Electricity Markets in the United States: A Brief History, Current Operations, and Trends

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Abstract The global energy landscape is witnessing a concerted effort toward grid modernization. Motivated by sustainability, skyrocketing demand for electricity, and the inability of a legacy infrastructure to accommodate distributed and intermittent resources, a cyber-physical infrastructure is emerging to embrace zero-emission energy assets such as wind and solar generation and results in a smart grid that delivers green, reliable, and affordable power. A key ingredient of this infrastructure is electricity markets, the first layer of decision-making in a smart grid. This chapter provides an overview of electricity markets which can be viewed as the backdrop for their emerging role in a modernized, cyber-enabled grid. Starting from a brief history of the electricity markets in the United States, the article proceeds to delineate the current market structure, and closes with a description of current trends and emerging directions.

1 Introduction

An electricity market enables trade of electricity between suppliers and consumers. An efficient market is one where electricity is traded at a price that minimizes the cost of generation while supplying the demand. The overall market goals are to ensure efficient pricing of electricity generation, incentivize enhanced grid services and infrastructure maintenance. The outputs of the electricity market can, therefore, be viewed as set-points for the actual units that generate or consume electricity. As electricity cannot be stored in large quantities at the current cost of energy storage, the amount of electricity generated must match the demand at every instant of time. It is, therefore, not surprising that electricity markets range over a broad timescale, from years to seconds, to accommodate planning as well as operations. Examples include markets for Forward Capacity, Energy, and Ancillary Services.

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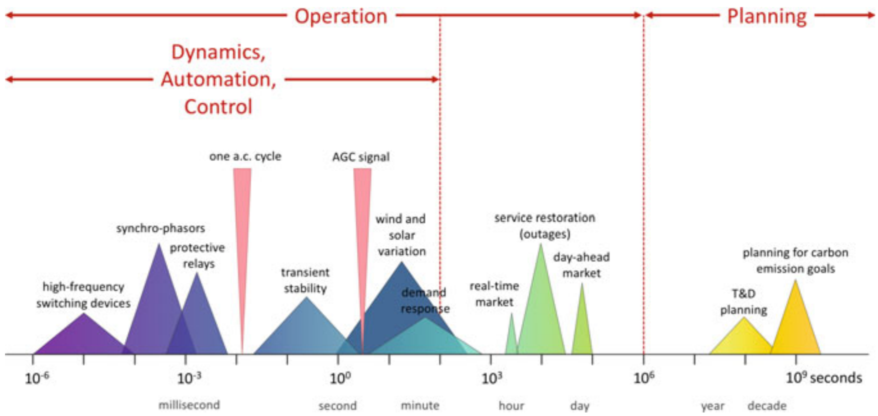

Fig. 1 Illustration of typical planning and operation market timescales (adapted from [55])

While economic theory is the underlying tool utilized in order to govern the principles of electricity markets, such a tool alone is not sufficient, as the products and services transacted in electricity markets have to interact with the physical grid and satisfy its constraints. That is, electricity markets lie in the intersection of two systems, the financial and the physical, which makes their analysis and synthesis highly challenging. What makes it even harder is the current transformation that the grid is witnessing, toward modernization, toward a cyber-enabled architecture, toward a smart grid. This transformation is, therefore, providing a cause for revisiting the electricity market structure, its mechanisms, and its overall coupling with the physical power grid.

Figure 1 shows typical timescales of commonly found markets in the US with respect to other power system planning and operation processes. Because of the multi-year lead times for building electric power plants and transmission projects, planning markets exist in many places in the US in order to ensure that the overall supply of electricity will be able to meet projected demand. Markets that govern operation, termed day ahead (DA) and real-time (RT) markets, ensure that the instantaneous supply of and demand for electric power are balanced in a least-cost manner. The DA market clears a day prior to operation for 24 hourly intervals, while the RT market clears an hour ahead of operation for 5–15 min intervals. Whether in planning or in operations, these markets operate following certain rules and guidelines, which are set by regional transmission operators (RTOs), in accordance with regulators appointed by the government.

In order to set the stage for the impact of the Smart Grid Vision on the market structure, in the following sections, this tutorial seeks to provide an overview of electricity market structure in the United States. A brief history of the electricity market is provided in Sect. 2. An overview of the market structure is delineated in Sect. 3. Some of the major changes that the smart grid paradigm has precipitated are discussed in Sect. 4.

2 A Brief History of Electricity in the US

Since the invention of electricity in the eighteenth century, the evolution of the electricity market can be organized into three parts, the War of Currents and rise of the vertically integrated firm (1880s–1930s) leading up to a viable business model for generating and delivering electricity, the regulated utility (1930–1970), and subsequent deregulation (1970–1990). Each of these parts are described in the sections below.

2.1 War of Currents and Rise of the Vertically Integrated Utility

Subsequent to the understanding of the generation of electricity, the technological battle that ensued pertains to the use of AC (championed by Nicola Tesla) versus DC (championed by Thomas Edison) for power generation and transmission. Edison's support for DC stemmed from the fact that his well-known invention of the light bulb needed a distribution network as a foundation for large-scale expansion, and he believed that low-voltage (110 V) direct current (DC) was the only safe way to distribute electric power. On December 17, 1880, he founded the Edison Illuminating Company and went on to establish the first investor-owned electric utility in 1882 at the Pearl Street Station. From the Pearl Street Station, Edison operated a low-voltage DC "microgrid", which provided 110 V DC to 59 customers in lower Manhattan in New York City [1]. A foil to this technology came from Tesla, who had initially worked for the Continental Edison company tasked with the redesign of Edison's DC generators, and came to believe that many of the DC generators' demerits could be overcome with AC-transmission. The subsequent battle of ideals, now famously dubbed as the War of Currents, would be won by Tesla, and led to a series of US patents that laid the foundation for the AC-alternative to Edison's DC system. These patents were then sold to the Westinghouse Electric Company in 1888. Its owner, George Westinghouse, took advantage of the limited transmission range of low-voltage DC-power, and expanded transmission to beyond urban centers. Subsequently, Westinghouse and his AC distribution system prevailed. The War of Currents ended when Thomas Edison, facing shrinking profits relative to his AC rivals, merged his company with a more successful AC firm, the Thomas-Houston Electric Company, to form General Electric in 1892. Battles between GE and Westinghouse continued for the next few years.

