Incorporation of Demand Response Resources in Resource Investment Analysis

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***Abstract*—The use of demand-side resources, in general, and demand response resources (DRRs), in particular, has increased over the last few years with rising fuel prices and growing environmental concerns. Integration of demand response resources in the competitive electricity markets impacts resource investment decisions on the supply- as well as the demand-side. There is a need to understand and assess the impacts of DRRs on resource investment strategies. We propose an analytical framework which may be deployed for the assessment of supply- and demand-side resource investment strategies. The salient features of the framework is the explicit representation of the interdependence between the operation of electricity markets and power system, and the resource investment decisions, as well as incorporation of DRRs in the models used in the framework. We design the framework so as to account for the uncertainty associated with the load and the available capacity of the resources. Efficient computational schemes are used for evaluating the uncertain market outcomes. We illustrate the application of the framework through representative simulation results.**

***Index Terms*—Decentralized decision making, demand response resources, resource investment analysis, uncertainty analysis.**

I. Introduction

INVESTORS, policy makers and planners conduct analysis of resource investment strategies to identify potential resource candidates to meet the future demand requirements. The methodologies adopted for such analyses have been significantly impacted by the changing electricity industry. With the wide spread restructuring of the industry around the world, resource planning function has ceased to exist as a centralized process. In fact, resource planning has turned into an investment analysis carried out by independent investors without much centralized coordination. The transmission usage and network congestion have begun to play a crucial role in determining the economic feasibility of the resource investments. Furthermore, the demand-side has become more active in the competitive markets and new players such as demand response aggregators have emerged. Although there exist many models which take into account one or more of the above developments, a unified framework which adequately incorporates the impacts of the competitive environment, the transmission congestion, new demand-side players and the decentralized nature of resource investments has not yet been proposed. In this paper, we propose such a framework to evaluate and compare resource investment options such as the conventional generation resources as well as the recent alternatives such as demand response resources (DRRs).

Resource investment analysis may be viewed as a multi-period optimization problem. Uncertainty of the future demand, the available resources, the future fuel prices and so on, makes the problem inherently stochastic. The solution of the problem requires the explicit consideration of the inherently uncertain future. The competitive electricity markets bring an additional layer of uncertainty to the investment decision making process since investors must take into account the interactions of their decisions with uncertain market outcomes. Reference [1] correctly identifies the need for new resource planning methodologies which explicitly consider the uncertainty around market outcomes as well as future demand. Several methodologies have been proposed in the literature which model the impacts of the competitive electricity markets for resource investment and planning purposes. Such methodologies have been extensively reviewed in [2]. The primary drawback of these methodologies is that they are only useful for assessment of and comparison between supply-side resource alternatives.

However, growing environmental and financial concerns have spearheaded the wider implementation of demand-side management activities and resulted in an increased consumer participation in demand response programs [3]. Consumers are being provided incentives for curtailing loads during peak load or high price periods. A new class of players has emerged, which we collectively refer to as the DRR players. These DRR players undertake the aggregation of individual loads of several customers and offer load curtailments in the competitive electricity markets. The DRR players compete with the supply-side sellers, consequently influencing market outcomes and the investment decisions on the supply-side as well as the demand-side. Also, the active participation of DRRs impacts transmission usage and affects congestion. The increased penetration of DRRs in the electricity markets brings about the need for an appropriate framework for analyzing investment strategies in the supply- and the demand-side resources on a consistent basis.

The framework proposed in this paper is capable of assessing the viability of resource investment candidates such as the conventional generators as well as the newer demand response options. Since the valuation of the candidate resource needs to explicitly consider the revenues earned by it in the competitive environment, we design the framework to simulate the operation of the centralized electricity markets over the investment recovery period. The economic signals from the market simulation may then be used to determine

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the cash flows for investment valuation purposes. Since the transmission network plays a crucial role in the determination of the market outcomes and the utilization of the resources, we explicitly represent the network effects in this long-term simulation. We assume that a single independent entity is responsible for the operation and the control of the transmission system as well as the different electricity markets. We refer to this entity by the generic name of *independent grid operator* (IGO) to encompass various organizations such as the independent system operator (ISO), the transmission system operator (TSO) and the regional transmission organization (RTO). The framework simulates the side-by-side operations of the electricity markets and the power system from the point of view of the IGO.

The major challenges imposed in the construction of the proposed simulation framework are the long study horizon, the inherent uncertainty of the future, the multiplicity of players, the competitive environment, and most importantly, the interdependence between investment decisions, market outcomes and system operations. In section II, we describe in detail how such considerations impact the structure of the framework and we state the assumptions made while designing the framework. The specific models used in this study are described in section III. The evaluation of candidate resources for investment analysis is discussed in section IV. We illustrate the applications of the framework through simulation results in section V and report the conclusions in section VI.

II. Description of the Framework

Each investment in a new resource – be it a generator on the supply side or a DRR on the demand side – impacts electricity market outcomes and transmission usage, and consequently, the economics of the electricity supply. Conversely, the side-by-side operations of the electricity market and the power system affect each resource investment decision. The analysis of resource investment strategies and alternatives requires the appropriate representation of the interdependence between resource investment decisions and the side-by-side operations of the electricity markets and the power system.

Due to the long recovery periods associated with the investments in new resources, the resource investment analysis typically spans multi-year study horizons. On the other hand, electricity markets are operated on day-ahead and an hourly basis while changes in the system dispatch decisions are made every 2 to 5 minutes. For the multi-year study horizons, a detailed representation of integrated market and system operations requires extensive computation. Therefore, the effective representation requires a careful balancing between the level of detail and the computational tractability.

