

IMPACTS OF DEMAND RESPONSE RESOURCES ON SCHEDULING AND  
PRICES IN DAY-AHEAD ELECTRICITY MARKETS

BY

RAJESH BAJJAL NELLI

THESIS

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Adviser:

Professor Peter W. Sauer

# ABSTRACT

This thesis addresses the explicit representation of demand-side resources as participants in the day-ahead electricity markets and assesses their impacts on scheduling and prices. These resources offer to reduce their loads and compete side-by-side with the supply-side resources in the hourly auctions in the day-ahead markets for energy and capacity-based ancillary services. These demand-side market participants are commonly referred to as demand response resources (DRRs).

The unit commitment problem is used as the vehicle for the study and to evaluate the changes in the operating schedules of the supply-side resources and the resulting prices. In the study, the load recovery effects that accompany the load curtailment that DRRs provide are assessed. A mixed-integer programming solver is used to explicitly represent the integral nature of the decision variables involved in determining the optimal schedules for next day system operations. The solutions of the unit commitment problem are studied to develop appropriate insights into the impacts of DRRs on the prices and quantities of energy and capacity-based ancillary services in the hourly auctions for the next day. The testing is performed on a test system with 24 supply-side resources, to quantify the role of the DRRs in the joint electricity markets for energy and capacity-based ancillary services.

*To Mom and Dad*

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# LIST OF ABBREVIATIONS

AGC	Automatic generator control
C-AS	Capacity-based ancillary service
CPP	Critical peak pricing
DLC	Direct load control
DOE	Department of Energy
DP	Dynamic programming
DRR	Demand response resource
FERC	Federal Energy Regulatory Commission
GUC	Generalized unit commitment
ISO	Independent system operator
LMP	Locational marginal price
LR	Lagrangian relaxation
LSE	Load serving entity
MCP	Market clearing price
MILP	Mixed-integer linear programming
MIP	Mixed-integer programming
MIQP	Mixed-integer quadratic programming
NERC	North American Electric Reliability Council
RTP	Real-time pricing
SCUC	Security constrained unit commitment
TOU	Time-of-use
UC	Unit commitment

# LIST OF SYMBOLS

$T$	the number of scheduling subperiods in the study, i.e., the scheduling period, in hours (h)
$t$	the index for the subperiods of the scheduling period, $t \in \{1, 2, \dots, T\}$
$D_t$	the total demand in the subperiod $t$ , in megawatts
$D_t^f$	the fixed component of $D_t$ in the subperiod $t$ , i.e., the non-price sensitive demand, in megawatts
$R_t$	the requested amount of capacity-based ancillary service in the subperiod $t$ , in megawatts
$N$	the number of generating units in the system
$k$	the index for the generating units, $k \in \{1, 2, \dots, N\}$
$u_{k,t}$	the unit commitment status variable for the unit $k$ in the subperiod $t$ , $u_{k,t} \in \{0, 1\}$
$p_{k,t}$	the power output of the unit $k$ in the subperiod $t$ , in megawatts, $p_{k,t} \geq 0$
$p_k^{max}$	the maximum output capacity of unit $k$ during the scheduling period, in megawatts
$p_k^{min}$	the minimum output capacity of unit $k$ during the scheduling horizon, in megawatts
$\sigma_{k,t}(\cdot)$	the energy offer function of the generating unit $k$ for the subperiod $t$ , with the argument $p_{k,t}$ , the amount of power generated, in dollars per megawatthour, $\sigma_{k,t}(\cdot) \geq 0$
$a_{k,t}$	the contribution of the generating unit $k$ for capacity-based ancillary service in the subperiod $t$ , in megawatts, $a_{k,t} \geq 0$
$a_k^{max}$	the maximum capacity contribution of the generating unit $k$ for the capacity-based ancillary service, over the scheduling period, in megawatts

$\xi_{k,t}(\cdot)$	the generating unit $k$ capacity-based ancillary service offer function in the subperiod $t$ , with the argument $a_{k,t}$ , the megawatts amount offered, in dollar per megawatt, $\xi_{k,t}(\cdot) \geq 0$
$M$	total number of demand response resources
$m$	index for the set of demand response resources, $m \in \{1, 2, \dots, M\}$
$v_{m,t}$	unit commitment status variable for demand response resource $m$ in subperiod $t$ , $v_{m,t} \in \{0, 1\}$
$d_{m,t}$	load curtailment contribution of demand response resource $m$ in subperiod $t$ , in megawatt
$d_m^{max}$	maximum load curtailment contribution of the demand response resource $m$ , in megawatt
$d_m^{min}$	minimum load curtailment contribution of the demand response resource $m$ , in megawatt
$\vartheta_{m,t}(\cdot)$	load curtailment offer function of demand response resource $m$ in subperiod $t$ , with the argument $d_{m,t}$ , the megawatt amount offered, dollar per megawatthour, $\vartheta_{m,t}(\cdot) \geq 0$
$\alpha_{m,t}$	capacity contribution of demand response resource $m$ for capacity-based ancillary service in subperiod $t$ , in megawatt
$\alpha_m^{max}$	maximum capacity contribution of demand response resource $m$ for the capacity-based ancillary service, over the scheduling horizon, in megawatt
$\chi_{m,t}(\cdot)$	demand response resource $m$ capacity-based ancillary service offer function in subperiod $t$ , with the argument $\alpha_{m,t}$ , the megawatt amount offered, in dollar per megawatt, $\chi_{m,t}(\cdot) \geq 0$
$\tau_k^d$	minimum downtime for unit $k$ , in hour
$\tau_k^u$	minimum uptime for unit $k$ , in hour
$\tau_{k,t}^-$	status indicator for unit $k$ downtime at the end of subperiod $t$ , in hour
$\tau_{k,t}^+$	status indicator for unit $k$ uptime at the end of subperiod $t$ , in hour
$b_k^s(\cdot)$	unit $k$ start-up price function, with the start-up time status indicator as the argument, in dollars; $b_k^s(\tau_{k,t}^-)$ is a component of the offer

$\phi_{m,t}^h$  subperiod  $h$  fraction of load curtailment and repayment proportion in subperiod  $t$ , for demand response resource  $m$ ;  $t = h, h + 1, \dots, h + 23$

$$\phi_{m,t}^h = \begin{cases} -1 & \text{if subperiod } t = h \\ \gamma_t \geq 0 & \text{if subperiod } t > h \end{cases}$$

# CHAPTER 1

## INTRODUCTION

On entering a room and flipping the switch, one expects the lights to turn on immediately. When millions of electricity consumers turn on/off various electric appliances it causes a change in the demand for energy. The aggregation of all the users creates a daily load pattern that varies widely between the peak and off-peak hours. In an electric grid, the energy consumption and production must balance at all times; any significant imbalance could cause grid instability or severe voltage fluctuations, leading to blackouts in the system. Therefore, sufficient resources are needed to meet the load in the system at any point in time; balance between load and generation can be achieved either by increasing the generation or by decreasing demand. *Demand response* in a broad sense is used to refer to mechanisms used to encourage consumers to reduce their load, thereby reducing the demand for electricity.

In the subsequent chapters of the thesis, the role of demand response in the modern power system is explored. But before that, light needs to be shed on the normal operations of the electric grid.

### 1.1 Background

As previously mentioned, sufficient generation is needed to meet the demand throughout the day; as a result it is possible that during the off-peak hours, some of the units might be operating at their minimum generating limit or might even be turned off. But, deciding which of the available units to turn on or off is a difficult decision to make, and an incorrect choice may lead to sub-optimal usage of

the available generation resources. Therefore, the problem confronting the power system operator is to determine which of the available units should be running or shut-down, during what time interval, and for how long. Unit Commitment (UC) is the process of determining the optimal unit generation schedule over a set time period subject to device and system operating constraints and operational policies and regulatory requirements. The UC objective is to minimize the operating cost for meeting the electric power demand by scheduling the available generators, while at the same time satisfying all the constraints on the system and the components.

Security constrained unit commitment (SCUC) is the determination of the schedules for the generating units, to minimize the operating costs while satisfying the prevailing constraints, including load balance, system spinning reserves, ramp rate limits, fuel constraints, emission requirements and minimum up- and down-time requirements. There are three key aspects involved in the SCUC determination: ensuring that the load demand and the reserve requirements are met, secure operation of the system, and accomplishing these at the least possible cost to the operator. The load constraint is the prime driver to the entire process and the system operator tries to guarantee that this is satisfied at all times. The normal operation of the system is assured by providing sufficient reserves even when problems arise in the system. Generally, the cost is minimized by committing less expensive units first (but this may not always be possible because of the constraints involved) and then dispatching the committed units according to the economic order of merit.

In the old utility environment, the system dispatcher for the utility had the knowledge of the system components, constraints and operating costs of the generating units, and this information would be used to determine the UC schedule. In the last decade, the industry has undergone restructuring such that the once vertically integrated generation, transmission and distribution systems are now unbundled to encourage competition. This shift has resulted in the formation of competitive wholesale electricity markets managed by independent system opera-

tors (ISOs). In many restructured systems, an ISO operates central energy markets and has the authority to determine a centralized unit commitment schedule to commit and schedule generators participating in the market. ISOs also function as balancing authorities, balancing supply and load, implementing congestion management, and providing reserves.

In the modern power systems, energy price need not be cost-based. Market participants offer energy into the competitive pool for each trading interval. At first glance, it may seem that the energy dispatch process in a price-based competitive pool is very similar to the conventional, cost-based dispatch, with the incremental costs of energy production being replaced by offer prices. However, the difference is in the fact that offer prices can vary according to bidding strategies that a supplier might follow and may be quite different from actual costs which are much more predictable and manageable from a dispatcher's point of view.

## 1.2 Overview of the Day-Ahead Electricity Markets

Power system restructuring has made it possible to identify, unbundle, and thereby open to competition various services that were normally carried out by a vertically integrated utility; i.e., restructuring of the electric industry has turned generation into a competitive activity taking place in a market-based environment. ISOs are responsible for facilitating such a market and for ensuring that the demand is met at all times. The markets can be classified, according to the time at which the market decisions are taken, as year-ahead, day-ahead or real-time. The timeline of these markets is given in Fig. 1.1. This thesis will focus on the day-ahead markets; hence, there is a need to know more about the buyers, the sellers and the market clearing methodologies of this market.

In the day-ahead market, the sellers submit sealed bids for the quantities they wish to sell and the corresponding prices. The sellers consist of various generation companies willing to generate power and demand-side participants

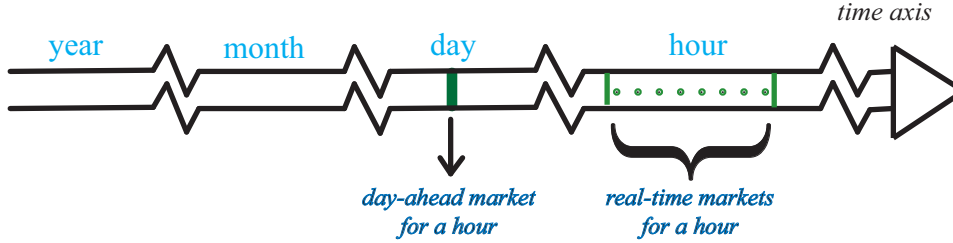


Figure 1.1: Timeline for electricity markets

ready to decrease the load they consume. The buyers also submit sealed bids indicating their willingness to buy electricity in the market. The buyers can make use of either price-sensitive or fixed demand bids. This collection of offers and bids in the market is used by the ISOs to determine the set of successful offers and bids and the resultant market clearing price. The type of dispatch model in which both the both energy and ancillary services are jointly cleared is known as simultaneous co-optimized market clearing, as shown in Fig. 1.2. When multiple products are involved, the merit-order or sequential dispatch methods may not achieve good results. The challenge is in handling the interaction between the various products that exist in the market and still yielding the most economical and reliable UC schedule. The objective of simultaneous market clearing is to minimize the net cost of meeting both energy demand and reserve requirements. The problem formulation for this method, including the supply- and demand-side energy and reserve offers and demand-side bids, is discussed in Chapter 3.

### 1.3 Overview of Ancillary Services

A common feature of the various designs of restructured electricity markets in the US and around the world is the designation of a system operator that is responsible for the reliable real-time control of the transmission system that enables operation of a competitive energy market. Energy is the primary commodity of the market, but the ISO is also responsible for real-time load balancing, conges-

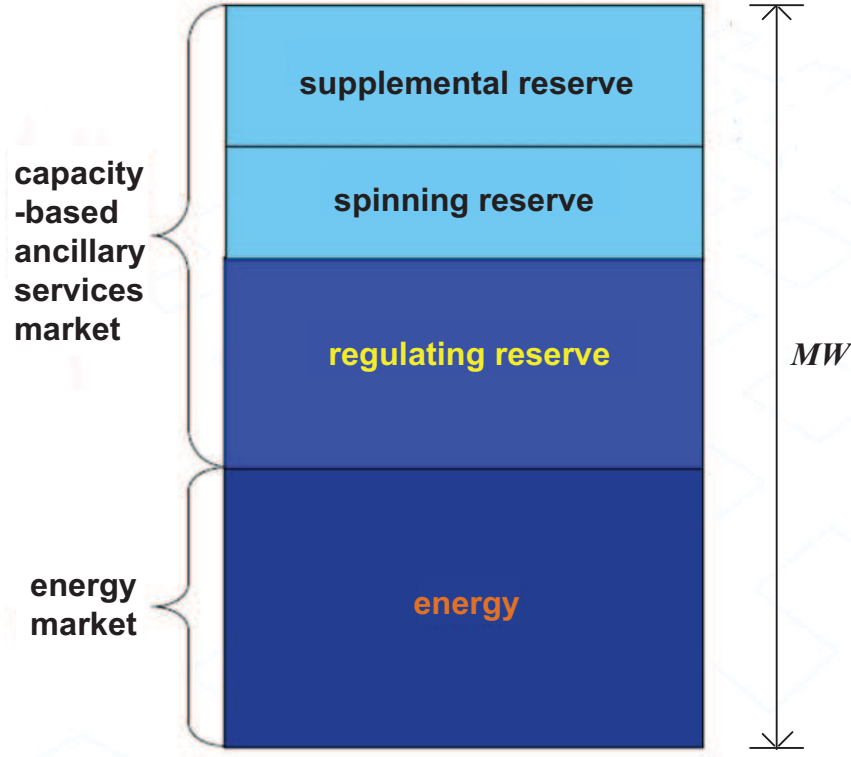


Figure 1.2: Energy and capacity-based ancillary service market

tion management and provision of ancillary services. The precise definition of the ancillary services varies across different restructured systems and so does the design of markets for competitive procurement and provision of such services. The proper product definition and design of ancillary service markets can influence the efficiency and performance of the markets and in turn influence system reliability. Ancillary services have been defined, to a great extent, by the North American Electric Reliability Corporation (NERC) and Federal Energy Regulatory Commission (FERC), respectively. In FERC's Order 888, a document ordering sweeping changes to the electricity industry vis-a-vis the unbundling of services, six ancillary services were recognized. In this document, FERC ordered that these particular services be included in an open access transmission tariff. Other services were recognized to exist, but were not identified in this document [1]. The six core ancillary services are so chosen because they are uniquely measurable and have distinct impacts on system reliability criteria. Each service is also affiliated with

one of the three corresponding reliability objectives, as listed below [2].

- Operating Reserves
  - Regulation
  - Spinning
  - Supplemental
- Bulk Transmission Reliability
  - Reactive power supply
  - Frequency response
- Emergency Service
  - Black-start capability

Under the operating reserves objective fall the regulation, spinning and supplemental reserves services. As the name suggests, these services are responsible for ensuring that there is always enough supply to meet the demand from one instant to the next. The second reliability objective, bulk transmission, is responsible for ensuring network (transmission system) security. Finally, under emergency preparedness falls system black-start capability. This reliability objective addresses the issue of restoring the bulk electric system in the event of a catastrophic failure. Regulation, spinning and supplemental reserve can be categorized as capacity-based ancillary services and the rest of the thesis will focus only on them.

## 1.4 Capacity-Based Ancillary Service

Table 1.1: Reserve deployment periods

Reserves	Deployment Periods		
	Seconds	Minutes	Hours
<b><i>Continuous</i></b>			
Regulation	X		
<b><i>Contingency</i></b>			
Spinning		X	
Non-Spinning		X	

As specified in NERC’s operating policy, reserves must be:

sufficient to account for such factors as forecasting errors, generation and transmission equipment unavailability, system equipment forced outage rates, maintenance schedules, regulating requirements, and load diversity [3].