The next step in the development of modern electricity markets in the US was entrepreneurial rather than technological. This step can be attributed to Samuel Insull, who introduced a demand-adjusted billing system in which there were two tiers of prices: one for low demand times and one for high demand times. This strategy increased profits by increasing overall power consumption, allowing the continuous running of base-load plants leading to better returns. Insull's holding companies grew in value to $500 million with a capital investment of only $27 million [68]. The stock market crash of 1929 and the ensuing Great Depression, however, introduced several singularities into the picture leading to a collapse of Insull's enterprise.

The above discussions indicate that economies of scale combined with concerns over reliability led to a firm establishment of the current grid infrastructure of AC generation and transmission. Large, vertically integrated utilities that generated, transmitted, and distributed power—and which were natural monopolies—arose to capture the economies of scale. After the collapse of Insull's company, it also became clear that these natural monopolies required regulatory oversight. This, in turn, led to Congress passing the Public Utility Holding Company Act (PUHCA) in 1935, which enabled state regulation of electric utilities, and gave federal oversight responsibilities to the Securities and Exchange Commission (SEC) and the FPC.

2.2 NERC, FERC, and Deregulation

The rapid expansion of electricity demand over the next few decades led to frequent brownouts in the 1960s, culminating in a massive blackout across the eastern seaboard in 1965, led to the creation of the National Electric Reliability Council (NERC) in 1968 that subsequently became the North American Reliability Corporation [29]. NERC divided North America into several interconnected regions and oversaw these entities to fulfill its mandate of ensuring reliability of the power system.

The energy crisis in the 70s, caused in part by the oil embargo, led to a shortage of natural gas, and rising oil prices. Due to the inefficient oversight of the FPC, Congress reorganized it as the Federal Energy Regulatory Commission (FERC), an independent commission within the newly formed Department of Energy in 1977. FERC worked to develop simpler approval procedures and eliminated the direct oversight of utilities, regulating instead the transmission grid, wholesale markets, and approvals of important mergers and acquisitions in the energy sector.

As a direct response to the energy crisis, Congress enacted the Public Utility Regulatory Policies Act (PURPA) in 1978, which promoted conservation, domestic energy production, and development of efficient co-generation and non-fossil fuel resources. PURPA also opened the market to non-utility generators or independent power producers (IPP) who could produce power at a lower cost than the vertically integrated utility, in which case the utility was mandated to buy this cheaper power and pass the "avoided cost" savings to their customers. This was an important first step toward broader restructuring of the electricity industry [56].

The late 1970s and 1980s saw continued, but gradual, deregulation of the energy sector. The Energy Policy Act of 1992 gave FERC the authority to mandate that a utility provides transmission access to eligible wholesale entities, including wholesale buyers such as large industrial customers and exempt wholesale generators (merchant generators). This was an important step in the development of bulk electricity markets in the US. It is important to note that retail competition and consumer choice, are not, and never were, under the authority of FERC, rather these decisions belong to state legislatures and regulators. Finally, in the 1990s, FERC issued a series of orders that led to modern-day wholesale electricity markets.

FERC Order 888, often referred to as the "open access" rule required utilities to unbundle wholesale generation and power marketing, identified ancillary services required to operate a bulk power system. To achieve the goal of open access, five non-profit Independent System Operators (ISOs) were created, California Independent System Operator (CAISO), New York ISO (NYISO), Electric Reliability Council of Texas (ERCOT), Midcontinent Independent System Operator (MISO), and ISO New England (ISO-NE). FERC Order 889 created the Open Access Same-time Information System (OASIS), which specified standards of conduct that would allow the transmission customers described in Order 888 to have nondiscriminatory access to the transmission grid, which was ensured by wholesale electricity markets run by the ISOs. FERC Order 2000 established guidelines that a transmission entity must meet to qualify as a regional transmission operator (RTO) and required that all public utilities that own, operate, or control transmission networks must "make certain filings with respect to forming and participating in an RTO" [23]. Every US ISO is also designated as an RTO—additional, non-ISO RTOs include PJM Interconnection (PJM) and Southwest Power Pool (SPP)—whose role of RTOs is largely similar to ISOs, but with additional responsibility for the reliable operation and expansion of the transmission grid.

FERC continues to issue rulings to improve market operation and ensure that consumers receive the lowest cost for reliable electricity, notable examples being Order 745 (in 2011) and Order 825 (in 2016). These are discussed in the subsequent sections, and are related to oversight of the emerging concepts of Demand Response and Settlement Reform, respectively.

3 An Introduction to Wholesale Energy Market Operation

Every RTO in the US operates multiple wholesale electricity markets, where various products and services are bought and sold, including bulk energy, financial transmission rights, and ancillary services. In this section, we focus on wholesale *energy* markets. We start by describing market objectives, followed by an introduction to day ahead (DA) and real-time (RT) energy market operation, typical unit commitment and economic dispatch (UC and ED) problem formulation, and, finally, an overview of typical settlement rules. This section is not meant to be a comprehensive guide to market products or operation in any particular RTO, but rather an overview of the energy market operation. The goal of this section is to provide a flavor of the kinds of problems that ISOs formulate and solve today. For details of the DA and RT markets as well as markets for forward capacity and ancillary services, we refer the reader to the publicly available best practice manuals and user guides published by the each [35, 57, 58, 62, 66].

3.1 Market Objectives

Every RTO in the US operates DA and RT markets, with the primary objective of maximizing overall social welfare—i.e., maximize the sum of consumer and producer surplus by maximizing their utility functions and minimizing their cost functions. Other market objectives include providing incentives for market participants to follow commitments and dispatch instructions, transparency, maintaining system reliability, and ensuring that suppliers have an opportunity to recover their costs. We discuss a generic implementation of a fully centralized UC in the DA market to determine the generators that will run in the operating day, followed by a nodal ED in the DA and RT markets. In the ED markets, we assume energy and reserve capacity are cleared simultaneously, which is a common practice in most RTOs today. We discuss a DA market model that is settled ex-ante (i.e., before operation) on hourly intervals, and an RT market that is settled ex-post (i.e., after operation) based on 5-min intervals.

3.2 Day Ahead and Real-Time Energy Markets

The main product that DA and RT markets deal with is energy, which is specified as a power set-point over an interval, including start time and duration, at a specific location on the network. Both DA and RT markets include a security constrained[1] ED to dispatch power in the most economical way possible given the forecast and physical operating conditions. The DA energy market also requires a security constrained UC to optimally schedule generators to ensure that they will be available to provide energy and other ancillary services in real time.