We assume that the intra-hour variations in the load demand are sufficiently small so that their impacts on the overall economics may be neglected. Consequently, we define one hour as the smallest indecomposable unit of time. We consider only the day-ahead hourly markets and the corresponding system operations and ignore the balancing mechanisms within each hour. We represent the system for each hour of the study period by the snapshot of the system corresponding to that hour and assume that the system stays in that state for the entire hour duration.

The hour-long time resolution allows the representation of short-term events of interest such as the variability of the load and the changes in the market outcomes and system conditions. However, for the multi-year study period, we need to take into account the seasonal/annual demand and load patterns as well as the uncertainty in the future including the availability of the generation units. To do this, we decompose the study period, $\mathcal{T}$, into T simulation subperiods, so that $\mathcal{T} \triangleq \{t_1, \ldots, t_T\}$. We use the subperiods to develop representations for the load and the available capacities of the resources which explicitly take into account the uncertain nature of these parameters.

We provide an overview of the structure of the proposed framework. We design an interconnected three-layer framework with the physical network, the *MWh* commodity markets and the uncertain load and resource models represented in three separate layers. We introduce appropriate *information flows* between the layers to represent the interactions between them. The information flows serve to interconnect the three layers into an integrated framework capable of assessing the impacts of candidate resources through long-term simulations of the side-by-side operations of the electricity market and the power system.

The three layers of the framework are summarized below. For each hour in the study period, the *system layer* provides the snapshot representation of the steady-state network in terms of its topology and other parameters and establishes the relationship between the net power injections at each node, system states and the line flows associated with the day-ahead operations. Corresponding to the hourly snapshot of the system layer, the *market layer* models the day-ahead energy market (DAM) in terms of the offers and the bids of the sellers and buyers, respectively. This layer contains the representation of the market equilibrium which is established by the IGO through the interactions with the system layer to determine the generation/demand schedule which satisfies the transmission constraints and the resulting energy prices. The *simulation layer* represents the uncertainty in the available capacities of the resources in the resource mix and the load demand. In addition to the representation of forced outages of generation units, this layer also contains information about the planned generation outages for the maintenance purposes. An investment in a new resource changes the existing resource mix, and this change is reflected in the simulation layer. The simulation layer is concerned with long-term effects in distinct contrast to the other two layers which are concerned with short-run decisions. Consequently, this layer covers the entire duration of the study, starting at the first hour of the first subperiod, t_1, till the last hour of the last subperiod, t_T. We represent the market and system model for each hour in each subperiod of the study period, as illustrated in Fig. 1.

We now describe the information flows between the layers. The simulation layer determines the load requirements as well as the set of supply- and demand-side resources available to meet these load requirements. Since the load requirements and the available resources impact the bids and the offers of the market participants, this information is communicated to the

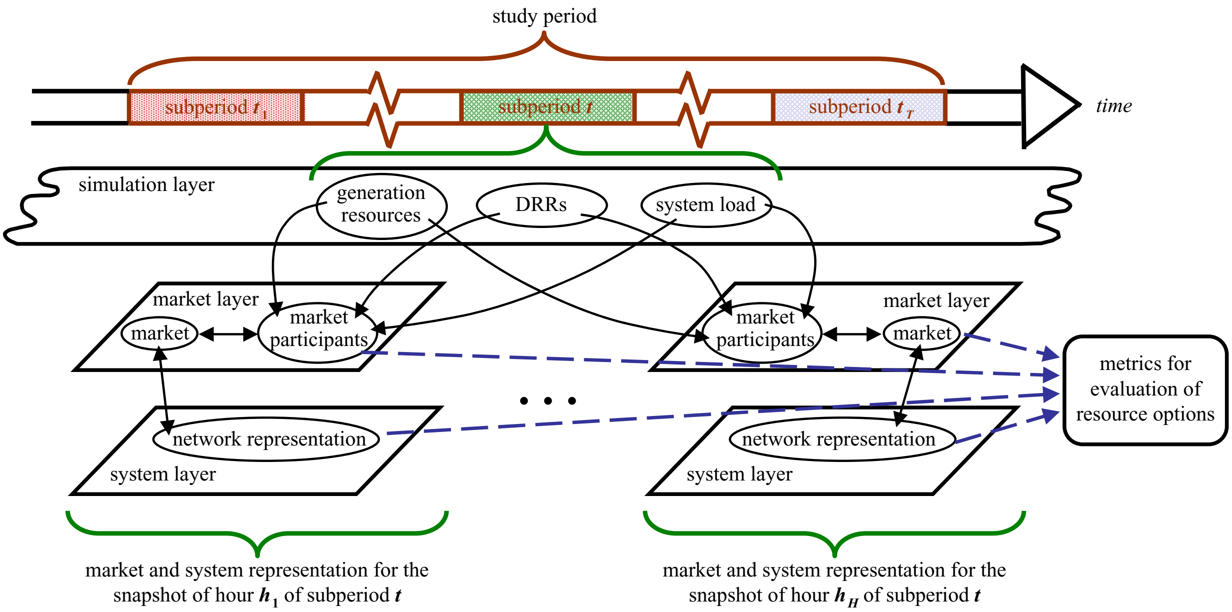


Fig. 1. The framework for resource investment analysis

market layer. The bids and the offers of the market participants determine the preferred energy purchase/sale transactions, which are then communicated to the system layer to verify the feasibility of these transactions. The system layer establishes the relationship between the generation/demand schedule at each node and defines the congestion conditions through explicit consideration of transmission capacity constraints. The system states and line flows are determined and this information is provided to the market layer to determine the market equilibrium. The economic signals resulting from the integrated market and system operations are used to evaluate relevant metrics for the assessment of candidate resources. Fig. 1 illustrates the information flows between the system, the market and the simulation layers. The dotted arrows indicate the economic signals resulting for the operations of the DAM and the power system which are used for the assessment of resource options.

