

PART

INTEGRATED SYSTEM AND MARKET OPERATION

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CHAPTER 1***BALANCE ECONOMIC
EFFICIENCY AND OPERATION
RISK MITIGATION****Hong Chen and Jianwei Liu*

SYSTEM OPERATION AND MARKET operation are tightly coupled. Electricity market operation is built upon secure system operation, trying to use market signals to address system operation needs and achieve economic efficiency. By responding to market price signals, market participants help with system operation. Therefore, the integrated system and market operation can be viewed as an engineering control system with dynamics and stability issues.

The integrated operation has a multifaceted nature. The ultimate goal is to reach the equilibrium of economic efficiency and operation risk mitigation. Finding and approximating equilibrium is an emerging frontline topic in the electricity market business.

This chapter reviews the state-of-the-art wholesale market structures and products, with the focus on their interactive impacts on daily system operations. Current challenges in approximating the equilibrium at independent system operator (ISO)/regional transmission operator (RTO) are also discussed.

Heuristic engineering efforts to approximate and achieve electricity market equilibrium at ISO/RTO have gained extensive attention from both market participants and regulatory agencies. Pennsylvania–New Jersey–Maryland (PJM)’s experience on evaluating and improving economic efficiency is discussed as a successful industrial practice in this domain. The practice of perfect dispatch (PD) at PJM has effectively measured economic efficiency in the PJM wholesale electricity market and has successfully provided guidance to system operators through daily operation. The PD practice has demonstrated over \$1 billion in production cost saving in the past 8 years, a good example of the huge potential in the research domain of this book.

Power Grid Operation in a Market Environment: Economic Efficiency and Risk Mitigation, First Edition.

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1.1 POWER SYSTEM OPERATION RISK MITIGATION: THE PHYSICS

1.1.1 An Overview of Power System

The major components of power system are generation resources, demand resources, or load, connected by transmission facilities and distribution facilities. Power system is considered as the largest machine (or control system) in the world [1].

Generation resources can be divided based on fuel types, such as nuclear, hydro, coal, oil, natural gas, diesel, wind, and solar. For demand, normally they are not very controllable to system operation. With smart grid technologies, some are now more responsive to system conditions, called demand response. Transmission facilities include transmission lines, transformers, capacitors, reactors, phase shifters, and FACTS devices, such as static var compensator (SVC) and TCSC. Transmission facilities normally connect to the higher voltage levels, for example, 1000, 765, 500, 345, 230, 138, and 115 kV for bulk power transfer. Distribution facilities normally operate under lower voltage levels (e.g., below 115 kV). Distribution facilities bring electricity down to end customers.

Power system operation is guided by the basic circuit theory: Ohm's law and Kirchhoff's laws:

- All the injections into a node are summed to be zero.
- The distribution of the flow is based on the resistances and reactances of the branches.

All facilities have physical limitations. As a control system, power system also has its dynamic characteristics and limitations.

Power systems are normally interconnected to reduce total generation requirement, reduce total production cost, and enhance reliability. For example, in North America, there are four major interconnections: the Eastern Interconnection, the Western Interconnection, the Electric Reliability Council of Texas (ERCOT) Interconnection, and the Hydro-Quebec Interconnection [2]. In Europe, there is the synchronous grid of Continental Europe, known as European Network for Transmission System Operators for Electricity (ENTSO-E) [3]. It is the largest synchronous grid in the world.

Frequency and voltage are the two most important parameters of an interconnected power system. They have to be maintained at normal values for stable system and safety of the equipment. For example, 60 Hz frequency is operated in North America and 50 Hz system is dominant in Europe, Asia, and other parts of the world.

1.1.2 System Operation Risk Mitigation

1.1.2.1 Keep Power Balance

Electricity demand is constantly changing in the system, every hour, every minute, and every second. It is significantly impacted by weather conditions and pattern of

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human activities. Due to limited energy storage devices, generation has to be balanced with demand at all times, which is a moving target.

If the total generation in the system is not balanced with the total system demand, system frequency changes. Over- and under-generation can impact system frequency, causing time error. If generation is higher than demand, frequency becomes higher; if generation is less than demand, frequency becomes lower.

For interconnected power systems, the interchanges with neighboring systems are also important components in keeping power balance. Some of the transactions can be scheduled ahead of time based on the specified rules. Therefore, power balance equation can be expressed by equation (1.1):

$$\text{Total generation} = \text{total demand} + \text{total loss} + \text{net interchange} \quad (1.1)$$

where total loss is the energy lost in the system equipment and net interchange is the net flow out of the interconnected system.

All generation resources have their physical limitations, such as time to start, minimum run time, minimum down time, minimum and maximum output, ramp rate, turnaround time, and mill points. To balance generation with demand and maintain system frequency, some generation (normally slow-start generation) has to be scheduled way ahead of time based on forecasted load. As the time is close to real time, more generation (normally fast start) is committed to balance demand. Every 5 min, generation is moved up or down to follow the load. For certain types of generating units which can move up and down within 4 s, called as regulation units, their output can be adjusted based on automatic generation control (AGC), which is often referred as secondary frequency control. The governor control of generators is often called as primary frequency control. In summary, generation is staged to balance with load and maintain system frequency.

Demand forecast, often called as load forecast, is important to schedule and dispatch generation. When scheduling generation 1 day to 1 week ahead, load is normally forecasted hourly for 24 or 168 h ahead of time. Many factors can impact load, therefore, they are factored into load forecast. The main impacting factors are temperature, humidity, wind speed, cloud covering, special social events, such as holidays or weekends. When dispatching generation in real time, very short term load forecast is used to forecast load every 5 min for 1–3 h ahead.

In North America, area control error (ACE) is used to identify the imbalance between generation and load (including interchange). Balance is measured by the frequency of the system. ACE is measured based on equation (1.2):

$$\text{ACE} = [\text{NI}_A - \text{NI}_S] - [(10 \times B) \times (F_A - F_S)] - I_{\text{ME}} \quad (1.2)$$

where NI_A represents the actual net interchange, NI_S represents the scheduled net interchange, B represents the frequency bias constant, which is an estimate of system frequency response, F_A represents the actual frequency, and F_S represents the scheduled frequency. I_{ME} represents the interchange metering error [4].

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There are variabilities and uncertainties in both generation and load. Tripped generators and sudden load increases cause the frequency to spike low while sudden large load decreases cause the frequency to spike high. To mitigate the associated power imbalance, reserves are needed in the system to control normal frequency deviation and to survive large disturbances. Reserves are the flexible unused available real power response capacity hold to ensure continuous match between generation and load during normal conditions and effective response to sudden system changes, such as loss of generation and sudden load changes. They are critical to maintain system reliability.

Reserves are secured across multiple timescales to respond to different events. The terminologies and rules vary in different systems, but they all share some fundamental characteristics. In general, some reserve types are for nonevent continuous needs; and others are for contingency events (e.g., loss of generator or facility tripping) or longer timescale events (e.g., load ramps and forecast errors). They are further categorized based on response time, online/offline status, and physical capabilities.

In North America, according to North America Electric Reliability Corporation (NERC), operating reserves are defined as “that capability above firm system demand required to provide for regulation, load forecast error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve” [2]. Reserves are often categorized as 30 min supplemental reserve, 10 min non-spinning reserve, 10 min spinning reserve, regulating reserve, and so on. Often, regulating reserves are procured in both upward and downward directions to respond to normal load changes. They are the reserves responsive to AGC command and only carried in regulating units. Contingency reserves are used for the loss of supply, for example, generation losses. Spinning or synchronized reserves are unused synchronized capacity and interruptible load which is automatically controlled and can be available within a set period of time. Non-spinning or non-synchronized reserves are real power capability not currently connected to the system but can be available within a specified time period, which may vary in different systems.

In Europe, reserves are generally defined in three categories: primary, secondary, and tertiary control [3]. Primary control is activated within 30 s to respond to frequency deviation. Secondary control must be operational within 15 min to respond to contingency event and consists of both AGC units and fast start units. Tertiary control has a slower response to restore primary and secondary control units back to the reserve state.

The reserve requirements are also set differently in different systems. Common practices are based on the largest contingency of the system. NERC BAL-002 standard requirement is to maintain at least enough contingency reserve to cover the most severe single contingency [2]. Each region/system has different operation practices. For example, in New York system, 10-min spinning reserve requirement is set as one-half of the largest single contingency [5], while PJM’s synchronized reserve requirement is set as the largest single contingency [6]. For regulating reserve, NERC does not impose explicit requirement, just to maintain sufficient regulating reserves to meet

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NERC Control Performance Standards (CPS1, CPS2, and BAAL) [2]. In Europe, primary control reserves are required based on members' share of network use for energy production. Secondary control reserves are required in proportion to the maximum of yearly load in the region. Tertiary control reserve requirements are set by the individual countries [7].

With increasing penetration level of intermittent renewable resources, the reserve requirements are being reevaluated and adjusted to account for increased variability. For example, in ERCOT, forecasted wind output is factored in setting the regulating and contingency reserve requirements [8].

Interchange uncertainty poses another challenge to maintain power balance. It is volatile, hard to forecast, and significantly impacted by the market dynamics. Efforts have been started to forecast interchange in some systems, for example, PJM system.

1.1.2.2 Maintain Network Security

Network (transmission and distribution) has limited capability to transfer power from generation to load due to facility thermal, stability, and/or voltage limits. Power transfer can be restricted to any of these limits, or combination. Network security constraints are nonlinear, especially stability limits and voltage limits. Security-constrained optimal power flow (OPF) is a fundamental tool to ensure a secure operation.

1.1.2.2.1 Facility Thermal Limitation Network facilities, such as transmission lines, transformers, have thermal ratings limiting the amount of current or apparent power that can be carried. Exceeding the thermal limits of transmission lines can cause the conductors to sag and stretch due to overheating, which could further result in faults or fires. Most equipment can be safely overloaded in certain degree. The key is how great the overload is and how long it does last. Typically, thermal ratings are set to allow specified overload for a specified period of time.

Due to thermal capabilities, the flow on any facility has to be within its thermal limit. Due to the uncertainty of facility tripping, it could overload other facilities. Therefore, the system has to be operated in a manner that it will stay within its limit under normal system condition and also under the conditions that another facility trips. The historical practice is $N-1$ contingency criteria, which means that when a facility trips, it will not incur overload on another facility.

In North America, normal continuous rating and emergency ratings (long term and short term) are specified for each facility [9]. Some systems have load dump ratings as well [10, 11]. Ambient temperature can affect facility thermal ratings significantly. Some systems have the thermal ratings corresponding to different temperature sets, such as PJM [10]. Dynamic line ratings are being implemented or investigated in many systems [3, 8]. The severity of thermal limit exceeding often determines corrective actions and time to correct with load shedding [10].

Power flow analysis and contingency analysis are used to determine the flow and contingency flow on the facilities. The actual flow on the facilities often comes from state estimation.

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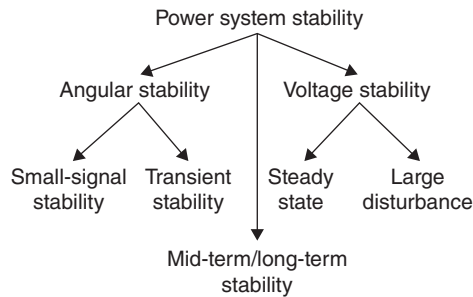


Figure 1.1 Power system stability categorization. Adapted from Kundur [12].

1.1.2.2.2 System Stability Limitation As a control system, power system is also subject to stability limitations, that is, system should be able to return to the stable state after a disturbance. As shown in Figure 1.1, there are two main stability categories experienced in a power system, namely, angular stability and voltage stability. Each category can be further divided based on how big the disturbance is: small perturbation and large disturbance. According to [12], there is also mid-term/long-term stability which involves large voltage and frequency shift.

