Commission for Energy Regulation

Key differences - centralised and decentralised electricity market designs

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Prepared by: PA Team

PA Consulting Group
Embassy House
Herbert Park Lane
Ballsbridge
Dublin 4
Tel: +353 1 6684346
Fax: +353 1 6681771
www.paconsulting.com

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1. KEY DIFFERENCES

This paper presents a discussion of the differences between centralised and decentralised electricity markets. This review is intended as additional information for industry participants interested in the CER Review of Electricity Trading Arrangements.

All aspects of these two market models are not covered in this paper. Rather, this paper is intended to highlight the key differences in the two market models and provide additional discussion of these key differences and selected concepts related to these differences.

We will provide a discussion of differences in:

- market operation and trading activity;
- real time price formation and disclosure;
- markets and pricing outside real time; and
- dispatch efficiency.

The key differences are discussed in summary in this chapter and in more detail in chapters two through to five.

1.1 MARKET OPERATION AND TRADING ACTIVITY

We provide a discussion of several factors in this section, including market operation, participant activity, and trading and risk management.

1.1.1 Market operation

In a centralised market, all electricity is sold to and bought from the market operator at the spot market price. The market operator takes the bids received and develops a market-clearing price that becomes the spot price, taking into consideration a range of factors including transmission congestion and system security. The market operator issues dispatch instructions to generators with accepted bids. The system operator (may also be the market operator) balances the system in real time.

In a decentralised market, participants submit schedules to the market operator. These schedules have loads and generation that are balanced (ie, the load and the generation are equal). Because balanced schedules may not actually be balanced in real time (and because transmission congestion may disrupt some schedules), the market operator buys some electricity and other services that are used to balance the market in real time.

1.1.2 Participant activity

In a centralised market, generators submit bids to the market operator. The market operator then determines the spot price and dispatch instructions that determine the operation of the generating plants. The market operator estimates demand, with some demand allowed to bid into the spot market. Participants may also offer various ancillary services to the market operator / system operator.

In a decentralised market, participants buy and sell most electricity to one another through bilateral contracts. These physical bilateral contracts between participants are arranged through bilateral negotiations or through organised exchanges. This market may have either voluntary or mandatory participation in a balancing market.

In theory, the flows of electricity under these two approaches may be the same in real time. In practice, there are likely to be differences due to different dispatch outcomes.

1.1.3 Trading and risk management

In a centralised market, all participants incur costs/ gain revenues at the spot price. As the spot price is likely to be volatile, this may present considerable financial risk. Participants hedge this risk by entering into contractual relationships outside the spot market, usually with other participants. In a pure centralised market the contracts are financial contracts such as contracts for differences (CfDs) based on the spot market price. Most participants have a portfolio of hedge contracts, but some load and generation is exposed to unhedged spot prices.

In a decentralised market, the primary financial impact on participants is from a portfolio of bilateral contracts. To the extent that a market participant has submitted a schedule to the market operator that is not balanced, this participant may also be exposed to the balancing market to make up the imbalance, incurring some financial risk. This risk is typically managed by using a portfolio of contracts that match load and by trading in short-term bilateral contracts close to real-time.

1.2 REAL TIME PRICE FORMATION AND DISCLOSURE

In general, a centralised market provides better price formation and transparency and has prices better aligned with market fundamentals as compared to a decentralised market. Also, the centralised market can provide useful pre-dispatch estimates that may not be as available or as useful in a decentralised market.

1.2.1 Price formation

In a centralised market, the spot price is formed by the intersection of all load and all supply bids. As all electricity is bought and sold in this market, the spot price resulting is reflective of the overall market situation with respect to supply and demand. This typically means that prices are high when demand is high and vice versa.

In a decentralised market, the only visible price may be the balancing market price. In this market the price is set from “inc” (incremental) and “dec” (decremental) bids around the declared scheduled quantities. Rather than reflect the overall market supply and demand, the balancing market and balancing market price may reflect only a very small percentage of the supply and demand in the market. Consequently, prices may be high in the balancing market at times when it is hard to balance schedules based on inc and dec bids (even if overall demand is not particularly high), so that balancing market prices may not reflect overall market supply and demand.

1.2.2 Price transparency

In a centralised market, prices are very transparent. Prices are disclosed in a centralised market every trading period (eg, half hour) as a single market clearing “spot” price – possibly for each location. This price represents the value of all electricity traded in that half hour at that location. The net impact on each participant is less transparent, as this impact is mitigated by hedge contracts that may not be public.

In a decentralised market there is much poorer price disclosure. While the balancing market price(s) may be visible, this is only a small part of overall market transactions. In some decentralised markets, the “buy” or spill price almost always differs from the “sell” or top-up price – sometimes by a very substantial margin. It is difficult to extrapolate from either or both of these prices to a “price for electricity”.

1.2.3 Link between prices and market fundamentals

A centralised market spot market is a very liquid market, with the spot price giving the best available indication at all times of the market’s estimation of the value of wholesale electricity. It takes account of generation cost and the players’ estimation of the scarcity value of generation. There is a strong relationship between contract prices and spot prices. While contract prices are confidential, these prices will not , in the long-term, deviate substantially from a risk-adjusted reflection of expected pool prices over the same period. Any deviation encourages the parties to go to the spot market rather than enter into hedges. Participants consciously use spot price predictions to set their contract prices.

In a decentralised market with a liquid market for short-term contracts, there may be some price disclosure with published forward prices. There is no spot market price to benchmark against. The prices of long-term contracts that form the majority of positions are usually not public and may contain complex pricing structures that make simple price comparisons difficult. Since negotiations are confidential, different players have no easy way of discovering the market price other than from any forward markets. There may be little or no natural arbitrage between public balancing market prices and contract prices.

1.3 MARKETS AND PRICING OUTSIDE REAL TIME

While the primary focus of this paper is on the real time markets and their differences, there are a number of differences between the two markets outside the real time market. The most important difference is the availability of useful pre-dispatch price estimates.

In the run-up to the real-time market, a centralised market may develop and disclose indicative spot market prices that enable participants to see the likely outcome and respond to physical circumstances, volatile prices and capacity shortages. In so doing, a more accurate auction is conducted in real time.

A decentralised market operator may also develop estimates of balancing market prices prior to real time. These estimates will, typically, be based on accumulated schedules, demand estimates, and known bids into the imbalance markets. Since many imbalances may not be known until real time, such estimates will be less useful than centralised market estimates that include the entire market.

1.4 DISPATCH EFFICIENCY

In a centralised market, the operation of the market gives rise to a dispatch that is closely aligned with marginal cost, with the lowest marginal cost unit dispatched first, and the highest marginal cost unit dispatched last. The resulting market dispatch will be consistent with that which would have been achieved by a regulated utility dispatch centre seeking to minimise total cost.

In a decentralised market, dispatch is declared using balanced schedules with no market price signal to influence dispatch priorities. This gives rise to the possibility that generators with higher marginal costs might be dispatched before those with lower marginal costs. While this might be corrected to some degree in the balancing market where more expensive plant is likely to offer an “inc” at a higher price, a decentralised market is less likely to result in efficient dispatch.

2. MARKET OPERATION AND TRADING ACTIVITY

In this Chapter, we provide a summary of key differences related to market operation and trading activity. We then provide discussions of concepts related to the two market designs, including:

- market time scales;
- contracting;
- unit commitment; and
- responsibilities of the system operator in real time

2.1 SUMMARY OF KEY DIFFERENCES

This section provides a summary of the key differences between the two market types in market operation and trading activity.

2.1.1 Centralised market

The business processes in a centralised market involve participants operating in the centralised market through bidding. All electricity is bought by the market operator from generators and sold by the market operator to supply companies or other buyers (eg, customers participating in the spot market directly). The market operator, as the counterparty to all spot market transactions, settles all trading in the spot market.

A typical centralised market involves a spot market that is a bid-based exchange, where generators bid into the market. Generators develop bidding strategies that are aimed at achieving desired generator operation levels and profitability.