III. Analytical Models with Explicit Representation of DRRs

In this section, we discuss the specific modeling used in the three layers of the framework. In particular, we focus on the modeling needs and impacts of integrating and representing DRRs in the framework. In addition to this, we also discuss the modeling of other key inputs for the simulation framework.

A. The System Layer

We consider a transmission network with $(N+1)$ buses and L lines. The set of buses is given by $\mathcal{N} = \{0, 1, \ldots, N\}$, with bus 0 being the slack bus. The net active power injection at each node $n \in \mathcal{N}$ is denoted by p_n and we define $\underline{\boldsymbol{p}} \triangleq [p_1, p_2, \ldots, p_N]^T$. The set of lines and transformers which connect the buses in $\mathcal{N}$ is denoted by $\mathcal{L} = \{\ell_1, \ell_2, \ldots, \ell_L\}$. We associate with each line $\ell \in \mathcal{L}$ the *ordered* pair $\ell = (m, n)$, with the convention that the direction of the flow on line ℓ is *from* the node m *to* the node n, so that the active power flow on line ℓ, denoted by f_ℓ, is non-negative, i.e. $f_\ell \geq 0$. We define $\underline{\boldsymbol{f}} \triangleq [f_{\ell_1}, f_{\ell_2}, \ldots, f_{\ell_L}]^T$. We denote by $\underline{\boldsymbol{B}}_d$ the diagonal branch susceptance matrix,

$$\underline{\boldsymbol{B}}_d \triangleq diag\{b_\ell : \ell \in \mathcal{L}\}$$

where b_ℓ is the susceptance of the line ℓ. We use the reduced branch-to-node incidence matrix, $\underline{\boldsymbol{A}}$, to characterize the topology of the transmission grid for the snapshot of the system corresponding to the hour h of the subperiod t. Then, the reduced nodal susceptance matrix, $\underline{\boldsymbol{B}}$, may be obtained as

$$\underline{\boldsymbol{B}} = \underline{\boldsymbol{A}}^T \underline{\boldsymbol{B}}_d \underline{\boldsymbol{A}} .$$

The representation of the power flow equations along with other operational constraints is used to describe the key characteristics of the transmission system. We assume that the power system is lossless and that the DC power flow conditions hold [4], so that

$$\underline{\boldsymbol{p}} = \underline{\boldsymbol{B}}\,\underline{\boldsymbol{\theta}} \tag{1a}$$

$$p_0 = \underline{\boldsymbol{b}}_0^T\,\underline{\boldsymbol{\theta}} \tag{1b}$$

$$\underline{\boldsymbol{f}} = \underline{\boldsymbol{B}}_d\,\underline{\boldsymbol{A}}\,\underline{\boldsymbol{\theta}} \tag{1c}$$

where $\underline{\boldsymbol{\theta}} \triangleq [\theta_1, \theta_2, \ldots, \theta_N]^T$ is the vector of voltage angles at the network nodes. The constraints on the real power flows through the transmission lines are represented through the following inequality:

$$\underline{\boldsymbol{f}} \quad \leq \quad \underline{\boldsymbol{f}}^{max} \tag{2}$$

where $\underline{\boldsymbol{f}}^{max} \triangleq [f_{\ell_1}^{max}, \ldots, f_{\ell_L}^{max}]^T$, with f_ℓ^{max} being the maximum active power flow allowed through the line $\ell \in \mathcal{L}$. We call a line ℓ *congested* if $f_\ell = f_\ell^{max}$. We call a transmission network *congested* if there is (are) one or more congested lines in the network.

B. The Market Layer

We extend the DAM representation of [5] to explicitly represent the DRRs as market participants. We denote by $\mathcal{S} \triangleq \left\{s^1, s^2, \ldots, s^S\right\}$ the set of supply-side sellers, and $\mathcal{B} \triangleq \left\{b^1, b^2, \ldots, b^B\right\}$ the set of pure buyers, who only purchase energy from the DAM. We denote by $\mathscr{C}^{s^i}\left(p^{s^i}\right)/\mathscr{B}^{b^j}\left(p^{b^j}\right)$ the seller s^i's offer price/buyer b^j's bid price as function of the active power supply/consumption. In addition to $\mathcal{B}$, we represent another class of buyers with the capabilities of providing demand response curtailments. We denote by $\widehat{\mathcal{B}} \triangleq \left\{\hat{b}^1, \hat{b}^2, \ldots, \hat{b}^{\hat{B}}\right\}$ the collection of such market participants, which may act as buyers as well as DRR sellers. We denote by $\mathscr{B}^{\hat{b}^j}\left(p^{\hat{b}^j}\right)$ the bid function of $\hat{b}^j$ as a buyer, for the purchase of $p^{\hat{b}^j}$ *MWh/h*. Similarly, we denote by $\mathscr{C}^{\hat{b}^j}\left(\hat{p}^{\hat{b}^j}\right)$ the offer function of $\hat{b}^j$ as a DRR seller, for the sale of $\hat{p}^{\hat{b}^j}$ *MWh/h* of demand response curtailment. We assume that $\hat{p}^{\hat{b}^j} \leq p^{\hat{b}^j}$, which implies that the entity $\hat{b}^j$ may only sell as much demand curtailment as the demand which $\hat{b}^j$ may have bought from the IGO as a buyer. The total contribution of the $\hat{b}^j$ to the pool demand for some system snapshot is given by $\left(p^{\hat{b}^j} - \hat{p}^{\hat{b}^j}\right)$ *MWh/h*. $\mathcal{B} \bigcup \widehat{\mathcal{B}}$ denotes the set of all the buyers in the DAM.