Voltage is the key to the overall stability of a power system. Angular stability is related to the angular separation between points in the power system; and voltage stability is related to the magnitude of the system voltages and reactive power reserves. Often, angular and voltage instability go hand in hand.

A power system is composed of many synchronous machines. Angular stability has to be maintained for the synchronization of the grid, to ensure that system torque and power angle remain controllable. The angles change as system conditions change. Interconnected power system loses synchronization when power transfer rises to extremely large magnitudes and power angles reach excessive values. Following a disturbance, transient stability becomes the concern. Power system may become unstable for a period of time: angles may reach high magnitudes and rapidly change over a wide range. Synchronous generators are critical to the transient stability analysis. When torque/power angles are too large, and disturbances occur, magnetic bonds of generators may be lost. System becomes angle unstable when system operators lose their ability to control angles and power flows.

Stability analysis is often used to determine stability limits. Many power systems restrict their real power transfers due to transient stability concerns, for example, those are the power systems with long transmission lines and remote generation.

Voltage stability is the ability of a power system to maintain adequate voltage magnitudes so that when the load is increased, the power delivered to that load also increases. In a voltage-stable system, both power and voltage are controllable. Voltage stability is mainly a function of power system load. Excessive loading in the power system leads to deficiencies in reactive power and the system is no longer able to support voltage. A voltage collapse could then occur. The shortage of reactive power drives voltage instability.

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When a power system experiences a voltage collapse, system voltages decay to a level from which they are unable to recover. Voltage collapse is a process during which voltage instability leads to loss of voltage in a part of the power system. A system enters a period of voltage instability prior to a voltage collapse. The effects of a voltage collapse are more serious than those of a typical low-voltage scenario. As a consequence of voltage collapse, entire systems may experience blackout. Restoration procedures are then required to restore the power system.

As power systems are pushed to transfer more and more power, the likelihood of voltage collapse occurring becomes greater. Voltage stability is mainly a concern in heavily loaded systems. Voltage stability has been responsible for major network collapse in recent years [13]. Often, system transfer capabilities are limited by steady-state voltage stability limits.

1.1.2.2.3 Voltage Limitation All equipments are designed to operate at certain rated supply voltages. Large deviation could cause damage to system equipment. High voltages can lead to the breakdown of equipment insulation, cause transformer overexcitation, and adversely affect customer equipments. Low voltages can impact power system equipment and operations in numerous ways.

Voltage control is closely related to the availability of reactive power. The amount of available reactive support often determines power transfer limit. Heavy power transfers are a principal cause of low voltage due to the reactive power losses. Lightly loaded transmission lines are a principal cause of high voltage. Capacitors, reactors, load tap changers (LTCs), and SVCs are the equipment to control system voltage. For example, reactive support from capacitor is often needed to help prevent low-voltage problem. In system operation, reactive reserves need to be maintained and voltage deviations need to be controlled.

Often, reactive transfer interfaces are defined across the transmission paths to prevent voltage criteria violation and voltage collapse. The interface limits are used to limit the total flow over the interfaces. The reactive limits are either pre-contingency active power limits, or post-contingency active power limits. PV curves are often used to determine reactive interface limits.

1.1.2.3 Energy Management System

Energy management system (EMS) is an important tool to assist power system operation. SCADA collects measurements for system components and alarms correspondingly based on measurement. State estimation provides current system status: topology, generation, load, and power flow. State estimation relies increasingly on new technologies, such as phasor measurement units (PMUs). Network applications, such as power flow analysis, contingency analysis, voltage stability analysis, and transient stability analysis, evaluate pre- and post-contingency thermal limits, voltage limits, and stability limits. $N-1$ contingency rule is commonly applied in practice. Contingency element could be generation or network facilities.

When a facility overloads, directed actions, such as adjusting phase shift regulators (PARs), switching reactive devices in/out of services or adjusting generator reactive output, switching facilities in/out of services, adjusting generation of real power

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output via re-dispatch, and adjusting imports/exports, can be used pre-contingency to control post-contingency operation. If directed actions do not relieve an actual or simulated post-contingency violation, then emergency procedures may be directed, including dropping or reducing load as required. Thermal and voltage constraints are often controlled cost-effectively on a pre-contingency basis.

EMS is also used to perform outage analysis to evaluate if an outage has reliability impacts. Long-term analysis could be 1–6 months ahead. Short-term analysis can be 1 day, 3 days to 1 week ahead. If an outage could jeopardize system reliability, it will be canceled or rescheduled. Outage analysis directly mitigates system operation risk.

1.1.3 New Trends of Power System Operation

Power systems are under significant changes in the twenty-first century globally, with the goals of improving efficiency of electricity production, transmission, and consumption. Rapid technology innovations such as smart grid technologies, new transmission and power electronic devices, and high-efficiency energy consumption technologies are emerging and have been utilized in today's power system planning and operation.

New trends in sustainable energy system development are also observed worldwide. Environmental issues, from pollution control of fossil fuel power generation and reliability enhancement of nuclear generation facilities, to massive integration of renewable energy resources, have brought in deep social and economic impact in today's system planning and operation practices.

Economic considerations have been coherent factors in power system planning and operation. Classic stories, such as AC/DC system competition in 1900s and the emerging of power pools, have educated many generations of power engineers on the integration of power system facilities. Growth of demands in overall energy consumption, increasing constraints of nature resources, and enhanced regional (and even global) system integration are still hot topics in the planning fields. Meanwhile, thanks to the diversified energy resources and modern power electronic technologies, micro-grids have been recognized as plausible approaches to modernized power system at or near the demand side. Hence, in order to adequately depict today's power grids for planners and operators, system models are becoming more and more complicated with details of new facilities, as well as dynamics and price elasticity characteristics of demands.

Electricity markets, which have been successfully implemented in many regions, have deeply reshaped power system planning and operation, philosophically and practically. Wholesale electricity markets not only provide platforms for energy transactions in forward and real-time (RT) markets, but also play key roles in system operation. Demand responses have shown significant effects on system reliability and market efficiency. Electricity markets need to be continuously developed and evolved to adapt to significant renewable resource penetration.

With these changes as background, power system planners, operation engineers, researchers, and policy makers are faced with the need of reviewing the upfront challenges in today's industry to be prepared for the future.

1.2 INTEGRATED SYSTEM AND MARKET OPERATION: THE BASICS

Electricity market operation needs to be tightly integrated with system operation, to reinforce reliable operation of the systems through strong financial incentives and bring efficiency to system operation.

1.2.1 Integrated Operation Philosophy

The objective of electricity markets is to improve economic efficiency, while risk mitigation remains the main focus of power system operation, as discussed in Section 1.1. These two different objectives often have opposite impact on resource scheduling, dispatch, and pricing. As shown in Figure 1.2, both objectives need to be respected in the integrated system and market operation. Figure 1.2 shows the integrated operation philosophy, not representing time sequences. The ultimate goal is to achieve market equilibrium, a balance between the two opposite objectives, that is, maximize total social surplus and minimize the total cost of operation risk.

Operating criteria drive system operation practices. They are often formulated as system operation constraints in the market operation administered by ISO/RTOs. The resulting prices and dispatch signals reflect system conditions related to the modeled constraints. By responding to prices, market participants, such as generation companies, load serving entities, distribution companies, transmission

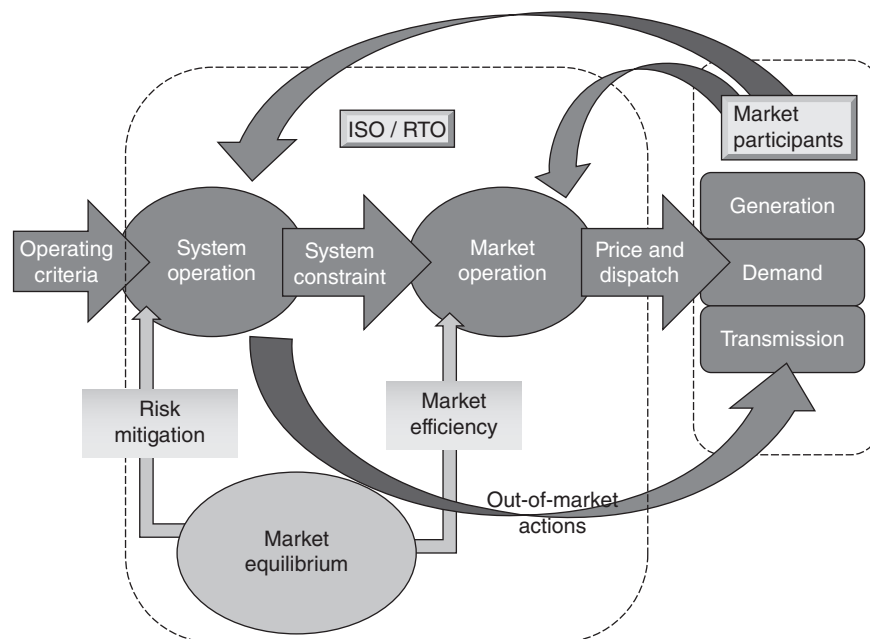


Figure 1.2 Integrated system and market operation.

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companies, and financial players, help to address system operation needs. Electricity market design has been targeted toward this goal [14–18].

Ideally, the integrated system and market operation creates a closed-loop system with prices as feedback signals. Price signals align the financial interest of market participants with system and market operation objectives. Market participants are integral parts of the decision loop. By responding to price signals, they help to achieve operation objectives. Market signals, such as locational marginal prices (LMPs) and ancillary service market clearing prices, are dynamically updated to reflect changing system operation conditions. Hence, the integrated system and market operation can be viewed as an engineering control system with dynamics and stability issues [19–21].

However, due to market design and software limitation, not all operating criteria can be incorporated into current market operation. Out-of-market (OOM) actions become unavoidable. They depress market prices, increase uplift, and negatively impact economic efficiency. Therefore, OOM actions need to be reduced to improve economic efficiency.

In practical implementation, economic efficiency is often achieved by total product cost minimization or total social surplus maximization. System risk mitigation is usually modeled as power balance constraints, reserve requirement constraints, and various network security constraints in the optimization process. Attaining the balance between economic efficiency and risk mitigation has been a continual challenge with a multifaceted nature. One of the key challenges is to incorporate the cost of operation risk.

1.2.2 Current Practices

1.2.2.1 Market Design

Electricity markets are functioning around the world, from North America, shown in Figure 1.3 [22] (Pennsylvania–New Jersey–Maryland (PJM) [23], Midcontinent [24], New England [11], New York [25], California [26], ERCOT [8], Southwest Power Pool (SPP) [27], Ontario [28], Alberta [29], and New Brunswick [30]), Latin America [31] (such as Mexico [32], Chile [33], Colombia [34], Brazil [35], Argentina [36]), Europe, shown in Figure 1.4 [37] (Internal Electricity Market managed by ENTSO-E [3], including Continental Europe [38–40], Nordic in Scandinavia [41], United Kingdom [42], Ireland [43], Baltic [44–46]), to New Zealand [47], Australia [48], and some parts of Asia (e.g., Singapore [49]) and Africa [50].

Multi-settlement market design with nodal market model is generally followed in North America, with individual market variations [18]. The model details can be found in Appendices 1.A and 1.B. Figure 1.5 shows the high-level design, with the time frame ranging from planning to real time. The target is reliable and efficient RT system operation.