While a generator might bid the entire output of a generating unit in a single bid, it is more typical for a generator to use multiple bids (eg, 10)[1] at different prices for each part of a generator's total available output. This provides a unit "supply curve" to the market operator. Deciding a bidding strategy involves deciding how much of each unit the generation company wishes to have operating in each trading interval (e.g. half-hour period) and at what price.

The market supply curve is the amalgamation of all the individual unit supply curves.

The market operator clears the real-time spot market at a single market-clearing price, through the selection of bids in increasing order of price[2]. If the market price exceeds the bid price for a unit (or any of the 10 segments bid for that unit), the unit will be included in the bids selected to run. If a bid is above the market-clearing price, that portion of the unit will not be dispatched.[3]

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1 Market rules usually require each distinct generating unit to separate bids and will also determine the number of bids allowed for each of these generating units.

2 Locational differences may complicate this by the inclusion of losses and congestion prices.

3 Additional rules are needed to reflect the use of minimum load and block load bids and other conditions.

Participants hedge the uncertainty of selling to or buying from the spot market by entering into financial arrangements such as contracts for differences (CfDs) based on the spot market price. Most participants will have a portfolio of hedge contracts and other instruments. Financial obligations under these contracts are settled between the parties to the contract[4].

2.1.2 Decentralised market

The emphasis of the business process in the decentralised market is, essentially, the reverse of that of a centralised market:

The primary driver of a decentralised market are physical bilateral contracts between power producers and consumers / retailers. Participants present these contractual obligations as "balanced schedules" of generation and load to the market operator.

The market operator in a decentralised market operates a balancing market to ensure that the total set of bilateral contracts allow the real-time physical market to clear (ie, all load is just supplied by generator output in each trading interval).

In a pure (mandatory) decentralised market, all participants must present balanced schedules that reflect accurate estimates of actual production and load. Inevitable differences arise between actual production and load and the amounts in a bilateral contract.[5] When participants rely on long-term contracts, a liquid shorter-term contract market is useful in helping the participants "trade out" any imbalances in the period close to real time in order to minimise imbalances.

The balancing market is used to make the final adjustments between balanced schedules and actual real-time production and load. The balancing market may also act to manage congestion, if participants are allowed to form schedules that assume no transmission constraints. The balancing market relies upon participants bidding the prices at which they are willing to alter their generation or load (termed "incs" and "decs").

Some balancing markets are voluntary markets, in that participants are not required to bid. Other markets require participation. In practice, balancing market prices may be volatile, with top-up prices at high levels and spill prices at low levels. Generators and load that have unpredictable and fluctuating levels may be exposed to the balancing market in spite of efforts to trade out of imbalances in the short term.

In some decentralised markets, the balancing market may also act as a real-time spot market where participants can choose to buy or sell (eg, by submitting unbalanced schedules). In other decentralised markets, the balancing market may be structured to prohibit or provide financial disincentives to imbalance purchases, usually by forming very high top-up prices and very low spill prices.

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[4] Even though some Market Operators (eg, Singapore) offer a hedge contract settlement service to market participants, the Market Operator is not a party to such contracts nor is the operation of the spot market directly affected by such contracts (except to the extent that participant bids reflect the financial incentives in the hedge contracts).

[5] Production differences might arise because a power plant experiences an outage or a power plant produces unpredictable and uncontrollable output (eg, wind or run-of-river hydroelectric). Load differences may be due to unexpected temperatures or simply due to the inability to precisely forecast the load from end-use customers.

2.2 MARKET TIME-SCALES

It is important to understand the time scales and the activities that occur in these time periods for both markets. As shown in **Error! Reference source not found.**, an electricity system has several time scales.

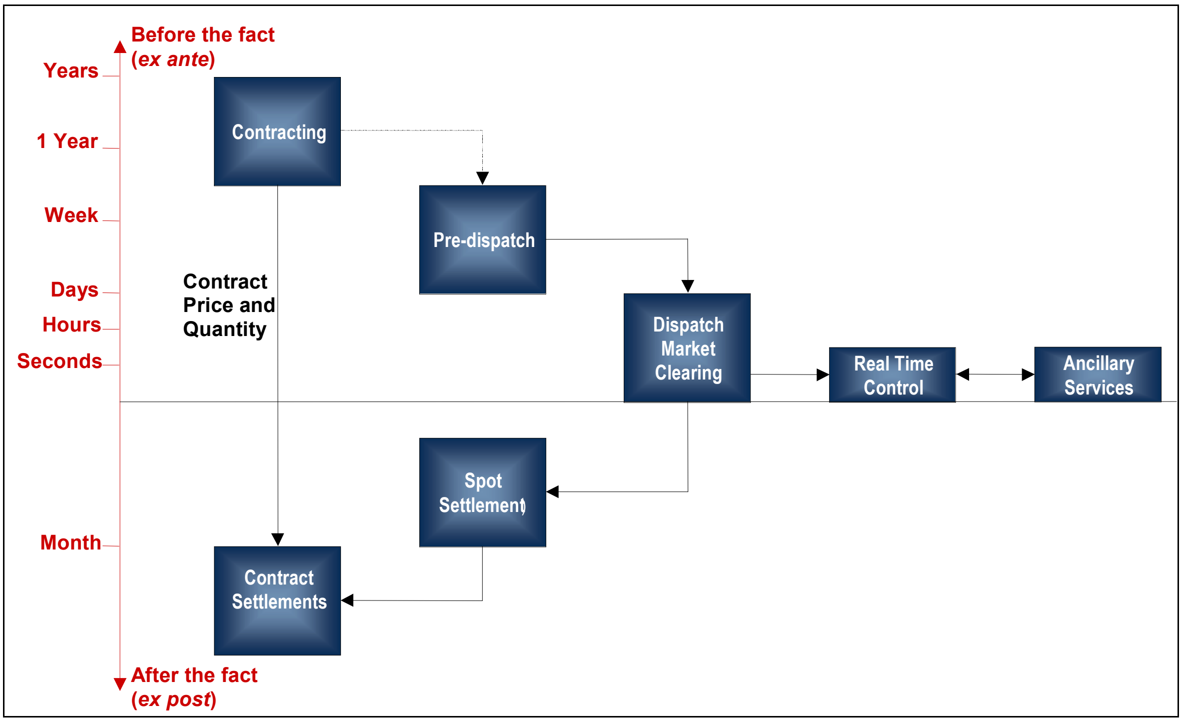

Figure 1: Market time scales

There is little difference in participant behaviour in the long term and medium term under both options. Although similar issues are present, the specific activities differ somewhat in the short-term prior to real time, real time and *ex post* in the two market structures.

2.2.1 Long term

This period is where decisions of capital expenditure are made. In this time scale, long run profitability is the key issue. For generators, consumers and transmission owners the prices received and paid must allow for a level of profitability that covers fixed and capital cost as well as variable costs. The market prices in the short and medium term, when accumulated over the longer term, indicate whether a capital decision is economic. Generator decisions include whether to install or decommission plant, what type of plant to install and where to locate it. On the demand side, consumers react to price expectations by (not) investing in electricity consuming plant, and by instituting efficiency measures, for example. Most consumers do not have good information on long-term price signals nor on the impact of any long-term changes in consumption or demand. Commercially, this time frame is characterised by interactions in the long-term contract market.

2.2.2 Medium term

This period is where decisions are made about plant availability, including maintenance. In this timeframe, generators and transmission companies seek to have their plant available for the crucial periods of demand and shut down for maintenance at low demand periods.

Participants are expected to trade in medium term contracts, so as to better adjust their contractual commitments to their expected physical output and availability.

2.2.3 Short term

Here, decisions are made about short-term contract positions, unit commitment and reserve availability. This period is between about 2 days and 1 hour (or shorter). Participants make detailed decisions about how they wish to operate. They decide an operating strategy and place their energy (and reserve) bids and schedules accordingly. This information is collected and analysed by the market operator through a pre-dispatch process that gives all market participants an idea of the shape of the market as they approach real time. Spot markets and balancing markets operate in the very short term.