The IGO collects all the offers and the bids from the day-ahead pool and determines the least-cost dispatch to meet the demand requirements using the offers for energy from the supply-side sellers as well as the offers for load curtailments from the DRR sellers [6]. Let $\mathscr{C}^s_n(\cdot)$ and $\mathscr{C}^{\hat{b}}_n(\cdot)$ represent the aggregated costs of the supply-side sellers and the aggregated costs of the DRR sellers at node n respectively. Then, the IGO's decision making process for the day-ahead operations for the snapshot corresponding to the hour h of the subperiod t may be expressed with the *transmission constrained problem* (TCP) formulation:

$$
(\text{TCP}) \begin{cases} \min \sum\limits_{n \in \mathcal{N}} \left[\mathscr{C}^s_n(p^s_n) + \mathscr{C}^{\hat{b}}_n\left(\hat{p}^{\hat{b}}_n\right) \right] \\ \text{subject to} \\ \underline{\boldsymbol{p}}^s - \left(\underline{\boldsymbol{p}}^b - \underline{\hat{\boldsymbol{p}}}^{\hat{b}}\right) = \underline{\boldsymbol{B}}\,\underline{\boldsymbol{\theta}} \quad \leftrightarrow \quad \underline{\boldsymbol{\lambda}} \\ p^s_0 - \left(p^b_0 - \hat{p}^{\hat{b}}_0\right) = \underline{\boldsymbol{b}}^T_0 \quad \leftrightarrow \quad \lambda_0 \\ \underline{\boldsymbol{B}}_d \underline{\boldsymbol{A}}\,\underline{\boldsymbol{\theta}} \leq \underline{\boldsymbol{f}}^{max} \quad \leftrightarrow \quad \underline{\boldsymbol{\rho}} \end{cases} \tag{3}
$$

where p^s_n denotes the total *MWh/h* offered by the supply-side sellers at bus n, $\hat{p}^{\hat{b}}_n$ denotes the total *MWh/h* offered by the DRR sellers at bus n, p^b_n denotes the total *MWh/h* demanded at node n by all the buyers and we define $\underline{\boldsymbol{p}}^s \triangleq [p^s_1, p^s_2, \ldots, p^s_N]^T$, $\underline{\hat{\boldsymbol{p}}}^{\hat{b}} \triangleq \left[\hat{p}^{\hat{b}}_1, \hat{p}^{\hat{b}}_2, \ldots, \hat{p}^{\hat{b}}_N\right]^T$ and $\underline{\boldsymbol{p}}^b \triangleq \left[p^b_1, p^b_2, \ldots, p^b_N\right]^T$.

The (TCP) formulation takes into account the limited transmission capacities and hence explicitly represents the interactions between the physical network model and the DAM model. The DAM is settled based on the optimal solutions of the (TCP), which we assume to exist. The optimal values of the decision variables determines the sales/purchases at each node $n \in \mathcal{N}$: $[p^s_n]^*$ denotes the total *MWh/h* sold by the supply-side sellers, $\left[\hat{p}^{\tilde{b}}_n\right]^*$ denotes the total *MWh/h* curtailed by the DRR sellers and $\left[p^b_n\right]^*$ denotes the total *MWh/h* demanded by all the buyers in the absence of load curtailments. The optimum values of the dual variables associated with the nodal power balance constraints, λ^*_n, are the location marginal prices (LMPs) for each node $n \in \mathcal{N}$. Each seller/buyer sells/buys energy at the LMP λ^*_n of the node n where he is connected. The payments collected from the buyers at the LMPs may not generate sufficient revenues for all the sellers. So, each buyer pay an additional per unit load reduction charge, $\lambda^{r\,*}$ to ensure adequacy of revenues for the DRR sellers,

$$
\lambda^{r\,*} = \frac{\sum\limits_{n \in \mathcal{N}} \lambda^*_n \cdot \left[\hat{p}^{\tilde{b}}_n\right]^*}{\sum\limits_{n \in \mathcal{N}} \left(\left[p^b_n\right]^* - \left[\hat{p}^{\tilde{b}}_n\right]^*\right)} . \tag{4}
$$

C. The Simulation Layer

This layer represents the probabilistic models for the available capacities for all the supply- and demand-side resources as well as the system load. We denote by $(\mathscr{R})_t$ the resource mix for the subperiod $t \in \mathcal{T}$. We now discuss the probabilistic models for each resource – be it a generator or a DRR – in the resource mix.

