission line l
$r(l)$	indices of receiving buses of transmission line l

where

$$y(x) = \text{argmin}_{y \in \mathcal{Y}} f(x, y) \tag{4}$$

$$s.t.\ g(x, y) \leq 0 \tag{5}$$

$$h(x, y) = 0 \tag{6}$$

In this general bilevel formulation, (1)–(3) represents the UL problem, and (4)–(5) denotes the LL problem.

A. UL PROBLEM FORMULATION

As an example, in Fig. 3, UL problem in CVDR program aims to minimize the NLs of LSEs. The NLs problem in CVDR program is interpreted as:

$$\min_{\Xi_{UL}} NLs := \sum_{t \in T} \sum_{b \in B} \Big[G_{t,b} \cdot \lambda_{t,b} - D_{t,b} \cdot \xi_{t,b} + \left(D_{t,b}^{base} - D_{t,b} \right) \cdot R_{t,b} \Big] \tag{7}$$

Subject to:
$$G_{min} \leq G_{t,b} \leq G_{max} \tag{8}$$

$$R_{min} \leq R_{t,b} \leq R_{max} \tag{9}$$

$$F_{t,l} = (\theta_{t,o(l)} - \theta_{t,r(l)})/x_l \tag{10}$$

$$F_l^{min} \leq F_{t,l} \leq F_l^{max} \tag{11}$$

$$-\pi \leq \theta_{t,o|r(l)} \leq \pi \tag{12}$$

$$G_{t,b} - \sum_{l|o(l)=b} F_{t,l} + \sum_{l|o(r)=b} F_{t,l} = D_{t,b} \tag{13}$$

where Equation (7) is the objective function of the UL problem which aims to minimize the total NLs of LSE in CVDR program. ($D_{t,b}^{base} - D_{t,b}$) represents demand reduction $X_{t,b}$. Constraints in (8) – (9) define the load dispatch constraints. The purchased power from wholesale market and customers financial incentives meet the minimum and maximum requirement. The value of $R_{t,b}$ indicates the willingness of LSE in CVDR program to avoid suffering NLs. Constraints (10) – (12) compute the power flows and enforce the power flow limits by using a DC load flow model. The nodal power balance constraint is enforced by (13).

B. LL PROBLEM FORMULATION

The LL objective function is to achieve maximal CUF. Price elasticity of demand denotes the relationship between a change in the demand of a commodity and the change in its price. The price elasticity of the kth aggregator is described as:

$$\beta^k = \frac{\Delta Q^k / Q^k}{\Delta P^k / P^k} \tag{14}$$

If the elasticity ratio is constant for the entire aggregator k, then (14) can be written as:

$$Q^k = \omega^k \cdot (P^k)^{\beta^k} \tag{15}$$

where the coefficient ω^k can be easily calculated from customer base demand $D_{t,b}^{base}$ and base price $P_{t,b}^{base}$ (retail rate $\xi_{t,b}$). Fig. 4 shows customers load demand and LSE supply curves variations before and after implementation of CVDR program. The solid line shows the price demand relationship without the application of CVDR. After applying CVDR program, customers reduce power demand $X_{t,b}$. CUF is the summation of customers surplus (CS) and financial incentives from LSE. Customer surplus is defined as the area beneath the demand curve between the lowest demand D_{min}, and the actual demand $D_{t,b}$ in Fig. 4.

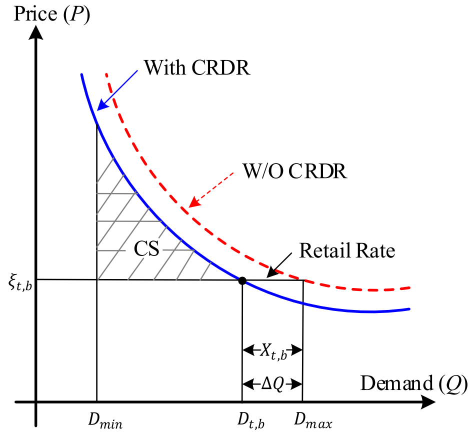

FIGURE 4. Illustration of CUF in CVDR program. The shaded area is CS.