There are multiple subcategories of operating reserve (Table. 1.1), which can be ordered by their quality (where high quality corresponds to a short time to deployment). These reserves, in descending order of quality, are frequency response, regulation, spinning, non-spinning, and load-following reserves. Typically a higher quality reserve can be used in place of a lower quality reserve, but at a cost.

### 1.4.1 Regulation

Regulation response services, also known as automatic generation control (AGC) allow the system operator to physically balance supply and demand on a real-time,

instant-to-instant basis. Regulating reserves are provided by resources that can adjust their output in response to a control signal generated by an AGC software application that transmits real-time control signals with a very short period (2 to 6 s). This ensures that at all times the demand-supply equilibrium is maintained as shown in Fig. 1.3.

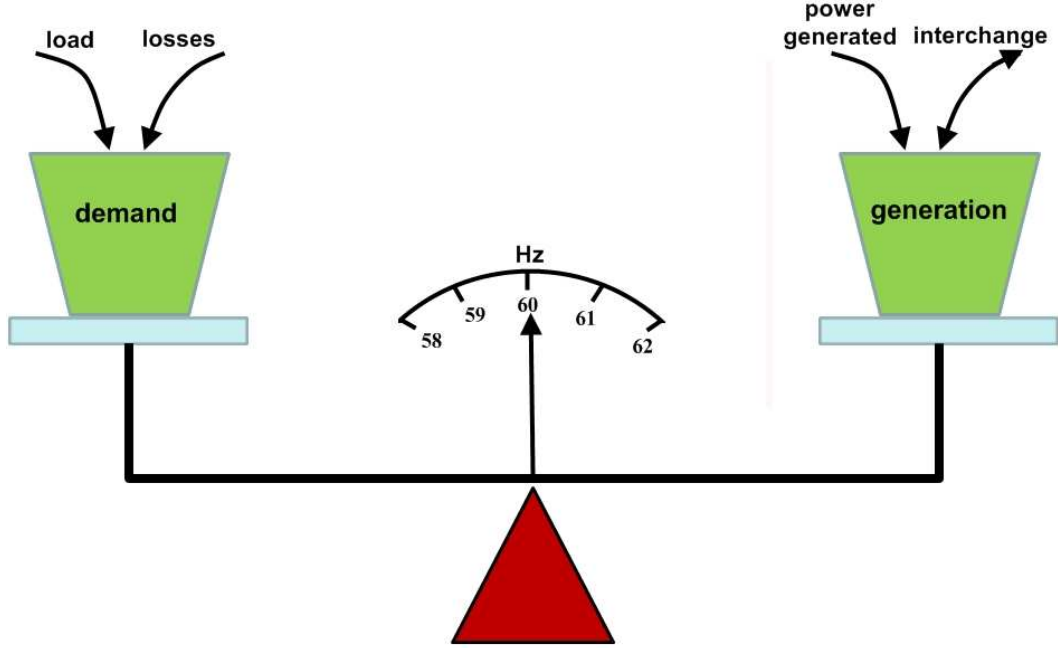


Figure 1.3: Energy balance

#### 1.4.2 Spinning reserve

Spinning reserve is the resource capacity synchronized to the system, which is able to immediately begin supplying energy or reduce demand, is fully available within 10 min, and is able to be sustained for a period of at least 30 min to provide the first level of contingency protection [4].

### 1.4.3 Supplemental reserve

Supplemental reserve is a resource capacity not synchronized to the system, which is able to supply energy or reduce demand, is fully available within 30 min, and can be sustained for a period of at least 60 min to provide a second level of contingency protection.

## 1.5 Market Clearing Strategies

The other challenge in operations and the dispatch of the generating units is how to deal with competitive bidding of other products such as contingency reserves and regulation capacity, part of the so-called ancillary services. As the electricity industry moves toward full competition, the various services previously provided by utilities are being unbundled. A lot of attention so far has focused on the structures of markets for energy and transmission, but the design of markets for ancillary services also requires serious attention and is getting more critical. Since the same generators that are providing energy often have to provide these ancillary services, the method of their selection and dispatch has serious implications for ensuring the smooth working of the power system. Different methods for energy and reserve dispatch also reflect the tradeoffs that govern market operation in a real-world power system. Several alternatives for energy and reserve dispatch are possible [5]: merit-order based dispatch, sequential dispatch, and joint or simultaneously co-optimized dispatch.

**Merit-order based dispatch:** A multi-product market like that for energy and capacity-based ancillary services can be regarded, in a very basic form as a collection of markets having a separate merit-order stack for each product. Each stack is generated based on the price and quantity of product offered by each participant. The offer and bid blocks may be arranged in decreasing and increasing order respectively to form the merit order for the system. The market

is then dispatched by traversing this stack, climbing up (down), the stacked bids (offers) until the load demand is met.

This approach is easy to understand and implement, but it may not lead to the feasible or optimal solution when there is a coupling between the products being sold. For example, a generator may be participating in both the energy and the ancillary services markets, and if it gets accepted in both, its total output capacity may fall short of the sum of energy and reserve to be dispatched.

**Sequential dispatch:** The sequential approach recognizes the deficiency of the merit-order based approach and proceeds to overcome it by defining a priority-based sequence of market commodities, progressively reducing the available capacity of each resource to meet system requirements for each commodity. The manner in which the coupling between products is recognized can vary.

This approach is intuitive. However, its inability to determine the best trade-offs in sharing limited resource capacity for energy and ancillary services may result in higher prices or even insufficient supply for the lower priority commodities. As a result, the market has transitioned from sequential optimized clearing of energy to a simultaneously co-optimized clearing of these products. On the other hand, the simultaneous approach is based on formulating the dispatch problem in the context of constrained optimization which provides improved coordination of energy and ancillary service dispatch to achieve the most secure and economical solution.

Further, with increasing energy costs, the manner in which the power system is operated is also changing. The ability of certain loads to reduce their demand in response to high electricity prices makes them an attractive option to employing expensive peak-load generators. Presently, efforts are being made by certain ISOs to ensure that there is no strict distinction made between generators and consumers (loads), i.e., the producers and consumers of electricity are treated impartially as players in the electricity market, participating with the intention of maximizing their profits. Therefore, the need for increased generation at times of

high demand can be treated symmetrically as the need for decrease in demand. The demand-side resources that participate in the market curtail their load for a specified period of time and they receive a payment in return, the magnitude of which depends on the demand reduced and the prevailing market prices. Therefore, high electricity prices can serve to encourage active demand side participation in the market.

## 1.6 Demand-Side Management

Demand-side management (DSM) programs consist of the planning, implementing, and monitoring activities of electric utilities, ISOs or RTOs that are designed to encourage consumers to modify their level and pattern of electricity usage. According to NERC, the various DSM programs commonly used fall under the categories of conservation, load management, demand response, distributed generation, and energy efficiency [6], as illustrated in Fig. 1.4.

*Distributed generation* refers to the usage of small generators, typically 10 MW or less, sited at or near the load, and attached to the distribution grid. Distributed generation can serve as a primary or backup energy source.

*Energy efficiency* refers to programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption, often without explicit consideration for the timing of program-induced savings. Such savings are generally achieved by substituting technically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating, motor drive), but using less electricity.

*Demand response* programs offer customers incentives to reduce energy demand during electricity supply emergencies, and opportunities to do so when prices are high in the wholesale electricity markets. These programs are examined in detail in the next section.

*Load management* refers to strategic reduction of electric energy demand dur-

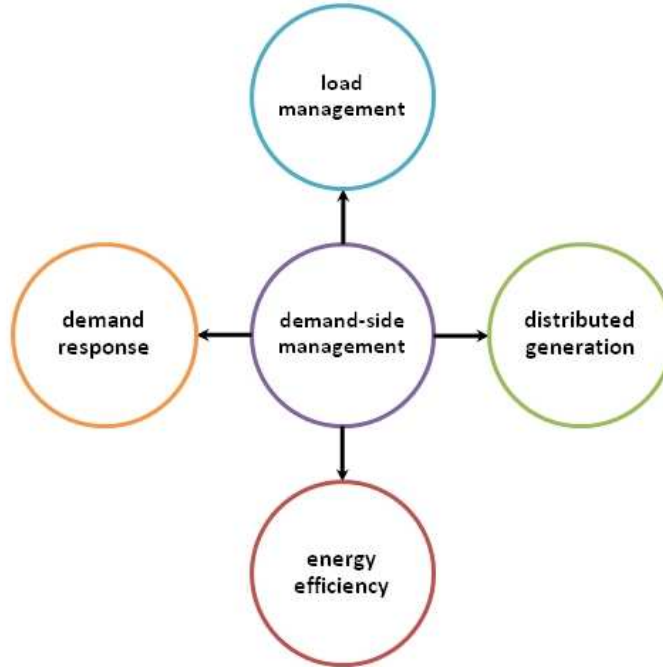


Figure 1.4: Demand-side management techniques

ing a utility’s peak generating periods. Load management differs from energy conservation in that its strategies are designed to either reduce demand or shift it from peak to off-peak times, while conservation strategies may primarily reduce usage over the entire 24-hour period.

## 1.7 Demand Response

At the most general level, demand response is the ability of electricity demand to respond to variations in price or other market conditions.

### 1.7.1 Definition

The U.S. Department of Energy in its February 2006 report to the Congress defined “demand response” (DR) as: *Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower elec-*

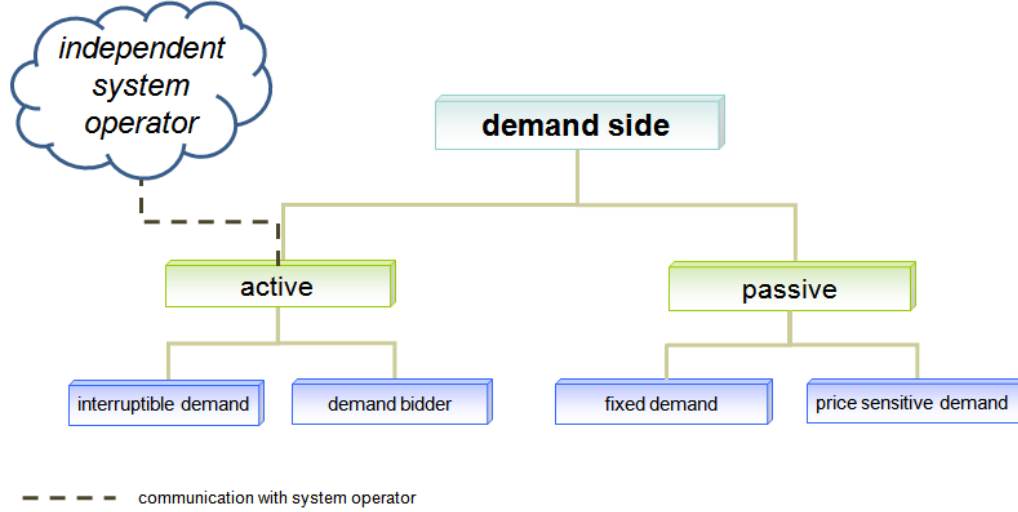


Figure 1.5: Demand-side categorization

*electricity use at times of high wholesale market prices or when system reliability is jeopardized* [7].

The electricity rates that the end-use customers see are based on the average electricity costs and bear little relation to the time-varying price of electricity. DR is a tariff or program designed to bring about changes in electricity use by end-use customers in response to changes in the price of electricity over time, or to incentivize lower electricity use at times of high market prices or low grid reliability. The driving force behind using DR programs is the fact that lower electricity use in peak periods creates benefits in the short run by reducing the amount of generation and transmission assets required to provide electric service. Figure 1.5 provides a graphic illustration of the DR categories that provide demand-side support to the system.

### 1.7.2 Passive demand response

Passive DR places the burden of action totally on the consumer, with no communication or interaction from the supply side other than a variation in price. Consumers are free to react to the fluctuations in price or not. Price-responsive demand and even fixed demand (absence of any responsiveness on part of the

load) can be considered as forms of passive DR. This can be adopted through different schemes like dividing the tariff into three or four parts, or time-of-use rates. But the only true manifestation of this approach is real-time pricing.

Real-time pricing programs are logical for large consumers because interval metering usually already exists, and the cost of collecting and processing interval meter data is small compared to the electric bill. These facilities also would have personnel or automated equipment that could manage the facility and react to high prices by actively modifying usage patterns; they might even have stand-by generation that can be used to reduce load during an extreme peak. The savings gained during thousands of low-priced hours makes the risk of high-priced periods acceptable. Also, consumers would need to save enough during off-peak tiers to pay for installation of required interval metering and for equipment necessary to automatically react to higher prices.

### 1.7.3 Active demand response

Active DR typically involves the use of some form of communication between the system operator and the customer, and the final control is exerted by the system operator. In a more abstract manner, active DR resources can be considered as a set of loads with a switch controlled by the system operator or load owner. Depending on the type of program the customers are participating in, the final decision about curtailing might be out of their hands and in those of the system operator. An active DR program participant makes an offer to curtail his load, or supply “negative watt” (NegaWatt), whenever a supply shortfall occurs. This allows the system operator (ISO/RTO) to balance the supply and the demand in the market. All demand reduction programs are ultimately price responsive; therefore, the distinction of active DR is its use of programs that feature direct communication between the system operator and the demand side.

## Interruptible demand

Interruptible demand programs are curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. The magnitude and the means of customer demand curtailment depend on the contractual arrangements. This can be voluntary, or in some instances the demand reduction may be effected by action of the system operator (remote tripping or direct load control) after notice to the customer in accordance with contractual provisions.

The class of devices or end users that are under direct remote control of the system operator are often referred to as direct load control devices. The system operator achieves load curtailment by interrupting power supply to individual appliances or equipment on customer premises. The most familiar active control systems are radio-controlled air conditioner cycling programs offered by many traditional utilities. Modern programs allow control through wireless or Internet-based control signals.

## Demand-side bidding

Demand-side bidding involves demand-side resources that bid into a wholesale electricity market offering load reductions, or agrees to curtail load when the price increases above a specified threshold price. If the curtailment bid is not accepted, then the resource behaves like a passive DR resource and may choose to reduce its load in response to a high price; in this case, the demand-side picture looks like Fig. 1.6. In this thesis, demand bidding programs are considered the only method through which the demand side can participate in the market, and such participants will be referred to from here on as *demand response resources* (DRRs).

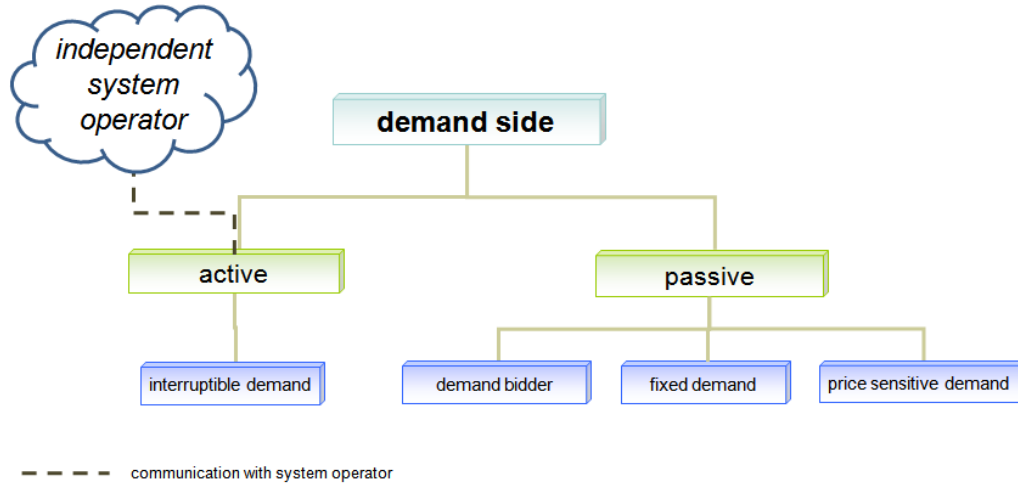


Figure 1.6: Demand-side categorization when demand-bid not accepted

The different services that can be provided by active DR are illustrated in Fig. 1.7. Demand bidding provides a service to the energy market by freeing up some capacity when it curtails its load. Since the opportunity to curtail demand in times of high prices or system emergency can decrease the need for the amount of generation to be kept on reserve, active DR also provides a service to the capacity-based ancillary service market.