2.2.4 Real time

Real time is where the actual energy supply of a particular unit is decided in order to meet actual demand. No market in operation actually works at real time, although some of them are pretty close. Because the market can only approximate real time, the system operator is actually responsible for navigating the system through the eventualities of the dispatch interval (switching, emergency responses etc) to ensure that “the lights stay on”. In order to fulfil this task the system operator will need to have contracted for a variety of “ancillary services”, such as load following, spinning reserve and reactive support that are controlled in real time.

2.2.5 Ex post

This is where market transactions are finalised on the basis of actual dispatch outcomes and prior contractual commitments. This may occur in a single integrated and centralised settlement process. Or there may be two distinct phases, a spot market settlement process, which must be centralised, and separate processes to deal with settlement of financial and bilateral contracts on a bilateral basis.

2.3 CONTRACTING

The key difference in trading activities within these time-scales is the role of contracting and the interaction of the spot market (or balancing market) with contract terms and positions.

2.3.1 Centralised market

In the centralised market, contracting is centred on hedging participants against price / volume volatility in the spot market. Holding a contract position is not a key requirement for market trading and some participants (for example, wind generators) may be prefer to be unhedged and always receive the spot price.

Generators may enter into long term contracts to provide revenue support or may use a retail supply business as a “natural hedge”. They may also structure a portfolio of medium and short-term hedge contracts and option/ insurance hedges to cover their risks in peak periods or when power plants are out for maintenance.

2.3.2 Decentralised market

The decentralised market is organised around bilateral contracting through physical supply contracts. Contracting arrangements are considered to be paramount and drive the structure of the trading arrangements. Particularly, any real-time "spot" market is only for the buying and selling of excess or deficit electricity, with such a real-time market referred to as a balancing market. Some markets go further and deliberately penalise transactions in the real-time spot market in order to discourage the use of that market for regular trading. Consequently, most of the energy market is traded and "cleared" by bilateral contracts for energy.

These contracts have a variety of terms and conditions but are primarily physical contracts for energy delivery with a specified quantity, price and delivery date. The portfolio of contracts held by a participant typically includes long-term supply contracts that specify quantities and prices for delivery at specified times of the day and week for a period of one or more years (and may be as long as the life of a power station). These contracts are normally specific to the requirements of the two parties concerned and they form the underlying revenue and cost support of the contracting parties. These long-term agreements will be supplemented by a variety of medium term (1 year or less) contracts of a similar nature.

Short-term (several days or weeks) and very-short term (hours before real-time) contracts may also be used in such markets. These are needed in order to match short-term imbalances between longer-term contract positions and expectations of actual production or load. To be effective, standard instruments that can be readily traded between parties are needed. Naturally, power exchanges arise to provide a ready and liquid market in such short-term contract instruments.

Balanced schedules sound like a simple way to ensure that participants contract effectively, but there have been examples where it has not necessarily worked. Without a power exchange (or equivalent) for short term trading it may be very difficult for participants to find buyers and sellers of contracts. Even with a power exchange, the requirement to balance (or nearly balance) their schedule can be difficult for many participants to achieve as real-time approaches and it may be a substantial overhead cost on participants in addition to trading in the balancing market.

Participants particularly exposed to unbalanced schedules are retailers who cannot control or accurately predict total customer load and generators who cannot control or accurately predict plant output (eg, wind generation).

2.4 UNIT COMMITMENT

In a typical regulated system (or a tight power pool), a system dispatcher takes full control of unit commitment[6] and of unit dispatch[7]. The system dispatcher uses information about each unit's physical capabilities, its start up and shut down costs, and its fuel costs and efficiency, amongst other things to make dispatch and unit commitment decisions aimed at achieving an objective of minimising system cost while meeting real time demand. This approach, done well, is a benchmark for efficient (ie, least cost) unit commitment.

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[6] Unit commitment is the decision whether to start up units that are not running and/or stop units that are running in anticipation of future changes in demand.

[7] Unit dispatch is the related process by which the output of individual units is varied in real time to meet load.

2.4.1 Centralised market with self-commitment

In many centralised markets, participants assume full responsibility for how and when their plant is committed and operated. Some centralised markets use a form of centralised unit commitment (eg, the original England & Wales pool) managed by the market or system operator on the basis of complex generator bids and side payments. The discussion here is focused on the self-commitment model.

In the self-commitment model, generators provide the market operator with simple bids, perhaps by segment of a generating unit. The market operator then uses a simple dispatch algorithm (market-clearing engine) to clear the market and run the system, typically with no look ahead other than ramping. The market-clearing engine is used in every dispatch period and used to generate a stream of pre-dispatch predicted prices prior to each dispatch period.

In order for generators to self-commit, they need to obtain and analyse market information. They must have the facility to frequently re-bid (ie, modify bids prior to real time) to reflect their changing position.

Each generating unit will determine their desired commitment, and submit bids accordingly for every dispatch period. Generators will bid:

- at zero or a negative price their minimum running capacity if the goal is to have this capacity generate under any circumstances (eg, not shut down overnight)
- at marginal generation cost for all capacity for which there is no concern about shutting down
- at prices above marginal generation cost for some capacity that will not be dispatched until the market clears at or above this high price

This strategy will result in a generating unit offer curve. Generators will typically develop and use their own decision models to assist with bidding and re-bidding strategies.

For example, where a generator is seeking to control hydro releases they will need to consider the information from the pre-dispatch schedules to help them understand how to achieve the generation they need in each hour. This makes the pre-dispatch information particularly important in their decision-making. In some markets (eg, Australia) participants demand a large number (up to 30) of alternative pre-dispatch scenarios to be updated and communicated regularly (eg, every half hour). Also participants will wish the pre-dispatch and re-bidding to continue to as close to real time as practical.

2.4.2 Decentralised market

In a decentralised market, self-scheduling of energy and ancillary services requires that the participants also take responsibility for their commitment decisions. They provide the system operator with simple information – schedules and inc/dec offer curves specified independently for each dispatch period. The system operator then uses a dispatch algorithm in operating the balancing market, typically with no look ahead.

Plants scheduled through a bilateral contract have commitment specified and known in advance, even if modified by the imbalance market in real time. The extent of modification is normally controlled by the inc/dec bids made into the imbalance market.

2.5 RESPONSIBILITIES OF THE SYSTEM OPERATOR IN REAL TIME

Electricity systems must be balanced in real time, so that demand and generation are matched at all locations. This is a requirement that must be met regardless of the market type.

Unlike most physical markets, an electricity market must be fully cleared in real time. There is very limited scope for inventory of electricity supply for use in a later period or delaying delivery of demand to a later date[8]. In addition, there are complex transportation issues in the transmission of electricity – both capacity limits and system security conditions – that must be managed in real time.

The dispatch software controls dispatch decisions coming up to real time and sets targets for dispatch at the end of each dispatch interval. However, within the dispatch interval actual events will inevitably be different from expectations due to deviations from projected load, or outages of generation plant or transmission lines. The system operator is responsible for the dispatch and security of the system within the dispatch interval, calling on ancillary services as required and making immediate decisions to ensure the security of the system.

The system operator is responsible for:

- checking the dispatch, and modifying it to provide any ancillary services not already accounted for;
- implementing the dispatch, by ramping units toward the dispatch targets[9] with fluctuations in load growth being absorbed by ancillary service arrangements, including frequency control capabilities, and possibly, periodic re-dispatch of generation plant;
- overseeing the action of systems and procedures to deal with recognised contingency situations (eg, loss of a single unit); and
- stepping in where necessary to deal with emergencies, including situations in which the pre-dispatch indicates an expected shortfall and the market cannot respond in time to rectify the situation.

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[8] This is limited to such facilities as pumped-storage hydroelectric plants (although the plant owner may not simply allow the system operator to use the facility as a balancing mechanism) and a very short-term ability to buffer minor load shifts by frequency shifts.