We use the conventional 2-state model to describe the available generation capacity in the subperiod t of interest. We assume, as is widely done in production costing and reliability assessment, that the units have uniform characteristics for each hour of the H- hour subperiod t. Then, the available capacity of generator g of supply-side seller s^i for each hour h of the subperiod t is modeled by the random variable (r.v.) $(\underset{\sim}{A}^{s^i,g})_t$. For simplicity of notation, we drop the subscript t for this discussion. The two-state representation of $\underset{\sim}{A}^{s^i,g}$ is given by,

$$
\underset{\sim}{A}^{s^i,g} = \begin{cases} 0 & \text{with probability } q^{s^i,g} \\ c^{s^i,g} & \text{with probability } \left(1 - q^{s^i,g}\right) \end{cases}
$$

where $q^{s^i,g}$ is the *availability* of the generator unit and $c^{s^i,g}$ is the capacity of the generator g. We assume that the r.v.s $\underset{\sim}{A}^{s^i,g}$ are independent of one another, so that the total available capacity of the seller s^i is denoted by the r.v. $\underset{\sim}{A}^{s^i}$,

$$
\underset{\sim}{A}^{s^i} = \sum_g \underset{\sim}{A}^{s^i,g} \tag{5}
$$

and the total available supply-side capacity is denoted by the r.v. $\underset{\sim}{A}^{\mathcal{S}} = \sum_{s^i \in \mathcal{S}} \underset{\sim}{A}^{s^i}$.

The available capacity for curtailment of the end-use consumer e enrolled in the demand response program of the DRR $\hat{b}^j$, depends on the fraction of the committed load being served in the corresponding hour and is hence modeled as a r.v. $\underset{\sim}{A}^{\hat{b}^j,e}$. We denote by $\underset{\sim}{A}^{\hat{b}^j}$ the available capacity of the DRR seller $\hat{b}^j$ for each hour h of the subperiod t, where

$$
\underset{\sim}{A}^{\hat{b}^j} = \sum_e \underset{\sim}{A}^{\hat{b}^j,e} \tag{6}
$$

and by $\underset{\sim}{A}^{\widehat{\mathcal{B}}} = \sum_{\hat{b}^j \in \widehat{\mathcal{B}}} \underset{\sim}{A}^{\hat{b}^j}$ the corresponding total available DRR capacity.

We make several simplifying assumptions while representing the load. We model the load as the sum of all the individual demands. Statistical regularity is obtained by summing over a large number of the individual random demands. The individual demands of the buyers are assumed to be a fixed fraction of the aggregated demand, known as the *system load demand*. The simulation layer contains the chronological model for the system load, obtained from the historical load data (as is the standard practice in conventional production costing and resource planning studies). As a result, the system load for each hour h of the subperiod t is known; we denote this load by $(\ \ell\ )_{t,h}$. For each hour h of the subperiod t, we simulate the market and system operations for the known system load - $(\ \ell\ )_{t,h}$, and for different combinations of the available resources based on the realizations of the r.v.s discussed in the previous section. Such detailed computations allow us to accurately predict all possible outcomes of the market and system operations for each hour in the subperiod.

However, such detailed simulations may be computationally intractable for large-scale systems. To ensure computational tractability, we choose representative sample of hours from each subperiod using the Latin Hypercube Sampling technique [7]. For implementation of the Latin Hypercube Sampling scheme, we need to develop the probabilistic representation of the system load for each subperiod.

We assume that the system load has uniform characteristics across each of the H hours of the subperiod t. Then, the system load demand in any arbitrary hour h of the subperiod t may be modeled as a r.v. $(\underset{\sim}{L})_t$. Again, we drop the subscript t as we focus on the characterization of load for the subperiod t. The *load duration curve* (LDC) obtained from the chronological model provides the complement of the cumulative distribution function (c.d.f.) of the system load $\underset{\sim}{L}$, denoted by $\mathbb{F}_{\underset{\sim}{L}}(\cdot)$ [8]. However, all chronological information is lost in the probabilistic load model. We make use of *demand classes* to represent the demand characteristics associated with different hours of the subperiod and capture some of the chronological information. We denote by $\hat{\underset{\sim}{L}}^d$ the load of the demand class d, for $d = 1, 2, \ldots, D$. Suppose that the load exhibits characteristics of the d^{th} demand class for $\hat{H}^d$ hours in the H-hour subperiod, then the c.d.f. of $\underset{\sim}{L}$ is expressed as,

$$\mathbb{F}_{\underset{\sim}{L}}(\ell) \;=\; \sum_{d=1}^{D} \mathbb{F}_{\hat{\underset{\sim}{L}}^d}(\ell) \cdot \frac{\hat{H}^d}{H} \,. \tag{7}$$

The probability distribution of $\underset{\sim}{L}^d$ is obtained from the chronological load model.

D. Inputs for Assessment of Resource Investment Options

For assessing the viability of the candidates for resource investments, we need the economic and technical specifications for each of the resource options. Specifically, the assessment requires economic specifications such as cost of producing energy or curtailing load, maintenance costs and investment costs for each of the candidates, in addition to their maintenance schedules. Other specifications for a generator resource include the timing, the location and the capacity of the resource along with the type of technology and the fuel requirements for the resource. Similarly, other specifications for a DRR include the timing, the location and the capacity of the resource.

The capital and operational costs associated with supply-side resources are well studied and reported in the literature [9]. The operational costs for demand response aggregation include the payments to the program participants – the end-users who schedule load curtailments, metering expenses, overhead expenses, and maintenance expenditures [10]. The fixed capital expenditures incurred for DRRs include the costs of setting up the control center and the costs of equipment for communication, control and monitoring [11].

For any generator resource candidate r, we denote by $\mathcal{C}^r(p^r)$ the cost of producing p^r *MWh/h*, which includes the variable operational costs as well as the fixed fraction of the maintenance costs for each hour h of the study period. $\mathcal{C}^r_I$ denotes the fixed capital investment costs for the resource r. Similarly, for any DRR investment option, we denote by $\mathcal{C}^r(\hat{p}^r)$ the cost of curtailing $\hat{p}^r$ *MWh/h* which includes the fixed fraction of the the recurring operational and maintenance costs and by $\mathcal{C}^{\hat{b}^j}_I$ the fixed capital costs.