The total CUF is described as:

$$\max_{\Xi_{PLL}} CUF^{PLL} := \sum_{t=1}^{T}\sum_{b=1}^{B}\Bigg[\int_{D_{min}}^{D_{t,b}}\left(\frac{Q_{t,b}}{\omega^k}\right)^{1/\beta^k} dQ_{t,b} - \xi_{t,b} \cdot \left(D_{t,b} - D_{min}\right) + \left(R_{t,b} - R_{min}\right) \times \left(D_{t,b}^{base} - D_{t,b}\right)\Bigg] \quad (16)$$

Subject to:

$$D_{min} \leq D_{t,b} \leq D_{max} : (\rho_{t,b}^{min}, \rho_{t,b}^{max}) \quad (17)$$

In Eq. (16), the first two parts indicate customers surplus, and the third part is the rewards from LSEs after the curtailment of $X_{t,b}$. Customers electricity demand after joint in the CVDR program is constrained with Eq. (17). Dual variables of each constraint are given in the parentheses after a colon.

The first reformulation of the problems from (7) – (17) consisting of replacing the LL problem (14) – (17) by its Lagrangian multipliers which results in a single-level optimization problem. The LL problem for a given UL vector $D_{t,b}$. The Lagrangian expression of LL problem is given as:

$$\mathcal{L}(D_{t,b}, R_{t,b}) = \sum_{t=1}^{T}\sum_{b=1}^{B}[\int_{D_{min}}^{D_{t,b}}\left(\frac{Q_{t,b}}{\omega^k}\right)^{\frac{1}{\beta^k}} dQ_{t,b} - \xi_{t,b} \cdot \left(D_{t,b} - D_{min}\right) + \left(R_{t,b} - R_{min}\right)\left(D_{t,b}^{base} - D_{t,b}\right) + \rho_{t,b}^{min} \cdot \left(D_{t,b} - D_{min}\right) + \rho_{t,b}^{max} \cdot \left(D_{max} - D_{t,b}\right)] \quad (18)$$

where

$$\frac{\partial \mathcal{L}(D_{t,b}, R_{t,b})}{\partial D_{t,b}} = \left(\frac{D_{t,b}}{\omega^k}\right)^{1/\beta^k} - \lambda_{t,b} - R_{t,b} + R_{min} + \rho_{t,b}^{min} - \rho_{t,b}^{max} = 0 \quad (19)$$

$$0 \leq D_{t,b} - D_{min} \perp \rho_{t,b}^{min} \geq 0 \quad (20)$$

$$0 \leq D_{max} - D_{t,b} \perp \rho_{t,b}^{max} \geq 0 \quad (21)$$

where $\rho_{t,b}^{min}$ and $\rho_{t,b}^{max}$ are dual constraints of (17). (20) and (21) represent complementarity constraints. Operator '$\perp$' denotes the inner product of two vectors equal to zero. There is at most one vector that is greater than zero, correspondingly the other will be zero. Therefore, the BP (7) – (21) can be recast as a single-level MPEC problem. The equivalent single-level minimization problem is nonlinear because the following nonlinearities appear in the problem: (i) products of continuous UL ($D_{t,b}$) and continuous LL ($R_{t,b}$) decision variables in objective function (7). (ii) products of UL ($D_{t,b}$) and LL ($\rho_{t,b}^{min}$, $\rho_{t,b}^{max}$) decision variables in (20) and (21).

These two nonlinearities are converted into an equivalent mixed-integer linear expression with 'Big-M' method [20].

$$0 \leq D_{t,b} - D_{min} \leq M_1 \cdot u_{t,b}^{min} \quad (22)$$

$$0 \leq \rho_{t,b}^{min} \leq M_1 \cdot (1 - u_{t,b}^{min}) \quad (23)$$

$$0 \leq D_{max} - D_{t,b} \leq M_2 \cdot u_{t,b}^{max} \quad (24)$$

$$0 \leq \rho_{t,b}^{max} \leq M_2 \cdot (1 - u_{t,b}^{max}) \quad (25)$$

$$-M_3 \cdot \left(1 - v_{t,b,j}\right) \leq D_{t,b} \cdot \tilde{R}_{t,b,j} - R_{t,b} \quad (26)$$

$$M_3 \cdot v_{t,b,j} \geq R_{t,b} \quad (27)$$

$$\sum_{j=1}^{N} v_{t,b,j} = 1 \quad (28)$$

where (22) – (23), (25) – (26) give the linearization of (20) and (21), respectively. (28) constraints that at each time interval only one financial incentive $\tilde{R}_{t,b,j}$ is chosen.