3.2.1 Day Ahead Markets

For simplicity, we ignore the security constraints of DA and RT operation, we begin with the basic UC and ED problem formulations. Inputs to the UC problem include load and weather forecasts, regulation and reserve requirements, and, from each market participant, bid/offer curves, start-up, and shut-down costs, generator parameters such as ramp up/down rates, along with integer minimum up/downtime constraints. We consider full network power flow constraints in our formulation. The output of the UC problem is the set of generators that will run at each of the 24 intervals in the operating day, which is called the *day ahead operating schedule*. Figure 2 shows a very simplified operational timeline of the DA market. Table 1 introduces all notations used in this article.

With these assumptions in place, the unit commitment problem is a mixed integer (linear) program (MIP) of the following form:

[1] Security constraints are additional constraints that ensure line flows do not exceed specified limits following the occurrence of any one of a set of specified contingencies.

Table 1 Notation used in the market problem formulations

Symbol	Description
$\mathcal{N}$	Set of buses in the network
$\mathcal{E}$	Set of branches in the network
$\mathcal{M}$	Set of generators participating in the market
$\mathcal{L}$	Set of loads participating in the market
$i \sim n$	Generator $i \in \mathcal{M}$ adjacent to bus $n \in \mathcal{N}$
p_{it}	Power dispatch of generator $i \in \mathcal{M}$ at time t
$\overline{p}_i$	Maximum stable power output of generator $i \in \mathcal{M}$
$\underline{p}_i$	Minimum stable power output of generator $i \in \mathcal{M}$
d_{jt}	Demand of load $j \in \mathcal{L}$ at time t
$k \sim n$	Line $k \in \mathcal{E}$ incident to bus $n \in \mathcal{N}$
$\overline{d}_j$	Maximum demand of load $j \in \mathcal{L}$
$\underline{d}_j$	Minimum demand of load $j \in \mathcal{L}$
D_t	Total demand at time t
r_{it}^u	Up-reserve capacity of generator $i \in \mathcal{M}$ at time t
r_{it}^d	Down-reserve capacity of generator $i \in \mathcal{M}$ at time t
R_t^u	Total up-reserve requirement at time t
R_t^d	Total down-reserve requirement at time t
u_{it}	Commitment flag of generator $i \in \mathcal{M}$ at time t, $u_{it} \in \{0, 1\}$
a_{it}	No-load cost for generator $i \in \mathcal{M}$ at time t
b_{it}	Marginal generation cost for $i \in \mathcal{M}$ or marginal utility of consumption for load $j \in \mathcal{L}$ at time t
z_{it}^u	Start-up flag for generator $i \in \mathcal{M}$ at time t, $z_{it}^u \in \{0, 1\}$
z_{it}^d	Shut-down flag for generator $i \in \mathcal{M}$ at time t, $z_{it}^d \in \{0, 1\}$
s_{it}^u	Start-up cost for generator $i \in \mathcal{M}$ at time t
s_{it}^d	Shut-down cost for generator $i \in \mathcal{M}$ at time t
$\overline{\Delta}_i^u$	Maximum up-ramp capability for generator $i \in \mathcal{M}$
$\overline{\Delta}_i^d$	Maximum down-ramp capability for generator $i \in \mathcal{M}$
f_k	Flow of real power on branch $k \in \mathcal{E}$
$\overline{f}_k$	Maximum allowable flow on branch $k \in \mathcal{E}$
$\underline{f}_k$	Minimum allowable flow on branch $k \in \mathcal{E}$

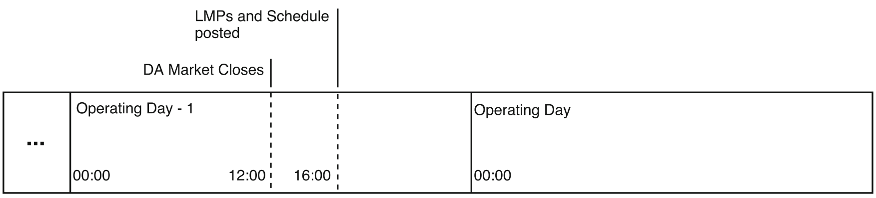

Fig. 2 Simplified DA scheduling timeline

$$\begin{aligned} &\underset{\mathbf{x}}{\text{minimize}} \quad \mathbf{1}_{24}^T\mathbf{C}\mathbf{x} \\ &\text{subject to} \\ &\quad \mathbf{H}\mathbf{x} - \mathbf{b} = \mathbf{0} \\ &\quad \mathbf{G}\mathbf{x} \leq \mathbf{0} \end{aligned} \tag{1}$$

where some of the decision variables (elements in $\mathbf{x}$) are binary start-up shut-down decisions. Modern optimization software packages employ branch and bound as well as branch and cut algorithms to solve these types of problems. The UC problem can be formulated as

$$\begin{aligned} &\underset{p,r,u,z}{\text{minimize}} \sum_{t=1}^{24} \sum_{i \in \mathcal{M}} \left[u_{it}a_{it} + b_{it}p_{it} + z_{it}^u s_{it}^u + z_{it}^d s_{it}^d\right] \\ &\text{subject to} \\ &\quad \sum_{i \in \mathcal{M}} p_{it} = D_t = \sum_{j \in \mathcal{L}} d_{jt} \\ &\quad \sum_{i \in \mathcal{M}} r_{it}^u \geq R_t^u \\ &\quad \sum_{i \in \mathcal{M}} r_{it}^d \geq R_t^d \\ &\quad p_{it} + r_{it}^u \leq u_{it}\overline{p}_{it} \\ &\quad p_{it} - r_{it}^u \geq u_{it}\underline{p}_{it} \\ &\quad p_{it} - p_{i(t-1)} \leq \overline{\Delta}_i^u \\ &\quad p_{i(t-1)} - p_{it} \leq \overline{\Delta}_i^d \\ &\quad u_{it} - u_{i(t-1)} \leq z_{it}^u \\ &\quad u_{i(t-1)} - u_{it} \leq z_{it}^d \end{aligned}$$