[9] Ramping can either be linear between the beginning and ending targets for all plant, or can be by priority based on the cost of different plant. In general costs can be reduced by ramping cheaper plant first. In the short term, this will increase generator profits, while not affecting prices. In the longer term, generators will be encouraged, and forced by competition, to offer at lower prices, and these cost savings will be passed through to consumers.

3. *REAL TIME PRICE FORMATION AND DISCLOSURE*

In this Chapter, we provide a summary of key differences related to real time price formation and disclosure. We then provide discussions of concepts relate to the two market designs, including:

- basic market pricing concepts;
- bidding behaviour; and
- aligning physical and economic activity through prices.

3.1 SUMMARY OF KEY DIFFERENCES

This section provides a summary of the key differences between the two market types in real time price formation and disclosure.

3.1.1 Centralised Market

In a centralised market:

- prices are transparent.
- prices are disclosed in a centralised market every trading period (eg, half hour) as a single market-clearing spot price, possibly for each location. This price represents the value of all electricity traded in that half hour at that location.
- the spot price gives the best available indication at all times of the market's estimation of the value of wholesale electricity, since a centralised market spot market is a very liquid market and reflects generation costs and participant's estimation of the scarcity value of generation.
- prices are volatile. Indeed, price volatility is necessary to provide mid-merit and peaking plant adequate revenue.
- participants typically use financial hedge contracts to manage spot price volatility.
- there is a strong relationship between hedge contract prices and spot prices. Hedge contract prices will not, in the long-term, deviate substantially from a risk-adjusted reflection of expected pool prices over the same period. Any deviation encourages one or other party to go to the spot market rather than take out a hedge. Participants consciously use spot price predictions to set their contract prices.
- pre-dispatch price predictions (ie, for a trading period in the future) will enable participants to see likely outcomes and respond by modifying bids. This allows the market participants to respond to changes in physical circumstances, volatile prices and capacity shortages. Pre-dispatch price disclosure reduces price volatility since players use that information to adjust their bids and offers.[10]

[10] For example, a load observing a predicted high price in a future trading period may decide to lower its usage in that period, while a generator may decide to bring an idle unit online to offer increased supply. Both actions would mitigate the predicted high price as re-bidding occurs and another round of pre-dispatch price predictions is released.

3.1.2 Decentralised Market

In a decentralised market:

- prices may be unknown for much of market volume (ie, the bilateral contracts).
- the imbalance market price does not reflect the value of all energy but only the value of energy imbalances. In some decentralised markets the spill price is separated from the top-up price – sometimes by a very substantial margin. It is difficult to extrapolate from either or both of these prices to a price for electricity.
- a liquid market for short-term contracts may provide some price disclosure with published forward prices. This may be the best published price the decentralised market produces. There is no spot market price to benchmark against.
- the prices of long-term contracts that form the majority of positions are usually not public and may contain complex pricing structures that make simple price comparisons difficult. Since negotiations are confidential, different players have no easy way of discovering the market price other than from the forwards market.
- unlike the centralised market, there may be little direct linkage between bilateral contract prices and balancing market prices.

3.2 ELECTRICITY PRICING CONCEPTS

3.2.1 Market clearing price

Economic theory uses supply and demand as the basis for determining price. A supply curve is postulated to describe the quantities that will be offered by producers at different prices. Similarly a demand curve describes the quantities that will be bought by consumers at different prices. The intersection of these two curves gives the price at which the same quantity is supplied as that which is demanded. This is the market-clearing price. It can be shown that this intersection maximises the net benefit from trade in the market, that is the benefits delivered to consumers, minus the costs incurred by generators, as defined by their respective demand and supply curves.

3.2.2 Centralised market

In an electricity market, the supply and demand curves are made explicit as in few other markets:

- the aggregate of offers by generators form the market supply curve. Each generator offers their plant into the market using a series of price/quantity bands or tranches. Each tranche defines a flat section of the supply curve. These price/quantity tranches may be arranged however the generator wishes, within certain standard guidelines, which we will discuss below.
- a similar principle applies to the bids by buyers that form the demand curve. In this case, however, there is usually much less flexibility, or willingness, in the physical consumption system to actually alter demand. Many consumers will find it enough to bid a fixed estimate of their load for the settlement period without attaching a price.

This relationship is shown in Figure 2.

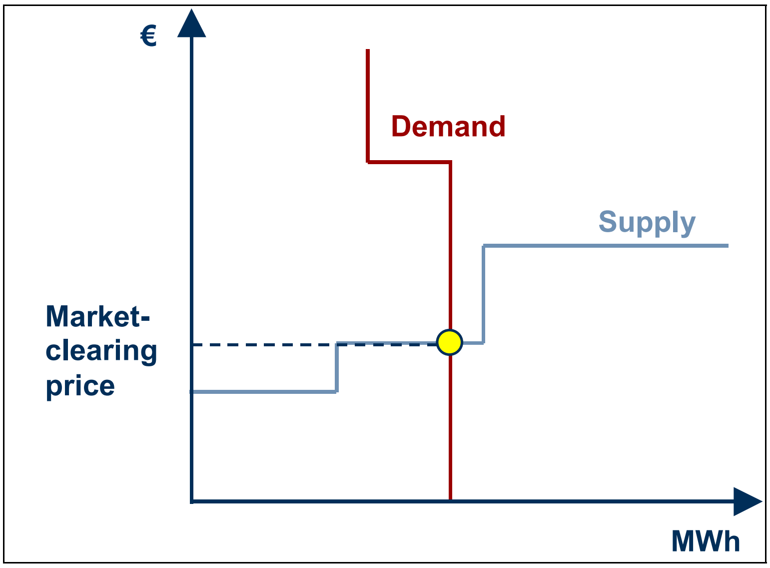

Figure 2: Market-clearing price

The market supply curve is the amalgamation of all of the individual supply curves at each location. The market demand curve is the amalgamation of all of the individual demand curves at each location. Where the two curves intersect is the market-clearing price.

In more sophisticated market designs the market-clearing price is determined using an optimisation technique that takes account of the real physical environment, and particularly the transmission system. This technique defines the economic and technical equations analytically and solves them mathematically.

In centralised markets, this market-clearing price is formed of the entire system demand and all generator bids.

3.2.3 Decentralised market

In decentralised market, there are also market-clearing prices that reflect the increment and decrement bids into the balancing market.

The system operator buys or sells energy imbalances. The system operator buys additional energy in Top-Up market as shown in Figure 3 and sells energy in a Spill market as shown in Figure 4. These markets may be settled separately or simultaneously.

Sellers in the Top-Up market can either consist of generators offering more capacity or consumers willing to reduce their load. A supply curve is formed as:

- generators offer an “increment” of additional energy or reserve capacity from plants, and
- consumers bid a “decrement” (or reduction) of from load into the market.

In a Spill market, buyers can be either consumers who require additional load or generators who are over-contracted and wish to reduce their generation. So the demand curve is formed when a generator bids a decrement of its energy or reserve capacity so as to reduce output of the plant from their scheduled quantity and a consumer offers an increment of its consumption or load.

In the Top-Up market the demand curve is determined by the system operator to be the increase in load required to balance the system, while in a Spill market the supply curve is the decrease in load required to balance the system.