IV. Evaluation of Candidate Resources for Investment

In order to make decisions regarding investments in resources, the economic viability of the candidate resources needs to be assessed. Standard techniques such as *net present value* (NPV) evaluations [12] may be used for this purpose. The NPVs of the candidate resources depend on the cash flows for the resources over the investment recovery period. In the restructured environment, the cash flows generated by each of the candidate resources depend on the revenues earned in the simultaneous functioning of the competitive markets and the power system. The framework discussed in section II along with models described in section III may be used for simulating the side-by-side operations of the DAM and power system, and the economic signals generated through the simulations may be used to evaluate the revenues and hence, the cash flows, for the candidate resources.

We denote by r the resource candidate being assessed, and we choose the associated investment recovery period as the study period, $\mathcal{T}$, for the simulations. The resource mix for each subperiod $t \in \mathcal{T}$ is given by $(\mathscr{R})_t \bigcup \{r\}$. Let us assume that the candidate r is a DRR which participates in the market with through the DRR seller $\hat{b}^j \in \widehat{\mathcal{B}}$ located at the node n. The revenues generated by the candidate r depend upon the curtailment by candidate r in the DAM and the LMP at the node n, for each hour of the study period. The uncertainty in the system load and available capacities of the sellers results in uncertainty in the buyers' bids and sellers' offers. This uncertainty propagates to the outcomes of the DAM and hence, the LMPs and the market allocations to the buyers and sellers are uncertain. We assume that the LMP at the node n and the

TABLE I
TEST SYSTEM DATA

supply- and demand-side resources	
total capacity (*GW*)	126
base coal units capacity (*GW*)	70
cycling units capacity (*GW*)	12
peaking units capacity (*GW*)	24
other generation capacity (*GW*)	20
total DRR capacity (*GW*)	3
load data	
annual peak demand (*GW*)	106
average hourly demand (*GW*)	63

curtailment alloted to resource r have identical characteristics for all the hours of a given subperiod $t \in \mathcal{T}$.

For each hour h of the subperiod t, the LMP at node n is denoted by the r.v. $(\utilde{\Lambda}_{\,n})_{\,t}$ and the load curtailment by resource r for the DRR seller $\hat{b}^{\,j}$ is denoted by the r.v. $(\utilde{\hat{P}}^{\,r})_{\,t}$. So, the revenues earned by r in any arbitrary hour h of the subperiod t are given by the product, $(\utilde{\Lambda}_{\,n})_{\,t} \cdot (\utilde{\hat{P}}^{\,r})_{\,t}$. We denote by $\mathcal{C}^{\,r}\left(\utilde{\hat{P}}^{\,r}\right)$ the costs incurred by the DRR in any arbitrary hour h of the subperiod t, where $\mathcal{C}^{\,r}(\cdot)$ is the cost function based the variable curtailment costs as well as the fixed operational and maintenance costs for each hour. Knowing the revenues earned and the costs incurred in each hour, the cash flow in each hour is given by $(\utilde{\Lambda}_{\,n})_{\,t} \cdot (\utilde{\hat{P}}^{\,r})_{\,t} - \mathcal{C}^{\,r}\left(\utilde{\hat{P}}^{\,r}\right)$. For the NPV evaluation, the cash flow for the hour may be estimated by its expected value, so that the expected cash flow over the H-hour subperiod t is estimated as follows

$$
\begin{aligned}
(\Pi^{\,r})_{\,t} &\approx H \cdot \mathbb{E}\left\{(\utilde{\Lambda}_{\,n})_{\,t} \cdot (\utilde{\hat{P}}^{\,r})_{\,t} - \mathcal{C}^{\,r}\left(\utilde{\hat{P}}^{\,r}\right)\right\} \qquad (8) \\
&= H \cdot \mathbb{E}\left\{(\utilde{\Lambda}_{\,n})_{\,t} \cdot (\utilde{\hat{P}}^{\,r})_{\,t}\right\} - H \cdot \mathbb{E}\left\{\mathcal{C}^{\,r}\left(\utilde{\hat{P}}^{\,r}\right)\right\}
\end{aligned}
$$

We use $\{(\Pi^{\,r})_{\,t} : \forall\, t \in \mathcal{T}\}$ as the cash flows in the NPV evaluation for the resource r. Investment in the resource r is viable if NPV ≥ 0.

From (8), it is clear that we need the distributions of $(\utilde{\Lambda}_{\,n})_{\,t}$, $(\utilde{\hat{P}}^{\,r})_{\,t}$ and $(\utilde{\Lambda}_{\,n})_{\,t} \cdot (\utilde{\hat{P}}^{\,r})_{\,t}$ to compute $(\Pi^{\,r})_{\,t}$. These distributions may be obtained by evaluating the outcomes of the (TCP) formulation expressed in (3) for all possible combinations of the realizations of the load, $(\utilde{L})_{\,t}$; the available capacities of the supply-side sellers, $(\utilde{A}^{\,s^{\,i}})_{\,t}$, $\forall\, s^{\,i} \in \mathcal{S}$; and the available capacities of the DRR sellers, $(\utilde{A}^{\,\hat{b}^{\,j}})_{\,t}$, $\forall\, \hat{b}^{\,j} \in \widehat{\mathcal{B}}$.