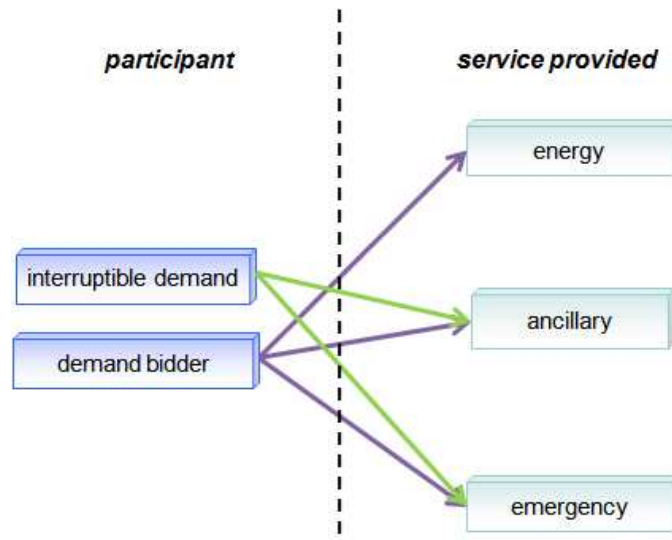


Figure 1.7: Services provided by active DR

Following is a real-life case study of a DR provider [8]. Associated Wholesale

Grocers (AWG) in Nashville serves as a hub for grocery storage and distribution to its more than 300 co-op members. The AWG facility is enormous, including more than 500,000 square feet of dry storage and 250,000 square feet of refrigerated storage. As a result, AWG is a major energy consumer, using more than 1 million kWh per month resulting in a \$ 1.4 million annual energy bill in 2007. AWGs local electric utility, Nashville Electric Service (NES), made demand response available to AWG. Established by the Tennessee Valley Authority (TVA) and offered by NES, AWG enrolled in the TVA-EnerNOC Demand Response program. AWG curtailed more than 850 kW by reducing its lighting and raising the temperature set points by approximately 3 °F in its cold storage areas during DR events lasting from 2 to 8 hours. These measures resulted in annual payments of more than \$ 25,000 for AWG.

Thus DR not only benefits the entire grid, but it also enables the DR providers to generate revenue for decreasing their load.

## 1.8 Objective of the Thesis

In order to understand the impact of integration of DR into the resource mix, a framework to reflect the effect of the usage of DRRs on the total demand, and use it in the unit commitment problem formulation, is proposed in the thesis. The solution of such a problem formulation would provide valuable insights into the merits and de-merits of including DRRs in electricity markets and thereby help in maximizing the benefits of a joint energy and reserves electricity market. Using the formulation, a real-life UC problem is solved and various sensitivity studies are conducted to fully explore the role of DR.

## 1.9 Literature Review

In this section, we explore the existing literature related to the solution of the UC problem, and also the role of DR in UC. The origins of the UC problem lie

in the hydrothermal coordination problem, i.e., how to split the generation in a mixed hydro and steam generating pool of units during a 24-hour period, so as to match the load at all times and also so that the daily volume constraints on the hydro units and the capacity limits and other constraints are respected for all the units. This is a very different problem from that of unrelated successive economic dispatches that was used before to cope with load fluctuation, and the fact that some of the constraints spanned different time slices of the period increased the complexity of the problem.

This led to the recognition of the UC problem as one having a large economic impact on the operation of the power system and a lot of research flowed into the field. In the following paragraphs the different methods that have been used to solve this problem [9]–[10] will be looked into to lay a foundation for the thesis.

In the exhaustive enumeration method, the UC problem is solved by enumerating all possible combinations of the generating units and then the combination that yields the least cost of operation is chosen as the optimal solution. In [11], the UC problem is solved for the Florida Power Corporation by using this method, but the method is not suitable for large systems.

The priority list method arranges the units based on the operational cost characteristics. This predetermined order is then used for UC, so that the system load is met at all times. Reference [12] applies priority listing for a system with import/export constraints. Also, [13] solves the multi-area UC problem using a priority ordering. The ranking process used for preparing the priority list is based on specific guidelines of the utility, lending flexibility to this method.

Dynamic programming (DP) is one of the earliest methods used to solve the UC problem [14]–[15]. DP searches the solution space that consists of the unit status for an optimal solution. The search can proceed in a forward or backward direction. Typically each hour of operation represents a stage in the DP. Forward DP finds the most economical schedule by starting at the initial stage, accumulating costs, then backtracking from the combination of least accumulated cost starting at the last stage and ending at the initial stage [16]. DP builds and evalu-

ates the complete decision tree to optimize the problem at hand. Thus, DP suffers from the “curse of dimensionality” because the problem grows rapidly with the number of generating units to be committed. But for a long period DP continued to be the best method for solving the UC problem.

The landscape of UC solutions underwent a change after Muckstadt and Koenig [17] published a paper introducing a technique called Lagrangian relaxation (LR) borrowed from the scheduling problem literature in the operations research community and applied it to solve the UC problem. In this approach, a Lagrangian dual function is formed by combining the constraints with the objective function using Lagrangian multipliers. The dual problem is then maximized to get to the solution. The coupling constraints of the primal problem are relaxed in the dual problem, which can then be separated into smaller subproblems. During optimization of the dual function, the solution of each subproblem provides a commitment schedule for the corresponding generating unit. But the optimal value found by this method can only be used as a lower bound of the optimal problem [18]–[19]. The LR method is beneficial for utilities with a large number of units since the degree of sub-optimality goes to zero as the number of units increases. Further, it can be easily modified to add new constraints and include unique characteristics of specific utilities.

A new approach for solving the UC problem based on the branch-and-bound method was proposed by Lauer et al. [20] and Cohen and Yoshimura [21]. The branch-and-bound procedure consists of the repeated application of these steps. First, the portion of solution space in which the optimal solution is known to lie is partitioned into subsets. Second, if all the elements in a subset violate the constraints of the problem, then that subset is eliminated. Third, an upper bound on the minimum value of the objective function is computed. Next, the lower bounds are computed on the value of the objective function when the decision variables are constrained to lie in each subset still under consideration. A subset is then eliminated if its lower bound exceeds the upper bound of the minimization problem. Finally, convergence takes place when only one subset of decision variables

remain, and the upper and lower bounds are equal for that subset.

The mixed-integer programming (MIP) approach solves the UC problem by reducing the solution search space by rejecting the infeasible subsets [22]–[23]. This is based on the extension and modification of the branch-and-bound method. The UC problem is partitioned into a nonlinear economic dispatch problem and a pure integer nonlinear UC problem based on Benders’ approach.

In several established electricity markets, energy and reserve are often traded and scheduled in separate markets [24]. These markets have reserves cleared in sequential order with only the generators submitting offers, and the system operator allocates the required amount after the energy market has been cleared. For the purpose of avoiding the market inefficiencies that might be created by this type of sequential model, a number of papers have researched the joint scheduling of generation and reserve [4], [25]. The existing work for the most part has emphasized the supply side only. But, as shown by the results in [26], consumers also possess the capability to participate in the market. The framework for the inclusion of demand-side participants is discussed in [27], and a modified version of this model is used as part of the thesis. The work in [28] deals with a similar problem, but the model adopted and the solution approach differ from those in this thesis.

## 1.10 Outline of the Thesis

This thesis contains four additional chapters. A brief review of the structure of the day-ahead ancillary service and energy market is given in Chapter 2. The market participants are also introduced and the characteristics of the market are discussed in this chapter.

In Chapter 3, a mathematical framework to formulate the UC problem and extend it for inclusion of DRRs is described. The nature of the problem is discussed and the solution developed. The software tool used is introduced and the modifications made on the UC problem formulation to ensure its proper solution

are addressed.

In Chapter 4, the test case is presented and the numerical results are discussed. Chapter 5 summarizes the thesis and gives recommendations for future work.

# CHAPTER 2

## DEMAND RESPONSE RESOURCES AND THEIR MODELING

This chapter explores the nature of demand response resources (DRRs) and their role in meeting the total demand in the system. The modeling of DRRs in the competitive electricity market environment is also discussed. The focus is on the contributions of DRRs to the day-ahead markets for the electricity commodity (MWh) and the capacity reserves service. The developed model is used in the unit commitment schedule determination in the next chapter.

### 2.1 Demand Response Resources

The demand-side bidding programs that participate in the day-ahead electricity markets are the DRRs. DRRs that offer a specified load reduction, with a specified duration and price in the day-ahead markets (DAMs), are to be considered. The DRRs are paid the market clearing price for curtailing their load, when required by the ISO.

DRRs are load resources that actively participate in the DAMs by expressing their willingness to reduce their electricity consumption, at a specified offer price. If the DRR offer price is below the market clearing price, the DRR offer is accepted for that subperiod. In DAMs, the market clearing price is set by the most expensive generating unit that is used to meet the demand in that subperiod. Without DRRs the subperiod market clearing price is set solely by the supply-side resources. At times of high demand the need for high-priced generating resources may lead to electricity price spikes. With the participation of the DRRs, their load reduction may avert the need for one or more of the high-priced generating

resources and thereby lead to lower market clearing prices.

## 2.2 Impact of DRRs on Electricity Markets

The impacts of DRRs on the day-ahead transmission unconstrained markets for energy and capacity reserves service are explored in this section. The independent system operator (ISO) runs the day-ahead electricity markets for meeting the needs for 24 hours of the next day. Typically, there are 24 hourly electricity markets run by the ISO for the next day. The ISO collects all the offers and bids from the generators and the loads, respectively, for all the subperiods of the period under consideration, referred to as the *scheduling horizon*, and uses them to determine the market clearing prices and the market clearing quantity for each subperiod. For a subperiod market, the ISO constructs the supply curve from the offers of the sellers and the demand curve from the bids of the buyers.

The focus of the discussion is on the day-ahead market corresponding to the subperiod  $t$  of one hour duration. Each generating unit  $k$  submits its offer in terms of its price-quantity pair information  $\{\sigma_{k,t}(\cdot), p_{k,t}\}$ . The ISO has the total demand forecast  $D_t$  to be met for the subperiod  $t$ . The DRR  $m$  is considered to participate in such a market. The offer of the DRR for load curtailment is submitted in terms of the price-quantity pair  $\{\vartheta_{m,t}(\cdot), d_{m,t}\}$ .

The ISO constructs the supply curve from the offers of the generators and determines the clearing price for the fixed demand  $D_t$  MW. The situation without any DRR participation is considered first.

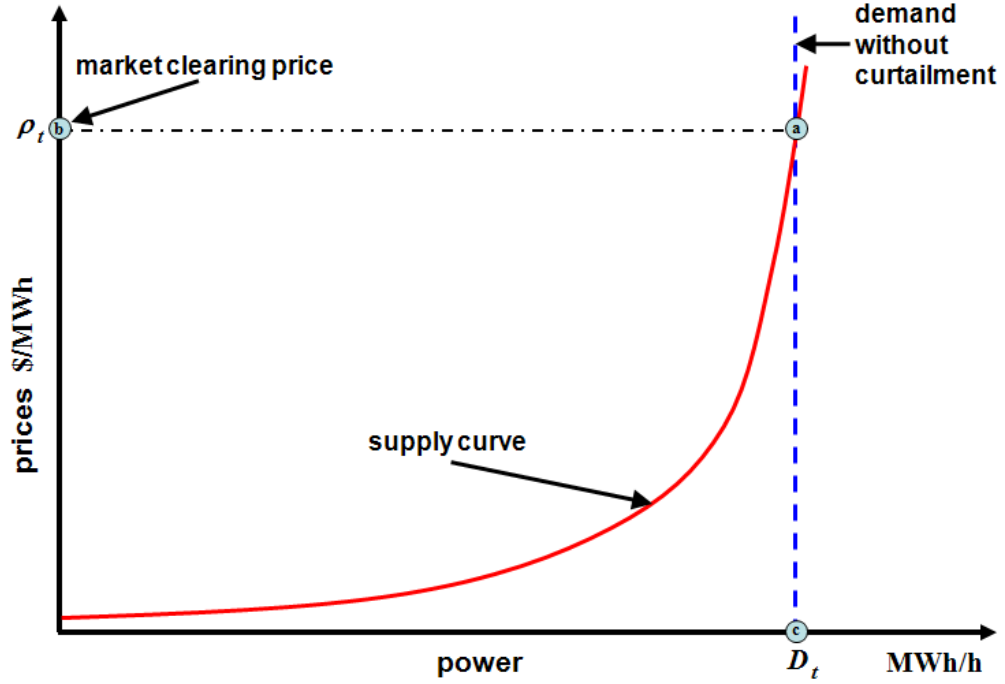


Figure 2.1: Market clearing price determination in a subperiod market with fixed demand

The concept can be illustrated with a supply and demand curve, shown in Fig. 2.1. An illustrative supply curve is shown as a solid line; the demand curve is idealized as a vertical dotted line, representing the fact that most customers are not directly exposed to changes in the electricity prices, so their short-term demand is unresponsive to price fluctuation. The ISO establishes the market clearing price  $\rho_t$  \$/MWh for the fixed demand. Such a situation is illustrated in Fig. 2.1 with the market clearing price given at the point of intersection of the supply curve and the fixed demand line.

The total payments to supply the fixed load of  $D_t$  MW is the product of  $D_t$  and  $\rho_t$ . In Fig. 2.1, the payment amount is indicated by the area under the supply curve.

Next, consider the case with the participation of the DRRs. The DRR  $m$  offers to provide a load curtailment  $d$  MW at a price  $\xi$ . In other words, its offer is the pair  $(d, \xi)$ . If  $\xi < \rho_t$ , the DRR  $m$  offer is accepted, since it costs less to reduce a MW of load than to provide electricity to supply the load. Therefore, the ISO

uses the supply curve to meet a demand of  $(D_t - d)$  or  $D'_t$  MW and establishes a new clearing price  $\rho'_t$ . The accepted DRR  $m$  offer shifts the demand curve to the left. This situation is shown in Fig. 2.2. Note that the new clearing price  $\rho'_t$  is not the actual price paid by the loads, since the payment to the DRR for its curtailment efforts also needs to be taken into account.

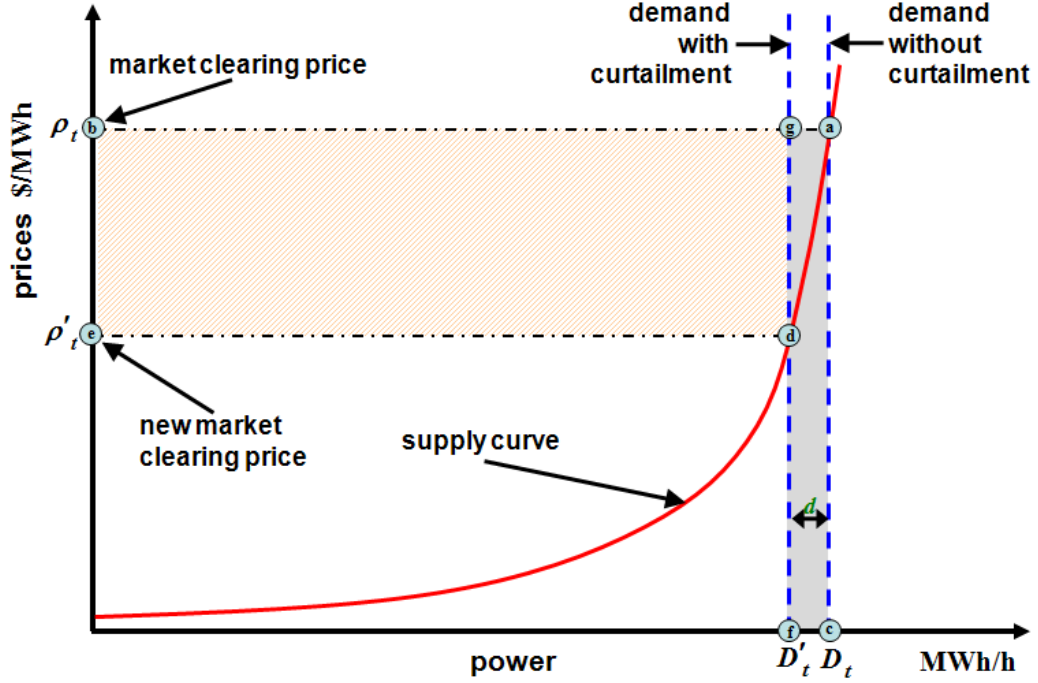


Figure 2.2: Market clearing price determination with demand reduction

The price savings to non-curtailed load is given by the area **gbcd**. Area **gbcd** represents savings to customers, but it also represents a reduction in revenue generated by the suppliers relative to the less efficient situation in which demand is unresponsive to market signals. The savings for the curtailed load are represented by the area **agfc**.