In the planning horizon, there are capacity markets to address resource adequacy, making sure that there will be sufficient capacity to meet future peak load plus reserve margin [11, 23–25]. Capacity markets address the “missing money”

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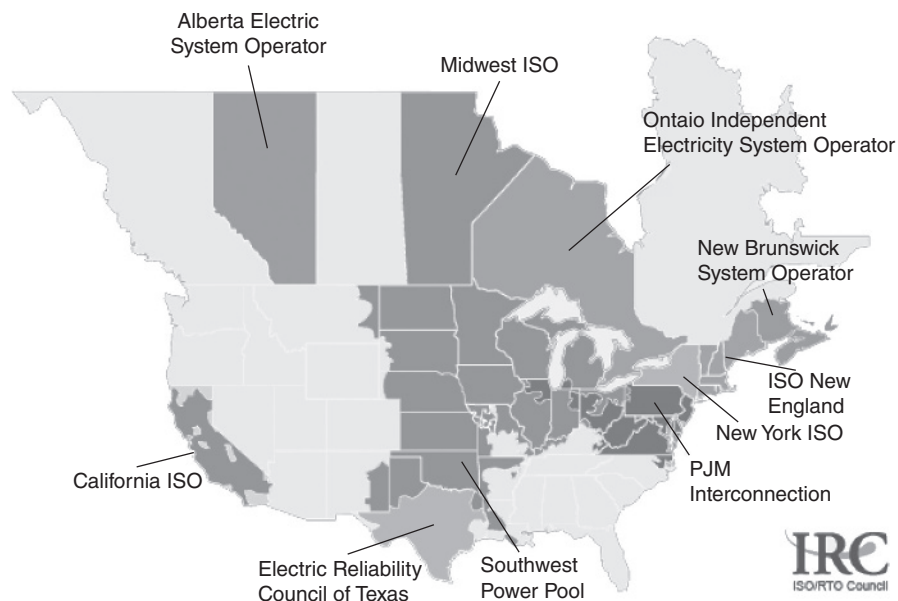


Figure 1.3 North America electricity markets. *Source:* http://www.nyiso.com/public/markets_operations/services/planning/iso_rto/index.jsp. Reproduced with permission of the ISO/RTO Council.

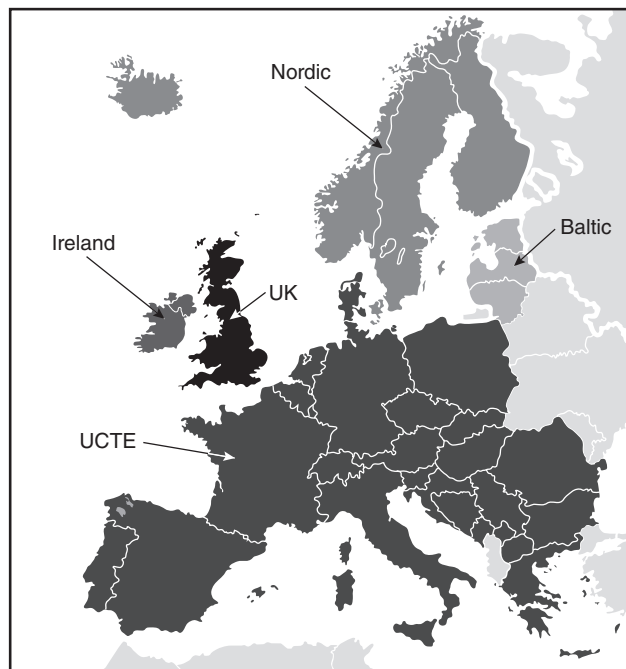


Figure 1.4 European electricity markets. *Source:* https://en.wikipedia.org/wiki/European_Market_Coupling_Company. CC BY-SA 3.0.

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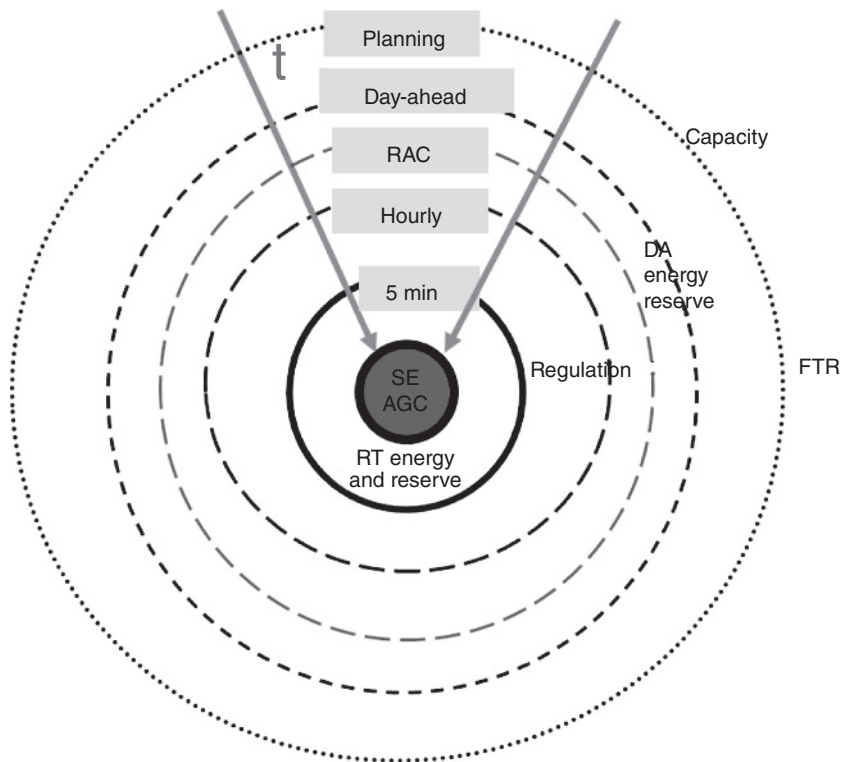


Figure 1.5 Multi-settlement market design.

issue and create long-term price signals that attract investments for both maintaining existing capacity resources and encouraging the development of new capacity resources. Locational capacity requirements are often set for capacity zones to reflect limited transfer capabilities. Some markets, for example, PJM [23] and New England [11], have long-term forward capacity markets (3 years forward). Forward design provides greater information into the reliability situation with enough lead time, so new entrants can compete against each other and avoid overbuilding. It could also lead to higher prices because generators face a bigger risk in committing to be there many years in the future. Performance-based capacity markets were recently implemented to better reward well-performing power plants and penalize those that fail to perform when needed most [11, 23]. It ensures that reliable supply will be available during extreme weather or other system emergencies. Some regions do not have capacity markets, but have resource adequacy programs to ensure long-term reliability [26, 27].

As a result of the nodal market model, prices are different at different locations to reflect transmission congestion. Financial transmission right (FTR) markets are created to hedge the risk of transmission congestion charges. FTRs are financial contracts entitling the FTR holders to a stream of revenues (or charges) based on

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the day-ahead (DA) hourly congestion price difference across an energy path. Long-term FTR auctions, annual FTR auctions, and monthly FTR auctions are normally available for market participants to buy or sell FTRs in the central market place.

Before each operating day, DA financial markets are cleared based on bid-in demand submitted by market participants and system reserve requirements. Besides generation offers and demand bids, there are also pure financial bids, known as “virtual bids”, such as INC (incremental bids), DEC (decremental bids), and up-to-congestion transactions, participating in DA markets [23]. Virtual bids help the convergence between DA markets and RT markets. The resulting DA hourly real power schedules and prices represent binding financial commitments to market participants. DA markets secure the majority of the resources for the operating day. The market clearing timelines vary for individual markets. Rules for generation offer differ in different markets as well. Generation offer information includes availability, price and/or cost offers, and operating parameters, such as ramp rates, startup time, shutdown time, minimum run time, minimum down time, and minimum and maximum generation.

Right after DA market clearing, there is re-bid period for market participants to adjust their bids. Reliability assessment commitment (RAC) processes then determine whether additional slow-start units are needed to meet forecasted load and operating reserve requirements for the operating day. In brief, RAC processes commit additional units to cover the difference between forecasted load and bid-in load, as well as the difference of corresponding operating reserve requirements. They bridge DA financial markets with physical system operation. The objectives are generally the lowest commitment cost to bring additional units online. Different objective, such as minimizing total production cost, has been discussed. In most North American markets, RAC processes are nonmarket processes with no price signal associated, except CAISO. Thus, it is an OOM action that contributes to uplift.

Within the operating day, some markets, such as PJM, New York, and California, have RT unit commitment processes to commit fast start resources with 2–3 h look-ahead time. The frequency of the case run, look-ahead time, commitment interval size, and the criteria for candidate flexible resources are different in different markets. Some markets have hourly regulation markets to secure regulation resources an hour ahead, so that the system has enough generators to provide fine-tuning that is necessary for effective system frequency control, as in the case of PJM and New England markets.

RT markets are balancing markets. Most of the RT markets co-optimize energy and reserves (such as regulation, primary reserves, contingency reserves) about every 5 min to send out dispatch and price signals, based on current system status, represented by state estimator (SE) solution, forecasted load, generators’ offer information, scheduled transactions, and system topology. The resulting dispatch and price signals are sent to market participants to balance system load, maintain system reserves, and resolve system congestions. Different markets have different types of reserves co-optimized with energy in real time. The look-ahead time for RT dispatch also varies, ranging from 5 to 15 min. Longer look-ahead time tends to generate stable dispatch; shorter look-ahead time could result in higher price volatility, especially due to

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limited ramping capabilities. Ex-post pricing is implemented in some markets to encourage market participants to follow dispatch [14, 51].

In RT operation, AGC adjusts generation output every 4 s to fine-tune system and maintain system frequency. RT markets and system operation rely on SE, which runs periodically to capture latest system status. Some systems, such as PJM, have SE solutions every minute. Some systems have SE solutions every 3–5 min. Timely capture of the latest system conditions can help make timely RT commitment and dispatch decisions, as well as other operation decisions, therefore, better system control and risk mitigation.

As shown in Figure 1.5, when it is closer to RT, the coupling between system and market becomes much tighter. For this reason, the focus of this chapter is from DA to RT operation time frame.

In Latin America, electricity markets generally follow “hybrid” model, that is, spot energy market, to ensure economic operation and forward contract auction, called as “competition for the market” to ensure long-term resource adequacy [52].

Europe has wholesale markets for energy (DA markets and intra-day markets) and balancing and ancillary service markets for grid support services [3, 37–46]. DA markets secure most of the resources to balance demand; intra-day markets are continuous markets, critical to handle uncertainties, for example, uncertainties brought by renewable resources. To secure supply in the medium and long term, capacity mechanism has been examined and debated.

1.2.2.2 Day-Ahead and Real-Time Market Clearing

Both DA and RT market clearing are essentially bid-based security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) processes with nodal pricing, which is essential to the success of economically efficient electricity markets.

Figure 1.6 shows the inputs for DA market, including both physical bids and virtual bids. The system topology is based on scheduled transmission outages. DA market is a whole-day process, with 24 hourly intervals. The cleared megawatts and prices are sent to all the bidders for the corresponding hours. Economic unit scheduling, that is, SCUC/SCED, and feasibility analysis are the two key components of DA market.

For SCUC/SCED, the objective is total production cost minimization or total social surplus maximization, with power balance constraint, and branch flow limits, transfer interface limits, and other transmission-related limits as transmission security constraints. The limits of these security constraints are based on operating limits determined through system study. Reserve requirement constraints are also included to align with system reliability criteria and practices. The mathematic model of SCUC can be found in Chapter 5, Section 5.2.1.

Feasibility analysis is to ensure the physical deliverability of the 24 hourly DA schedules. It checks the network security of the economic scheduling results. Once a limit violation is identified, the corresponding constraints are then enforced into the next SCUC/SCED run. The hourly constraint sensitivities are inputted to the

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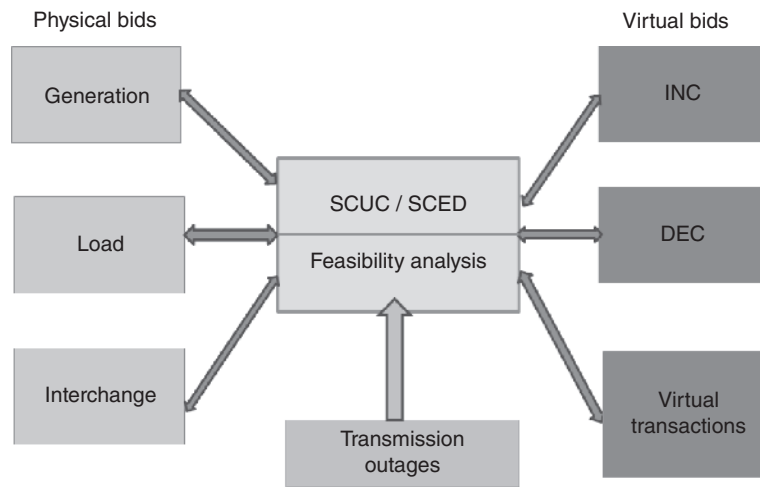


Figure 1.6 DA market clearing.