C. MIXED-INTEGER LINEAR PROGRAMMING FORMULATION

Using the linearized methods from (22) – (28). the single-level mixed-integer linear programming (MILP) formulation is given as follows:

$$\min_{\Xi_{UL}} NLs := \sum_{t \in T}\sum_{b \in B}\Big[G_{t,b} \cdot \lambda_{t,b} - D_{t,b} \cdot \xi_{t,b} + \left(D_{t,b}^{base} - D_{t,b}\right) \cdot R_{t,b}\Big] \quad (29)$$

Subject to

$$G_{min} \leq G_{t,b} \leq G_{max} \quad (30)$$

$$R_{min} \leq R_{t,b} \leq R_{max} \quad (31)$$

$$F_{t,l} = (\theta_{t,o(l)} - \theta_{t,r(l)})/x_l \quad (32)$$

$$F_l^{min} \leq F_{t,l} \leq F_l^{max} \quad (33)$$

$$-\pi \leq \theta_{t,o|r(l)} \leq \pi \quad (34)$$

$$G_{t,b} - \sum_{l|o(l)=b} F_{t,l} + \sum_{l|o(r)=b} F_{t,l} = D_{t,b} \quad (35)$$

$$D_{t,b} = \omega^k \cdot \left(\lambda_{t,b} + R_{t,b} - R_{min} - \rho_{t,b}^{min} + \rho_{t,b}^{max}\right)^{\beta^k} \quad (36)$$

$$D_{min} \leq D_{t,b} \leq D_{max} \quad (37)$$

$$0 \leq D_{t,b} - D_{min} \leq M_1 \cdot u_{t,b}^{min} \quad (38)$$

$$0 \leq \rho_{t,b}^{min} \leq M_1 \cdot (1 - u_{t,b}^{min}) \quad (39)$$

$$0 \leq D_{max} - D_{t,b} \leq M_2 \cdot u_{t,b}^{max} \quad (40)$$

$$0 \leq \rho_{t,b}^{max} \leq M_2 \cdot (1 - u_{t,b}^{max}) \quad (41)$$

$$-M_3 \cdot \left(1 - v_{t,b,j}\right) \leq D_{t,b} \cdot \tilde{R}_{t,b,j} - R_{t,b} \quad (42)$$

$$M_3 \cdot v_{t,b,j} \geq R_{t,b} \tag{43}$$

$$\sum_{j=1}^{N} v_{t,b,j} = 1 \tag{44}$$

The proposed bilevel problem in (7) – (17) is recast as a MILP problem in (29) - (44). MILP is solvable by using branch-and-cut solvers in commercial software.

Algorithm 1 Optimal Financial Incentives Allocation Method

procedure: PRE-PROCESSING PROCEDURE
 $\tilde{R}_{t,b,j} \leftarrow \tilde{R}^{initial}_{t,b,j}$
 $NLs(\{b, k\}) \leftarrow 0$
 while $\tilde{R}_{t,b,j} \leq R_{max}$ **do**
  $D_{t,b} \leftarrow \omega^k \cdot \left(\lambda_{t,b} + \tilde{R}_{t,b,j} - R_{min}\right)^{\beta^k}, \forall b \in B$
  $NLs(\{b, k\}) := \sum_{t \in T} \sum_{b \in B} \left[G_{t,b} \cdot \lambda_{t,b} - D_{t,b} \cdot \xi_{t,b} + (D^{base}_{t,b} - D_{t,b}) \cdot \tilde{R}_{t,b,j}\right]$
  $\varphi(\{b\}) \leftarrow NLs(\{b, 1\})$
  if $\varphi(\{b\}) > NLs(\{b, k\}), \forall k \neq 1$
   $\varphi(\{b\}) = NLs(\{b, k\})$
  end if
  $\tilde{R}_{t,b,j} \leftarrow \tilde{R}_{t,b,j} + R_{step}$
 end while
 return: $R^*_b = argmin_{\tilde{R}_{t,b,j}} \varphi(\{b\})$
 return: $D^*_b \leftarrow \varphi(\{b\})$
end procedure