After the day ahead operating schedule has been set, the units are dispatched in one hour intervals for every hour of the operating day. Inputs to the DA Economic Dispatch (DA-ED) include weather, load, reserve requirements, bid and offer curves, commitment status, and reserve levels of each generator, in addition to the full DC-load flow network. The outputs are generator setpoints for every hour, locational marginal prices (LMPs), and reserve prices. With linearized cost curves and DC-load flow assumptions, for each $t = 1, \ldots, 24$, ED is a linear program of the following form:

$$\begin{aligned} &\underset{\mathbf{x}}{\text{minimize}} \quad \mathbf{c}^T\mathbf{x} \\ &\text{subject to} \\ &\quad \mathbf{H}\mathbf{x} - \mathbf{b} = 0 \\ &\quad \mathbf{G}\mathbf{x} \leq 0 \end{aligned} \tag{2}$$

Specifically, the DA-ED can be written as

$$\begin{aligned}
&\underset{p,d,r}{\text{minimize}} \sum_{i\in\mathcal{M}} b_i p_i - \sum_{j\in\mathcal{L}} b_j d_j \\
&\text{subject to} \\
&\qquad \sum_{i\sim n} p_i - \sum_{j\sim n} d_i + \sum_{k\sim n} f_k = 0, \quad \forall n \in \mathcal{N} \\
&\qquad f_k \leq \overline{f}_k \\
&\qquad f_k \geq \underline{f}_k \\
&\qquad \sum_{i\in\mathcal{M}} r_i^u + \sum_{j\in\mathcal{L}} r_j^u \geq R^u \\
&\qquad \sum_{i\in\mathcal{M}} r_i^d + \sum_{j\in\mathcal{L}} r_j^d \geq R^d \\
&\qquad p_i + r_i^u \leq \overline{p}_i \\
&\qquad p_i - r_i^d \geq \underline{p}_i \\
&\qquad d_j + r_j^u \leq \overline{d}_j \\
&\qquad d_j - r_j^d \geq \underline{d}_j
\end{aligned} \tag{3}$$

The DA-ED results in a binding agreement to buy, sell, or reserve the cleared energy, defined as the specified power setpoint over the one hour interval, at the LMP. The LMP, often denoted by λ_n, represents the cost to serve the next increment of load at node $n \in \mathcal{N}$. Mathematically, the λ_n is the sum of the Lagrange multiplier of the power balance constraints (sometimes called "system lambda" or energy price) and the Lagrange multipliers of the flow constraints (congestion component) described in (3).

$$\lambda_n = \lambda_{energy} + \sum_k \mu_{n,k} \tag{4}$$

where λ_{energy} denotes the energy component of the LMP and $\mu_{n,k}$ denotes the congestion component of the LMP. The energy component, λ_{energy}, is the shadow price of the energy balance constraint in (3). Note that all real-world markets include a loss component of LMP—or at least a modification of the energy component to account for losses—which has been ignored for simplicity. The congestion component, $\mu_{n,k}$ is the shadow price of the flow constraints for branch k weighted by the impact it has on node n. The dispatch schedule and LMPs are binding, which results in a single settlement for each market participant each time they are dispatched.

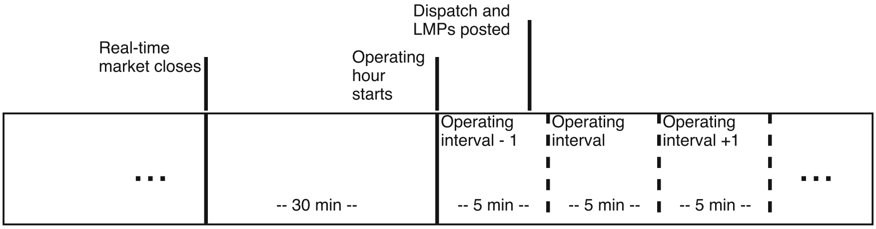

Fig. 3 Simplified RT market operation timeline

3.2.2 Real-Time Market

During the operating day, the DA-ED is augmented by the RT-ED according to the physical operation of the transmission network. Inputs to the RT market include the DA-ED as initial conditions, real-time topology, and network flows from a state estimator, in addition to the inputs used in the DA-ED. Today, it is a common practice for the RTO to run the markets on an operating hour schedule, where bids and offers are collected for an entire hour at once. The market will close at least 30 min before the operating hour begins, which implies that all inputs from market participants must be collected before this time. Throughout the operating hour, the ED is solved, typically every 5 min, to determine the dispatch and LMP, which are used in a second settlement. Figure 3 shows a typical timeline for real-time market operation and dispatch of the second operating interval in the operating hour. This timeline corresponds to current operation at ISO-NE in the Northeastern United States, where certain parameters to the DA bids and offers may be submitted no later than 30 min before the start of the next operating hour to be used as inputs to the real-time market. Other RTOs may differ in the specific timing, but for the most part operate in a similar manner.

3.3 Regulation Markets

In addition to energy and reserves, most RTOs also operate markets for a number of different ancillary services, the most prominent of which is the regulation market. Regulation actually consists of two separate products—capacity and service. Regulation capacity is measured in MW over a specified interval, and ensures a certain amount of room is available for the operator to deviate from the real-time market dispatch. Regulation service, measured in MW/min, is necessary for the RTO to be able to instantaneously match supply and load. Typically, the regulation service market will operate subsequently to the DA and RT energy and reserve markets, while regulation capacity is co-optimized with energy and reserves.

In order to participate in the regulation service market, resources must be able to receive the automatic generation control (AGC) dispatch signal, which is sent every 2–4 s. Additionally, they must be able to respond to AGC signal, and demonstrate a minimum performance standard. The market clears with the least-cost set of resources needed to meet the regulation service requirement.

While the market is cleared on a least-cost basis, the RTO will dispatch resources in a way that maximizes system performance. In other words, once the resources have been cleared in the market, they are not dispatched economically. The disconnection between reliability requirements and economic operation is an opportunity for new market design and/or new products.

3.4 Settlement Rules

Settlement rules precisely specify how market participants pay or get paid for the energy or services they provide. Thus, these rules are a key component of market design and the ability of a market to achieve its objectives.

The settlement rules take into account generator schedules, dispatch orders, actual produced or consumed energy and services, and the cleared price for energy and services. However, settlements are not simply equal to the price times the quantity of power delivered at a specific time and location. As settlements often occur ex-post, they may be based on an average price over a period of time or an average quantity over a given geographical region. Settlement rules may also include other components to provide proper incentives for market participants to continue participating in the market and to follow the operational dispatches. While the intention of the market is to provide an incentive for participants to continue providing a good or service while maximizing overall social welfare, poorly implemented settlement rules may undermine this objective.