SCUC/SCED. In the case of marginal loss pricing, hourly loss sensitivities are fed into the SCUC/SCED as well.

The iteration between SCUC/SCED and feasibility analysis ends when no more limit violation is detected. The solution method details can be found in Chapter 5, Section 5.2.2.

Figure 1.7 shows the inputs for RT market. There is no virtual bid in RT market. Generation is committed and dispatched based on forecasted load and scheduled interchange for the look-ahead intervals. Some markets have multi-interval time-coupled RT solution process.

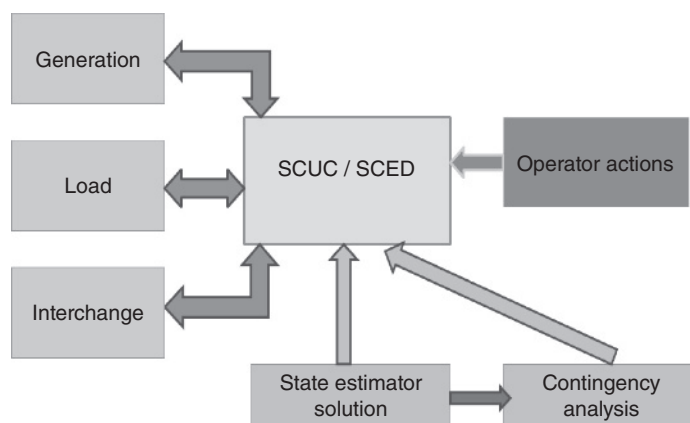


Figure 1.7 RT market clearing.

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In RT market, SCUC/SCED bases on actual RT system status and topology and provides commitment and dispatch for the study intervals. The actual RT system is represented by the latest SE solution. Based on the SE solution, RT contingency analysis performs AC power flow-based contingency analysis for each defined contingency. When possible upcoming transmission limit violation is detected, system operators will investigate solutions to the problem. If generation re-dispatch is required, system operators will activate the transmission constraint to the RT SCUC/SCED. The constraint sensitivities and loss sensitivities at the current system operation point are also provided to SCUC/SCED. Binding transmission constraints indicate that generation re-dispatch is actually required to relieve the congestions. As the result of RT SCUC/SCED, the real power (MW) dispatch is generated for each resource, and the price is calculated at each pricing location.

To manage the risk posted by the uncertainties, as well as the limitation of current tools, operator actions are also important parts of the RT market operation. For example, operators can adjust load bias to reflect anticipated load forecasting error and anticipated generation changes. They can also adjust transmission limit control with certain conservativeness, as well as accounting for rapid flow increase so that desired control can be obtained early. Sometimes, operators can even manually commit units to prepare for generation bidding parameter changes and quick transmission control.

In both DA and RT markets, LMPs are generated as part of the SCED process and determined by the shadow prices of the power balance constraints and security constraints [53]. It is locational and time specific, and has three main components: energy, loss, and congestion. If there is no congestion in the system, the congestion component is zero. Under marginal loss pricing, there is loss component as well. The details can be found in Appendices 1.A and 1.B.

LMP-based congestion management is a key feature of the integrated system and market operation. Responding to LMPs, market participants could help mitigate system operation risk. LMPs encourage efficient use of the system and enhance reliability. In the long run, they encourage new generation sources to locate in areas where they will receive higher prices, signal large new users to locate where they can buy lower cost power, and encourage the construction of new transmission facilities in areas where congestion is common, in order to reduce the financial impact of congestion on electricity prices.

1.2.2.3 Intra-day Commitment/Markets

The majority of the energy/capacity is traded in DA markets. After closing of the DA market to the delivery of the next operating day, system conditions can change, sometimes, significantly: load can be significantly higher/lower than DA load; generation, for example, a big nuclear unit can trip after being cleared in DA market; natural weather condition change, such as wind or cloud covering, can cause significant renewable generation change. Intra-day markets are important for system to adjust to the changing conditions, ensuring the least cost capacity to provide power and ancillary services for the operating day.

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Intra-day markets are continuous markets, critical to handle uncertainties, especially the uncertainty introduced by renewable resources. In Europe, intra-day markets happen around the clock every day, until 1 h before the delivery. It is becoming increasingly important as more wind power enters grid [54]. It is critical to the increased share of renewable energy in the energy mix. Intra-day markets result in revised flexible operation decisions to mitigate the impact of renewable uncertainties, and also allow the producers to make decisions closer to real time by adjusting intra-day bids. Overall, intra-day markets encourage efficient dispatch.

In the United States, some markets have intra-day commitment [11, 23–26]. Unit commitment is adjusted based on changing system conditions and updated offers/bids, to ensure least cost generation scheduling. However, no price signal is generated, that is, it is a nonmarket process.

1.2.2.4 Ancillary Service Markets

Ancillary services are the services necessary to support the transmission of electric power and maintain reliable operations of the interconnected system. These services generally include frequency control, spinning reserve, non-spinning reserve, replacement reserve, voltage support, and black start. Traditionally ancillary services have been provided by generators; however, with the integration of intermittent generation and the development of smart grid technologies, more resources, such as demand and batteries, can provide ancillary services now. Currently, voltage support and black start are still cost based, and there is no market yet. Ancillary service markets are therefore mainly reserve markets.

As mentioned in Section 1.1.2.1, maintaining reserves is essential in system operation. Reserve markets or ancillary service markets are created to provide market-based mechanism for the procurement of reserves on the system [55]. Transparent price signals incentivize generating and demand resources to provide flexible capability to the grid. In most US markets, reserves are jointly scheduled with energy in the DA markets and/or RT markets. Different markets have different types of reserve products co-optimized with energy [15, 51]. The detailed mathematical model can be found in Section 5.2.1.

In most of the current markets, reserve requirements are predetermined based on historical data, corresponding to operation practices, for example, $N-1$ or $N-2$ contingency criteria. To account for limited import capabilities, zonal reserve requirements are often defined, either statically or dynamically based on actual interface flow and limits. Reserve clearing prices (RCPs) are then derived from the shadow prices of the reserve requirement constraints. Reserve demand curves are usually defined for pricing reserves under scarcity [56]. In some market, post zonal reserve deployment transmission constraints are incorporated to address reserve deliverability issue [57].

To be in compliance with FERC Order 755 [58], performance-based regulation markets have been implemented in the United States. Generators are paid not only for their regulating capacity, but also for their actual performance.

To align with system operation needs, some markets are considering new reserve products, such as ramping products to procure sufficient ramping capability

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to handle uncertainties, as in the case of CAISO and MISO. Dynamic reserve requirements and/or dynamic reserve zones have also been extensively discussed to capture updated system requirements and accommodate new challenges, such as volatility and uncertainty brought by intermittent renewable resources and increased pressure to improve economic efficiency. However, practical implementation is still a challenge. In February 2015, FERC issued a NOPR to allow third-party provision on primary frequency response service to balancing authorities that may have a need for such a product to meet NERC Standard BAL-003-1 obligations [59, 60]. This opens the door for the market-based primary frequency response product.

1.3 ECONOMIC EFFICIENCY EVALUATION AND IMPROVEMENT: THE ECONOMICS

Increasing economic efficiency is the objective of electricity market and has been on the center of electricity market design and operation. There are many different definitions of economic efficiency. One popular and easier one is total system production cost or total social surplus as an efficiency measure. The lower the total system production cost or the higher the total social surplus, the higher the economic efficiency.

Correctly setting price leads to the most efficient use of scarce resources. Marginal cost pricing is generally applied in electricity markets, that is, setting the price of a product equal to the extra cost of producing an extra unit of output. It not only provides basis to collect revenues for suppliers, but also serves as a signal of how much the product is worth, and impacts both consumption and production level.

1.3.1 Current Practices

The general principle of electricity market design is to incorporate system needs into market signals, that is, prices, which need to be transparent and competitive. Multi-settlement market design, LMP-based congestion management, and energy and ancillary services co-optimization are consistent with this general principle.

However, as mentioned in Section 1.2.1, currently, not all system operation needs can be incorporated into market prices. Uplift or make-whole payment becomes necessary to provide incentives for resources to follow system dispatch instruction and provide production cost guarantee.

Due to the discrete nature of unit commitment problem, no exact prices can support the quantity determined in unit commitment and dispatch in the economic equilibrium [60]. The uplift caused by unit commitment is therefore unavoidable, but should be relatively small.

OOM actions are often the causes for high uplift payment, which usually indicates the inefficiency of the operation. Therefore, uplift can be used to evaluate economic efficiency [15]. Reducing uplift is one of the focuses of many electricity markets.

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Considering the close coupling between system operation and market operation in real time, the main focus has been on RT uplift, which is mainly caused by RT unit commitment and other manual dispatch actions. For example, due to market modeling or software limitation, during fast load pickup time, operators may pre-position the system, such as pre-loading generation before its DA schedule, so that it comes online earlier to gain ramping capability of the system or run a unit longer than its DA scheduled hours to anticipate potential transmission problem or load increase.

To enhance economic efficiency, the primary focus has been put on incorporating system operation needs into market clearing process, so that operation risk could be mitigated through price signals. The efforts on ancillary service markets, such as explicit model ramping requirements and dynamic reserve requirements, as discussed in Section 1.2.2.4, are followed under this philosophy.

Another focus is on improving RT unit commitment, which refers to the unit commitment outside of DA market, including unit commitment during RAC process and intra-day RT operation. Using software to provide RT commitment suggestions provides more economic solution than operator manual commitment decision.

During the northeast Polar Vortex in January 2014, unprecedented increase in uplift was experienced in US northeast markets, and triggered dialogue and coordination between gas and electricity industries, as well as the design change needed for generators to update their offers to reflect gas cost volatilities. As a result, intra-day offers are being implemented in US electricity markets.

1.3.2 Perfect Dispatch at PJM

In the integrated system and market operation, one of the key challenges is to balance economic efficiency with operation risk mitigation. PJM explicitly developed the PD concept and process to address this challenge.

PD concept and process were developed to evaluate economic efficiency and improve operation, that is, manage operation risk more economically [15]. PD solution is based on actual load and generation availability, actual interchange, actual transmission topology, and actual transmission constraints, assuming that system operation criteria are given or set by external entities. ISO/RTOs need to comply with those security operation criteria. In this sense, PD solution balances economic efficiency with operation risk mitigation [15].

PD solution is obtained with all known factors, that is, without uncertainties. RT operation is, however, not perfect. There is always deviation between RT operation and PD solution. The deviation could be caused by uncertainties in load, generation, transaction or caused by dispatch actions. Deviation from RT operation to PD solution has been used to indicate how far the actual operation is from the perfect deterministic equilibrium solution, as shown in Figure 1.8 [15]. One of the deviation measurements is the difference between total RT bid-based production cost and the total bid-based production cost in PD solution, called the “perfect dispatch savings.” PD savings has been used at PJM as the index to evaluate economic efficiency.