The load cut of the DRR receives payment that compensates the DRR for the service. Typically, the DRR is paid the market clearing price and, in effect, the DRR receives payment for the energy savings its curtailment produces. The payment to DRR  $m$  is therefore  $\rho'_t * d$  \$ and is allocated to all the loads on a simple pro rata basis. Thus, each MW of demand pays an additional  $\frac{\rho'_t * d}{D'_t}$  \$ and

so the price for the buyers is  $\hat{\rho}_t$  \$/MWh, where

$$\hat{\rho}_t = \rho'_t + \frac{\rho'_t * d}{D'_t} \quad (2.1)$$

Next, consider the case with both fixed and price sensitive load and extend the simplified situation for fixed demand that was discussed earlier.

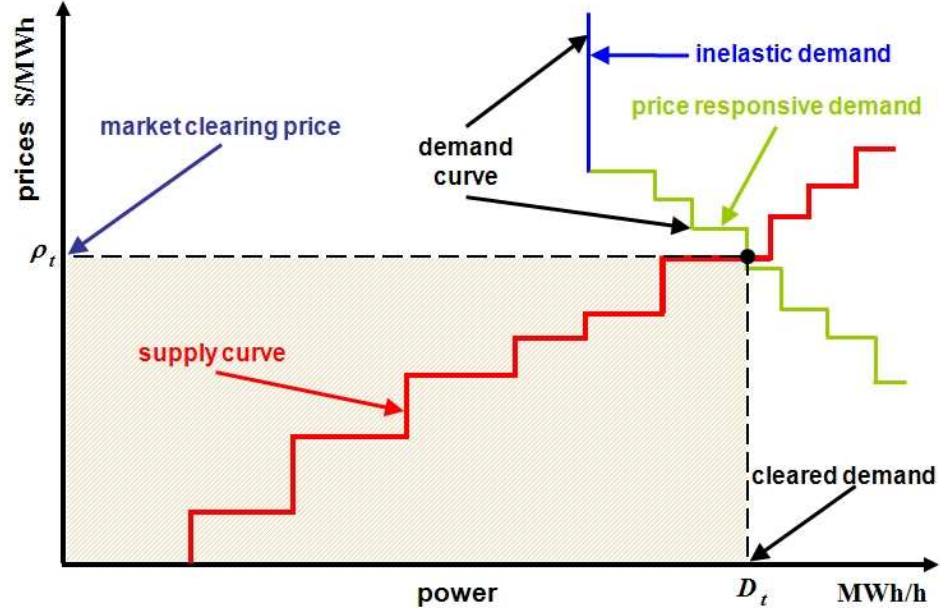


Figure 2.3: Supply and demand curves

The ISO collects the offers from the generators and the bids from the loads. Now, instead of all the demand being fixed, a price-sensitive component is also introduced. The ISO establishes the market clearing price  $\rho_t$  \$/MWh. But not all the demand is cleared; only the load willing to pay more than the market clearing price will be served by the generators. Such a situation is illustrated in Fig. 2.3.

The total payments to supply the load of  $D_t$  MW is the product of  $D_t$  and  $\rho_t$ . In Fig. 2.3, the payment amount is indicated by the shaded area under the supply curve.

Next, similar to the case with only fixed demand, a case with the participation of the DRRs is considered. The DRR  $m$  offers to provide a load curtailment  $d$  MW at a price  $\xi$ . If  $\xi < \rho_t$ , the DRR  $m$  offer is accepted. Now, just sufficient

supply to meet a demand of  $D'_t$  is needed. But, depending on the supply curve, the market clearing price may decrease or stay the same. The new clearing price  $\rho'_t$  as shown in Fig. 2.4 is the same as  $\rho_t$ .

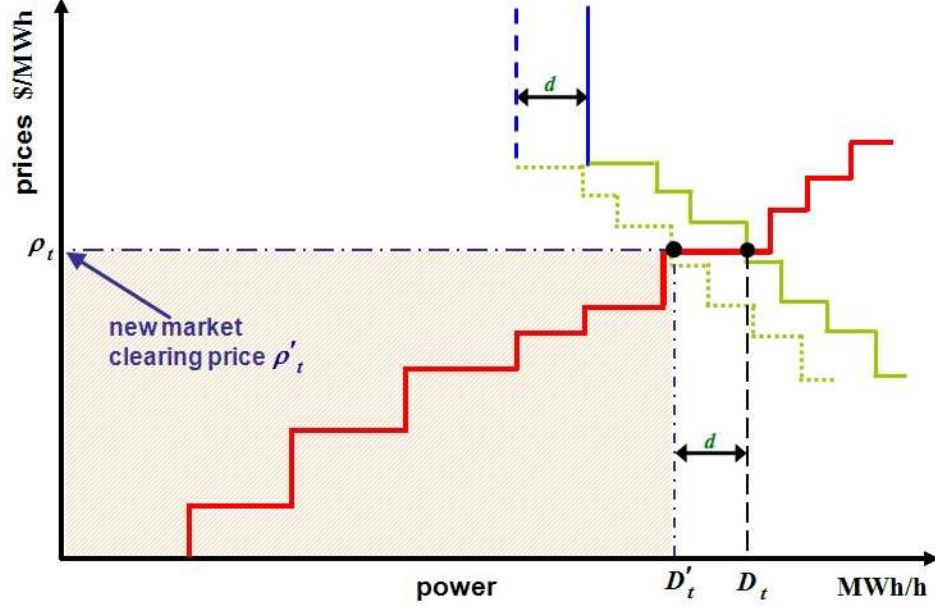


Figure 2.4: Impact of DRRs

Similar to the earlier case of only fixed demand, the payment to DRR  $m$ ,  $\rho'_t * d$  \$ is allocated to all the loads in proportion to their demand and the increased price to be paid by each MW of demand is indicated by Eq. (2.1).

In some of the existing markets, energy and capacity-based ancillary services can be supplied by generators and DRRS through a process of competitive bidding. The fact that the same resource and the same capacity may be used to provide different products at the same time, implies that the capacity-based ancillary service market operation needs to be closely coordinated with the energy market. As previously mentioned in the introduction, this close coordination is best achieved through joint simultaneous optimization of capacity-based ancillary service and energy markets.

In the joint optimization approach, the objective is to minimize the total cost of providing capacity-based ancillary service along with energy offers to meet forecast

demands as well as capacity-based ancillary service requirements. The allocation of limited generation capacity among energy and capacity-based ancillary service for a supply-side resource is determined in terms of its total cost of providing each of the electricity market products relative to other competing resources.

The deployment of DRRs is a mechanism for harnessing the load reduction capabilities of a few of the market participants. The ISO can opt to use such resources whenever it is more economical than deploying supply-side resources. The DRRs may offer load curtailment in direct competition with the offers of supply-side resources for capacity reserves. Such offers are accepted by the ISO as long as the costs of the associated reduction in reserves are below the costs of using the supply-side resources. Using DRRs to provide capacity-based ancillary service can free up some of the generating capacity that would have been locked for fulfilling this need. In addition, the use of DRRs has an impact on the competitive acquisition of reserves. The amount of reserves required by the system is a function of the total system demand, and the reduction in the load resulting from the DRR deployment reduces the reserves requirements.

Thus, upon the inclusion of DRRs in the capacity-based ancillary service market, the capacity-based ancillary service provided by some of the expensive generating units can be replaced by the cheaper DRRs.

## 2.3 The Modeling of DRRs in the Day-Ahead Electricity Markets

One hour is defined as the smallest indecomposable unit of time. The DRR model makes use of the following notation:

- the total fixed demand  $D_t^f$  to be met in subperiod  $t$ ;
- the total requested amount of capacity-based ancillary service  $R_t$  in the subperiod  $t$ ;
- the power output  $p_{k,t}$  of the unit  $k$  in subperiod  $t$ ;

- the capacity offered  $a_{k,t}$  by unit  $k$  for the capacity-based ancillary service in subperiod  $t$ ;
- the load curtailment contribution  $d_{m,t}$  of DRR  $m$  in subperiod  $t$ ;
- the capacity offered  $\alpha_{m,t}$  by DRR  $m$  for the capacity-based ancillary service in subperiod  $t$ .

The total fixed demand  $D_t^f$  in the subperiod  $t$  is met using the  $N$  generating units and  $M$  DRRs in the system as shown in Eq. (2.2).

$$\sum_{k=1}^N \{p_{k,t} \cdot u_{k,t}\} = D_t^f - \sum_{m=1}^M \{d_{m,t} \cdot v_{m,t}\} \quad (2.2)$$

$$\forall t = 1, 2, \dots, T$$

where  $u_{k,t} \in \{0, 1\}$  and  $v_{m,t} \in \{0, 1\}$  are the unit commitment status flags for generating unit  $k$  and DRR  $m$  respectively. In case the DRR  $m$  offer to curtail load does not get accepted, i.e.,  $v_{m,t} = 0$ , then in this thesis, the assumption is that the demand remains unchanged. Therefore, the DRR  $m$  continues to draw its share of the load from the system.

The total requested amount of capacity-based ancillary service is supplied as shown in Eq. (2.3).

$$\sum_{k=1}^N \{a_{k,t} \cdot u_{k,t}\} + \sum_{m=1}^M \{\alpha_{m,t} \cdot v_{m,t}\} \geq R'_t \quad (2.3)$$

$$\forall t = 1, 2, \dots, T$$

where  $R'_t < R_t$  is the modified demand for capacity-based ancillary service in subperiod  $t$ . It is less than  $R_t$ , since the total load has decreased due the use of DRRs, thereby leading to a lower need for capacity-based ancillary service.

## 2.4 DRR *Payback Effect* Modeling

While a DRR whose offer gets accepted provides a load cut for the subperiod, the energy that is reduced may be paid back in subsequent subperiods. All such deferred energy usage is assumed to occur within 24 subperiods of the curtailment. The deferred energy usage or load recovery is referred to as the *payback effect*. As a result, the total demand increases during one or more non-curtailment periods. The total payback may be less than, equal to, or greater than the energy associated with the load curtailment. Therefore, the DRRs may alter the demand in subperiods other than those in which they reduce demand. The effect on the demand in a system with four DRRs is illustrated in Fig. 2.5.

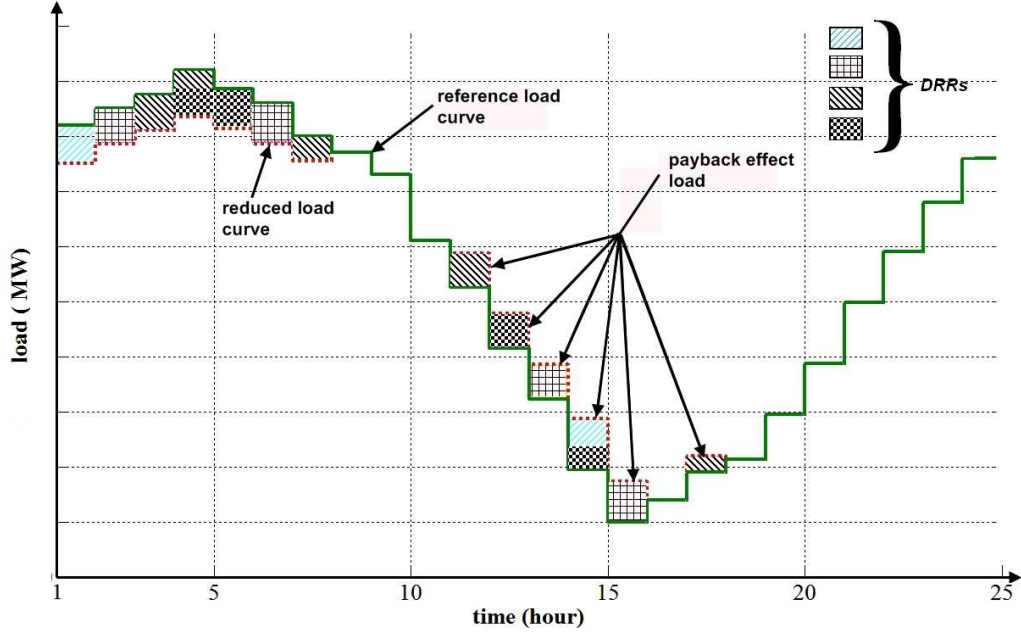


Figure 2.5: Effect of DRRs on the load curve

In the day-ahead scheduling of resources by the ISO, the payback effect must be explicitly considered in correctly representing the changed load profile resulting from the load recovery entailed by the load reduction. In turn, the change in the system load will cause changes in the market clearing prices. It is not known whether the DRR offers will be accepted and hence the amount of load recovery is also not known, since it is entirely a function of the amount of load reduction.

This thesis assumes that, with the offer of each DRR, the information on the payback effect is made available to the ISO. The DRR specific fraction of the load cut in a subperiod  $h$  is recovered in the 23 hours that follow the curtailment. A variable  $\Phi_{m,t}^h$  is introduced to denote the fraction of the load cut in a 24-hour period for the DRR  $m$  submitting a load curtailment offer in subperiod  $h$ . Thus, the variable  $\Phi_{m,t}^h$  captures completely the load reduction and repayment effect of the DRR  $m$ .

Therefore, the net demand to be supplied by the generators is no longer an exogenous parameter, but rather an endogenous variable which is unknown and whose value needs to be determined. A matrix  $\Phi^h$  to model the load curtailment is introduced in subperiod  $h$  and its associated repayment. The number of columns in the matrix  $\Phi^h$  is fixed at 24, and the number of rows equals the number of participating DRRs.

The matrix  $\Phi^h$  is constructed for every subperiod  $h$  in the scheduling horizon using all the  $M$  DRRs. The structure of the matrix is depicted in Fig. 2.6. The entry corresponding to the  $m^{th}$  row (DRR) and the  $t^{th}$  column (subperiod) of  $\Phi^h$  is denoted by  $\phi_{m,t}^h$ . The matrix contains three different categories of elements. In Fig. 2.6, the shaded areas correspond to the load curtailment periods, the cross-hatched areas correspond to the load recovery period and the periods not corresponding to either are in white. All the values in the matrix are in proportion with the load curtailed by the DRR in the subperiod  $h$ . A zero entry in  $\Phi^h$  implies that DRR  $m$  has no impact in subperiod  $t$ . The entry  $\phi_{m,t}^h$  when the DRR  $m$  provides load curtailment in subperiod  $h$  is  $-1$ , and there are positive valued entries  $\phi_{m,t}^h$  for subperiod  $t, t > h$  when payback occurs.

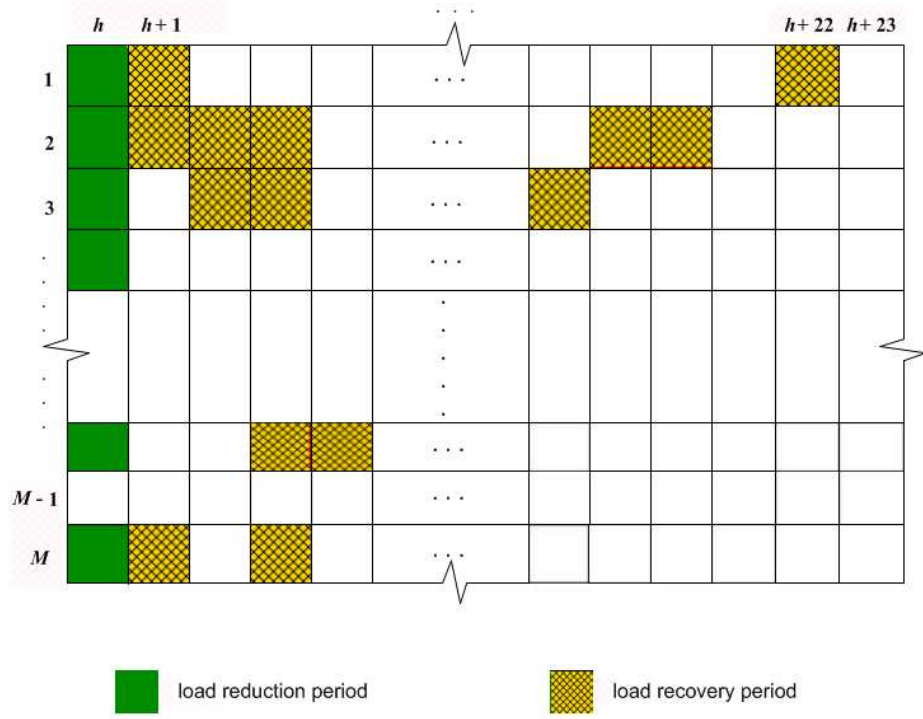


Figure 2.6: Structure of matrix  $\Phi^h$  for load curtailment in the subperiod  $h$  and corresponding repayment in subsequent periods

The use of  $\Phi^h$  allows us to model different load repayment patterns. The matrix  $\Phi^h$  is developed for each subperiod  $h$ , where one or more DRRs provide load curtailment, and in this manner it is possible to capture the load curtailment and payback effects throughout the scheduling horizon.