A multi-iteration CVDR adjustment process is presented in Algorithm 1. The computational complexity of CVDR grows linearly with the number of financial incentives intervals. CVDR program converges to the global optimal solution with a time of $O\left(\frac{R_{max} - R_{min}}{2}\right)$.

III. NUMERICAL STUDY

Simulations of 3-bus and IEEE-8500 Node radial network are implemented with GAMS [21]. All calculations are executed running MATLAB® for handling input and output data via GDXMRW. The optimization problem was formulated and solved in GAMS BUILD 24.8.1 employing the CPLEX™ 12.7.0.0 solver [22] for MILPs on a 64-bit MS Windows 7 with 8GB RAM and Core-i3, 3.9GHz (4-core) CPU clocked at 3.90GHz. Additionally, the benchmark systems in this paper are executed in OpenDSS [23] to extract reactance matrix.

A. 3-BUS DISTRIBUTION NETWORK

The block diagram for a 3-bus test system is shown in Fig. 5. Customer loads affiliated to Bus 1 and Bus 2 which are fully occupied by residential customers are denoted as Aggregator 1. Aggregator 1 is composed of load capacity 30kW and 40 kW respectively. The daily demand profile for Aggregator 1 is shown in Fig 6. (a). Aggregator 2 is a small commercial customer with load capacity 70kW for which the 24 h demand profile is exhibited in Fig.6 (b). The retail rate offered to each customer is 100$/MWh, as shown in Fig. 7.

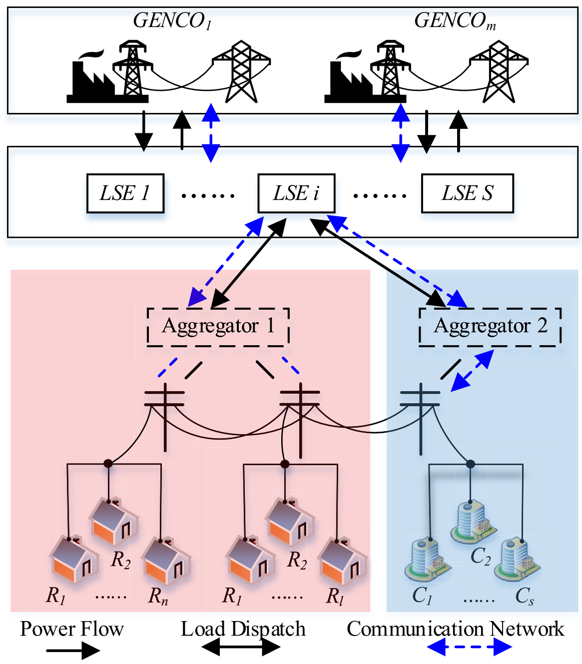

FIGURE 5. 3-bus radial network single-line diagram.

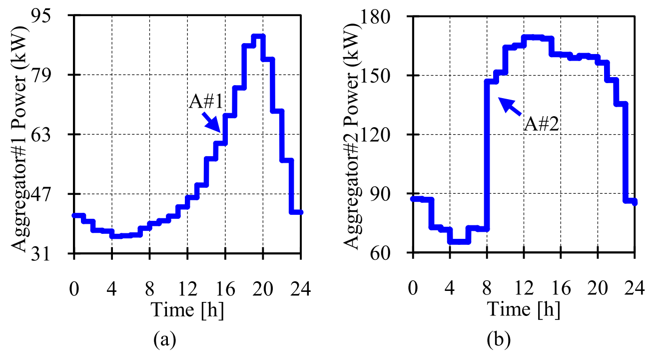

FIGURE 6. Baseline profiles for the 3-bus distribution system. (a) 24 h demand profile for Aggregator 1 (residential customers). (b) 24 h demand profile for Aggregator 2 (commercial customers).