Dispatch actions have been the main focus of economic efficiency improvement, since it is the most controllable part. Dispatch actions mainly include constraint

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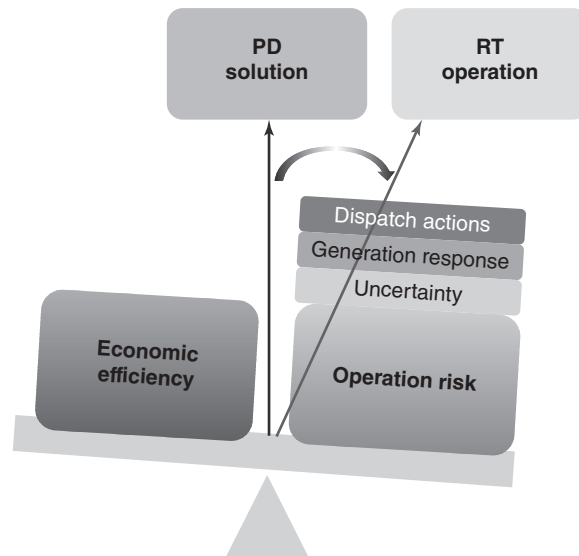


Figure 1.8 Perfect dispatch concept. *Source:* Chen and Bresler 2010 [15]. Reproduced with permission of the Institution of Engineering and Technology (IET).

control, RT steam commitment, and RT combustion turbine (CT) commitment. PD had been serving as PJM corporate goal for 7 years. The idea is to achieve economic efficiency through improving dispatch actions, which is the main contributor for RT uplift.

There were different goal focuses for different years, as shown in Figure 1.9. For the first 2 years, 2008–2009, the focus was on conservative constraint control. For 2010, the focus was on RT steam unit commitment, evaluating steam units called outside of DA Market, that is, during the RAC process. For the last 4 years, PD had been focusing on RT fast start units, mainly CT commitment, one of the major dispatch actions in RT. CT commitment, which is the process of selecting the most economic CTs to meet load and relieve congestions, is one of the most challenging dispatch actions in real time.

1.3.3 Economic Efficiency Improvement at PJM

Based on the major economic efficiency performance impacting factors, PJM has been working on improving operation practices and software tools to improve economic efficiency.

Figure 1.10 shows the PD saving due to conservative transmission limits. Diamond line shows the PD saving using the actual limiting control; and square line shows the PD saving using the 100% of the limit. For about 1 month period in 2008, the daily average PD saving difference was about \$73k [15]. To improve dispatch and address conservative constraint control, PJM changed operation practice on thermal

1.3 ECONOMIC EFFICIENCY EVALUATION AND IMPROVEMENT: THE ECONOMICS 23

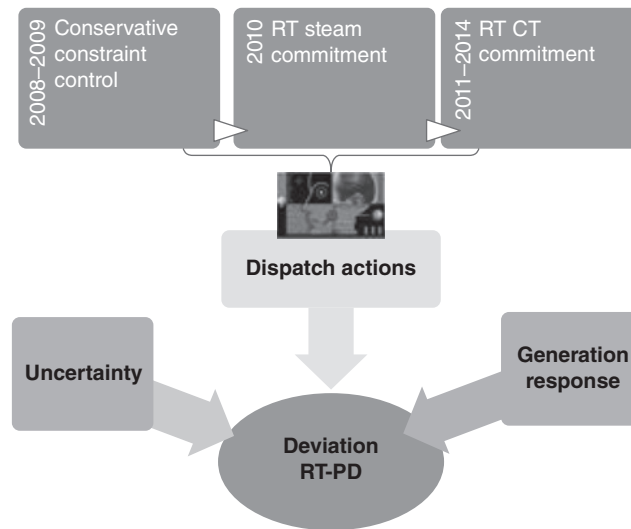


Figure 1.9 Perfect dispatch goals at PJM.

contingency constraint control starting from February 1, 2009, from 97% to 100% of emergency rating.

Constraint analysis has been provided to identify most efficient control actions for transmission constraint control, considering constraint volatility, constraint interactions, and unit impact patterns. Figure 1.11 shows a sample volatile constraint. Solid line represents RT flow, dotted line shows the thermal limit, and dashed line shows the controlled flow in PD solution. In RT operation, six quick-start CTs were

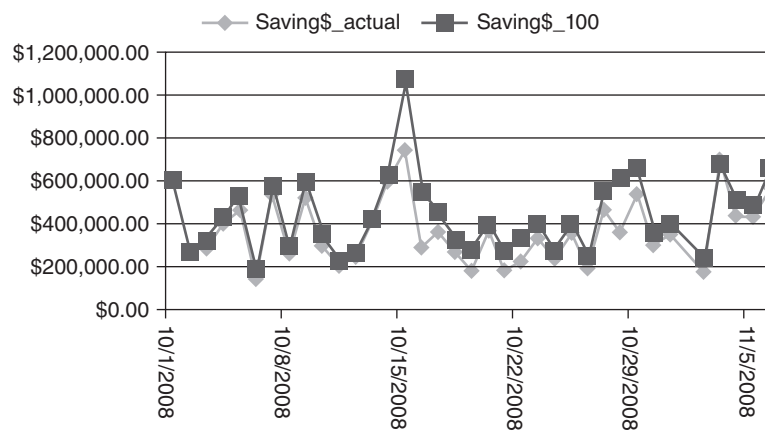


Figure 1.10 PD saving difference between 100% limit control and actual limit control. *Source:* Chen and Bresler 2010 [15]. Reproduced with permission of the Institution of Engineering and Technology (IET).

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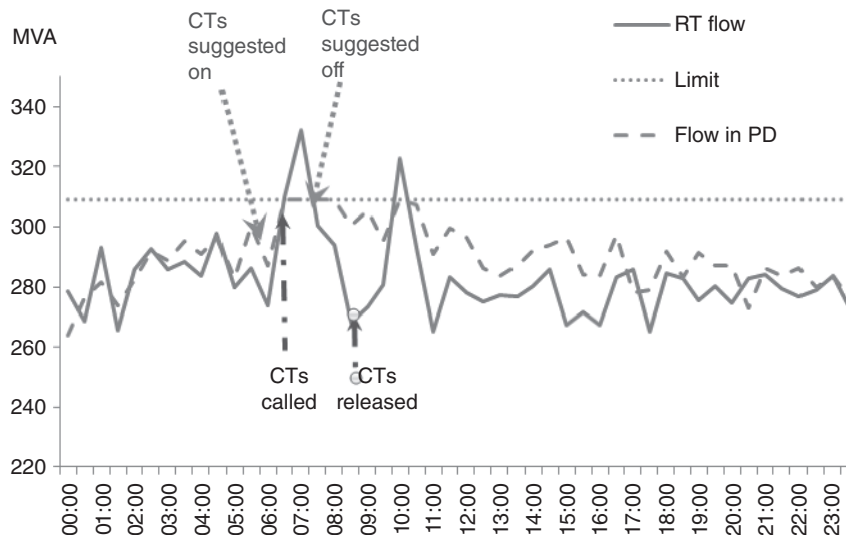


Figure 1.11 Constraint control analysis.

called before 7:00 to control the constraint when the flow was sharply increasing and approaching the limit during morning peak, shown by the dot dashed arrow. The flow quickly dropped after 7:00 when the CTs came online. The CTs were released around 9:00 after the flow dropped to 87% of the limit. After the CT release, the constraint flow bounced back and was over limit again around 10:00. With steam unit re-dispatch, the flow was then controlled under the limit. In PD solution, only two CTs were recommended to come on at 6:30 and off at 7:30, shown by the dotted arrow. The constraint flow was controlled right at the limit from 6:30 to 8:00 with both CTs and steam unit re-dispatch. Constraint analysis suggests to control earlier so that less quick-start CTs are used, which leads to overall economic solution. Controlling earlier also gives time to re-dispatch steam units for constraint control. Overcommitment often happens when the flow is over limit. More adaptive constraint control is desirable to achieve consistent control on the transmission constraints.

PJM has also been working on improving dispatch tools to help with dispatch decision making. For example, RAC application was developed to help commit slow-start units outside of DA market, embedded with three pivotal supplier (TPS) test, an integrated market mitigation process at PJM. Time-coupled multi-interval RT commitment and dispatch, IT-SCED and RT-SCED, was implemented in 2010 to provide better load pickup and peak load coverage, as well as forward-looking capability to prepare early for load or for constraint control. RT energy and reserve co-optimization was implemented in 2012 to provide market signals for reserves and overall economic solution in real time.

PD solution often suggests better RT unit commitment decision, for example, start control earlier by calling less expensive units having relatively long startup time instead of having to run expensive units later. In this case, dispatch acts more

1.3 ECONOMIC EFFICIENCY EVALUATION AND IMPROVEMENT: THE ECONOMICS 25

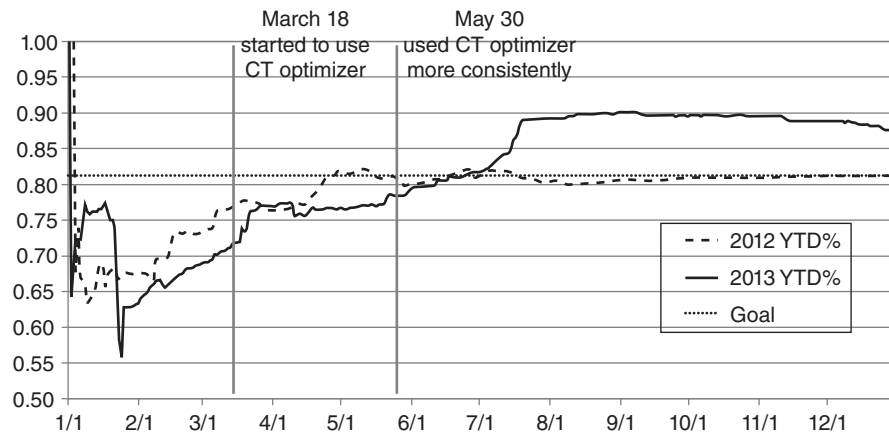


Figure 1.12 Impact of CTO to the perfect dispatch goal.

proactively, therefore, more efficiently. Based on this idea, CT optimizer (CTO) was developed to help dispatch to commit fast start units with relatively longer time-to-start (TTS) and minimum run time (MinRunTime). Previously, no tool was available for this type of units, since their parameters are outside of IT-SCED evaluation horizon, and dispatch had to make manual decision. It is often hard to make economic manual commitment. Embedded cost of high startup and no load cost and long minimum run time were often missed due to low incremental cost. It was also hard to evaluate the need of these CTs based on current system condition. CTO provides 24 h evaluation for long TTS and minimum run time fast start units, minimizing total production cost, based on latest load forecast and unit status. The results can be updated during the day when system conditions change significantly.

Figure 1.12 shows the impact of CTO to the PD performance score. Dashed line shows the 2012 year-to-date (YTD) PD score; solid line shows the 2013 PD score; and dotted line shows the 2013 PD goal. CTO was started to be used during the week of March 18, 2013. For that week, just 5 days, PD score increased 4.4%, as we can see from the sharp increase of the solid line. Starting from May 30, 2013, CTO has been used more consistently. This was one of the major factors for the significant increase in 2013 PD score. For 2013, the total PD saving was \$221 million.

All these applications form well-staged unit commitment, as shown in Figure 1.13. RT operation is based on DA commitment, which sets majority of the unit commitment for the operating day. At 18:00 before operating day, based on load forecast, RAC evaluates whether additional slow-start units are needed to cover load and operating reserve for the operating day. At the beginning of the operating day, CTO provides a whole-day 24 h recommendation of fast start unit commitment. It provides a fast start unit plan for the day. Normally, dispatch uses CTO to call the fast start units which have relatively long time to start and minimum run time. CTO runs multiple times during the day, typically at the beginning of the day, or going into peak. Based on short-term load forecast (STLF), IT-SCED looks ahead 2 h to

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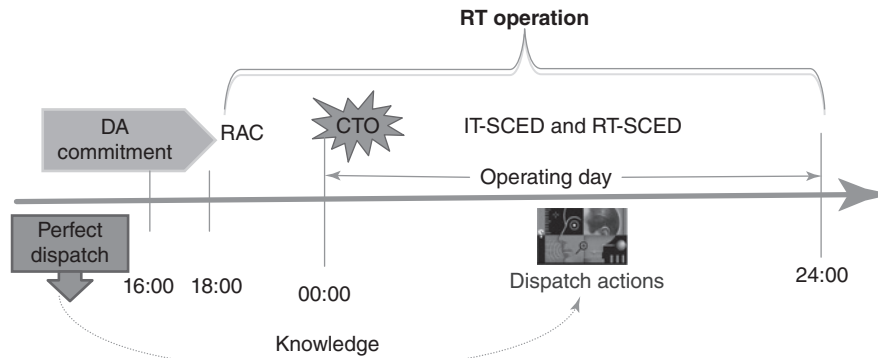


Figure 1.13 RT operation: staged unit commitment with multiple scenarios.

provide fast start unit commitment recommendation and RT-SCED looks ahead 15 min to send dispatch signals to resources. This way, slow-start resources must be committed before uncertainties are resolved and fast start resources and dispatch of all committed resources will be scheduled after uncertainties are resolved. All these tools have multiple scenarios to hedge uncertainties.