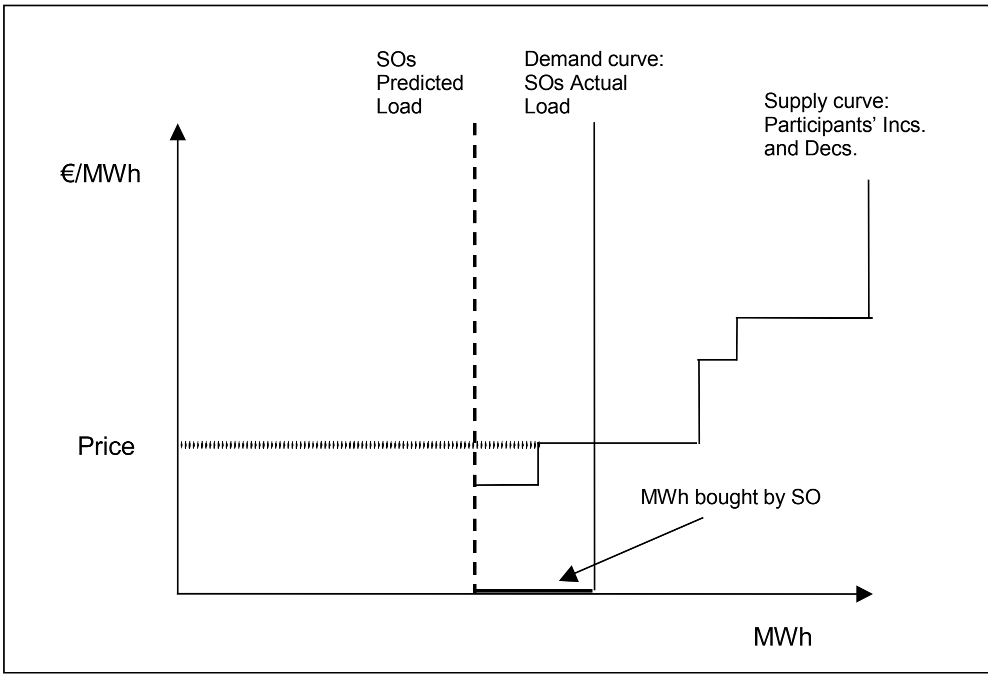

Figure 3: Top-Up imbalance market

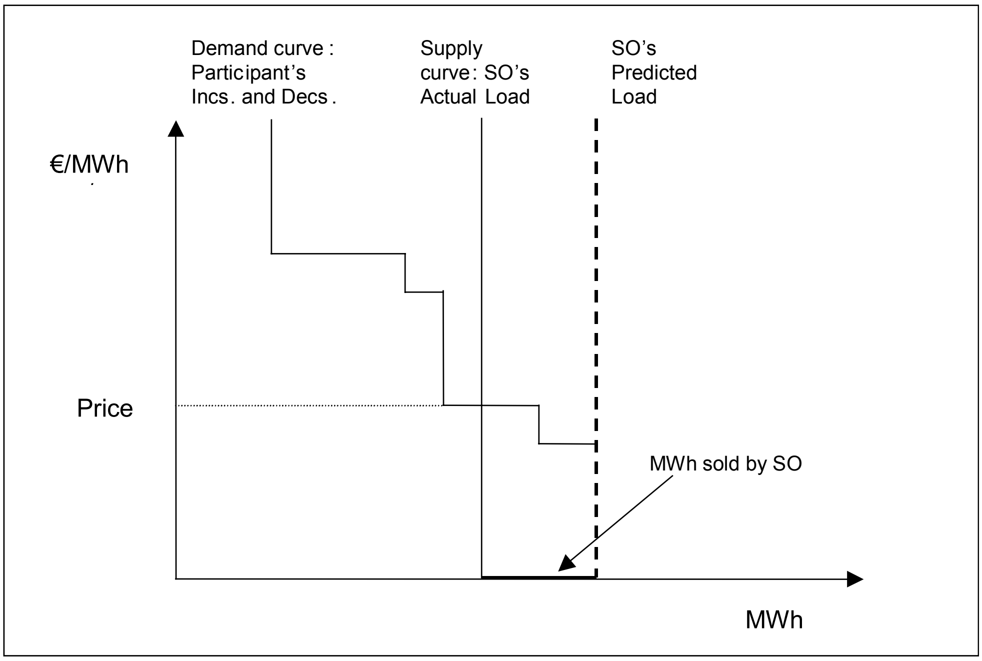

Figure 4: Spill imbalance market

In reality, most of the bidding into the imbalance market is by generators. Consumers usually face much less flexibility, or willingness, to actually alter their load. Some buyers are willing to bid interruptible load into the reserve market.

In some markets, the system operator solves the imbalance market by using a simple stack approach, where the market price is determined to be the marginal bid /offer required to meet the imbalance requirement.

For more sophisticated market designs and for some specific types of markets (eg, markets for energy required to alleviate congestion), the market-clearing price is determined using an optimisation technique that takes account of the real physical environment.

Using the market-clearing price approach there is normally only one imbalance market (either a Top-Up market or a Spill market is operational, but not both) and one market-clearing price at which the market operator/system operator buys and sells. However, there can be several imbalance markets (Top-Up and Spill) at different locations if system congestion is present.

Some decentralised markets have implemented a structure that deliberately penalises the use of the imbalance market by using a split imbalance market, providing participants with incentives to ensure that contract positions are balanced. The imbalance market is split into a Top-Up market and a Spill market for imbalances, with:

- a premium price charged to those buying in the Top-Up market and a discounted price offered to those selling to the Spill market.
- different bids and offers by participants for increments and decrements.

Typically, the Top-Up market has a substantially higher price than the Spill market. The impact of such a split market is that load will contract with generators to be over-contracted to avoid the possibility of buying at high Top-Up prices. This means that there are consistent sales to the Spill market, further exacerbating low Spill market prices.

3.3 BIDDING BEHAVIOUR

3.3.1 Centralised markets

In a very competitive centralised market, suppliers will be driven to offer bids at their short-run marginal cost (SRMC). Since the most expensive plant that is required to meet demand determines the market-clearing price, many participants will have offered below the market-clearing price. The amount of revenue above the marginal cost of generating reflects a contribution to fixed operating costs, capital recovery and profits.

No competitor will enter the market for the long term unless they expect to cover their long run marginal cost (LRMC) over the long run. That includes full recovery of their capital, operating and maintenance costs.

However, this does not mean that each generator will receive a full return in each trading interval. In some trading intervals (and in some years) a generator may receive little more than coverage of variable and fixed operation costs. In other trading periods (and in other years) the same generator may receive returns in excess of LRMC returns. It is the long run total return that is important. For this reason each generator looks for opportunities to receive a market price above their SRMC. Those opportunities may be regular margins or infrequent price spikes.

Occasional high prices (ie, price spikes) improve the profitability of all generators that are selling into the market. These price spikes are especially important for peaking plants. Since peaking plant may only operate a small percentage of the time, high prices – well above SRMC – are needed to cover fixed costs. Unfettered and volatile spot prices ensure that a balanced portfolio of new entrants will receive sufficient returns.

There is often a belief that the supply curve proposed by a generator will, or should, directly reflect its actual SRMC. This may or may not be the case, since the offer curve will be used for various purposes. Basically, a generator will use the offer curve to signal to the system operator how it wishes to be dispatched. But it also uses the offer curve to attempt to influence the market price. Typical sculpting of the supply curve bids might include:

- generation at "must run" levels may be offered at a low price below SRMC, possibly at a negative price. This reflects the high cost of shut-down and start-up.
- generation quantities corresponding to take-or-pay fuel contracts, or to water in a hydro reservoir that would otherwise be spilled may be offered at zero price. (This may actually the SRMC for such plant, under these circumstances.)
- generation up to a plant's contracted level may be offered at close to SRMC, but would avoid running at less than SRMC.
- generation up to a level where plant wants to capture further market share may be offered at SRMC or a price just below the SRMC of the next higher bid (if known).
- further generation may be offered at prices above SRMC, perhaps even above LRMC in the hope that, if demand is high or other plant is out of service, a high market-clearing price can be achieved.
- peaking plant, in particular, may bid some of its capacity at very high prices (ie, just below VoLL[11] in order to ensure that prices rise to a very high level in circumstances where, had this plant not been available, shortage would have occurred.

In the lower sections of the supply curve the plant is attempting to be a price taker, and in the upper sections a price setter. Some plant may decide to be only a price taker (base load plant), others only a price setter (peaking plant). Depending on the market situation these dynamics can be quite intricate.