In regulation markets, it is common to provide market participants with a regulation *performance* score, a number between 0 and 1, that measures how well the dispatch signal was followed. The settlements are then made based on the cleared regulation price (or hourly average regulation service price) multiplied by the performance score. This type of settlement incentivizes market participants to closely follow the dispatch signal, which is essential for regulation services. In addition to a performance score, regulation settlements include a make-whole component, which ensures that the generator is always compensated for the costs it incurs to provide regulation service. For example, in ISO-NE the regulation, settlement includes *payments* for any market participant that provides regulation service or capacity and includes *charges* for any market participant with an obligation to serve load. The net settlement is computed as

$$S_{net} = R_{service} + R_{capacity} + R_{mwp} - \left(R_{charge} + R_{mwc}\right). \tag{5}$$

The regulation service payment $R_{service}$ is based on the cleared service price, the service provided and the performance score. The regulation capacity payment $R_{capacity}$ is based on the cleared capacity price and regulation capacity—which are co-optimized in the energy market—weighted by the performance score. The regulation charge R_{charge} and regulation make-whole charge R_{mwc} are owed by each market participant based on their relative real-time load obligation. This ensures that generators can be fairly compensated for providing regulation services, particularly in times of large load deviations. We refer the reader to [34] for more details on settlement rules and [25] for a market design that leads to reduced make-whole payments by the ISO.

Up to this point, we have summarized the history, development, and operation of wholesale electricity markets in the United States. The next section looks at trends in electricity markets today which will drive their future development, including distributed generation, demand-side management, direct load control, and transactive control.

4 Current Trends in the Electricity Market

Environmental concerns and economic and political requirements [3], have put pressure on the electric power industry to significantly increase electricity generation and to search for new sources of energy. Renewable resources not only provide the capability of reduced CO_2 emissions, but also have a low if not near-zero marginal cost of energy.

The volatility inherent to wind power producers (WPPs) has posed challenges to the operations of RTOs, which have gradually modified their regulations as their reliance on wind power increases. The variability and uncertainty of renewable generation will substantially increase the need for operational reserves to balance supply and demand instantaneously and continuously [32, 50, 65]. Under low adoption of wind power, RTOs have opted for limited regulation and control over the power output of WPPs, allowing them to inject their generation when available, and treating them as negative load. As wind volatility becomes a more significant part of the energy balance problem and causes high congestion costs and significant reliability challenges, this practice has begun to change, with RTOs opting for additional market mechanisms such as market dispatch and penalties for unmet commitments in energy markets.

Another forthcoming challenge is the total system inertia and contingency reserve capacity decrease as non-dispatchable renewable generation displaces conventional generation. This results in the reduction in the amount of critical operating decisions that need be made from minutes to seconds or even sub-seconds. Therefore, it is becoming extremely difficult for system operators to maintain the stability and reliability of their networks. In order to facilitate the paradigm shift to achieve higher energy efficiency in the future, more flexible and fast-acting resources are needed to handle the uncertainties and variabilities introduced by such uncontrollable and intermittent energy resources. A prevailing trend to combat the uncertainties on the generation side, is to reduce uncertainty on the load side through demand-side management, direct load control, and transactive control. These emerging trends and associated challenges are discussed in the subsequent sections.

4.1 Dispatchable Wind Power

The first large-scale WPPs were integrated to the California electric grid during the 1980s, motivated by the Public Utility Regulatory Policies Act of 1978 which required companies to purchase a certain amount of renewable energy [20]. Given the comparatively small dependence on these power plants and the intermittency associated with their wind resource, limited control over wind generation was initially required throughout the different RTOs. Wind power plants were treated as negative loads, that is, their instantaneous power output was always purchased at the market-clearing price. This meant that the volatility of their generation was largely absorbed by other power plants, mimicking variations in electric demand [9].

Between the 1980s and the early 2000s, the average capital expense in wind generation dropped by close to 65% while average capacity factors (a proxy for performance) improved by over 20%, even when curtailments due to congestion and grid reliability concerns are included [44]. Decreasing costs and increasing efficiencies prompted energy developers to invest in WPPs. In states with significant wind resources in rural areas, such as Texas, investments in transmission lines were made to bring power from windy regions to load centers. ERCOTs Competitive Renewable Energy Zone expansion invested $7 billion between 2008 and 2013, increasing the capacity of the West–East Corridor by 18.5 GW [45]. Such investments have allowed for an integration of 74 GW of wind power capacity to the US electric grid by 2015, primarily in the Midwest, Texas, and California [20].

Ancillary markets, such as balance reserves, and relatively fast-clearing real-time energy markets have enabled the integration of WPPs to higher fractions of total generation through the use of fast-ramping, low relative efficiency, natural gas-fired power plants [7, 9, 45]. RTOs with larger fractions of wind integration, such as MISO and CAISO, have run into issues in treating wind as a negative load, leading to additional technology implementation and control. Wind constitutes approximately 7% of the generation mix in MISO and CAISO, with peaks well over 50% renewable energy [10, 26]. These RTOs have resorted to economic dispatch systems, where wind is curtailed when additional generation poses a threat to transmission lines or the energy balance of the region. In California, approximately 1% of potential renewable generation is curtailed due to operational concerns [10].

Even in RTO operating regions where wind is dispatched by a market, costs associated with wind volatility are socialized among generators and consumers, as most integration mechanisms focus on internalizing congestion-related operational stresses under high generation but fall short of forcing WPPs to internalize costs for low production. However, wind power producers are on track to face significant penalties when energy commitments are not met. ISO-NE is an example of an operating region where the RTO is requiring wind to bid in day-ahead energy markets for planning and capacity commitment firming (implemented technology for remote dispatch by mid-2016, requiring Day-Ahead bidding by mid-2019) [33]. By charging penalties when generation commitments are not met, RTOs can pass on costs related to balance reserve requirements and fast-ramping of other power plants to

WPPs. The transition from negative load to economic dispatch and firming of generation commitments lead wind power producers to internalize costs associated with wind resource volatility and more accurately reflect the cost of their generation in the market.

4.2 Demand-Side Management

Current power grid operation predominantly relies on scheduling and regulating generation resources to supply electric loads and balance load changes. Due to inherent limitations of most conventional generators in providing fast-ramping capacities, the power grid solely based on supply-side control will not be able to support the large-scale integration of renewable energy. Alternatively, in addition to generators, electric loads can be used to balance between supply and demand. This practice is often referred to as the demand-side control or demand response (DR).