At the time of this writing, it is still challenging to incorporate uncertainties in the market clearing engines. Also, it is computationally very expensive and challenging to the stochastic or robust optimization software, especially tackling real-world problem.

From practical operation point of view, PJM addresses uncertainty through multistaged and continuous commitment. Instead of one piece of complicated software, multiple simple and fast software tools are staged for different levels of uncertainties. As we all know, when time is close to RT, uncertainty becomes much lower. For PJM system, there are lots of resources with fast startup capability, considering all uncertainties before operating day scheduling process could be overkill, especially if the gas-fired units are marginal units. Currently, over 30% of the marginal resources are gas units [23].

Dispatch makes all operation decisions. They use all these tools to operate the system. Knowledge is the key. PD provides operational analysis as knowledge for dispatch, based on previous operating days. This expert knowledge from PD as heuristic knowledge can help with setting or selecting scenarios, getting the solution needed for the system. Valuable PD analysis, commitment, and constraint control suggestions are provided to dispatch every day. The operation pattern is summarized as experiences or lessons learnt to make improvement suggestions.

In summary, staged unit commitment plus PD-based knowledge system effectively helps dispatch mitigate uncertainty and improve operation efficiency.

Figure 1.14 shows one of the ways knowledge is extracted from PD. It is a visual tool to compare fast start unit commitment at different stages, DA, CTO, IT_SCED as well as PD solution and RT. Dispatch consistently references this commitment comparison chart for historical days, and also the summary of daily operation with

1.3 ECONOMIC EFFICIENCY EVALUATION AND IMPROVEMENT: THE ECONOMICS 27

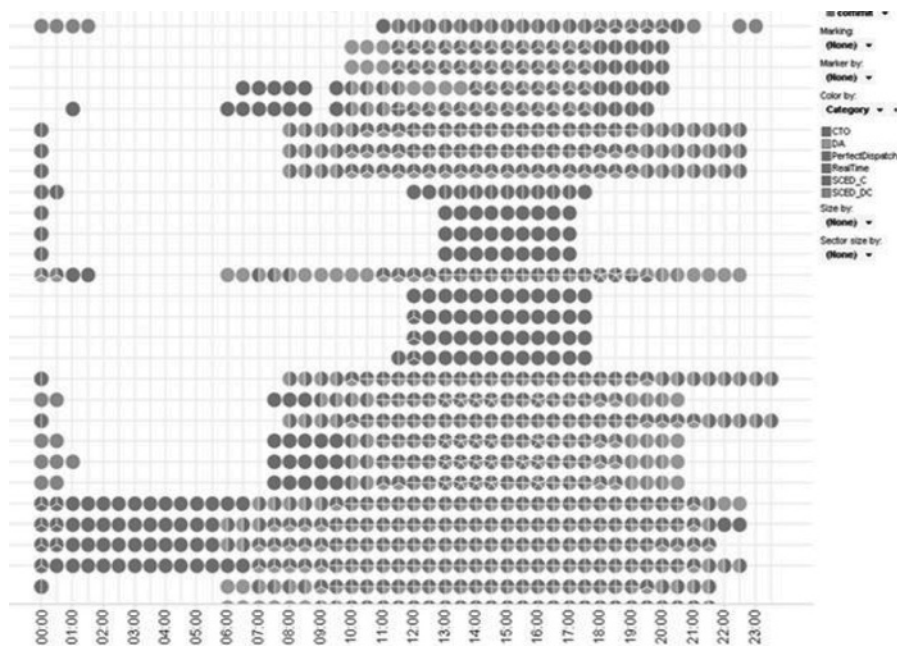


Figure 1.14 CT commitment comparison chart.

recommendations. Each color represents the commitment from one application. For example, for a unit and a specific hour, if all the applications commit it, it is shown as a five-color sliced pie.

To improve unit performance, on the one hand, unit performance impact information was provided to market participants, such as economic impact of unit performance, to increase their awareness, so that participants could provide more accurate bidding information, such as economic minimum, economic maximum, up and down ramp rate, and startup time [15]. On the other hand, efforts are being made toward accurately modeling unit characteristics, such as combined cycle unit modeling, pump storage modeling, and ramp rates, in economic scheduling and dispatch software. The idea of adaptive generation modeling has also been discussed [15].

After all these years' improvement, the economic efficiency of the system operation has been significantly improved. By the end of 2015, the cumulative production cost saving since 2008 was about \$1.2 billion, as shown in Figure 1.15. RT operation becomes much closer to the perfect solution, as shown in Figure 1.16.

The effort on improving economic efficiency continues. From the beginning of 2015, PJM started to tackle uncertainty, which caused the deviation from RT to PD solution: quantifying the impact of uncertainty and further reducing the impact, as shown in Figure 1.16.

Tackling uncertainties has always been part of the system operation to mitigate operation risks. Besides load uncertainty and growing uncertainty brought by renewable resources, interchange uncertainty is becoming one of the primary

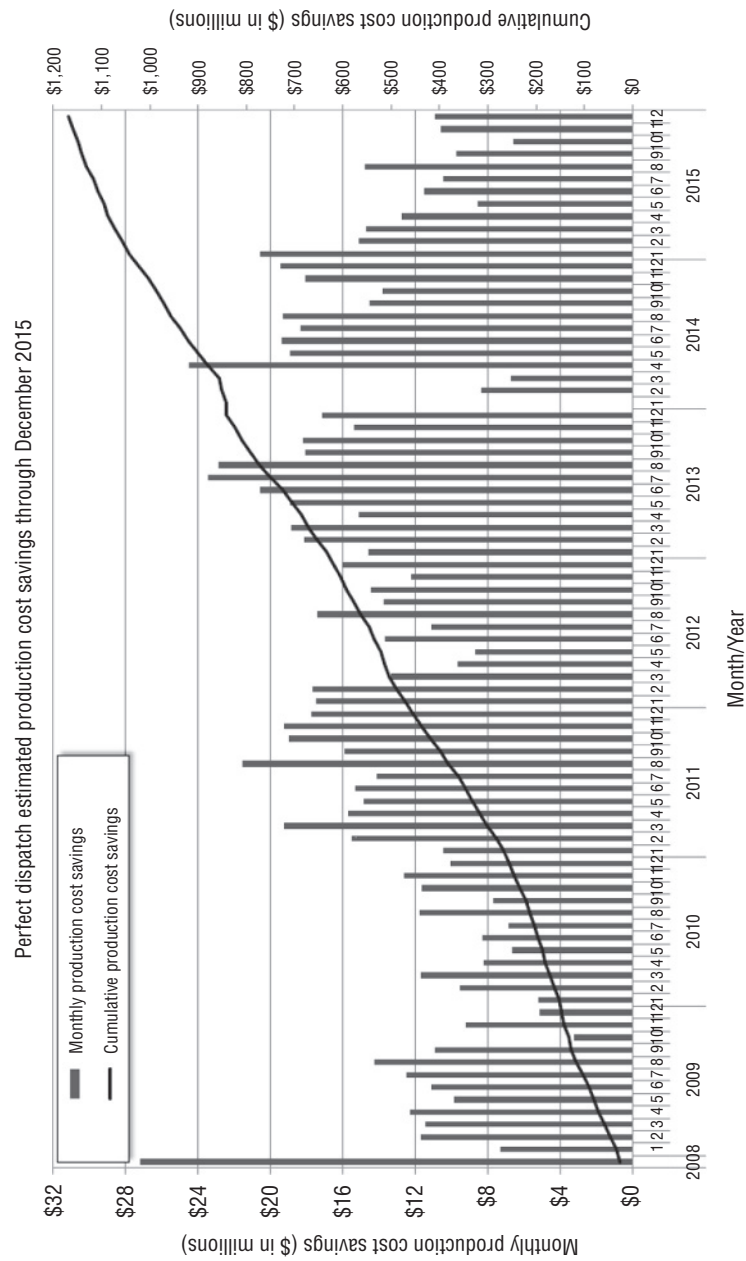


Figure 1.15 Perfect dispatch estimated production cost savings.

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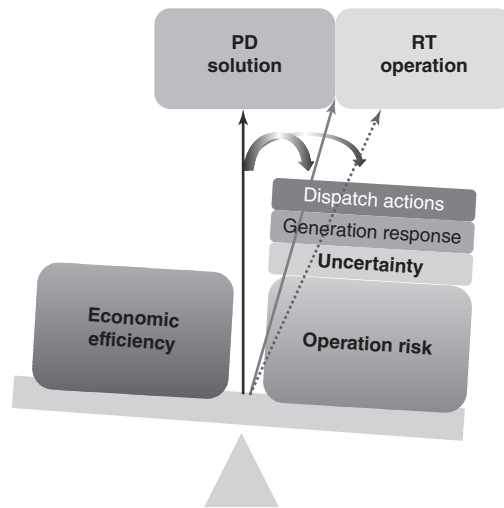


Figure 1.16 Improved economic efficiency.

uncertainty factors faced by system operators today. Uncertainties directly impact economic efficiency and remain to be a challenge. For 2015, PJM focused on tackling the load and interchange uncertainties, quantifying the monetary impact, as well as improving the processes to manage the uncertainties.

The focus was on tracking the load and interchange forecast at 18:00 of the previous operating day, used by RAC process to commit slow-start units; and the 2 h ahead load and interchange forecast used by IT-SCED to commit fast start units. The potential monetary impact was estimated based on system production cost. Each day, for each component, there was a forecast accuracy performance score calculated based on production cost impact. The goal was to improve economic efficiency through forecast improvement.

Figure 1.17 shows the component level performance. Dot-dashed line, representing 18:00 load forecast, significantly dropped during the last 2 weeks of

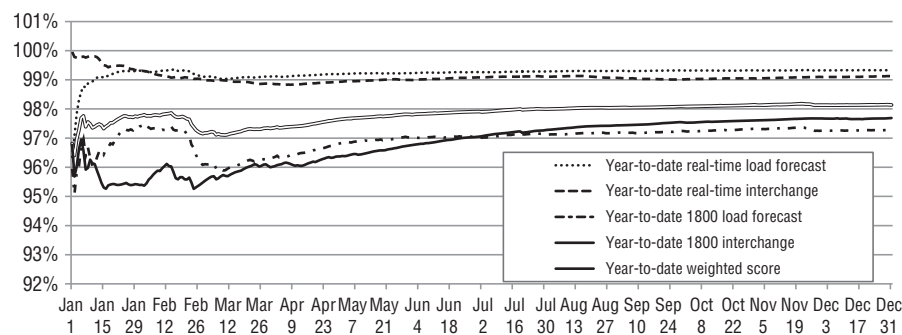


Figure 1.17 Forecast accuracy component level performance.