At the start of an electricity market, many buyers will not have the experience or reliable historical data to bid their load accurately into the market. Other consumers, on the other hand, may wish to make bids from the start of the market.

A market could require mandatory demand-side bids from market start. This requirement would likely include the designation of a bidding agent (likely a supply company) to manage bidding for small consumers and others wishing not to bid directly.

More commonly, demand-side bidding would be permitted but not mandatory. In that case, the system operator would estimate the total load to account for those consumers not bidding into the market.

[11] VoLL is the Value of Lost Load, typically representing the price of energy not served when the market does not clear and blackouts occur. This may also be the maximum allowed bid or market price.

3.3.2 Decentralised market

Participants in the decentralised market are offering to the system operator schedules of contractual obligations that the market participants wish meet in the market. These form the bulk of the energy flows in the dispatch[12]. Bidding into the market is limited to assisting the system operator to correct for imbalances in the schedules and resolving system infeasibilities in the dispatch.

Bidding in decentralised markets is limited to the balancing market.[13] A generator may offer a bid into the Top-Up market, in order to maintain output volumes due to:

- generator "must run" or minimum run levels; or
- generation output that corresponds to take-or-pay fuel contract volumes

Where the desired generator output volume is not fully covered by bilateral contracts, the generator can attempt to get dispatched in the imbalance market. This offer might be at a low price.

However, in the Top-Up market for incremental generation, a generator might put bids at whatever price they can to capture a substantial return. Their offer strategy will depend on:

- when a generator needs additional output, bids would likely be at a price just above SRMC, perhaps corresponding to the SRMC of the next most expensive plant, to ensure maximum opportunity to sell.
- where the generator is simply looking to increase profits, bids might be at a higher price, and perhaps even above that needed for full recovery of costs.
- peaking plant, in particular, may bid some of its capacity at the maximum allowed bid price in to capture profits when shortages would have occurred had the bid not been accepted.

These bidding strategies work best in a market-clearing price market as opposed to a pay-as-bid market.[14] At lower sections of the supply curve the plant is attempting to be a price taker, and in the upper sections a price setter.

Where the bids are being used for both energy imbalance due to both inaccurate forecasting and congestion management the opportunities for being dispatched are uncertain.

In a decentralised market all but a small fraction of the costs and revenues of the participants is determined in the bilateral contracts markets. Conversely, since only a

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12 In the first year of NETA only 2% of energy was traded through the balancing market.

13 This discussion is focused on the market operator, so that it ignores the possibility of a bid-based exchange to trade short-term bilateral contracts.

14 The market-clearing price concept is assumed throughout this paper. In some markets, there is a different concept that calls for each bidder to receive its bid price rather than the market-clearing price. This is referred to as a "pay-as-bid" market. If effect, a decentralised market with bilateral contracts is a pay-as-bid market, as the negotiated price defines the payment terms. Pay-as-bid pricing in a centralised market approach is widely seen as an undesirable approach, as this removes the incentives to bid in a manner that allows efficient dispatch.

small fraction of the revenues of generators and costs of buyers comes from trading in the balancing markets, the bidding behaviour of participants in this market may be difficult to analyse. The bids into the balancing markets may reflect either a substantial quantity of spare capacity bidding for a small amount of load or only a few generators offering imbalance energy at high prices. Imbalance prices reflect the amount and level of imbalance bids, not the overall price of energy or the overall market surplus or shortage.

Unlike a centralised market, where spot prices and hedge contract prices are linked, there may be little linkage between the prices in the imbalance market and the bilateral contract market prices. This is especially the case where the market rules require balanced schedules and do not contemplate or allow purchases in the imbalance market as a legitimate substitute for submitting a balanced schedule.

3.4 ALIGNING PHYSICAL AND ECONOMIC ACTIVITY THROUGH PRICES

The physical feasibility of the power flow in the network, in terms of transmission line limits and other system security and stability requirements, is critical and cannot be violated. Meeting this requirement is more difficult in an electrical system (unlike that for almost any other product – including gas) by the requirement for real-time balancing of supply and demand.When demand occurs it must be met immediately from generation and must be immediately dispatched across the transmission system.

Pricing mechanisms should provide incentives that are consistent with meeting physical system and security requirements. Without the ability to store electricity, there is no buffer between production and consumption to soften this direct linkage between the economic system and the physical system. For these reasons, the alignment and coherence of the physical and economic systems are especially important.

3.4.1 Centralised market

A centralised market uses a “price-based dispatch” approach for dispatching and pricing that allows the physical dispatch and market prices to be optimised simultaneously and to be mutually consistent. Using price-based dispatch, a single optimisation is performed with all of the system requirements modelled in a linear programming optimisation model. For each dispatch interval, dispatch is determined by an optimisation that accounts for:

- energy offers;
- reserve offers (if used);
- transmission system parameters, modelled using DC load flow equations;
- reserve requirements;
- most recently observed plant status;
- demand side bids (or forecast load).

A particular consequence of this approach is that it can produce accurate locational or nodal prices, to the extent that the transmission system is accurately represented in the market model.

Nodal pricing is a mechanism that reveals, at each point in the system, the cost incurred to meet an increment of load at that location. Nodal pricing provides efficient short run locational pricing. In a nodal pricing regime, prices differ across points or nodes in the network due to the presence of both physical losses and network constraints (congestion).

In the fullest implementations of price-based dispatch, prices may reflect the presence of security, reserve and other constraints as well. Such prices provide the correct economic signals to market participants so that all participants:

- pay and are paid the marginal value of their consumption and production;
- are dispatched optimally with respect to the market prices; and so
- are provided incentives to comply with dispatch instructions.

In mathematical terms, nodal and reserve prices may be determined from the “shadow prices” produced by the optimisation software. Prices will be produced for energy at each node, and for each co-optimised ancillary service.

3.4.2 Decentralised market

Decentralised electricity markets use bilateral contracts and resulting schedules to drive the dispatch of the system. The schedules that define dispatch quantities from each plant and withdrawals from each location are submitted to the market operator, who accepts these as firm commitments that must be satisfied if possible.

Participants may submit schedules to market operator without formally considering the physical feasibility of these schedules. When participants are aware of obvious constraints, attempts to will be made to adjust schedules in order to mitigate their exposure to the imbalance markets. However, electrical systems are highly interdependent and the system impact from the dispatch or load of one participant will be heavily influenced by the schedules of others. It is difficult to ensure that an individual submission will be feasible when integrated with other submissions.

Since system security cannot be compromised by the contractual relationships of the participants, these contractual requirements will not be met where they violate system feasibility. The result may be that schedules are partially or wholly rejected.

The need to reconcile bilateral contract schedules with the system operator’s requirement that the system dispatch be feasible forms the basis for the markets for ancillary services (reserves and energy imbalance) in the decentralised market.

Physical security is achieved by a series of activities that may a part of a single integrated process. This process may include co-optimisation of the energy and reserve markets to reflect transmission and system security constraints:

- schedules are tested for their impact on congestion. In some markets this is done on a zonal basis. Zones are determined in advance, perhaps annually, and the significant congestion constraints are used for the first cut at schedule feasibility. If schedules create congestion participants are invited to revise their schedules.
- to correct for remaining congestion on the basis of submitted schedules, resources are purchased to provide plant available to meet energy requirements.
- simultaneously, participants submit “self-arranged” ancillary service schedules for operating reserves, which must also be validated by the system operator, and additional reserves purchased to meet system operator requirements.
- as real time approaches, the requirements for energy and reserves are matched against further updates to the participant schedules and the system operator’s own load estimates. This review considers zonal congestion and supply/demand imbalances.

- finally, real time dispatch is based on the system operator's load forecasts, participant dispatch schedules and the bids and offers for energy imbalances. These inputs are combined to create a dispatch schedule that is feasible across the whole grid (ie, at both the zonal level and local level).

Where the same resource is being offered for energy reserves, the physical reality requires that these resources cannot be provided simultaneously. However, it also requires that the resource be in the correct state of readiness (eg, plant cleared for spinning reserve is also cleared for at least its minimum energy level). This is usually the responsibility of the participant.