Traditionally, electric loads were considered to be passive and non-dispatchable elements of the power grid. However, various grid services that were traditionally delivered by generators only [12] can now be provided by a collection of electric loads through proper coordination and control with required speed, accuracy, and magnitude. Popular load types used for DR are thermostatically controlled loads (TCLs), including residential air conditioners, water heaters, and refrigerators, deferrable loads such as dryers and electric vehicles, and commercial HVAC (heating, ventilation, and air-conditioning) systems. Due to the large population size and fast aggregated ramping rate of these electric loads, DR has an enormous potential to reliably and economically offset the dynamic variability introduced by renewable generation.

Besides the emergence of DR, another growing trend in the power grid is the integration of distributed energy resources such as distributed generator and energy storage in power distribution systems. These distributed energy resources (DERs) are small and highly flexible compared with conventional generators. If appropriately coordinated and controlled, DERs and DR can collectively become a valuable system asset playing an increasingly important role in the future smart grid. Their seamless integration into power distribution systems will lead to efficient grid operation and high renewable penetration without compromising the stability and reliability of the power grid.

4.3 Direct Load Control

The coordination and control of electric loads to provide various grid services have been extensively studied in the literature. Direct load control (DLC) is one of the most popular demand response approaches. It allows electric loads to be remotely controlled by an aggregator (for example, utility company) based on prior mutual financial agreements, referred to as contracts. Traditional DR programs use DLC to deliver services such as peak shaving and load shifting [16, 19, 43]. The latest development in this area focuses on modeling and control of electric loads such as TLCs [6, 11, 37, 41, 54, 76], plug-in electric vehicles [48, 67], and data center servers [15, 47] to provide various grid services including frequency regulation and load following. In addition, there are also efforts on the design of financial contracts between the aggregator and individual loads under DLC. The essential step in the design of DLC is the development of an aggregated model that can accurately capture the collective dynamics of the load population.

Existing works on aggregated modeling have focused mainly on air conditioners and water heaters [5, 11, 18, 49]. The key idea of this approach is to characterize the evolution of the temperature density for the load population. Several first-principle-based approaches such as deterministic fluid dynamics approach [22] and stochastic differential equation approach [51] were proposed, which lead to a Fokker–Planck type of partial differential equation (PDE). In [11], the analytical solution to this PDE was derived in a much simplified setting, and provided useful insights into the transient dynamics. Besides those first-principle-based approaches, Markov-chain-based approaches were also studied in [39, 49, 53], where state transition probabilities between discrete temperature bins were derived based on simplified first-order models or directly from the simulated training data. However, both first-principle- and Markov-chain-based approaches are subject to several limitations for practical applications. First of all, most of the approaches model individual loads using a first-order differential equation, yet such a model is insufficient to capture the dynamics of TCLs that have large heat capacities. For example, in the case of air conditioners, it is essential to model the dynamics of both air and mass temperature dynamics because the house mass is so large that it will significantly affect the transients of air temperature. Second, homogeneity is a common assumption in many aggregated models, which does not hold in general. It is important to consider the diversity in load parameters in order to generate realistic aggregated responses [5, 39, 75]. The methods in [39, 49, 61] considered the heterogeneity in some parameters but still assume the homogeneity for the rest of parameters. Finally, the existing aggregated models usually allow the existence of short cycling for individual TCLs. These models cannot be directly applied to air conditioners for which there exist protection schemes that prevent the device from the short cycling. Hence, a new Markov-chain-based aggregated modeling that accounts for second-order equivalent thermal parameter models [72] of individual air conditioners was proposed in [13, 76, 77] to systematically address all the above issues.

Several non-density-based methods have also been proposed in [36, 37, 42], whose the main objective is to represent the aggregated dynamics using simple linear state-space or transfer function models. Compared with aggregated modeling, the design of aggregated controller is relatively simpler. With a good aggregated model of the load population, many well-established control methods such as Model Predictive Control [39], Lyapunov-based control [5], or simple inverse control [53] can be directly applied to regulate the aggregated power response so that it matches the given reference signal.

The most important advantage of DLC is that it can achieve reliable and accurate aggregated load response. Its implementation in practice, however, has been challenged often due to privacy and security concerns. This is because most of the models require information about the state of the end-use appliance owned by customers in order to design control strategies. On the other hand, there are also concerns that DLC signals could be disruptive to local constraints and inevitably result in adverse effects such as response fatigue [27]. Another important paradigm for demand response as an alternative to DLC is price responsive control (PRC), which sends price signals to customers so that they can individually and voluntarily manage their local demand. Unfortunately, under existing PRC schemes, it is difficult to achieve an acceptable level of predictable and reliable aggregate load response. *Transactive control* is a more comprehensive approach compared to PRC, and addresses the reliability concerns while maintaining the privacy and security advantages that PRC has over DLC. This is the focus of the following section.

4.4 Transactive Control

The most common examples of PRC in place today include time of use (TOU) pricing, critical peak pricing (CPP), and real-time pricing (RTP) [2, 8, 14, 30]. There have been many demonstration projects [22] to validate the performance of PRC in terms of payment reduction, load shifting, and power shaving. However, the existing approaches either directly pass the wholesale energy price to customers or modify the wholesale price in a heuristic way. Therefore, it is very difficult for PRC to achieve predictable and reliable aggregated load response that is essential in various demand response applications.

Transactive control, which is sometimes referred to as market-based control, has been proposed as an alternative to PRC that can integrate DERs and DR in power distribution systems and then into the transmission system to realize the transactive operation for the entire power grid. It shares the same advantage of PRC in preserving customer privacy by using internal price as the control signal. However, the internal price is systematically designed according to specific control objectives, which can be dramatically different from the wholesale price (see, for example, [17, 46]). Hence, transactive control shares the advantage of DLC, and avoids the shortcomings of PRC, in having a more predictable and reliable aggregated load response. Because transactive control borrows ideas from microeconomics [52] into the controller design, it is amenable to problems where self-interested customers are involved [21, 63]. Furthermore, it can also greatly facilitate the coordination and control between DERs and electric loads in the future distribution systems [73].