The financial incentives vary from 1$/MWh to 100 $/MWh with 2$/MWh incremental step, thus $R^{max} = 100$ $/MWh, and financial incentives sets at each time interval are:

$$\tilde{R}_{t,b,j} = \{1, 3, \ldots, 100\}, \quad \forall t \in \{19, 20, 21\}, \quad j \in \{1, 2, \ldots, 50\} \tag{45}$$

The time scale for this numerical study is 24 h, with a time granularity of 1 hour. Thus, the time sets will be $T = \{1, 2, \ldots, 24\}$. Three scenarios of CVDR program are performed:

(1) *Scenario#1*: Without applying for CVDR program;
(2) *Scenario#2*: With applying for CVDR program;

Fig. 8 displays 3-bus operation factors variation with financial incentives. Fig. 8(b) shows that when incentive value increases, LSE needs to pay more rebates to customers. Fig. 8(c) – (d) show LSE purchasing cost and selling revenue are decreasing along with the increment of incentive value. Fig. 8(e) demonstrates that LSE cost reaches the optimal

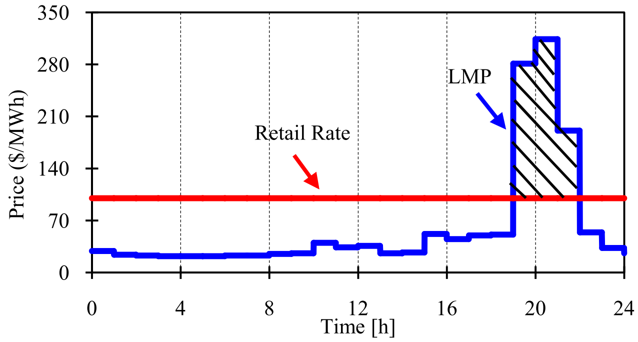

FIGURE 7. 24 h LMPs and flat retail rate profile of 3-bus distribution system from PJM on July 20th, 2015 [24]. The shaded area is the total NLs of LSE.

TABLE 2. LSE and customer cost during peak demand for 3-Bus system without CVDR program.

Peak Hour	19:00		20:00		21:00	
Aggregator ID	A#1	A#2	A#1	A#2	A#1	A#2
Demand (kW)	89.37	159.34	83.16	156.39	69.25	147.64
Purchasing Cost ($)	25.12	44.78	26.12	49.12	13.22	28.18
Selling Revenue ($)	8.94	15.93	8.32	15.64	6.92	14.76

A#1 = Aggregator 1, A#2 = Aggregator 2

TABLE 3. Comparison of CVDR program and base case for 3-Bus system during peak demands.

Peak-Demand (19:00-21:00)	W/O CVDR Program	W CVDR Program	Reduction (%)
LSE Cost ($)	116.02	101.86	12.21
Incentives Payment ($)	0.00	9.74	–
Selling Revenue ($)	70.52	46.25	34.41
Purchasing Cost ($)	186.54	148.11	20.60
System Demand (kW)	705.15	559.87	20.60

value when incentive value is 67$/MWh. Fig. 8(e) shows the whole system demand consumption for the optimal incentive value 67$/MWh. When peak appears at 19:00, power reduction is 41.14 kW. Peak demand reductions are 39.44 kW and 35.32 kW at 20:00 and 21:00.

Table 2 gives the hourly demand and cost of each Aggregator for the peak period before applying for CVDR program. It can be determined that Aggregator 2 which is only preoccupied with commercial loads consumes almost double the demand than Aggregator 1. The price elasticity of Aggregator 1 and Aggregator 2 are set as -0.45 and -0.3, thus $\beta^1 = -0.45$ and $\beta^2 = -0.3$. Comparison of CVDR program with base case during peak demand is tabulated in Table 3. LSE cost reduces 12.21% when customers' demands reduce by 145.28 kW. LSE pays 20.6% less to bourse market and incurs 34.41% electricity selling revenue reduction from customers.