Note that although we assume r to be a DRR, a similar method may be used for judging the viability of a supply-side resource investment candidate. Also, the metrics obtained from the long-term simulations may be used for comparative assessments between various resource investment candidates.

V. SIMULATION RESULTS

We provide a representative example to illustrate the functioning of the framework. We consider a test system which is representative of a large-scale ISO network with 241 buses and 555 lines. The test system characteristics are discussed in TABLE I. The DAM for the test system meets the demand requirements using both generation resources and DRRs. However, we assume that the DRRs only offer curtailments during DAM corresponding to the on peak hours as defined by NERC [13].

In this example, we assume that a DRR seller at node 10 is considering an investment in 60 *MW* of DRR aggregation facility. The study period usually considered is about 10 years. However we illustrate the working of the framework for 1 year and explain how we may evaluate the annual cash flows using the framework. We choose one week as the duration of the subperiods. For the sake of simplicity, we assume that the bids and offers of market participants remain unchanged for during each week. We use linear expressions for the cost and benefit functions for the players in the DAM,

$$
\begin{aligned}
\mathscr{C}^{\,s^{\,i}}(p^{\,s^{\,i}}) &= \gamma^{\,s^{\,i}} p^{\,s^{\,i}} \quad \forall\, s^{\,i} \in \mathcal{S} \\
\mathscr{B}^{\,b^{\,j}}(p^{\,b^{\,j}}) &= \beta^{\,b^{\,j}} p^{\,b^{\,j}} \quad \forall\, b^{\,j} \in \mathcal{B} \\
\mathscr{C}^{\,\hat{b}^{\,j}}(\hat{p}^{\,\hat{b}^{\,j}}) &= \gamma^{\,\hat{b}^{\,j}} \hat{p}^{\,\hat{b}^{\,j}} \quad \forall\, \hat{b}^{\,j} \in \widehat{\mathcal{B}} \\
\mathscr{B}^{\,\hat{b}^{\,j}}(p^{\,\hat{b}^{\,j}}) &= \beta^{\,\hat{b}^{\,j}} p^{\,\hat{b}^{\,j}} \quad \forall\, \hat{b}^{\,j} \in \widehat{\mathcal{B}}
\end{aligned}
$$

We assume that bid and the offer parameters, $\beta^{\,b^{\,j}}, \beta^{\,\hat{b}^{\,j}}, \gamma^{\,s^{\,i}}$ and $\gamma^{\,\hat{b}^{\,j}}$, change due to the seasonal demand patterns – an increase (decrease) in demand causes an increase (decrease) in these parameters. To describe the possible bids and offers over the year, we decompose the year into four seasons and we select a typical representative week from each of the seasons. We simulate the market and system operations over each of the typical weeks corresponding to the four seasons and use these results to estimate the outcomes for the entire year.

In order to evaluate the cash flows for each of the typical weeks, we need to estimate the distributions of the LMP at node 10: $\utilde{\Lambda}_{\,10}$; the curtailment by the candidate DRR: $\utilde{\hat{P}}^{\,r}$ and the revenues earned by the candidate: $\utilde{\Lambda}_{\,10} \cdot \utilde{\hat{P}}^{\,r}$; for each hour in the typical week for each of the four seasons. In the light of the large scale test system, we use Monte Carlo simulation [14] techniques to estimate these distributions. We use the Latin Hypercube Sampling technique to constrain the number of Monte Carlo simulations by efficiently sampling across the distributions of the inputs. Fig. 2 shows the distributions of the outcomes, while the statistics of the empirical outcomes such as means, medians and standard deviations are listed in TABLE II.

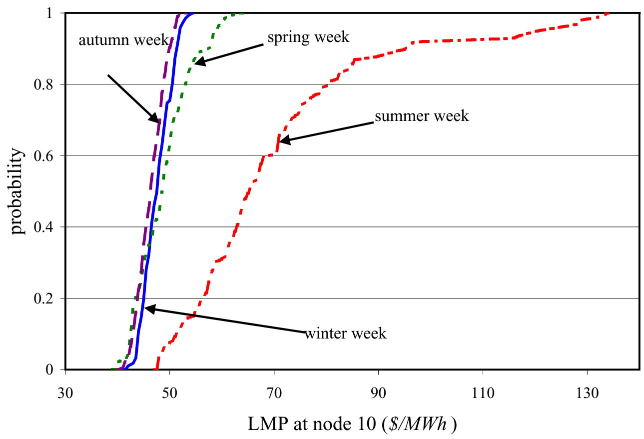
We assume that the fixed maintenance costs of the candidate DRR for a week are given by $\$\ 10,000$ and the per unit costs of curtailment are given as 15 *\$/MWh*. Then, the cost function for the DRR candidate r, $\mathcal{C}^{\,r}(\cdot)$, takes the form

$$
\mathcal{C}^{\,r}(\hat{p}^{\,r}) = 15\hat{p}^{\,r} + 59.52
$$

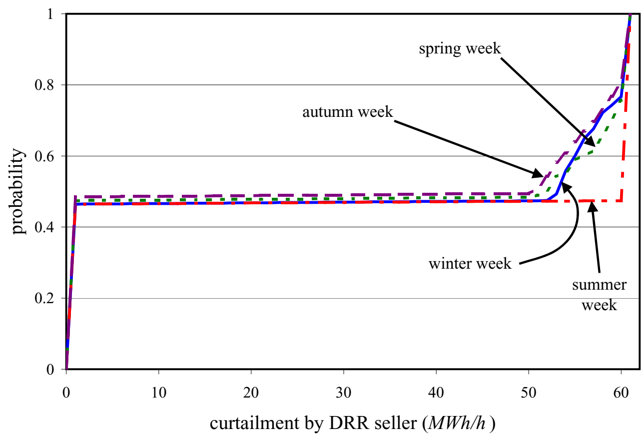
for curtailment of $\hat{p}^{\,r}$ *MWh/h* for any hour of the week. The costs incurred by the DRR candidate and the resulting cash flows for the typical seasonal weeks are in TABLE III. Then, the cash flow for the year is given by