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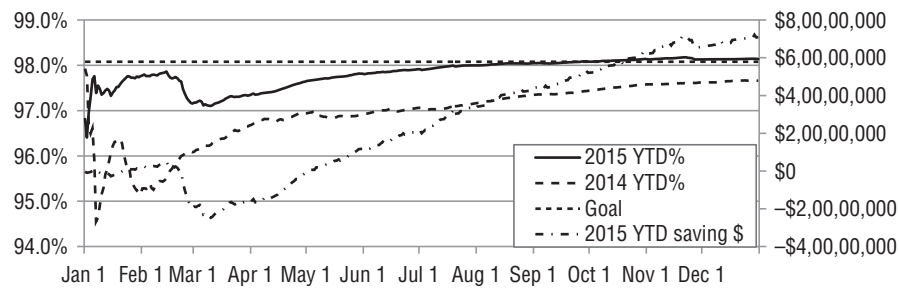


Figure 1.18 Forecast accuracy performance.

February. The new winter peak was set on February 20, 2015, at 143,295 MW. On that day, mean absolute percentage error (MAPE) of 18:00 load forecast was 1.7%, still less than 2%; however, its monetary impact was big, with low performance score of 94%. The solid line, representing 18:00 interchange, dropped first, then continuously increased from February 25, which was the day 18:00 simple interchange forecast was implemented.

Figure 1.18 shows the 2015 YTD performance compared with 2014 YTD performance. Solid line represents 2015 YTD performance; dashed line represents 2014 YTD baseline performance; dotted line represents 2015 goal; and the dot-dashed line represents the 2015 YTD monetary saving comparing to 2014. The vertical axis on the left shows the YTD performance and the vertical axis on the right shows the monetary saving. Comparing solid line with dashed line, 2015 performance was much better than 2014 baseline performance. Looking at the dot-dashed line, the YTD saving by the end of December was about \$71 million. The improved efficiency comes from forecasting improvement.

As shown in Figure 1.19, to improve load forecast, multiple forecasting methods are used, from simplest similar day to neural network models with different

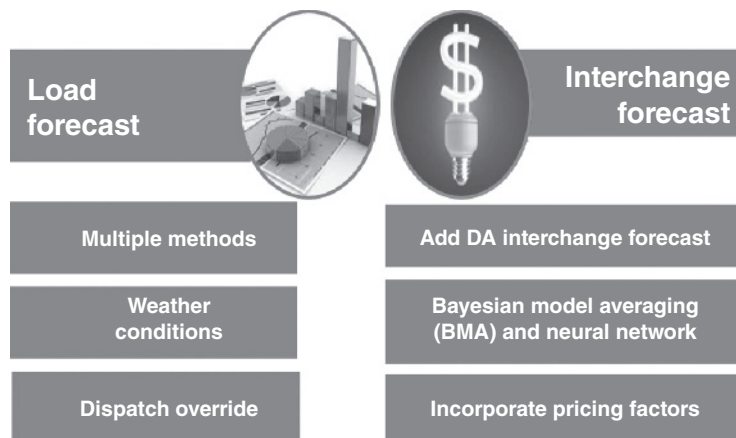


Figure 1.19 Forecasting improvement.

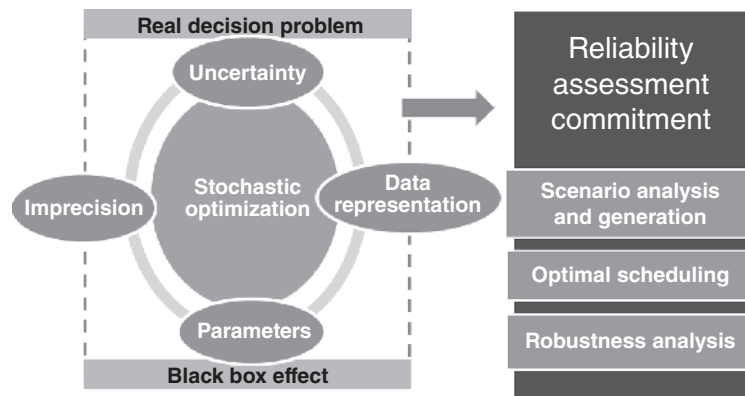


Figure 1.20 Robustness analysis of RAC.

factors considered, such as temperature and humidity. Weather condition significantly impacts system load. Better weather condition forecast, such as temperature, wind speed, humidity, and cloud covering across the region, helps to improve load forecast. Last but not least, dispatch empirical knowledge is also used. To improve interchange forecast, simple interchange forecast using similar day patterns was implemented for RAC on February 25, 2015. The accuracy has significantly improved. The performance increased from previous average of 95% to current average of 98%. Bayesian model averaging and neural network methods are also used for interchange forecast. Pricing factors are planned to be incorporated in the future to further improve interchange forecast.

In addition, to help dispatch hedge the uncertainty caused by load, RAC process is further improved to provide the corresponding load coverage for the slow-start unit commitment, based on the historical statistic data of the load. As shown in Figure 1.20, due to many uncertainty factors and data imprecision, the real decision problem is by nature a stochastic optimization problem. However, using stochastic optimization requires explicit data representation (e.g., probabilities), which is normally not known and needs strong assumptions. Further, an enormous number of parameters are introduced in the approach and can lead to black box effect, which is not desirable in the decision-aiding process. Practically, to hedge risk, robustness analysis is integrated into RAC decision. First, based on historical data, uncertainty is modeled in a manageable set of scenarios and incorporated in RAC. Then, the optimal scheduling solutions for these scenarios are obtained. The robust analysis is to evaluate the “robustness” of the scheduling solution, which is insensitive to data uncertainty and can cover a range of scenarios.

1.3.4 Challenges

1.3.4.1 DC Model in Market Clearing

DC model is generally applied in the market clearing process for the sake of solution stability and speed. However, the limit of the DC approximation, such as no losses

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and no reactive power calculation, brings complexity and difficulty to the modeling of losses and voltage-/reactive power-related constraints. Since RT AC power flows are available from the latest SE solution data, the information can be utilized to modify the flow calculation in the dispatch process for higher accuracy.

With DC model in the clearing engine, transmission losses are modeled as a linearization function of bus injections and withdrawals, and the total system loss from the AC solution is used to calculate the deviation from linearization. Transmission losses are explicitly modeled in power balance constraints and transmission security constraints. Load-weighted distributed slack busses are normally used as market reference to keep reference at the system load center [62].

The linear network model also limits the capability of representing reactive power-related constraints in market clearing. In terms of voltage-/reactive power-related transmission security constraints, general practice is that they are translated to the real power limits or thermal surrogate limits, then LMP-based congestion management is used to reflect the system voltage-related control needs. In the case that there is no corresponding real power limits created for voltage and voltage stability problems, operators' manual actions have to be taken, either committing units or manually dispatching down units for voltage support. These OOM actions result in uplift in market operation.

When thermal surrogate is used for voltage- and reactive power-related control, units are re-dispatched based on sensitivity of generation of real power change to the real power flow change on the thermal surrogate. Sometimes, using thermal surrogate for voltage control is not very effective and could also have undesirable system-wide impact. Meanwhile, sensitivities directly related to loading margin indicate the effectiveness of the control actions to voltage collapse problem [63–66]. It would be desirable to use loading margin sensitivities for generation re-dispatch when the system is constrained by voltage stability, so that voltage collapse could be controlled more cost-effectively. Further, load has big impact on voltage stability, and load reduction is sometimes more effective than generation re-dispatch to control voltage collapse problem. Therefore, highly nonlinear voltage stability-related constraints need to be explicitly modeled in the market clearing process [63, 64].

1.3.4.2 *Deterministic Methods in Market Clearing*

Currently, all the market clearing tools are based on deterministic methods. There is no easy way to incorporate uncertainty data. Stochastic programming and/or robust optimization are still not used in practical systems yet, due to modeling and computation challenges.

Under current practices, security criteria are considered set by the reliability standard. There is not much variation based on risk assessment. For example, reserve requirements are normally statically predetermined based on historical data and/or procedure and do not vary based on changing system reliability needs. Most of the times have higher level of conservativeness than required by the actual conditions, which adversely impact economic efficiency. $N-1$ and/or $N-2$ contingency criteria are also extensively used. It is easy to implement, but ignores the probabilities of

contingencies. It often leads to higher cost due to over-conservativeness. Occasionally, it may adversely impact reliability.

To increase economic efficiency, considering that the probability of contingency occurrence is very small, thermal contingency control could be less conservative. The take-risk strategy could effectively reduce the operation cost [67]. The challenge is how to accurately determine the probability of the contingency, so that proper contingencies can be considered in system and market operation. At present, probability analysis has not been used in RT operation, due to data availability, model complexity, and long computing time.

Stringent deterministic methods also cause transmission constraints to bind or unbind abruptly, resulting in dispatch swing or solution volatility. Manual dispatch actions sometimes are taken under operation pressure to obtain more “stable” or “reasonable” solutions. However, manual action could adversely impact economic efficiency. With current deterministic practices, adaptive rating could help to improve economic efficiency and system reliability.

Uncertainties always exist in system operation. With current deterministic methods, it is challenging to handle the increased uncertainty brought by high penetration of renewable resources, impacting transmission constraint control, as well as properly reflecting system reserve needs. In the systems with significant percentage of renewable resources, such as California, ramping limits play critical roles in system operation. Stochastic methods will be covered in Chapters 5 and 6 to address the challenges.

1.3.4.3 Resource Modeling in Market Clearing

Due to software limitation, resources have limited parameters modeled in market clearing engine, normally including startup time, shutdown time, minimum run time, minimum down time, ramp-up limit, and ramp-down limit. Sometimes, the bid-in parameters cannot reflect the physical limitations, for example, dynamic ramping capabilities, startup and shutdown profiles, operating bands, turnaround time, and mill point. In this case, dispatch signals may be difficult to follow.

Combined cycle unit modeling is another challenge. The easiest way and also the most common way is to model combined cycle plants as composite units, which have same bid-in parameters as other units. With composite model, market participants have to provide proper parameters to reflect combined cycle plants’ physical capabilities, which is hard to be accurate. Also, it is hard to reflect actual transmission constraint impact from each component. Some markets, such as ERCOT, use component-based model to reflect actual components’ characteristics and impact. The number of combined cycle units to commit in the market is still limited in ERCOT, since most of them are self-scheduled. Therefore, performance is not a big concern there. However, for bigger markets with more combined cycle commitment in DA, performance issue definitely needs to be addressed before actual application.

Pump storage modeling is another challenge. Limited energy generation model is used for simplicity [11]. How to schedule or optimize pump storage hydro in market clearing is still a hot topic which has significant practical values. More sophisticated three-stage models, that is, pumping, generating, and offline stages, are also used

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[23]. The detailed modeling of other storage devices, such as batteries, and demand responses are still needed to be explored and refined in practices.

1.3.4.4 Real-Time Commitment and Pricing

RT unit commitment has been providing incremental unit commitment based on changing system conditions. It improves economic efficiency in general.

However, due to the nature of the commitment problem, the LMPs may not justify the commitment decision, which could result in RT uplift. As an effort to further reduce uplift, different pricing mechanisms are used to reflect certain commitment cost in LMPs. Some markets have special pricing logic to allow fast start units to set price when the units are actually needed for system operation [23]; some markets amortize commitment cost in the incremental bid cost [11]; and some markets implement extended LMP model [24]. What should be the right price? There is still no definite answer for it.

Convex clearing algorithms, as those used in some places in Europe, are great in this perspective, as they produce definite prices.

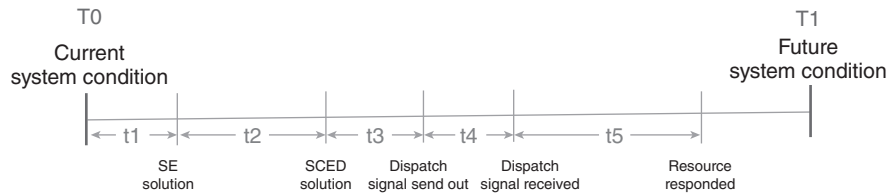
1.3.4.5 Topology Flexibility

System topology is normally considered given in market clearing. In RT operation, topology control is only used for a predetermined set of transmission switching options and considered as no-cost solution. The flexibility of system topology is underused due to tool limitation. During operational planning, the outage analysis is mainly focused on reliability impact. The decision to approve or deny outage request is mainly based on reliability study. There is still no systematic way to evaluate the economic impact of outages. Some markets start to have simplified process [11, 23]. Harnessing topology flexibility is still challenging at this stage in practices and will be extensively discussed in Chapters 7 and 8.