Fig. 9 shows peak demand comparison for both aggregators in the scenarios of without and with CVDR program. Fig. 9(a) shows residential customers power reduction where peak demand curtailment is 18.42 kW at 19:00. Aggregator 1 continuously reduces 20.61% power consumption at hour 20:00 and 21:00. Correspondingly, in Fig. 9(b) commercial

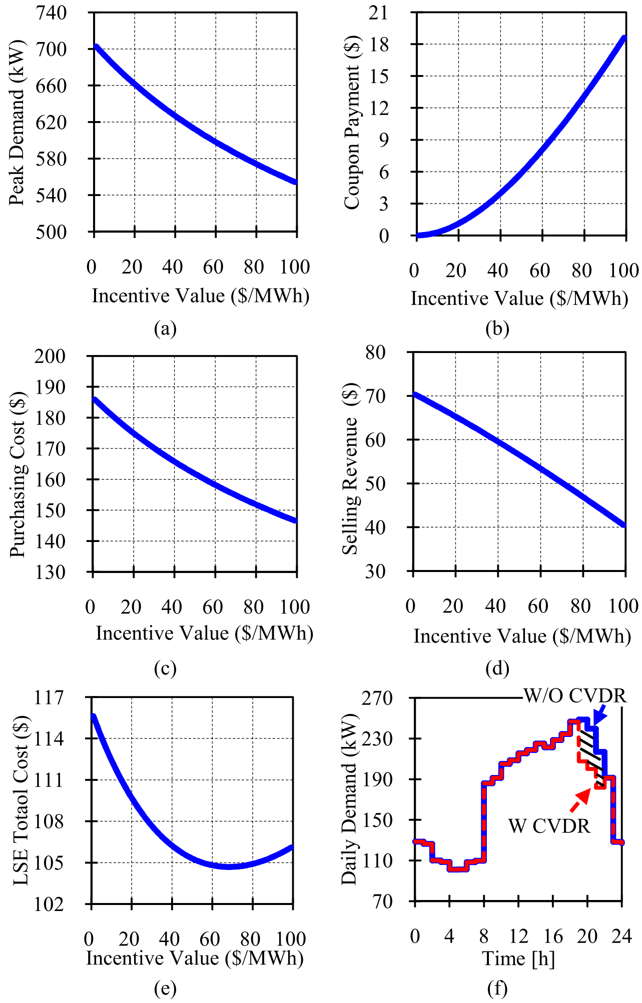

FIGURE 8. Situations of the 3-bus distribution system in scenarios of financial incentives varying from 0$/MWh to 100$/MWh. (a) Total peak demand variation with incentive value; (b) Financial incentives payment variation with incentive value; (c) Selling revenue variation with incentive value; (d) Purchasing cost variation with incentive value; (e) LSE total cost variation with incentive value; (f) 3-bus system 24 h power consumption profile at optimal incentive value 67$/MWh. Energy Savings during peak can be calculated by the shaded area.

customers curtail 22.72 kW, 22.30 kW, and 21.05 kW consumption respectively during LMP spikes appearance.

B. 8500-NODE RADIAL DISTRIBUTION NETWORK

The IEEE 8500-Node radial system represents the general topology of distribution systems used in North America [25]. The peak power is 9.23 MW. The 8500-Node system consists of 100% residential customers. There are 1244 residential customers in this network. The 8500-node system is divided into three aggregators and one non-participation load (NPL). For each aggregator, its composition is tabulated in Table 4. Aggregator 1 has 749 customers, which owns 60.24% of the total capacity. Aggregator 2 and 3 consume 2.19 MW and 1.19 MW. The number of non-participation load accounts for 39, which are mainly consisted of fixed loads, such as lighting, stoves, and home computers. 24 h power consumption profiles for each aggregator and non-participation customers are shown in Fig. 10(a). Due to a shortage of photovoltaic