Some decentralised markets have a separate market for each ancillary service as well as the energy balancing market. A generator can bid its plant into one or all of these markets. The markets are independent and run in a pre-determined order by the market operator. A generator offering into such a series of markets is required to select a price/quantity offer for each energy and reserve market, but also reflect the priority ordering of the markets[15].

[15] The ERCOT market in Texas clears the day-ahead reserve market before the energy balancing market.

4. MARKETS AND PRICING OUTSIDE REAL TIME

While the primary differences in the two market models are related to the real-time operation of the spot market on the one hand and the balancing market on the other hand, these markets are often supported and supplemented by extensive trading and even organised markets outside the real-time markets. This chapter provides a discussion of these supporting markets and the processes and concepts underlying them.

4.1 CENTRALISED MARKET

All centralised market regimes involve some form of *ex ante* pricing (if only in the form of projections and forward contracting), and all involve some form of real-time or *ex post* pricing, (if only in the form of penalties for dispatch deviations). Since, in a dispatch-based market, pricing and dispatch are so closely linked, it is not surprising that forward (*ex ante*) pricing and pre-dispatch planning are also closely linked.

The term "*ex ante*" can be used to refer to prices produced at any time prior to real time. Three *ex ante* timeframes are commercially important in the context of a centralised market:

- a weekly look-ahead framework for system planning will produce indicative prices;
- a day-ahead timeframe in which day-ahead *ex ante* prices will be formed for each trading period by the first pre- dispatch optimisation for the trading day. These prices would be published as part of the pre-dispatch process, and may be updated regularly through to real time, and may be either firm or indicative[16]; and
- a real-time timeframe in which real-time *ex ante* prices will be formed for the next trading period before the dispatch optimisation itself.

4.1.1 Look ahead projections

Some centralised markets provide a weekly pre-dispatch for short term system planning. Others provide for an indicative "look-ahead" as an aid to system planning and warning to participants of significant up-coming events, for example, outage schedules and demand variations (such as public holidays etc)[17]. The market usually works better if such eventualities are known in advance. Hydro stations that are self-committing and have a daily energy limit have a particular need to understand the upcoming day.

The purpose of a look-ahead projection is to commence the process of "discovery" of system conditions and the corresponding dispatch and prices. The process for the look-ahead projection is conducted as follows.

- it commences one week (or even more) in advance of real time, or, alternatively the look-ahead goes to a fixed day of the week, (eg, Sunday).
- participants supply their indicative offers daily. Where a participant fails to submit a new offer, previously submitted standing offers are used.

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[16] Firm *ex ante* pricing, would involve an "*ex ante* market", which is discussed in a later section.

[17] The Australian Short-Term PASA (Projected Assessment of System Adequacy) is a look-ahead process, although it excludes any indication of market offers/bid prices. There is presently no weekly look-ahead in the NZ market.

- in order to give participants more complete information, the system operator/market operator develops daily pre-dispatch prices based on several load scenarios. This sensitivity enables the participants to make more reliable decisions.
- the corresponding dispatch/pricing scenarios are formed and disseminated on a daily basis.

While providing participants with additional information, the downside of this process is the requirement to keep a weekly database, and the potential burden of regular updating for both the market operator / system operator and the participants[18].

4.1.2 Day-ahead Pre-dispatch

In addition to the weekly look-ahead, electricity system operation requires a more accurate day-ahead pre-dispatch.

This process, running right up to real time, is particularly important in a self commitment market where generators need to be able to make well-informed decisions about how to offer in order to run their plant as they require. Sensitivity, using several scenarios, around the load projections may be required to enable participants to assess their strategies. The price and dispatch information is indicative only, unless a decision is made to implement a "firm" market based on pre-dispatch prices.

Commonly, a day-ahead pre-dispatch involves:

- a rolling horizon from 12-36 hours in advance, with 24 hours being added to the horizon daily when the horizon has shortened to 12 hours, so that the pre-dispatch always has a horizon of, say, 12:00 midnight.
- all participants, except those below a threshold size, supplying their offers/bids, just as for the look-ahead projection
- the system operator/market operator supplying several load scenarios, and producing associated dispatch/price scenarios. This information enables a participant to estimate the system supply curve (or at least the supply/demand intersection). Generators need to understand this sensitivity in order to help them make unit commitment decisions, and develop their offers into the market.

Accuracy and active participation are obviously important in order to promote meaningful pre-dispatch and prices. This implies a requirement for some degree of discipline on the process. This may be provided by commercial pressures via a firm *ex ante* market or by restrictions on changes to offers, once submitted.

4.1.3 Re-bidding

Re-bidding allows market participants the opportunity to better their financial position or their physical dispatch after initial offers/bids have been received and the initial day ahead pre-dispatch schedule is published.. Typical re-bidding scenarios are:

- a generator wishes to run at a fairly constant level all day, or not run at all, but finds that it has been cleared to run over some hours but not over others. Re-

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18 Using standing data that reflects the participant's standard bids and offers may substantially reduce this burden.

bidding allows the generator to either lower its price so that it runs continuously, or to raise its price and bid itself out of the market so that it does not run at all.

- a large consumer finds that the price has risen to such an extent that it is not economical to purchase at that price. By re-bidding a smaller amount at a high price - provided the consumer is able to control the load - it is possible to reduce the demand, and possibly to lower the price to a more satisfactory level.

The ability to tailor offers to evolving circumstances is clearly important; Singapore, Australia and New Zealand have allowed re-bidding from the start of each market, while California introduced re-bidding in response to requests from participants.

Since the pre-dispatch process aims to provide reliable information to participants and the system operator, re-bidding needs to occur freely as close as possible to real time. Stopping re-bidding at, say, 4 hours prior to real time might be put in place initially, based on experience in other markets, to allow reasonable time to communicate, collect and process data. As experience is gained and systems become robust, this period might be reduced to 1 hour or even less.

In order to allow participants to respond to “emergencies” after re-bidding has ceased, re-declaration of availability and demand can occur, up to real time for bone fide reasons. Bona fide reasons would include plant failure. It is essential that plant be promptly re-bid under such circumstances, since otherwise the dispatch will be seriously distorted.

Re-bidding is sometimes argued to provide an opportunity for participants to game the market by strategically altering their offers to increase prices. The system operator, too, may feel the need for some assurance that offers are not going to change arbitrarily close to real time. But other mechanisms can be employed to limit both tendencies, and re-bidding recognises the fact that the electricity market is constantly changing, as are generator capabilities, particularly if generators must work around dynamic gas or hydraulic constraints.

The timing of the final re-bidding round is determined by when the system operator / market operator needs to determine final commitment decisions. There is tension between the system operator/market operator wanting as much time as possible before real time for this comfort and to order generators to ramp, and the participants wanting the ability to re-bid up to real time in order to “optimise” their response to the changing conditions in the market and, in the case of hydro, the state of their storage or river flow.

4.1.4 Firm *ex ante* markets

Some regimes have a firm (ie financially binding) market in advance of real time. We refer to it as a “forward” market. This forward market could be 24 hours ahead, 12 hours ahead or even 4 hours ahead. The principle is the same. PJM and the modified New England markets both have firm forward markets.

The forward market is, in essence, a short-term contracting market with the forward price setting the contract strike price. In some jurisdictions this is a voluntary market, and as such the market operator need not offer it. Participants are free to enter into such contracts either bilaterally or through an “exchange”. Other jurisdictions have a compulsory market. Where the market is compulsory it is used to bind participants to make firm financial commitments that correspond to their dispatch commitments. The subsequent real time market clears the contracts struck in the forward market.

In the forward market, generators contract with the market operator for the quantities that are cleared by the forward pre-dispatch process at the forward market price determined by the pre-dispatch. Similarly, the consumers also contract with the market operator for the demand-side quantities that are cleared by the forward pre-dispatch process at the forward market price.