Therefore, the subperiod  $h$  load curtailment and repayment proportion in subperiod  $t$ ,  $t = h, h + 1, \dots, h + 23$  for DRR  $m$ ,  $\phi_{m,t}^h$  is given by:

$$\phi_{m,t}^h = \begin{cases} -1 & \text{if } t = h \\ \gamma_t \geq 0 & \text{if } h < t \leq h + 23 \\ 0 & \text{otherwise} \end{cases} \quad (2.4)$$

In order to include the payback load in the DRR model in Eq. (2.2) and Eq. (2.3), the change in the system load because of the load repayment in the subperiod  $t$  due to the load reductions ( $d_{m,h}$ ) in the previous subperiod  $h$  needs

to be taken into account. Let  $N_T$  be the set of all generating units committed during the subperiod  $t$ ,  $M_t$  be the set of all DRRs committed during subperiod  $t$  and  $M_h$  the set of DRRs whose payback load appears in subperiod  $h$ . The modified DRR model including payback effect is given by:

$$\begin{aligned} \sum_{k=1}^{N_t} \{p_{k,t}\} &= D_t^f - \sum_{m=1}^{M_t} \{d_{m,t}\} \\ &+ \sum_{h=1}^{t-1} \sum_{m=1}^{M_h} \{\phi_{m,t}^h \cdot d_{m,h}\} \\ &\forall t = 1, 2, \dots, T \end{aligned} \quad (2.5)$$

In the capacity-based ancillary services market, the generating units and DRRs whose offers are accepted provide the required amount of the capacity-based ancillary service. The DRR accepted to provide capacity-based ancillary service may or may not be called into action in real time. Therefore, it cannot be known in advance at what time load repayment occurs.

$$\begin{aligned} \sum_{k=1}^{N_t} \{a_{k,t}\} + \sum_{m=1}^{M_t} \{\alpha_{m,t}\} &\geq R'_t \\ &\forall t = 1, 2, \dots, T \end{aligned} \quad (2.6)$$

Hence in the thesis, the load repayment that might occur on providing the capacity-based ancillary service is not taken into consideration.

## 2.5 Summary

This chapter has discussed the nature of DRRs and their role in the day-ahead markets. The impacts of the DRRs on the market clearing price for a specific subperiod have been studied, so as to explore the interactions between the supply and the demand sides when DRRs participate in the markets. The concept of *payback effect* was discussed and a model to explicitly account for load recovery

and the modeling of the payback effects was developed. Key modeling elements for DRRs were also provided. These modeling elements will be used in the UC problem formulation in the next chapter. The model developed allows for a more realistic examination of the effects of inclusion of DRRs in the electricity markets. Modeling elements discussed in this chapter constitute one of the major contributions of the thesis.

# CHAPTER 3

## THE UNIT COMMITMENT PROBLEM

The unit commitment (UC) problem in a power system involves determining the start-up and shut-down schedule of units to be used to meet the forecast demand over a specified short-term period, with a typical duration of 24–168 h. The solution of the UC problem involves two interrelated decisions [17]. One is the determination of the start-up and shut-down of each generating unit, so as to specify the units that are operating during each subperiod of the specified period. This determination takes into account the requirements for system capacity including reserves, the economics and physical constraints on each unit and various system, operational and regulatory/policy considerations and constraints. The second is the *economic dispatch* decision and is a byproduct of the UC solution. The dispatch decision involves the allocation of the system demand and spinning reserves capacity among the units during each subperiod of operation. The two interrelated decisions are determined by the UC problem solution of an optimization problem whose objective is to determine the overall least-cost solution for operating the power system over the scheduling horizon.

This chapter describes an extended UC problem formulation so as to explicitly take into account the deployment of the DRRs. The nature of the extended problem formulation and the characteristics associated with its solution are analyzed. At the start of the discussion is a brief review of the electricity markets, so as to appropriately represent the UC problem in the competitive environment.

### 3.1 Review of the Electricity Market

A fundamental element of a well functioning electricity market is the ability to maintain the security and reliability of a physical power system while simultaneously providing correct economic signals to enable competitive market activities. The simultaneously co-optimized energy and capacity-based ancillary services market introduced in Chapter 1 and used throughout this chapter is one way of meeting these requirements.

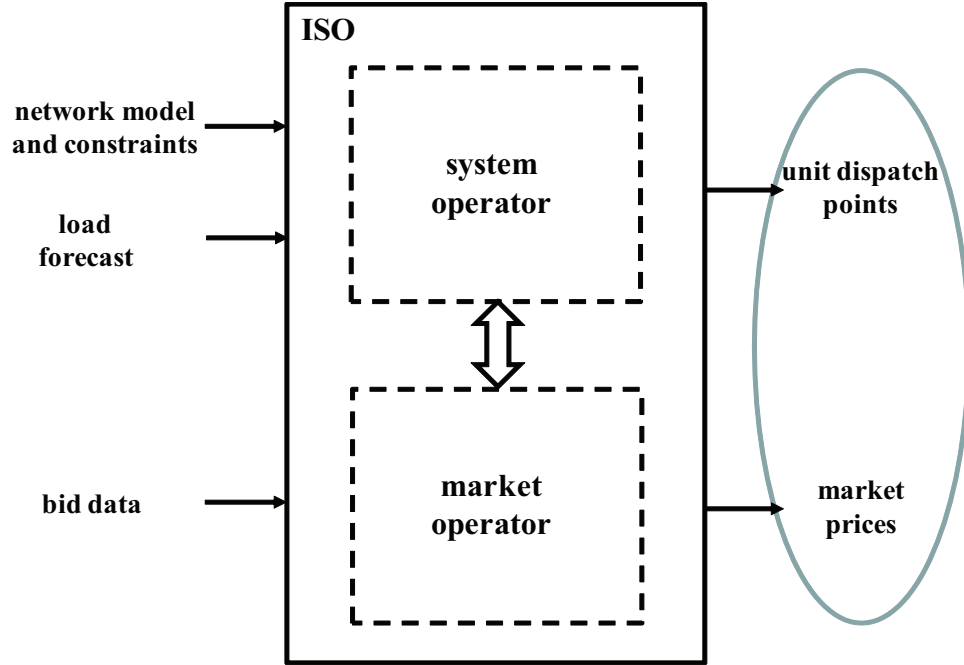


Figure 3.1: Day-ahead market framework from ISO's perspective

One hour is defined as the smallest, indecomposable unit of time. The day-ahead market can be considered a collection of 24 separate electricity markets, one for each hour of the next day. Based on historical data and meteorological predictions, the system operator draws up a demand forecast for each hour of the scheduling period. The system operator also accepts bids and offers from the sellers and buyers, respectively, for each hour of the day-ahead market. As seen in Fig. 3.1, the system operator uses the bids, offers, and demand forecast to formulate the UC problem of determining the commitment and dispatch schedule

with the offered units to meet the specified demand and reserve at least cost. The solution arrived at by the system operator provides the market clearing price and the market clearing quantity for each product at each hour of the scheduling period.

The market will simultaneously clear and price energy, regulation, spinning reserve, and supplemental reserve for the day-ahead scheduling period. Though the day-ahead market consists of 24 hours, it needs to take into account units which might have total required start-up, shut-down and running durations exceeding 24 hours. Therefore, to get a better solution, the UC problem is solved for durations greater than 24 hours and then the extra hours are discarded. In the capacity-based ancillary services market, substitution of a higher value service like regulation for a lower value service like spinning reserve is allowed. Hence, for the remainder of the thesis spinning reserves are considered the only participating capacity-based ancillary service product in the market. Further, the market participants (i.e., the sellers and buyers) may not always be connected to an actual physical resource or load asset, but only sellers and buyers possessing physical generation resources or load assets are considered in the thesis.

### 3.2 Review of the UC Problem Formulation

UC problem is an optimization problem that yields the schedule of units to minimize the operating costs of the power system, while taking into account various factors like the minimum unit down time and run time, unit maximum and minimum generation limits, etc. The problem is further complicated by the fact that it is necessary to know not only when the unit has to operate, but also the generation level at which it has to operate. As the time for which scheduling is done increases, the number of possible solutions also increases rapidly. Thus, the presence of multiple decisions to be made for the numerous units implies that the UC problem has to be carefully cast into a proper mathematical framework, so that the optimal schedule in a computationally efficient manner can be obtained. In

the following section, the mathematical framework to represent the UC problem is developed.

As previously stated, the goal of the UC problem is to minimize the total operation cost over the scheduling period  $T$ , or minimize the the sum of the production cost, the start-up cost and the shut-down cost over all subperiods  $t$  of the scheduling period. In this thesis, the assumption is that the shut-down costs are to be included in the start-up cost of each unit.

Start-up costs occur if unit  $k$  is shut down in subperiod  $t - 1$  and is operating in subperiod  $t$ . If  $u_{k,t}$  is the status of generating unit  $k$  in subperiod  $t$ ,

$$u_{k,t} = \begin{cases} 1 & \text{if the unit is in operation} \\ 0 & \text{if the unit is shut down} \end{cases}$$

Thus start-up cost is incurred if  $u_{k,t-1} = 0$  and  $u_{k,t} = 1$ . At the end of subperiod  $t$ , let the downtime of unit  $k$  be given by

$$\tau_{k,t}^- = (\tau_{k,t-1}^- + 1) \cdot (1 - u_{k,t}) \quad \forall t = 1, 2, \dots, T \quad (3.1)$$

and the corresponding uptime by

$$\tau_{k,t}^+ = (\tau_{k,t-1}^+ + 1) \cdot u_{k,t} \quad \forall t = 1, 2, \dots, T \quad (3.2)$$

Let  $b_k^s(\cdot)$  be the unit  $k$  start-up price function, with the start-up time status indicator as the argument; then the start-up cost incurred by unit  $k$  is given by

$$\text{start-up cost} = b_k^s(\tau_{k,t-1}^-) \cdot (1 - u_{k,t-1}) \cdot u_{k,t} \quad (3.3)$$

Production cost for a subperiod  $t$  consists of the cost incurred when unit  $k$  supplies amount  $p_{k,t}$  of power in the energy market or contributes  $a_{k,t}$  in the capacity-based ancillary service market. Let  $\sigma_{k,t}(\cdot)$  be the energy offer function of the generating unit  $k$  for the subperiod  $t$ , with the argument  $p_{k,t}$ , and let  $\xi_{k,t}(\cdot)$

be the generating unit  $k$  capacity-based ancillary service offer function in the subperiod  $t$ , with the argument  $a_{k,t}$ , the megawatt amount offered,  $\xi_{k,t}(\cdot) \geq 0$ . Then, the total production cost of unit  $k$  for the subperiod  $t$  is given by

$$\text{production cost} = \{\sigma_{k,t}(p_{k,t}) + \xi_{k,t}(a_{k,t})\} \cdot u_{k,t} \quad (3.4)$$

The system operator needs to minimize the operating costs over all the  $N$  individual units for the entire scheduling period  $T$ , so that the objective function of the UC problem is to determine

$$\min_{\mathbf{u}, \mathbf{p}, \mathbf{a}} \left[ \sum_{k=1}^N \sum_{t=1}^T b_k^s(\tau_{k,t-1}^-) \cdot (1 - u_{k,t-1}) \cdot u_{k,t} + \sum_{k=1}^N \sum_{t=1}^T \{\sigma_{k,t}(p_{k,t}) + \xi_{k,t}(a_{k,t})\} \cdot u_{k,t} \right] \quad (3.5)$$

When a generating unit is on, its generation and ancillary services are constrained by its operational characteristics. For unit  $k$ , let  $p_k^{\min}$  be its minimum capacity,  $p_k^{\max}$  be its maximum capacity,  $a_k^{\max}$  be the maximum capacity-based ancillary service capability, and  $\tau_k^d$ ,  $\tau_k^u$  be the minimum down- and uptimes, respectively. In the thesis, the ramping rates of the units are not included in the definition of the up- and downtimes. The following operating constraints have to be met:

$$\left. \begin{aligned} p_{k,t} &\geq 0 \\ p_k^{\min} &\leq p_{k,t} \leq p_k^{\max} \\ 0 &\leq a_{k,t} \leq a_k^{\max} \\ p_k^{\min} &\leq p_{k,t} + a_{k,t} \leq p_k^{\max} \end{aligned} \right\} \begin{aligned} &\forall t = 1, 2, \dots, T \\ &\forall k = 1, 2, \dots, N \end{aligned} \quad (3.6)$$

Further, once started, the duration for which the unit is operating has to be more than the minimum uptime, and once shut down, the unit cannot be restarted until the end of the minimum downtime duration:

$$\tau_{k,t} \geq \tau_k^d, \tau_{k,t} \geq \tau_k^u \quad \forall t = 1, 2, \dots, T, k = 1, 2, \dots, N \quad (3.7)$$

For all the subperiods  $t$ , all the units have to supply the demand for energy ( $D_t^f$ ) and capacity-based ancillary service ( $R_t$ ) in the system, as given by:

$$\sum_{k=1}^N \{p_{k,t} \cdot u_{k,t}\} = D_t^f \quad \forall t = 1, 2, \dots, T \quad (3.8)$$

$$\sum_{k=1}^N \{a_{k,t} \cdot u_{k,t}\} \geq R_t \quad \forall t = 1, 2, \dots, T \quad (3.9)$$

Thus collecting all the previous equations,

$$\min_{\mathbf{u}, \mathbf{p}, \mathbf{a}} \left[ \begin{aligned} & \sum_{k=1}^N \sum_{t=1}^T b_k^s(\tau_{k,t-1}^-) \cdot (1 - u_{k,t-1}) \cdot u_{k,t} \\ & + \sum_{k=1}^N \sum_{t=1}^T \{\sigma_{k,t}(p_{k,t}) + \xi_{k,t}(a_{k,t})\} \cdot u_{k,t} \end{aligned} \right] \quad (3.10)$$

subject to

$$\sum_{k=1}^N \{p_{k,t} \cdot u_{k,t}\} = D_t^f \quad \forall t = 1, 2, \dots, T \quad (3.11)$$

$$\sum_{k=1}^N \{a_{k,t} \cdot u_{k,t}\} \geq R_t \quad \forall t = 1, 2, \dots, T \quad (3.12)$$

$$p_{k,t} \geq 0 \quad \forall t = 1, 2, \dots, T \quad (3.13)$$

$$\left. \begin{aligned} p_k^{\min} &\leq p_{k,t} \leq p_k^{\max} \\ 0 &\leq a_{k,t} \leq a_k^{\max} \\ p_k^{\min} &\leq p_{k,t} + a_{k,t} \leq p_k^{\max} \end{aligned} \right\} \begin{aligned} &\forall t = 1, 2, \dots, T \\ &\forall k = 1, 2, \dots, N \end{aligned} \quad (3.14)$$

$$\tau_{k,t} \geq \tau_k^d, \tau_{k,t} \geq \tau_k^u \quad \forall t = 1, 2, \dots, T, k = 1, 2, \dots, N \quad (3.15)$$

The formulation in Eqs. (3.10)-(3.15) is referred to as the UC problem. The capacity limits of the individual units are handled through Eq. (3.14). Equation (3.15) handles the minimum up/downtime constraint. Given the status indicator for the total unit uptime until the previous hour ( $\tau_{k,t-1}^+$ ), it is possible to calculate

Eq. (3.15) by

$$\tau_{k,t} = (\tau_{k,t-1}^+ + 1) \cdot u_{k,t} \quad (3.16)$$

and check for

$$\tau_{k,t} \geq \tau_{k,t}^u \quad (3.17)$$

Similarly, the minimum downtime constraint is calculated as follows. Given the status indicator for the total unit downtime until the previous hour ( $\tau_{k,t-1}^-$ ), calculate Eq. (3.15) by

$$\tau_{k,t} = (\tau_{k,t-1}^- + 1) \cdot (1 - u_{k,t}) \quad (3.18)$$

and check for

$$\tau_{k,t} \geq \tau_{k,t}^d \quad (3.19)$$

Thus, the equations presented in this section represent the mathematical formulation of the UC problem.

### 3.3 Extended Problem Formulation

The inclusion of DRRs to the resource mix means that there is an option other than the generators to meet the demand. But as explained in Chapter 2, the use of DRRs may result in payback load, making the determination of the optimum schedule even more difficult. The UC problem formulation of Eqs. (3.10)-(3.15) is extended to include the payback effects of the DRRs [29]. The DRR model presented in Eqs. (2.3) and (2.5) is used to handle the extended problem in the familiar structure of the UC problem [30].