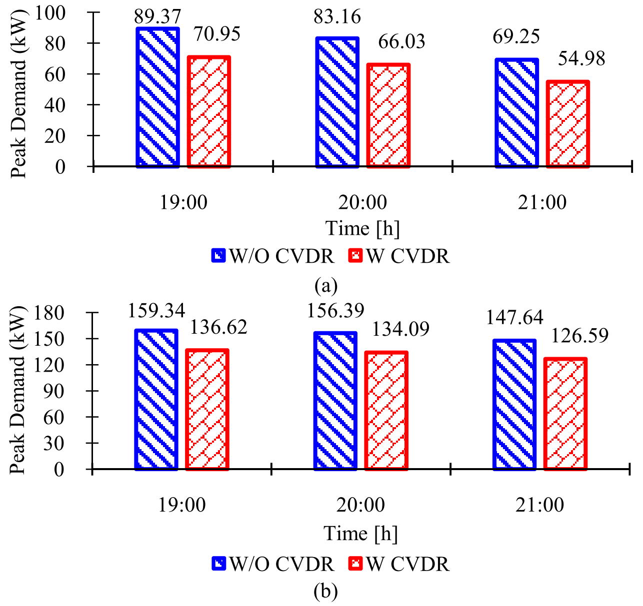

FIGURE 9. Power consumption comparison of without CVDR program and with CVDR program during peak demand from 19:00 to 21:00. (a) Aggregator 1 demand profile comparison of without CVDR program and with CVDR program; (b) Aggregator 2 demand profile comparison of without CVDR program and with CVDR program.

TABLE 4. Fundamental composition of different aggregators.

Aggregator ID	A#1	A#2	A#3	NPL
House Numbers	749	295	161	39
Capacity (MW)	5.56	2.19	1.19	0.29
Percentage (%)	60.24	23.73	12.89	3.14
Price Elasticity	-0.45	-0.42	-0.40	–

A#1 = Aggregator 1, A#2 = Aggregator 2, A#3 = Aggregator 3, NPL = Non-Participation Load

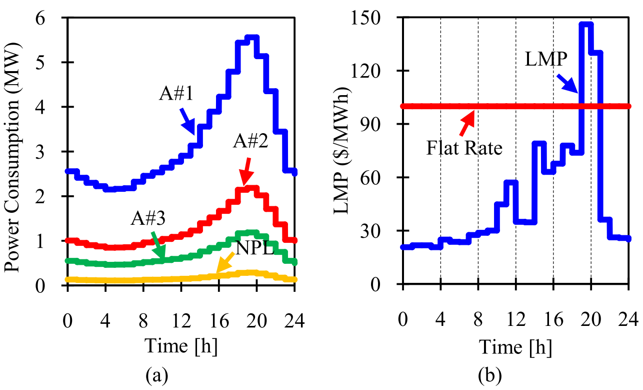

FIGURE 10. 8500-Node 24 h power demand and LMP on April 6th, 2017 from PJM [32]. (a) 24 h load profile for each aggregator and non-participation load. (b) Corresponding LMP (spike occurs at 19:00) and a flat rate for the 8500-Node distribution network.

generation during the night from 19:00, LMP increases dramatically. Customers procure power from LSE with a flat retail rate, as shown in Fig. 10(b). The price elasticity of Aggregator 1, Aggregator 2 and Aggregator 3 are set as -0.45, -0.42 and -0.40.

The optimal financial incentive is 15$/MWh when the NLs of LSE no longer decrease. Table 5 represents the changes

TABLE 5. Different factors for each aggregator in 8500-node network

Peak Hour	Impact Factors	Aggregator ID A#1	A#2	A#3
19:00	PDR (kW)	338.82	262.31	186.76
	PCR ($)	49.49	38.31	27.28
	SRR ($)	33.88	26.23	18.68
20:00	PDR (kW)	313.05	232.35	173.29
	PCR ($)	40.71	30.21	22.53
	SRR ($)	31.31	23.23	17.33

PDR = Peak Demand Reduction, PCR = Purchasing Cost Reduction, SRR = Selling Revenue Reduction