The idea behind transactive control is actually not new, and can be traced to concepts outlined in [64]. These concepts also recognize that different regions are structured in a variety of ways that cover wholesale power markets, electricity delivery markets, retail markets, and vertically integrated service provider markets. Transactive approaches appear to have the potential to be incorporated into many different structures and mechanisms that allow them to coexist with present operational approaches.

Current research activities on transactive control have mainly focused on innovating end-user loads with enhanced intelligence and launching field demonstrations involving various parties such as grid operators, energy supply companies, vendors, and regulators. In the United States, three major field demonstration projects were executed under the support from the U.S. Department of Energy to illustrate and prove the technology feasibility of transactive control in practice. Each of these three projects is summarized below, details of which can be found in [40].

4.4.1 Olympic Peninsula Demonstration

The Olympic Peninsula Demonstration (2006–2007) [24, 28] was the first proof-of-concept demonstration project on transactive control. This demonstration was located on the Olympic Peninsula of Washington State. The Penninsula is served by a capacity-constrained, radial transmission system connection to the Pacific Northwest power grid. The area had been experiencing a significant population growth and it had already projected by that time that power transmission capacity in the region may be inadequate to supply–demand during extremely cold winter conditions. The objective of this project was to evaluate practical and economical alternatives to new transmission and distribution construction by coordinating distributed energy resources and electric loads for congestion management. It used a 5-min double-auction market to coordinate five 40 HP water pumps distributed between two municipal water-pumping stations, two distributed diesel generators (175 and 600 kW), and electric water and space heating loads of 112 residential houses. This demonstration established the viability of transactive control in achieving multiple objectives such as peak load reduction and energy cost saving.

4.4.2 AEP gridSMART® Demonstration

The AEP gridSMART® Demonstration (2010–2014) [70, 71] was built upon the technology implemented in the Olympic Peninsula Demonstration and market-based incentive signals. This project used a 5-min double-auction market again to coordinate residential and control air conditioners on each of four distribution feeders for congestion management. However, it introduced an additional real-time pricing (RTP) component by incorporating PJMs 5-min wholesale locational marginal price (LMP). The overview of the RTP system design in this demonstration is illustrated in Fig. 4.

The AEP gridSMART® demonstration had three specific objectives [69]. The first is to build a transactive control platform to demonstrate the capability of responsive end-user loads in providing benefits to the utility and the consumer. The second was to actively educate consumers in innovative business models that encourage flexibility in energy use in return for reward and energy saving. The third is to record

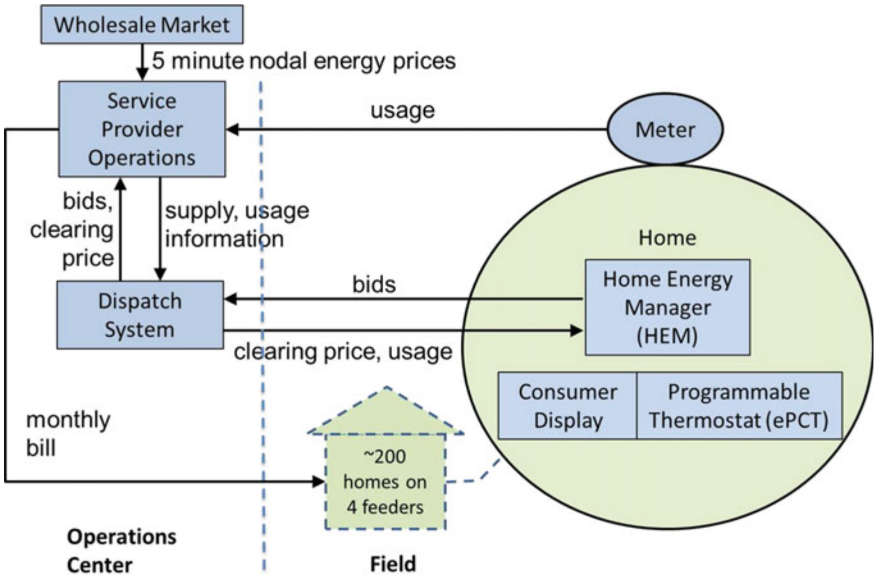

Fig. 4 Overview of the RTP system in the AEP gridSMART® Demonstration (reproduced from [40] ©2016IEEE and used with permission)

the system operation to study the technology performance and also the consumer behaviors under varying operating conditions.

4.4.3 Pacific Northwest Smart Grid Demonstration

The Pacific Northwest Smart Grid Demonstration (PNWSGD) (2010–2015) [31, 60] was a unique demonstration of unprecedented geographic breadth across five Pacific Northwest states—Idaho, Montana, Oregon, Washington, and Wyoming as shown in Fig. 5. There were 55 unique instantiations of distinct smart grid systems demonstrated at the project site. The local objectives for these systems included improved efficiency and reliability, energy conservation, and demand responsiveness. In this demonstration project, a new transactive approach was deployed to coordinate distributed energy resources and address regional objectives including the mitigation of renewable energy intermittency and the flattering of system load. Unlike the one based on the double-auction market, this approach is based on peer-to-peer negotiations as illustrated in Fig. 6. The major objective of this demonstration was to establish a more efficient and effective power grid that can simultaneously reduce fossil fuel consumption and CO_2 emissions, improve system stability and reliability, increase renewable penetration, and provide greater flexibility for customers.

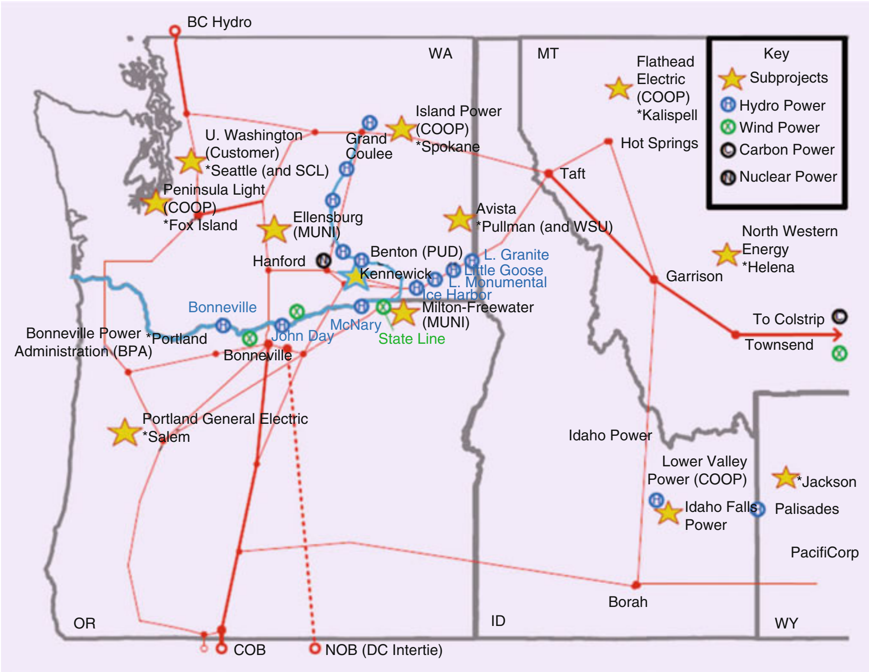

Fig. 5 The geographical region, participants and major generation and transmission of the PNWSGD (reproduced from [40] ©2016IEEE and used with permission)