In addition to the notation defined in Chapter 2, let us define a few more

notations. Let  $M$  be the number of DRRs in the system and  $m \in \{1, 2, \dots, M\}$  be the index for DRRs. Further, let  $d_{m,t}$  be the load curtailment contribution of DRR  $m$  in subperiod  $t$  and  $\alpha_{m,t}$  be the capacity contribution of DRR  $m$  for capacity-based ancillary service in subperiod  $t$ .

The problem facing the system operator is to find the optimal system schedule considering all the available generation units and DRRs, in order to minimize the total cost of providing both energy and capacity-based ancillary service for the entire scheduling period.

In order to obtain the extended UC problem formulation from the basic UC formulation, DRRs need to be included in the objective function and in the constraints. The cost incurred by the system operator when DRR  $m$  reduces its demand by  $d_{m,t}$  in subperiod  $t$  is given by  $[\vartheta_{m,t}(d_{m,t}) \cdot v_{m,t}]$ , and when it provides  $\alpha_{m,t}$  of capacity-based ancillary service, the cost incurred by the system operator is  $[\chi_{m,t}(\alpha_{m,t}) \cdot v_{m,t}]$ . The power balance constraint and the capacity-based ancillary service constraint in Eqs. (3.11) and (3.12), respectively, are replaced by Eqs. (2.3) and (2.5), so as to include DRRs and their payback effect.

$$\min_{\mathbf{u}, \mathbf{v}, \mathbf{p}, \mathbf{d}, \mathbf{a}, \alpha} \left\{ \begin{aligned} & \sum_{k=1}^N \sum_{t=1}^T b_k^s(\tau_{k,t-1}^-) \cdot (1 - u_{k,t-1}) \cdot u_{k,t} \\ & + \sum_{k=1}^N \sum_{t=1}^T \{ \sigma_{k,t}(p_{k,t}) + \xi_{k,t}(a_{k,t}) \} \cdot u_{k,t} \\ & + \sum_{m=1}^M \sum_{t=1}^T \{ \vartheta_{m,t}(d_{m,t}) \cdot v_{m,t} \} \\ & + \sum_{m=1}^M \sum_{t=1}^T \{ \chi_{m,t}(\alpha_{m,t}) \cdot v_{m,t} \} \end{aligned} \right\} \quad (3.20)$$

subject to

$$\begin{aligned} \sum_{k=1}^N \{ p_{k,t} \cdot u_{k,t} \} &= D_t^f - \sum_{m=1}^M \{ d_{m,t} \cdot v_{m,t} \} \\ &+ \sum_{m=1}^M \sum_{h=1}^{t-1} \{ \phi_{m,t}^h \cdot d_{m,h} \cdot v_{m,h} \} \\ &\forall t = 1, 2, \dots, T \end{aligned} \quad (3.21)$$

$$\sum_{k=1}^N \{a_{k,t} \cdot u_{k,t}\} + \sum_{m=1}^M \{\alpha_{m,t} \cdot v_{m,t}\} \geq R'_t \quad (3.22)$$

$$\forall t = 1, 2, \dots, T$$

$$\left. \begin{aligned} p_{k,t}, d_{m,t} &\geq 0 \\ p_k^{\min} &\leq p_{k,t} \leq p_k^{\max} \\ 0 &\leq a_{k,t} \leq a_k^{\max} \\ p_k^{\min} &\leq p_{k,t} + a_{k,t} \leq p_k^{\max} \end{aligned} \right\} \begin{aligned} &\forall t = 1, 2, \dots, T \\ &\forall k = 1, 2, \dots, N \end{aligned} \quad (3.23)$$

$$\left. \begin{aligned} 0 &\leq \alpha_{m,t} \leq \alpha_m^{\max} \\ d_m^{\min} &\leq d_{m,t} + \alpha_{m,t} \leq d_m^{\max} \end{aligned} \right\} \begin{aligned} &\forall t = 1, 2, \dots, T \\ &\forall m = 1, 2, \dots, M \end{aligned} \quad (3.24)$$

$$\tau_{k,t} \geq \tau_k^d, \tau_{k,t} \geq \tau_k^u \quad \forall t = 1, 2, \dots, T, k = 1, 2, \dots, N \quad (3.25)$$

The problem listed in Eqs. (3.20)-(3.25) is referred to as the generalized UC (GUC) problem and it takes into account the contribution of DRRs and the effect of payback load on the scheduling of the units.

### 3.4 Mixed-Integer Linear Program Approach

The GUC problem formulated in the previous section has a nonlinear objective function and nonlinear and inter-temporal constraints. Further, the participation of DRRs and the fact that the occurrence of payback load cannot be predicted complicate matters. Therefore, there is a need to restate the GUC problem in such a manner that the solution process is simplified. For this purpose, this section describes the details of the conversion of the nonlinear functions into a linear form, so that they are suitable for solution by a MILP solver.

Many advanced commercial packages are available to solve the MILP problem. In this thesis, the GUC problem described in Eqs. (3.20)-(3.25) is solved using the MILP solution technique, making use of the optimization software CPLEX. CPLEX is a sophisticated and computationally efficient tool that can handle even

large-scale MILP problems. Tomlab, a general purpose development environment in MATLAB, was used to code the problem into a format solvable by CPLEX.

Tomlab, the product of the Tomlab optimization company, is a general purpose development environment in MATLAB for solving optimization problems. The Tomlab/CPLEX package can be used to find the decision variable  $\underline{\mathbf{x}} = [x_1, x_2, \dots, x_i]$  using CPLEX through the Tomlab environment, given that the problem can be arranged in the following form:

$$\begin{aligned} \min_{\underline{\mathbf{x}}} \quad & f(\underline{\mathbf{x}}) = \frac{1}{2} \underline{\mathbf{x}} \underline{\mathbf{F}} \underline{\mathbf{x}}' + \underline{\mathbf{c}}' \underline{\mathbf{x}} \\ \text{subject to} \quad & \\ & \underline{\mathbf{x}}_L \leq \underline{\mathbf{x}} \leq \underline{\mathbf{x}}_U \\ & \underline{\mathbf{b}}_L \leq \underline{\mathbf{A}} \underline{\mathbf{x}} \leq \underline{\mathbf{b}}_U \\ & \underline{\mathbf{x}} \text{ is an integer} \end{aligned} \tag{3.26}$$

where  $\mathbf{c}, \underline{\mathbf{x}}, \underline{\mathbf{x}}_L, \underline{\mathbf{x}}_U \in \mathcal{R}^n$  and  $\underline{\mathbf{F}} \in \mathcal{R}^{n \times n}$ ,  $\underline{\mathbf{A}} \in \mathcal{R}^{m \times n}$  and  $\underline{\mathbf{b}}_L, \underline{\mathbf{b}}_U \in \mathcal{R}^m$ . The *cplexTL* solver present in this package is capable of solving LP, MILP, and mixed-integer quadratic programming (MIQP) problems and is used in this thesis to solve the GUC problem. The *cplexTL* solver solves problems in the form of Eq. (3.26) [31].

Substituting  $\underline{\mathbf{F}} = \mathbf{0}$  in the objective function of Eq. (3.26) gives us the general form of a MILP problem:

$$\begin{aligned} \min_{\underline{\mathbf{x}}} \quad & f(\underline{\mathbf{x}}) = \underline{\mathbf{c}}' \underline{\mathbf{x}} \\ \text{subject to} \quad & \\ & \underline{\mathbf{x}}_L \leq \underline{\mathbf{x}} \leq \underline{\mathbf{x}}_U \\ & \underline{\mathbf{b}}_L \leq \underline{\mathbf{A}} \underline{\mathbf{x}} \leq \underline{\mathbf{b}}_U \\ & \underline{\mathbf{x}} \text{ is an integer} \end{aligned} \tag{3.27}$$

The structure of the GUC problem can be manipulated to fit Eq. (3.27). The objective function would have to be expressed in the matrix multiplication form,

in which case the vector  $\underline{\mathbf{c}}$  would contain the start-up, energy and ancillary service offers of the participating resources. All the GUC constraints would have to be expressed in the form  $\underline{\mathbf{b}}_{\mathbf{L}} \leq \underline{\mathbf{A}} \mathbf{x} \leq \underline{\mathbf{b}}_{\mathbf{U}}$ , where  $\underline{\mathbf{b}}_{\mathbf{L}}$  and  $\underline{\mathbf{b}}_{\mathbf{U}}$  are the lower and upper limits, respectively. Note that in Eq. (3.27) the decision variables can only be summed up, not multiplied. The prohibition on multiplication of decision variables also makes it necessary to separately calculate the start-up flag for unit  $k$  at time  $t$   $s_{k,t}$  using the unit commitment variables for the present and the prior hour. The start-up flag is defined to take on values 1 or 0 only, and it is calculated using:

$$\begin{aligned} s_{k,t} &= u_{k,t} - u_{k,t-1} \\ s_{m,t} &= v_{m,t} - v_{m,t-1} \end{aligned} \tag{3.28}$$

Next, the following  $T$  and  $N$  dimensional vectors are defined:

$$\begin{aligned} \mathbf{D} &= [D_1, D_2, \dots, D_T]', & \mathbf{R} &= [R_1, R_2, \dots, R_T]', \\ \mathbf{u}_{\mathbf{k}} &= [u_{k,1}, u_{k,2}, \dots, u_{k,T}]', & \mathbf{p}_{\mathbf{k}} &= [p_{k,1}, p_{k,2}, \dots, p_{k,T}]', \\ \mathbf{a}_{\mathbf{k}} &= [a_{k,1}, a_{k,2}, \dots, a_{k,T}]', & \mathbf{v}_{\mathbf{m}} &= [v_{m,1}, v_{m,2}, \dots, v_{m,T}]', \\ \boldsymbol{\alpha}_m &= [\alpha_{m,1}, \alpha_{m,2}, \dots, \alpha_{m,T}]', & \mathbf{d}_{\mathbf{m}} &= [d_{m,1}, d_{m,2}, \dots, d_{m,T}]', \\ \boldsymbol{\xi} &= [\xi_1, \xi_2, \dots, \xi_N]', & \boldsymbol{\vartheta} &= [\vartheta_1, \vartheta_2, \dots, \vartheta_N]', \\ \boldsymbol{\chi} &= [\chi_1, \chi_2, \dots, \chi_N]', & \mathbf{b}^s &= [b_1^s, b_2^s, \dots, b_N^s]', \\ \boldsymbol{\sigma} &= [\sigma_1, \sigma_2, \dots, \sigma_N]', \end{aligned}$$

and the  $NT$  and  $MT$ -dimensional vectors:

$$\begin{aligned} \mathbf{u} &= [u_1^T, u_2^T, \dots, u_N^T]', & \mathbf{p} &= [p_1^T, p_2^T, \dots, p_N^T]', \\ \mathbf{v} &= [v_1^T, v_2^T, \dots, v_M^T]', & \mathbf{a} &= [a_1^T, a_2^T, \dots, a_N^T]', \\ \mathbf{s} &= [s_1^T, s_2^T, \dots, s_N^T]', & \mathbf{d} &= [d_1^T, d_2^T, \dots, d_M^T]', \\ \boldsymbol{\alpha} &= [\alpha_1^T, \alpha_2^T, \dots, \alpha_M^T]' \end{aligned}$$

Using the previous definitions, Eq. (3.20) is rewritten to obtain the general form of the objective function of the GUC problem:

$$\min_{\mathbf{u}, \mathbf{v}, \mathbf{p}, \mathbf{d}, \mathbf{a}, \alpha} \begin{bmatrix} \mathbf{b}^s & \sigma & \xi & \vartheta & \chi \end{bmatrix} \begin{bmatrix} \mathbf{s} \\ \mathbf{u} \\ \mathbf{v} \\ \mathbf{p} \\ \mathbf{d} \\ \mathbf{a} \\ \alpha \end{bmatrix} \quad (3.29)$$

For a generating unit  $k$  for period  $t$ , Eq. (3.29) expands into

$$\min_{\mathbf{u}, \mathbf{p}, \mathbf{a}} \left[ b_1^s * s_{k,t} + 1 * u_{k,t} + \sigma_{k,t} * p_k^t + \xi_{k,t} * a_{k,t} \right] \quad (3.30)$$

For a DRR  $m$  for period  $t$ , Eq. (3.29) expands into

$$\min_{\mathbf{v}, \mathbf{d}, \alpha} \left[ b_1^s * s_{m,t} + 1 * v_{m,t} + \vartheta_{m,t} * d_m^t + \chi_{m,t} * \alpha_{m,t} \right] \quad (3.31)$$

The solution to the GUC problem can be obtained by minimizing Eqs. (3.30)-(3.31) over the entire time period for all the units and DRRs subject to all the unit and time constraints respectively.

In Eqs. (3.20)-(3.23), most of the constraint functions can be easily transformed to correspond to the structure in Eq. (3.27); exceptions are the total demand constraint and the capacity-based ancillary service constraint. Both these equations contain two decision variables—the unit commitment status and the generation/curtailment level of the units—multiplied by each other.

A general representation is as follows:

$$f(h, \delta) = h \delta$$

such that

$$\delta \in \{0, 1\} \quad (3.32)$$

$$h_L \leq h \leq h_U$$

where  $h$ ,  $\delta$  are the decision variables,  $\delta$  is a  $\{0, 1\}$  integer variable, and  $h$  is a continuous variable.

When a function of two variables is linear with respect to each variable, it is known as a bilinear function. The bilinear function in Eq. (3.32) needs to be linearized to make it suitable for solving with MILP. A bilinear function can be transformed into a linear function by adding several extra constraints as indicated in the following steps:

- Replace  $h\delta$  by introducing a continuous variable  $y$ , obtaining the logical conditions

$$\begin{aligned} \text{Let } y &= h\delta \\ \text{so that} & \\ \delta = 0 &\rightarrow y = 0 \\ \delta = 1 &\rightarrow y = h \end{aligned} \tag{3.33}$$

- This gives the following extra constraints:

$$\begin{aligned} y - L\delta &\leq 0 \\ -h + y &\leq 0 \\ h - y + M\delta &\leq L \end{aligned} \tag{3.34}$$

where  $L$  is an upper bound for  $h$  (and hence also for  $y$ ) [32].

For illustration purposes, the UC problem with only the generation resources is considered. As mentioned in Eq. (3.33),  $y_{k,t}$  is introduced to replace each  $(p_{k,t} \cdot u_{k,t})$  term, leading to a new set of constraints. Equation (3.35) gives the set of equations needed to be substituted in Eq. (3.11).

$$\begin{aligned}
\sum_{k=1}^N y_{k,t} &= D_t^f \\
y_{k,t} - p_k^{max} \cdot u_{k,t} &\leq 0 \\
-p_{k,t} + y_{k,t} &\leq 0 \\
p_{k,t} - y_{k,t} + p_k^{max} \cdot u_{k,t} &\leq p_k^{max}
\end{aligned} \tag{3.35}$$

The capacity-based ancillary service constraint represented in Eq. (3.12) is also subject to a linear transformation. The term  $z_{k,t}$  is introduced to replace each  $(a_{k,t} \cdot u_{k,t})$  term in Eq. (3.12). This leads to a new set of constraints:

$$\begin{aligned}
\sum_{k=1}^N z_{k,t} &= R_t^f \\
z_{k,t} - a_k^{max} \cdot u_{k,t} &\leq 0 \\
-a_{k,t} + z_{k,t} &\leq 0 \\
a_{k,t} - z_{k,t} + a_k^{max} \cdot u_{k,t} &\leq p_k^{max}
\end{aligned} \tag{3.36}$$

These new constraints are inserted in the left-hand sides of Eqs. (3.21) and (3.22), and then, along with the right-hand sides, are converted into the required format. The bilinear functions involving the DRR terms are similarly converted into linear functions. Once there are only linear functions present in the GUC problem, it is possible to utilize the MILP solver to find the solution to the problem using CPLEX.

### 3.5 Summary

In this chapter, the UC formulation was presented and then modified to allow for the inclusion of DRRs into the problem formulation. The problem formulation was discussed, and the objective function and the associated constraints were explored. In addition, the solution methodology was also discussed. The material presented in this chapter provides a background to interpret the results presented

in the next chapter.

# CHAPTER 4

## NUMERICAL RESULTS AND ANALYSIS

The discussion in the previous chapters provides a conceptual understanding of how DRRs can be included in the process of scheduling the units for the day-ahead market and also the important role of DRRs in setting aside the usage of more expensive units. The focus of this chapter is on simulating the impact of DRRs and their associated payback load on the scheduling of generating units, market clearing prices and the total scheduling cost. An extensive set of simulations is carried out to study the impact of the usage of DRRs on the system operation.