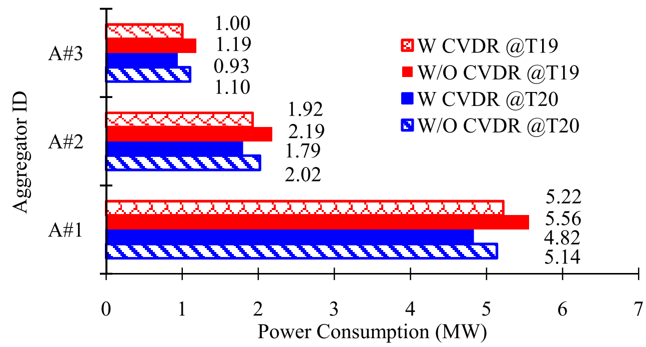

FIGURE 11. Power consumption comparison of without CVDR program and with CVDR program during peak demand at 19:00 and 20:00 for each aggregator in the 8500-Node distribution network.

of impact factors, such as peak demand reduction (PDR), purchasing cost reduction (PCR), and selling revenue reduction (SRR) for each aggregator during peak demand. It can be determined that the NLs of LSE can be alleviated with the application of offering financial incentives to customers. Fig. 11 depicts the actual power demand for each aggregator at peak hour 19:00 and 20:00. With the application of CVDR program for 3-bus and IEEE 8500-Node distribution system, it can be concluded that CVDR program can simultaneously help LSE to reduce unexpected losses and defer the power system construction investment.

IV. DISCUSSION

Incentives induced CVDR program aims at reducing high risks of the NLs when a contingency occurs. DR policy-making strategies should achieve the following principles: (1) Firstly, LSE should make remedies during uncertain circumstances which target at reducing monetary losses. (2) Secondly, customers need compensations while taking actions.

In this proposed CVDR program, electricity demand under CVDR program is determined as:

$$D_{t,b} = \omega^k \cdot \left(\lambda_{t,b} + R_{t,b} - R_{min}\right)^{\beta^k} \tag{46}$$

It can be determined from (46) that customers load reduction is only related to financial incentive value. The parameters $\lambda_{t,b}$, R_{min}, and β^k are all known for specific customers cluster. Because $(\lambda_{t,b} + R_{t,b} - R_{min}) > 1$ is always true in this CVDR program, customers with higher $|\beta|$ value behave as dominant players to help LSE reduce NLs. Thus, it will be reasonable and effective to allocate higher proportion financial incentives to dominant aggregators.

V. CONCLUSION

This paper introduces an innovative DSM method, CVDR program, which provides an elastic and voluntary participation for end-users in the smart grid. Simultaneously, a bilevel scheme is proposed to ascertain the LSE-customer demand dispatch optimality. The effects of the CVDR program are examined with a 3-bus and the IEEE 8500-Node radial systems. All simulations are carried out with CPLEX under GAMS and MATLAB via GDXMRW. Numerical studies unveil that CVDR program can enhance customers willingness in demand response and achieve economic savings and peak shaving for LSE.

The appearance of peak LMP is primarily caused by the soaring penetration of renewable generation in power system. The intermittent of enormous distribution generations (DGs) aggravate fluctuation of the power supply and intraday pricing. The future work will focus on integrating BESS with renewable energy-based distribution generation to flatten power generation and customer consumption, which will further reduce the NLs of LSE.

ACKNOWLEDGMENT

The authors would like to thank Associate Professor Francisco de Len, Assistant Professor Yury Dvorkin, Dr. Tianqi Hong and Dr. Ashhar Raza at the Department of Electrical and Computer Engineering at New York University, Zhechao Li at the State Key Laboratory of Advanced Electromagnetic Engineering and Technology, Huazhong University of Science and Technology for their sincere help for valuable discussion.

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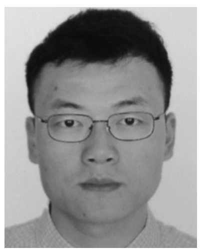

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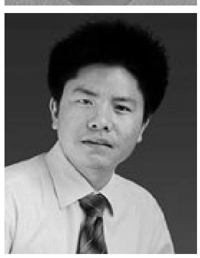

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