1.3.4.6 Dispatch Time Delay and Volatility

Most of the research efforts are focused on algorithms and functional improvement. In reality, time delay is also a very important factor impacting dispatch, which is currently not explicitly factored into the algorithms yet.

As shown in Figure 1.21, from current system condition T0, to future system condition T1, total time delay can easily add up to at least 5 min currently. At PJM,



$$\text{Total dispatch time delay} = t1 + t2 + t3 + t4 + t5$$

Figure 1.21 Dispatch time delay.

the SE solution is updated every minute. In other ISO/RTOs, SE solution could be updated less frequently, for example, every 3–5 min. Therefore, t_1 could be around 1 min, or longer. SCED solves based on SE solution and could take around 2 min. Dispatch evaluates SCED solutions and sends out final dispatch signals. The process t_3 could take about 1–3 min. For the extreme situation, it may even take 5 min. From dispatch signal sent out, to resources receiving dispatch signal, it takes about 1 min. Resources then respond to the dispatch signal to meet future load and system needs. The time delay, t_5 could take from 1 to 5 min. Therefore, the total dispatch delay can easily add up to 6–14 min. The look-ahead time, $T_1 - T_0$, should be greater than the total dispatch time delay; otherwise, the solution would not be very accurate.

Due to these time delays, dispatch needs to control early to avoid potential overload. Currently, there is no good way to systematically predict how early it should be, heavily depending on dispatch experiences. Furthermore, generation response is not quite predictable either. Properly factoring time delay of price control can help improve economic efficiency of RT system operation.

1.4 FINAL REMARKS

Figure 1.22 summarizes the road map toward better price signals to reflect operation risk mitigation and incentivize resources for more flexibility to respond to system operation needs, therefore, improved economic efficiency. It captures latest industry practices, which is still changing.

There are three main stages of market design and implementation.

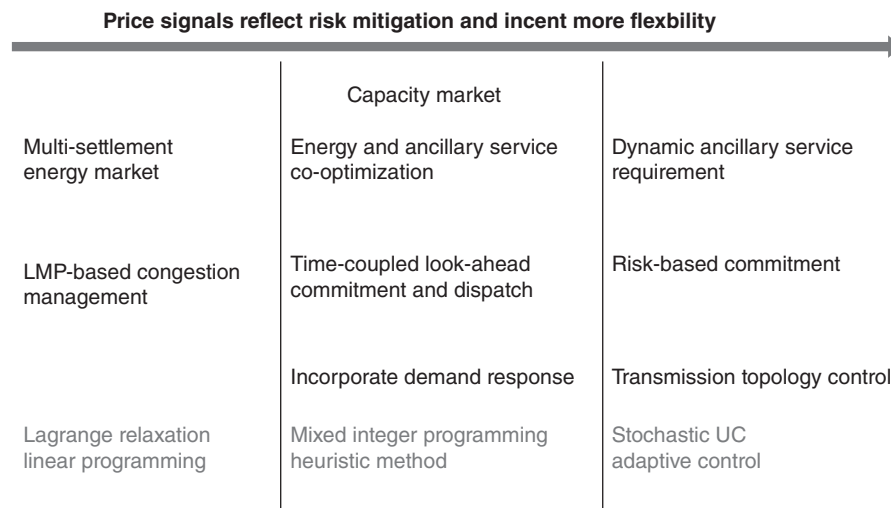


Figure 1.22 Road map.

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The first stage sets the basic market design: multi-settlement energy market and LMP-based congestion management. During the first stage, solution algorithm was mainly Lagrange relaxation and linear programming.

The second stage starts to develop capacity market to provide long-term reliability price signals, implement ancillary service markets which is co-optimized with energy to provide overall economic efficiency, use time-coupled look-ahead commitment and dispatch to help RT operation, and also incorporate demand response in the market to help both reliability and efficiency. During this stage, mix-integer programming is used in the solution, and different heuristic methods are also developed to help with market solution.

Markets are further evolving into the third stage, working on dynamic ancillary service requirements and risk-based commitment to handle increased system uncertainties, and exploiting transmission topology control for both reliability and economics. These new development features need new algorithms to support, such as stochastic unit commitment and adaptive control. The rest of the book will address some of these challenges.

APPENDIX 1.A NOMENCLATURE

<i>i</i>	Index for all generators
<i>j</i>	Index for all price-sensitive demands
<i>t</i>	Index for all reserve types, for example, 10-min synchronized (or spinning) reserve, 10-min non-synchronized reserve, and 30-min operating reserve
<i>k</i>	Index for all transmission constraints
<i>s</i>	Index for all reserve constraints
<i>n</i>	Index for all busses in the system
<i>G</i>	Set of generators
<i>RC</i>	Set of reserve category
min	Superscript that indicates the minimum value
max	Superscript that indicates the maximum value
SE	Superscript that indicates values obtained from state estimator solution
10	Superscript that indicates values that can be achieved in 10 min
30	Superscript that indicate values that can be achieved in 30 min
up	Superscript that indicates the upper bound
dn	Superscript that indicates the lower bound
<i>c</i>	Offer price for generators
<i>b</i>	Bid price for price-sensitive demand
<i>o</i>	Offer price for reserves
<i>R</i>	Reserve quantity

P	Generation output
D	Output of price-sensitive demand
L	Fixed demand
flow	Real power flow over a transmission line or a transmission corridor
Q	Reserve requirement
P_{loss}	System real power losses
$\delta_{t,i}^x \text{ or } j$	Binary value: 1 represents that reserve type t from generator i or price-sensitive demand j belongs to the set x
RC_i^T	Ramping capability of generator i within the dispatch interval T
RC	Ramping capability for generators or price-sensitive demand
λ	Shadow price of energy balance constraint
μ	Shadow prices of transmission security constraints
β	Shadow prices of reserve requirement constraints
γ	Shadow prices of capacity constraints
η	Shadow prices of ramp constraints, or upper/lower bounds of generators and price-sensitive demand
$\xi_{t,i}^{\min}$	Shadow prices of lower bounds for reserve quantity

APPENDIX 1.B ELECTRICITY MARKET MODEL

Most of the electricity markets are administered by ISO/RTO or market administrators. Market participants include generation companies (GenCo), distribution companies (DisCo), load serving entities (LSE), transmission companies (TransCo), pure financial companies, large industry load, or load aggregators.

Offers are submitted for generators and bids are submitted for dispatchable demand. Uniform marginal pricing is commonly used in current electricity market clearing, that is, market price is determined by the intersection of supply curve and demand curve [68]. All supply units with prices lower or equal to the market price are scheduled to produce.

Energy and reserve co-optimization-based market clearing model is generally used. The objective function is to minimize the total production cost, as shown in equation (1.B.1)

$$\text{Min } \sum_{i \in G} \left(c_i P_i + \sum_{t \in \text{RC}} (o_{t,i} \cdot R_{t,i}) \right) + \sum_j \left(-b_j \cdot D_j + \sum_{t \in \text{RC}} (o_{t,j} \cdot R_{t,j}) \right) \quad (1.B.1)$$

subject to the following constraints:

(1) Energy balance constraint:

$$(\lambda) : \sum_{i \in G} P_i = \sum_n L_n + \sum_j D_j + P_{\text{loss}} \quad (1.B.2)$$

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where interchanges are considered in the fixed demand, L_n in this case. System loss is linearized as following:

$$P_{\text{loss}} = \sum_i \left(\frac{\partial P_{\text{loss}}}{\partial P_i} \cdot P_i \right) + \sum_n \left(\frac{\partial P_{\text{loss}}}{\partial L_n} \cdot L_n \right) + \sum_j \left(\frac{\partial P_{\text{loss}}}{\partial D_j} \cdot D_j \right) + \text{offset}$$

where offset is the linearization error [62].

(2) Transmission security constraints:

$$(\mu_k) : \text{flow}_k \leq \text{flow}_k^{\max} \quad (1.B.3)$$

Based on linearization, transmission flow is represented as following:

$$\text{flow}_k = \sum_i \left(\frac{\partial \text{flow}_k}{\partial P_i} \cdot P_i \right) + \sum_n \left(\frac{\partial \text{flow}_k}{\partial L_n} \cdot L_n \right) + \sum_j \left(\frac{\partial \text{flow}_k}{\partial D_j} \cdot D_j \right) + \text{bias}$$

where bias is the linearization error.

(3) Reserve constraints:

$$(\beta_s) : \sum_i \sum_t (\delta_{t,i}^s R_{t,i}) + \sum_j \sum_t (\delta_{t,j}^s R_{t,j}) \geq Q_s \quad (1.B.4)$$

(4) Capacity constraints for units:

$$(\gamma_i) : P_i + \sum_t R_{t,i} \leq P_i^{\max} \quad (1.B.5)$$

(5) Capacity constraint for dispatchable demand:

$$(\gamma_j) : D_j - \sum_t R_{t,j} \geq D_j^{\min} \quad (1.B.6)$$

(6) Ramp constraints for generating units:

$$(\eta_i^{\text{up}}) : P_i \leq P_i^{\text{SE}} + \text{RC}_i^T \quad (1.B.7)$$

$$(\eta_i^{\text{dn}}) : P_i \geq P_i^{\text{SE}} - \text{RC}_i^T \quad (1.B.8)$$

(7) 10-min ramp capability constraints:

$$(\eta_i^{10}) : \sum_t (\delta_{t,i}^{10} \cdot R_{t,i}) \leq \text{RC}_i^{10} \quad (1.B.9)$$

$$(\eta_j^{10}) : \sum_t (\delta_{t,j}^{10} \cdot R_{t,j}) \leq \text{RC}_j^{10} \quad (1.B.10)$$

(8) 30-min ramp capability constraints:

$$(\eta_i^{30}) : \sum_t (\delta_{t,i}^{30} \cdot R_{t,i}) \leq \text{RC}_i^{30} \quad (1.B.11)$$

$$(\eta_j^{30}) : \sum_t (\delta_{t,j}^{30} \cdot R_{t,j}) \leq \text{RC}_j^{30} \quad (1.B.12)$$

(9) Upper and lower bounds of decision variables

$$(\eta_i^{\min}) : P_i \geq P_i^{\min} \quad (1.B.13)$$

$$(\eta_i^{\max}) : P_i \leq P_i^{\max} \quad (1.B.14)$$

$$(\eta_j^{\min}) : D_j \geq D_j^{\min} \quad (1.B.15)$$

$$(\eta_j^{\max}) : D_j \leq D_j^{\max} \quad (1.B.16)$$

$$(\check{\epsilon}_{t,i}^{\min}) : R_{t,i} \geq 0 \quad (1.B.17)$$

$$(\check{\epsilon}_{t,j}^{\min}) : R_{t,j} \geq 0 \quad (1.B.18)$$

For constraints (1.B.2)–(1.B.18), λ , μ , β , γ , η , and $\check{\epsilon}$ are the corresponding shadow prices, that is, Lagrange multipliers.

Based on marginal pricing, the LMP for each bus n is defined by equation (1.B.19):

$$\text{LMP}_n = \lambda \left(1 + \frac{\partial P_{\text{loss}}}{\partial D_n} \right) - \sum_k \left(\mu_k \cdot \frac{\partial \text{flow}_k}{\partial D_k} \right) \quad (1.B.19)$$

The RCP is defined by equation (1.B.20):

$$\text{RCP}_{t,i} = \sum_s (\beta_s \cdot \delta_{t,i}^s) \quad (1.B.20)$$

When the capacity constraint binds, energy price LMP_n is coupled with reserve clearing price $\text{RCP}_{t,i}$.

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