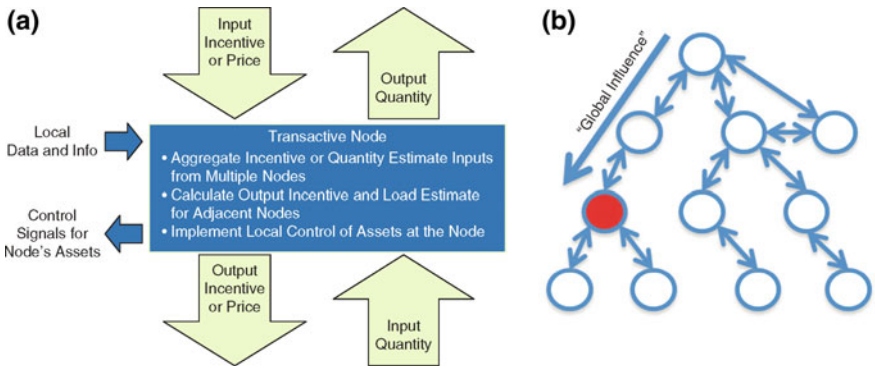

Fig. 6 Overview of the transactive approach deployed in the PNWSGD (reproduced from [40] ©2016IEEE and used with permission)

5 Challenges and Opportunities

In the sections above, we have attempted to introduce the reader to electricity markets, the first building block that lays the foundation for a reliable and affordable electricity infrastructure. With a focus on the United States, we have outlined a brief history of electricity markets, current operation of wholesale markets, and emerging trends. Due to the overall trend toward deregulation, the structure of markets covering planning and operations of the power grid, and the emphasis on DERs and DRs, similar changes are being investigated in electricity markets across the globe, though details of the workings of RTOs, wholesale markets, and retail markets differ. In addition, the evolution of and emerging topics in markets are tightly interwoven with technological advances in the cyber aspects as well as other technological domains such as storage and power electronics. Here too, specific trends and topics that are dominant in different parts of the world have differed.

A clear message that is apparent from the discussions above is that changes in market structures are needed because of the growing penetration of DERs and because of the high potential of DRs. Systems and control tools that can provide guidelines and foundations for these emerging trends are therefore imperative. An overall framework including models and methods for the quantification and realization of performance metrics such as robustness, resilience, and reliability need to be developed. The successful demonstration projects on transactive control as well as the promising approaches of DERs indicate that there are a number of opportunities for the controls community to develop such a rigorous theoretical framework for integration of DR and DERs into the electricity market. In the three challenge articles that follow, some of the opportunities and forward-looking directions are discussed. These span theoretical issues such as non-convexities and multiple timescales, practical challenges related to hedging in future markets, setting up retail markets, integration of multiple demand response units, and a redesign of markets and control to have better ancillary services. A brief summary of each of these articles follows. Several other directions on developing a dynamic framework with hierarchical, co-optimization, passivity, and game theory based components are currently being pursued to develop new solutions and architectures in electricity markets (see for example [4, 25, 38, 59, 74]) and are not included in this volume.

The paper *Some Emerging challenges in Electricity Markets* authored by S. Bose and S.H. Low focuses on five different challenges that are precipitated due to the growing penetration of renewables. The first concerns a fundamental theoretical issue of how non-convexities in constraints and feasibility sets need to be addressed, and how pricing these non-convexities may be used as incentives for introducing corrective action. The second is the need to understand how forward markets can be designed so as to guard against risks against large forecast errors with a large penetration of renewables-based generation. The third is a challenge associated with integrating storage devices with a possible approach that views storage devices as entities similar to those in a transmission infrastructure that helps manage congestion. How the hedging of associated price variations needs to be carried out is addressed.

The fourth challenge pertains to strategic market players and the use of game theory for analyzing strategic interactions. The final challenge pertains to the setting up of a retail market, where varied issues need to be addressed including the services provided by aggregators, both of distributed generation and flexible demand, appropriate coordination that ensures economic and physical goals of the distribution grid, and varied demand response structures such as direct load control and Transactive control.

The paper *Incentivizing Market and Control for Ancillary Services in Dynamic Power Grids* authored by K. Uchida, K. Hirata, and Y. Wasa addresses a redesign of the energy management system in an electricity market, with the goal of improving the quality of ancillary services. With increasing renewables, a high- speed market-clearing structure may be called for that ensures all private information of market players and reliable performance of the related frequency response. Limitations and fundamental challenges related to market design and the necessary incentives, when it comes to the integration of the requisite economic models and dynamic characteristics of the power grid are discussed. A specific model-based method is outlined as a possible approach for overcoming these challenges.

The paper *Long term challenges for future electricity markets in the presence of Distributed Energy Resources* authored by S. Muhanji, A. Muzhikyan, and A.M. Farid outlines three main challenges including (i) a simultaneous management of the technical and economic performance of the electricity grid (ii) spanning multiple timescales during operation, and (iii) enabling multiple demand-side resources. Reducing day-ahead and real-time market time steps so as to reduce load following, ramping, and regulation reserve requirements, development of new control architectures that are able to respond quickly to real-time changes in grid operations, and market structures that enable the participation of and proper compensation for such services are stressed in (i). Multi-timescale approaches so as to reduce the impact of net load variability and forecast error away from scheduled set points and related perspectives are stressed in (ii). Design and analysis of transactive control of demand-side management so as to lead to an appropriate balance of physical as well as economic signals is underscored in (iii).

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