$$
\Pi\,|_{\,year} \;=\; \$\ 10817271
$$

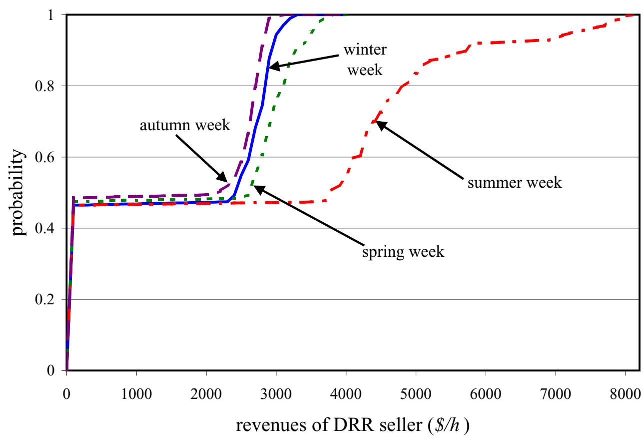
In order to determine the viability of the investment in the candidate DRR, we need to evaluate the cash flows over all



(a) c.d.f. of $\underset{\sim}{\Lambda}_{10}$



(b) c.d.f. of $\underset{\sim}{\hat{P}}^{r}$



(c) c.d.f. of $\underset{\sim}{\Lambda}_{10} \cdot \underset{\sim}{\hat{P}}^{r}$

Fig. 2. distributions of the market outcomes for the candidate DRR for the typical seasonal weeks

the years in the study horizon. Similar techniques may be employed for such evaluations. However, while simulating over the multi-year horizons, assumptions need to be made regarding investments by other players.

The investor may wish to compare the DRR aggregation option against a supply-side alternative. Let us suppose that the investor wishes to compare the DRR candidate r with a

TABLE II
STATISTICS OF MARKET OUTCOMES FOR THE CANDIDATE DRR r FOR TYPICAL SEASONAL WEEKS

LMP at node 10 (*$/MWh*)			
seasons	mean	median	standard deviation
winter	47.56	47.55	2.78
spring	48.74	48.53	5.33
summer	70.53	65.13	19.96
autumn	46.34	46.23	2.67
curtailment by the candidate DRR r (*MWh/h*)			
seasons	mean	median	standard deviation
winter	30.50	53.21	28.94
spring	30.13	51.73	29.17
summer	31.80	60.00	30.10
autumn	29.13	50.53	28.79
revenues earned by the candidate DRR r (*$/h*)			
seasons	mean	median	standard deviation
winter	1461.19	2409.60	1391.43
spring	1577.29	2621.30	1539.02
summer	2630.69	3781.15	2639.76
autumn	1345.45	2173.15	1332.05

TABLE III
DETERMINATION OF CASH FLOWS (IN *$/week*) FOR TYPICAL SEASONAL WEEKS

seasons	costs incurred	revenues earned	cash flow
winter	86871.09	245480.09	158609.00
spring	85939.77	264985.22	179045.45
summer	90136.00	441955.08	351819.08
autumn	83411.51	226035.77	142624.26

100 *MW* coal unit resource option, $\bar{r}$, at the node 89. Once again, we compute distributions of the LMP at node 89: $\underset{\sim}{\Lambda}_{89}$; the energy offered by the candidate resource: $\underset{\sim}{P}^{\bar{r}}$ and the revenues earned by the candidate: $\underset{\sim}{\Lambda}_{89} \cdot \underset{\sim}{\hat{P}}^{\bar{r}}$. The statistics of the revenues for the candidate $\bar{r}$ are presented in TABLE IV. By comparing the statistics for the revenues generated by the resource candidates r and $\bar{r}$, it is evident that the coal generator $\bar{r}$ would procure more revenues during the summer as compared to the DRR r; but it procures very low revenues during the other three seasons. The reason for this disparity in the revenues is the following: the offers by the DRR r are much lower than the offers by the coal unit $\bar{r}$, i.e. $\gamma^{r} < \gamma^{\bar{r}}$. In spite of this, the investment in the coal unit may be attractive if the price of coal is very low, as compared to the curtailment costs of the DRR. However, to make an informed choice between the two resource options, a more detailed analysis is required over a multi-year study horizon.

VI. Conclusion

We proposed an analytical framework for long-term simulations of the electricity markets and power systems for the purposes of resource investment analysis. This framework

TABLE IV
STATISTICS OF REVENUES OF THE GENERATOR CANDIDATE $\bar{r}$ (IN *$/MWh*) FOR TYPICAL SEASONAL WEEKS

seasons	mean	median	standard deviation
winter	0.60	0.00	5.98
spring	769.33	0.00	1920.46
summer	5557.96	5872.32	3000.44
autumn	0.00	0.00	0.00

explicitly incorporates the interactions between the resource investment decisions and operations of the market and power system. We developed analytical models to be used in the framework with particular emphasis given to the representation of DRRs in these models. Consequently the framework is useful for analyzing resource investment options on the supply as well as the demand side. We illustrated the application of the framework through a representative simulation study.

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