There are several pre-requisites for a successful forward market:

- there should preferably be some kind of indicative look-ahead "price discovery" process prior to the forward market to give participants information going into that market.
- there should be comprehensive demand-side bidding in the forward market, since otherwise the market operator will find it necessary to provide a balancing 'bid" in order to produce an acceptable pre-dispatch, which undermines the integrity of this market[19]. Also some participants may find themselves contracted for quantities estimated by the market operator since, otherwise, the market operator itself will be exposed to risk with respect to the extra quantities that it has contracted for generators to supply.
- all long term contracting needs to be struck against the forward market price, otherwise these contract quantities will be double counted, giving participants strong incentives not to offer them into the day-ahead market, and thus distorting the pre-dispatch, and there may also be significant inter-nodal risk that would be difficult to hedge between the two markets.
- the transmission company may be made financially responsible for transmission failures that occur between the forward and real-time markets. If not, the market operator may face this financial risk.

While there is an argument for the desirability of a forward market, it is very important that reliable information be available for participants. It is also important that all demand-side participants are involved in the market, either directly or through an agent. If information regarding load is not reliable enough to enable all spot market participants to participate effectively in this market, the integrity of the market is questionable.

4.1.5 *Ex post* and real time markets

The actual focus of the spot market is ultimately on the real time market. The spot market prices are determined based only on "real-time" dispatch. But it should be recognised that real-time dispatch is still only an approximation to what really happens in real time. In reality there are discrepancies (accidental or deliberate) between the information on which the dispatch instructions are based and the actual events. Thus the market is not actually in "real time". It is either just before real time – hence an *ex ante* real time market, or after real time – hence an *ex post* real time market.

The market in Australia, for example, is a 5-minute *ex ante* real-time market:

- the generators' offers are taken from the last re-bidding round;
- the load is estimated for the end of the 5 minute dispatch interval;

[19] Although note that it would be acceptable if smaller participants were to appoint some party preferably not the Market Operator, to act as their agent in this regard.

- just before the 5 minute period commences the market is cleared for that load and those offers; and
- the prices are published just before the 5-minute dispatch period commences.

The dispatch solution sets the “targets” that each generator has to meet at the end of the 5 minutes. Since the settlement period is 30 minutes, the 30-minute prices are the average of those for the 5-minute intervals involved. These prices are applied to the metered quantities for the half-hour.

There will be discrepancies between the *ex ante* dispatch targets and actual events. The system operator handles these differences using ancillary services (primarily short term reserves such as spinning reserves and load following services). With an *ex ante* real-time market, prices correspond to the dispatch instructions, although the quantities being metered correspond to the actual events.

The New Zealand market, on the other hand, is an *ex post* market:

- a pre-dispatch is run to determine the dispatch targets at the end of the half-hour, and *ex ante* indicative prices;
- the quantities are metered for the half-hour; and
- the next day the market is re-cleared to determine *ex post* prices using the generation offers for the half-hour, and the metered loads for the half-hour;
- for settlement these prices are applied to the metered quantities for the half-hour, both generation and load.

Since the dispatch is *ex ante* and the market is re-cleared *ex post* there is a discrepancy between the dispatch instructions and the market prices. The alignment between market prices and actual system conditions is closer, though[20].

The PJM real-time market is close to the New Zealand model but uses actual metered dispatch and metered load along with the bids of a limited subset of plant to determine the *ex post* prices

4.2 DECENTRALISED MARKET

4.2.1 *Ex ante* price formation

Decentralised markets involve some form of *ex ante* pricing (primarily in the form of the prices for forward contracts and prices of reserves), and some form of real-time pricing (prices of reserves and balancing energy).

Three *ex ante* timeframes are commercially important in the context of a decentralised market:

- contract negotiations and power exchange trades prior to submitting the required balanced schedules for real-time dispatch.
- in some markets there is a day-ahead timeframe in which day-ahead *ex ante* dispatch schedules and reserve allocations are made. Reserve prices are formed

[20] Although note that the potential for mis-alignment between *ex ante* and *ex post* assessments will be very much less in a market which uses 5 minute intervals, as in Australia, rather than half-hourly intervals (as in New Zealand).

for each trading period of the following day. These schedules and possibly the prices are published to relevant participants as part of the pre-dispatch process.

- a real-time timeframe in which real-time prices, usually *ex ante*, will be formed for the next trading period from the clearing of the market for balancing energy.

4.2.2 Day-ahead process

For those decentralised markets that use it, the Day Ahead process, running right up to just before real time gate closure (the last time when revised schedules can be submitted), is particularly important for the participants and the system operator to mange congestion, and buy reserve capability and for the participants to update and revise their schedules in the light of system operator announced information.

The day-ahead pre-dispatch process involves a period starting early on the day before real time running up to an hour (or so) before real-time. During that time (in approximate order of events):

- market operator/system operator publishes the system information and requirements prior to receiving participant schedules.
- participants submit their schedules for energy and reserves.
- market operator/system operator validates the schedules and tests for congestion and notifies participants of discrepancies.
- participants resubmit their schedules, present a usage plan for each generating unit, and submit bids and offers for ancillary services.
- system operator/market operator purchases reserves and ensures sufficient plant is available for congestion management.
- participants submit updated schedules and ancillary service bids to reflect changing circumstances.

5. DISPATCH EFFICIENCY

In this Chapter, we provide a summary of the key differences between the two market types in dispatch efficiency. This chapter builds on the concepts and discussions in the earlier chapters.

5.1 CENTRALISED MARKET

In a centralised market, generators are encouraged to offer their plant to the market in such a way that they only run when their SRMC is less than the spot price. While short-run marginal cost may be modified by factors such as the desire to keep a plant operating overnight and to recover start-up costs, the overall dispatch order will be consistent with that that would have been achieved by a regulated utility dispatch centre seeking to minimise total cost.

A centralised market will typically result in generators being dispatched according to their short run marginal cost merit order, even if the market clearing price is not always equal to the short-run marginal cost of the last unit dispatched (ie, marginal generators may bid above marginal cost to cover fixed costs and capture a return on capital).

Frequent market interactions (ie, every 30-minute trading interval or every 5-minute dispatch interval) allow market participants to understand market dynamics and reach equilibrium bidding strategies in a relatively short amount of time.

5.2 DECENTRALISED MARKET

In a decentralised market, most dispatch is decided by bilateral contracts and the resulting balanced schedules. There is no real time (or close to real time) market price signal to influence dispatch priorities. A decentralised market offers no formal process whereby generators with low marginal costs are dispatched before those with higher marginal costs. This suggests that a decentralised market may well result in an inefficient dispatch of power plants.

This lack of efficient dispatch may be corrected to some degree by the balancing market, where generators with higher marginal costs are likely to submit an “inc” bid into the Top-Up market at a higher price than a generator with a lower marginal cost. However, issues related to start-up/shut-down costs, take-or-pay contracts, and other things are likely to be more pronounced in a very thin imbalances market.

Theory suggests that participants may negotiate a set of bilateral contracts that would move toward efficient dispatch because this would result in lower costs across the entire market. However, there are considerable impediments to this outcome. Achieving efficient dispatch in actual practice in a decentralised market will be difficult due to a number of factors, including:

- lack of information about other bilateral contracts;
- need for extensive learning on the part of negotiating parties in each bilateral negotiation; and
- typically complex (eg, two part payment) bilateral contract terms.

Bilateral contract pricing information is not generally available to parties outside the contract. The market cycle may be quite long for contract renegotiations (several months or even years compared to minutes for trading in a centralised market). Bilateral contracts, with complex and non-standard terms and pricing features may not be easily compared, even if information is available. These factors suggest that the learning process may take a long time to iterate to equilibrium. In the meantime, changes in plant efficiency, fuel costs, the mix of plant operating and other market conditions affect the dynamics of the process and conspire against achieving a long-run equilibrium position.

The development of exchanges that trade in relatively standard contract types may move the decentralised market more quickly toward efficient dispatch.