### 4.1 Test System

The test system used in the simulations is a 22 generating unit system owned and operated by the New Brunswick Power Corporation (NB Power) [33]. The data for the 22 units is provided in Appendix B. Units 1 and 9 are coal units, 2 to 6 are oil units, 7 and 8 are orimulsion units, 12 to 16 and 10 are combustion units, 11 is a nuclear unit and 17 to 22 are hydro units. The test case is supplemented by the addition of DRRs.

The hourly load data is a scaled down version of the MISO load curve for the week starting July 31, 2006, and ending August 5, 2006. In the simulation study conducted, ramping constraints are ignored, startup costs are time independent, and transmission constraints are ignored. Attention is focussed on the energy market in order to get a better understanding of the consequences of DRR usage.

## 4.2 Simulation Results

### 4.2.1 Reference case

First, consider the UC solution in the absence of DRRs. The load curve and the market clearing prices at each hour are shown in Fig. 4.1. As expected, the maximum market clearing price of 126.97 \$/MWh is reached for the hour with the maximum load cleared (3795 MW) during hour 16.

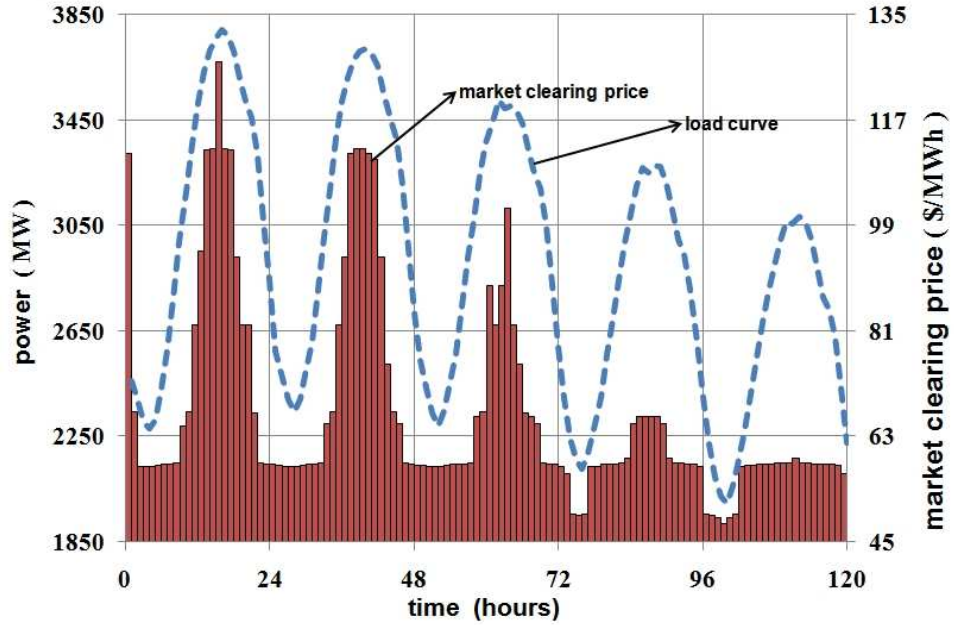


Figure 4.1: Reference case - load curve and market clearing price

### 4.2.2 Reference case with single DRR

A single DRR is added to the resource mix of the reference case with the limitation that the DRR can participate only for an hour in a 24 h period of time. The addition of the DRR has an immediate impact on the market clearing prices. As shown in Fig. 4.2, the market clearing price during hour 16 drops to 112.02 \$/MWh from 126.97 \$/MWh in the reference case. The price also drops in the peak periods corresponding to the next four 24 h periods, due to the DRR being committed.

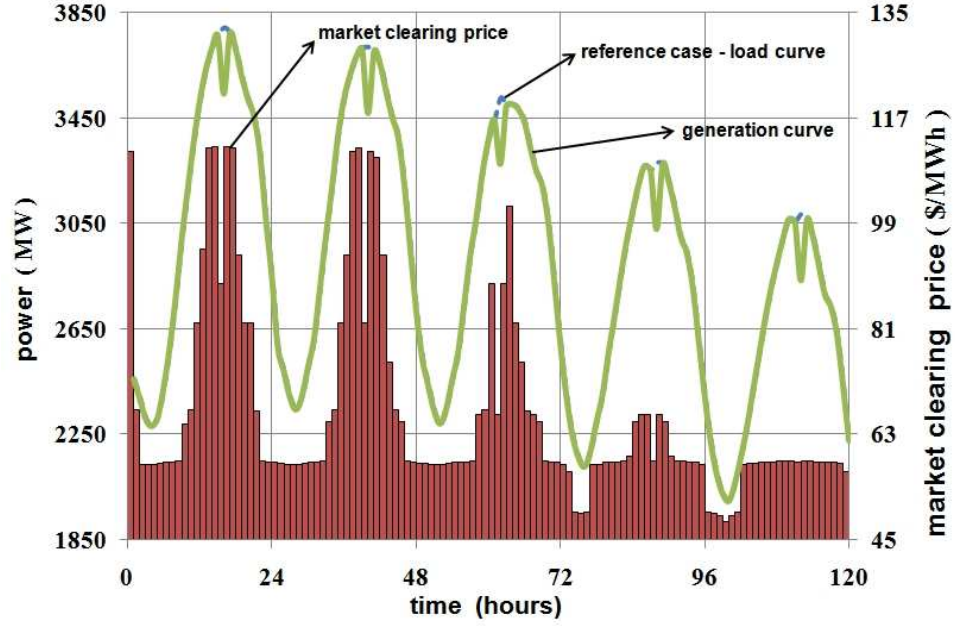


Figure 4.2: Single DRR - load curve and market clearing price

The impact of increased DRR curtailment capacity on the system is also of interest. The sensitivity of the system to increased DRR curtailment capacity is tested by measuring the change in the total cost for supplying the forecast load.

The UC problem tries to minimize the scheduling cost, which is defined as the total cost including start-up, no-load, and the variable operating costs over the entire scheduling period. Therefore, the variation of the scheduling cost with the capacity of the DRR provides a good measure of the efficacy of DRR usage.

Figure 4.3 shows that the scheduling cost decreases as the amount of load reduced by the DRR increases. The curtailment by DRRs substituting the generation by more expensive generating units is the cause of the decrease in the scheduling cost.

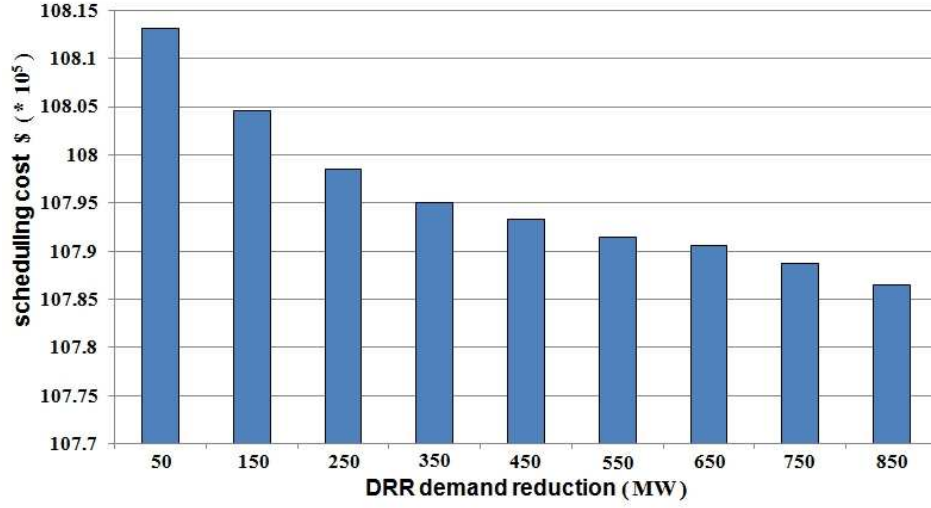


Figure 4.3: Scheduling cost vs. DRR curtailment capacity

#### 4.2.3 Reference case with single DRR and payback load

Next, consider the payback load associated with the single DRR used. For this case, the DRR is assumed to increase its demand by an amount equivalent to its load curtailment (i.e., 100 % payback load), 12 h after the curtailment occurs. The impact of the payback load on the market clearing prices is observed in Fig. 4.4.

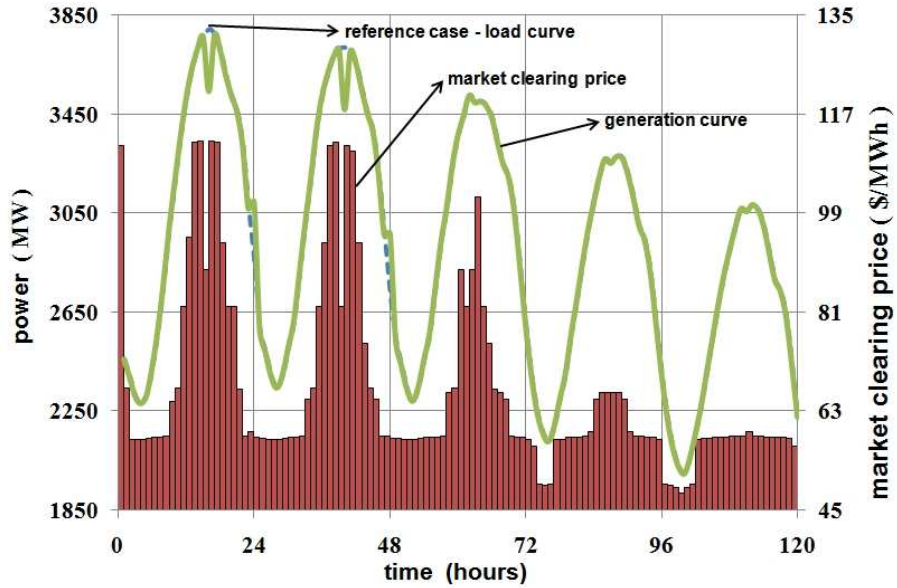


Figure 4.4: Single DRR with payback effect – load curve and market clearing price

The introduction of the payback load has an immediate effect on the market clearing prices. Of the 5 days for which scheduling takes place, the DRR does not get committed on days 3 to 5, whereas it gets committed on all the five days in the absence of payback load. It is worth noticing that the DRR remains uncommitted, even though its curtailment offer is lower than that of competing generators. The fact that DRRs are not used is because, when the additional cost of the payback load and its influence on the market clearing price at the hour in which payback occurs are taken into consideration, the DRR is no longer the most economically viable alternative.

Another fact that can be highlighted is the influence of the payback load on the DRR offer. Consider a fixed level of load curtailed and a fixed hour at which the payback load appears. A sensitivity study can be conducted by increasing the payback load to ascertain its influence on the DRR offers.

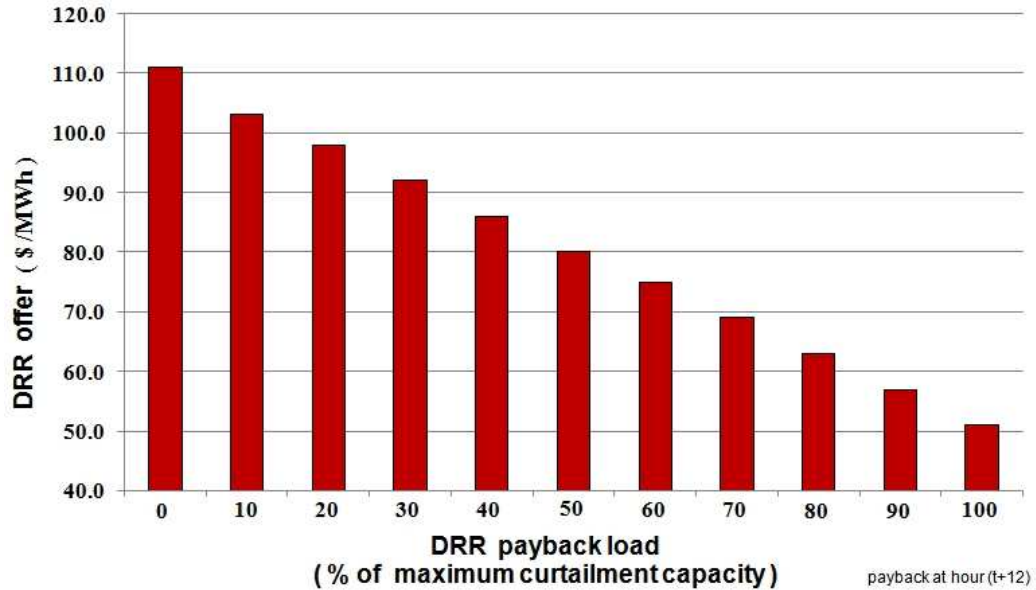


Figure 4.5: Cleared DRR offer vs. payback load

From Fig. 4.5, it is apparent that the highest DRR offer that gets accepted decreases as the payback load increases. On considering the payback load, the hidden costs attached with the usage of DRRs are more clearly represented. This gives a more complete picture of the true cost related to using DRRs, namely, the

increase in the market clearing price at a later hour because the total demand increased at that hour, due to the payback load. As the payback load increases, the DRR risks pricing itself out of the market if it prices its load curtailment too high.

#### 4.2.4 Multiple DRRs

The effect of increased number of DRRs competing in the market on the market clearing prices is also investigated. For this purpose five more DRRs are introduced, so that the test system now consists of 22 generating units and 6 DRRs. It is assumed that each DRR participates for only an hour in each 24 h period. Further, out of the participating DRRs, there are two that are competing to curtail load during the same hour. This is to highlight the fact that the DRRs may compete not only with the generators, but also with each other.

Consider the scenario in which all the DRRs, including the two competing in the same hour, get scheduled in the day-ahead market. This results in the DRRs diminishing the market clearing price during times of high demand. This case is illustrated in Fig. 4.6.

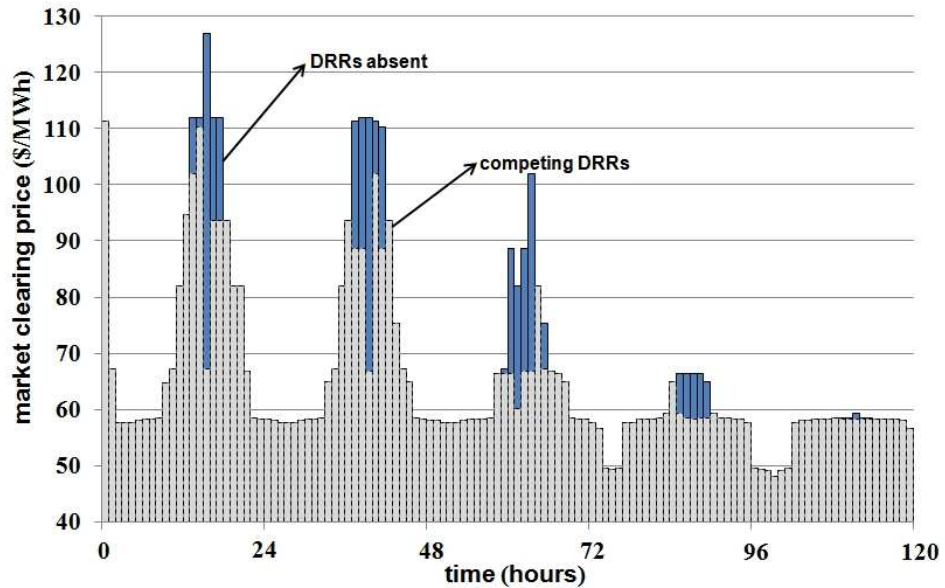


Figure 4.6: Competing DRRs where both get cleared

The use of two DRRs in hour 16 leads to a drop in the market clearing price from 126.97 \$/MWh to 67.16 \$/MWh.

Next, examine the case in which only one of the two DRRs competing in the same hour gets cleared. The other DRR prices itself out of the market. As seen in Fig. 4.7, the prices during the hours in which the DRRs compete are still lower than the reference case, but higher than those charted in Fig. 4.6.

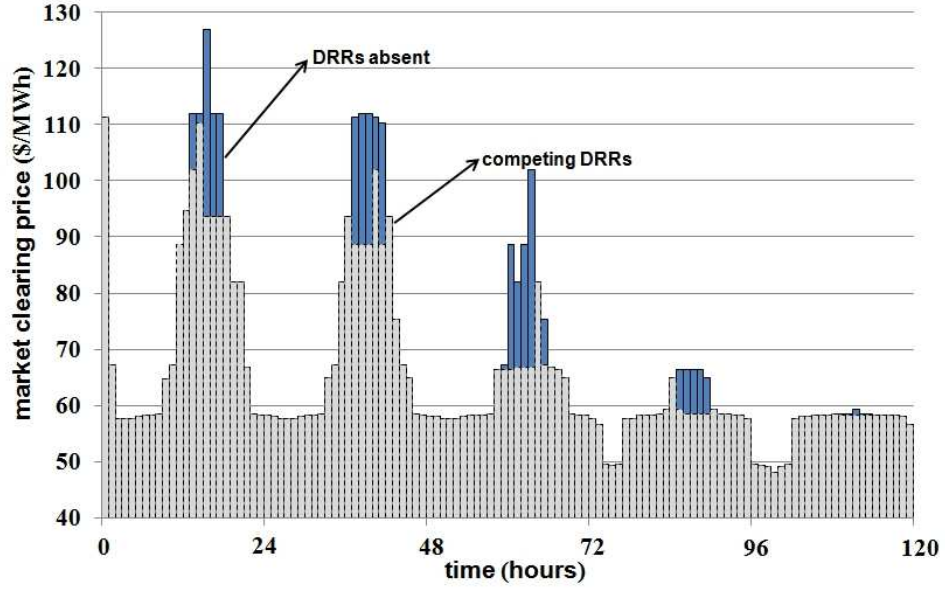


Figure 4.7: Competing DRRs where only one gets cleared

Further let us evaluate the behavior of the market clearing price, with varying system peak load and how it is influenced by the usage of DRRs. The price duration curve (PDC) is constructed by ignoring time and rearranging the loads in decreasing order from the highest to the lowest.

Figure 4.8 depicts the PDC for varying loads in the absence of DRRs. The peak loads are represented as a percentage of the total generation capacity in the system. The maximum market clearing price varies from 67.16 \$/MWh to 210 \$/MWh as the peak load increases. The system operator is forced to schedule more expensive generators as the total demand to be met increases; this fact explains the different levels of the price curves.

Next, the market clearing price in the presence of DRRs is examined at differ-

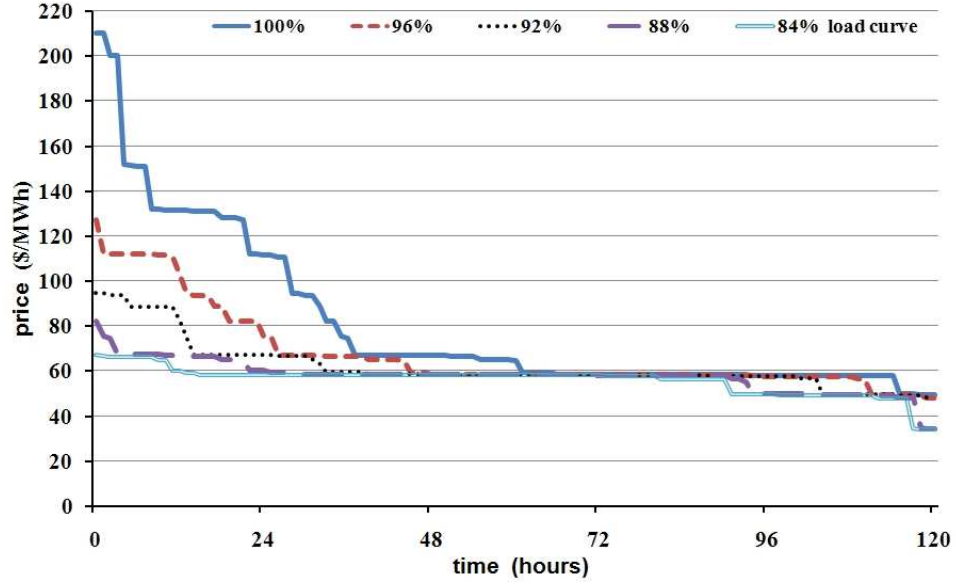


Figure 4.8: Price duration curve for different load levels, in the absence of DRRs

ent load levels.

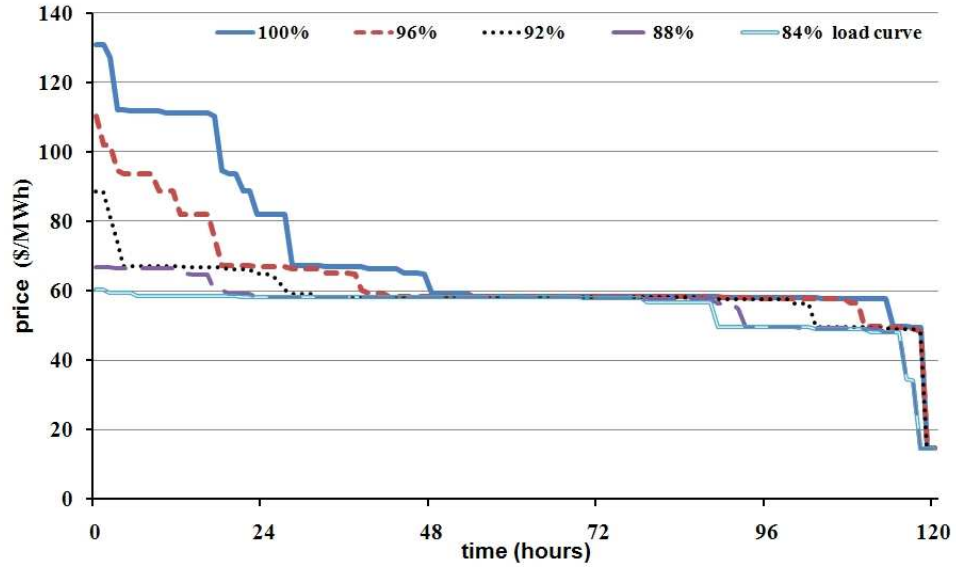


Figure 4.9: Price duration curve for different load levels, in the presence of DRRs

Figure 4.9 illustrates the PDC in the presence of DRRs. The use of DRRs decreases the highest market clearing prices at all the load levels. Further, the total number of hours for which the market clearing price is above 120 \$/MWh decreases from 22 h in the absence of DRRs to 3 h in their presence for the highest

load curve. The other peak load levels also witness a reduction in market clearing prices, but not to this extent. Thus, the highest impact of the use of DRRs is at times of high system demand.

The impact of DRRs on generators is examined by plotting the unit commitment status variable for units 13–16. These units sell their output on the market in the price range from 93.59 \$/MWh to 151.56 \$/MWh. Figure 4.10 plots the unit commitment status variable in the absence of DRRs.

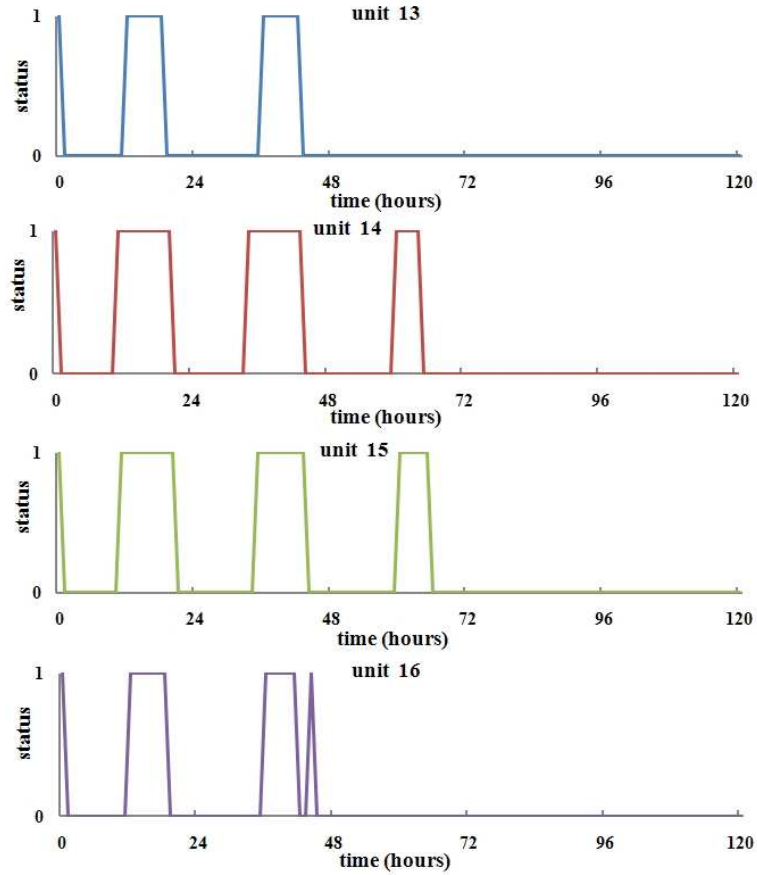


Figure 4.10: UC status variable in the absence DRRs

Figure 4.11 plots the status variable in the presence of DRRs. Observe that the usage of the generators has decreased in the presence of DRRs, since DRRs provide a less expensive option to the system operator compared to the generating units.

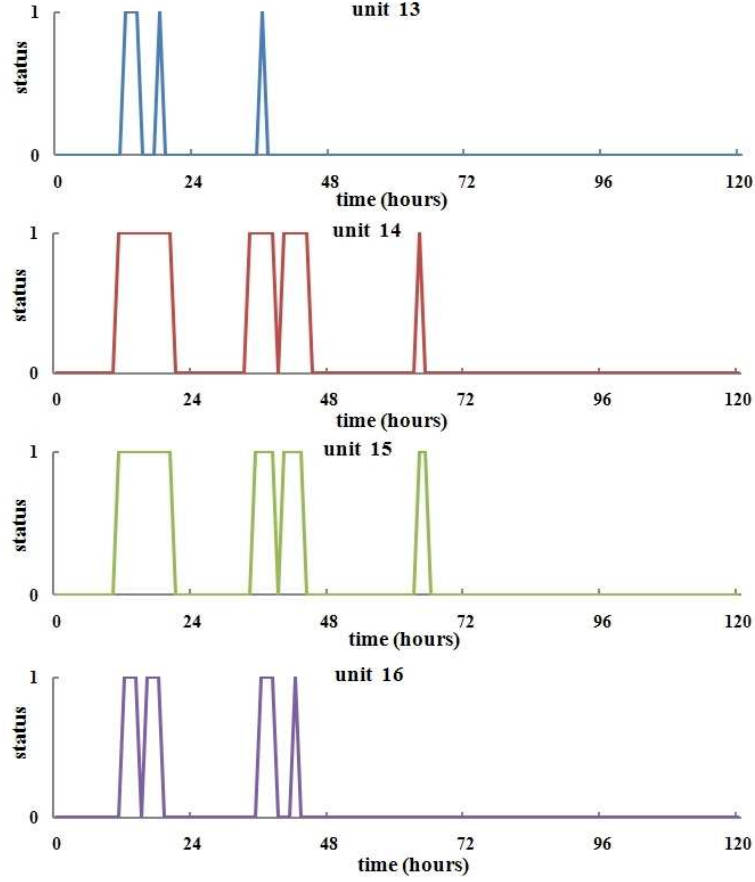


Figure 4.11: UC status variable in the presence DRRs

### 4.3 Concluding Remarks

The results of the simulation studies on the test system were presented in this chapter. Using different scenarios, the role of the DRRs in the day-ahead energy market was explored. The use of DRRs benefits the system by bringing about a decrease in the total scheduling cost. The relation between the DRR and its associated payback load and its influence on the DRR offer was also brought into focus. It was found that the magnitude of payback load and the period of its occurrence can hinder the use of DRRs by the system operator.

Multiple DRRs were introduced to address competition between DRRs. The nature of the impact of multiple DRRs on the market clearing price was evaluated. The use of multiple DRRs is a very effective strategy to combat high prices in the

electricity market. The influence of varying load levels on the use of DRRs and its impact on the market clearing prices were also examined.

# CHAPTER 5

## CONCLUSION

In this thesis, the UC problem formulation is extended to better incorporate DRRs. The system operator accepts bids from generators to sell and offers from DRRs to curtail, then determines a minimum cost schedule of the available units to meet the energy and capacity-based ancillary services demand.

The key feature of the work in this thesis is the development of a model to explicitly include DRRs, their demand curtailment and the associated payback effect. The model is then used to extend the UC formulation. The advantage of the model developed is that it has the flexibility to allow the effective capture of different kinds of load curtailment and payback scenarios. The extended UC problem is solved using a MILP based solver.

The numerical results provide some insight into the operation of DRRs in a competitive market. One salient feature of the numerical work is the impact of the use of DRRs on the market clearing prices. The presence of DRRs leads to a lowering of the market clearing prices, and the decrease is more pronounced on days with higher levels of system demand. A strong incentive exists for the ISOs to encourage more DRR participation in their markets. The presence of a number of competing DRRs makes it possible to lower energy consumption across peak demand periods, thereby decreasing the price spikes.

However, introduction of the payback effect leads to an increase in the effective cost of using DRRs, and leads to a decrease in the number of successful DRR offers. Some work has been done pertaining to the magnitude and time of the payback load, but detailed study of the payback effect is beyond the scope of this presentation. Such work is left for future research. Since payback load can appear

over periods of low system load, the integration of DRRs and an intermittent energy source like wind energy is another interesting topic for future work.

Developments in the United States have indicated that the use of DRRs is gaining favor among the system operators and the end-users. The measures to be undertaken to encourage DRRs and ensure fair treatment for all the participating resources constitute a difficult challenge for the electric industry. But what is clear is that the electricity market will be required to adjust to the phenomena of active demand-side participation, posing new problems for engineers and offering new avenues for future research.

# APPENDIX

The unit characteristics of the generators used in the numerical analysis and their initial states are specified in Table A.1.

Table A.1: Generating unit data

unit	maximum power output	minimum power output	start-up cost	minimum up time	minimum down time	initial on(+) /off(-)	initial status	price segment 1 (\$/MWh)	segment 1 minimum power output	segment 1 maximum power output	price segment 2 (\$/MWh)	segment 2 minimum power output	segment 2 maximum power output	price segment 3 (\$/MWh)	segment 3 minimum power output	segment 3 maximum power output
<b>1</b>	480	175	2290	4	6	10	1	14.67	175	280	17.26	0	150	19.85	0	50
<b>2</b>	13	2	1574.2	6	6	10	1	55.01	2	5	64.72	0	6	74.43	0	2
<b>3</b>	122	30	310	6	6	10	1	48.07	30	62	56.55	0	30	65.03	0	30
<b>4</b>	370	80	870	2	6	10	1	49.64	80	150	58.1	0	150	66.84	0	70
<b>5</b>	370	80	870	2	6	10	1	49.4	80	150	58.4	0	150	67.16	0	70
<b>6</b>	370	80	870	2	6	10	1	49.06	80	150	57.72	0	150	66.38	0	70
<b>7</b>	123	35	510	6	6	10	1	25.26	35	63	29.72	0	30	34.18	0	30
<b>8</b>	215	85	1320	6	6	10	1	25.53	85	135	30.03	0	60	34.53	0	20
<b>9</b>	61	15	420	6	6	10	1	23.17	15	31	27.26	0	25	31.35	0	5
<b>10</b>	29	3	40	0	1	-10	0	75.34	3	11	88.63	0	15	101.92	0	3
<b>11</b>	680	100	640	4	4	10	1	2.14	100	290	2.52	0	300	2.9	0	90
<b>12</b>	110	20	150	2	1	-10	0	82.02	20	50	130.79	0	40	150.56	0	20
<b>13</b>	110	20	150	1	1	-10	0	112.02	20	50	131.79	0	40	151.56	0	20
<b>14</b>	110	50	150	1	1	-10	0	93.59	50	70	110.28	0	20	126.97	0	20
<b>15</b>	110	50	150	1	1	-10	0	94.59	50	70	111.28	0	20	127.97	0	20

Table A.1: Generating unit data (continued)

unit	maximum power output	minimum power output	start-up cost	minimum up time	minimum down time	initial on(+) /off(-)	initial status	price segment 1 (\$/MWh)	segment 1 minimum power output	segment 1 maximum power output	price segment 2 (\$/MWh)	segment 2 minimum power output	segment 2 maximum power output	price segment 3 (\$/MWh)	segment 3 minimum power output	segment 3 maximum power output
<b>16</b>	110	20	150	1	1	-10	0	111.83	20	50	131.57	0	40	151.31	0	20
<b>17</b>	502	20	0	0	0	10	1	10	20	75	58.26	0	377	200	0	50
<b>18</b>	123	20	0	0	0	10	1	10	20	30	59.26	0	58	210	0	35
<b>19</b>	64	12	0	0	0	10	1	10	12	20	60.26	0	24	220	0	20
<b>20</b>	20	5	0	0	0	10	1	10	5	10	61.26	0	5	230	0	5
<b>21</b>	19	4	0	0	0	10	0	10	4	10	62.26	0	5	240	0	4
<b>22</b>	14	0	0	0	1	10	0	10	0	6	63.26	0	4	250	0	4

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