



Alberta Wholesale Electricity Market

September 29, 2010

The Market Surveillance Administrator is an independent enforcement agency that protects and promotes the fair, efficient and openly competitive operation of Alberta's wholesale electricity markets and its retail electricity and natural gas markets. The MSA also works to ensure that market participants comply with the Alberta Reliability Standards and the Independent System Operator's rules.

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1 Introduction

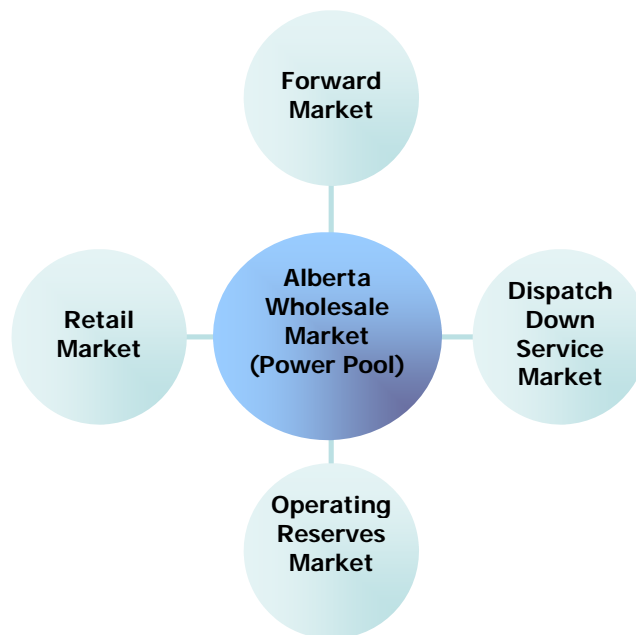
In 1996, Alberta began operating its wholesale hourly electricity market known as the Power Pool. This was the first such spot market in Canada and for Alberta was an important step down the path towards a more market-based approach to providing for the province's electricity needs. In 2000, physical rights to the output of the existing generators that had been built under the previous regulated environment were auctioned off as Power Purchase Arrangements (PPAs) and January 1, 2001 marked the beginning of the current market structure that includes both the PPAs and the opening of retail competition. Despite some retirements since 2001, the amount of generation in the Alberta market covered under the terms of those PPAs is still close to 50% of total in-province capacity.

The purpose of this report is to provide a general description of the Alberta wholesale electricity market as an important component of the overall electricity market structure.

In Alberta, by law, all wholesale electrical energy from generation that is not consumed on site must flow through the Power Pool. The Power Pool is operated by Alberta's Independent System Operator (ISO) whose company name is Alberta Electric System Operator (AESO). The Power Pool is the physical clearing market for the Alberta Interconnected Electric System (AIES). An important point is that the AESO is *independent* of any other market participant. Thus the AESO is able to undertake its many varied duties without any actual or perceived favouritism towards the companies with whom it has interactions.

One of the most important tasks of the AESO is to operate the wholesale spot market (Power Pool) such that the market operates in a fair, efficient and openly competitive manner. The electricity market in Alberta encompasses a number of inter-related sub markets as shown in Figure 1.1.

Figure 1.1 Alberta's Electricity Market Structure



The wholesale **Power Pool** is the spot market for bulk wholesale electrical energy where the price is set in real time through a mechanism whereby generating units are dispatched as required to balance total load with supply and price is set by the marginal producer.¹ More details are provided in Section 3.

In order to operate the electric system in a safe manner, the AESO needs operating reserves including regulating reserves, spinning reserves and supplemental reserves. These are procured by the AESO in a separate **operating reserves market** called Watt-Ex which is housed at the Natural Gas Exchange (NGX), as well as through Over-The-Counter (OTC) transactions. The MSA has discussed the operations of this market in many of its quarterly reports and provided a more educational description in our report entitled *Operating Reserves Procurement – Understanding Market Outcomes*, September 16, 2009.

Since late 2007, the advent of the market changes brought about through the ‘Quick Hits’ rules included a new sub market called **Dispatch Down Service (DDS)**. The primary purpose of this market is to have generators voluntarily step out of the energy market for a period to help offset the price depressing effects of some other generators who are forced into the market due to transmission constraints (known as Transmission Must Run, or TMR). The MSA has previously analyzed and commented on this market in our report entitled “*Quick Hits*” *Review: Dispatch Down Service*, July 10, 2008.

Many generators and consumers choose to make their purchases ahead of real time and thus avoid being exposed to prices at the Power Pool. The buying and selling of electrical energy ahead of the production and consumption is done in the **Forward Market**. The MSA recently published an educational piece on the forward market, *An Introduction to Alberta’s Financial Electricity Market*, April 9, 2010.

All the above markets relate to wholesale energy. The Alberta **Retail Market** is that market which ultimately serves the needs of the smaller retail customers, including all residential consumers. The MSA reported on the retail electricity and natural gas markets in *Retail Review: Electricity and Natural Gas*, February 13, 2009.

For the overall Alberta electricity market to truly thrive, all these sub markets need to work together. They lever off each other.

The operating reserves market and Dispatch Down Service market are directly connected to the wholesale Power Pool since they ‘compete’ for supply from the existing generating fleet. At any moment, all the needs of the energy market, operating reserves market and Dispatch Down Service market must be met from the available resources, basically in-province generation that is not on maintenance. Note that there is no joint optimization by the AESO of offers to the three markets. Load participates in the supplemental reserve market to a moderate extent, and the BC inertia provides some spinning and supplemental reserves to Alberta. However, the bulk of these services are met by the generating fleet in Alberta. Participants rationally make choices among these markets to maximize value and accordingly prices are linked. In 2009, the dollar value of these markets was \$5,000 million, \$90 million and \$13 million for energy, operating reserves and Dispatch Down Service, respectively.

Forward market prices relate to the wholesale Power Pool in that the prices are a view on how the Pool prices will settle in future months and years. Similarly, retail prices are linked to forward prices in that retailers buy from the forward market as a major input cost to providing energy for their smaller

¹ Loads are allowed to bid into the market and thus are eligible to set price. However, in practice they rarely elect to do so.

customers. Forward market prices are created through the interactions of these buyers and sellers. It yields a forward price curve that represents participants' forward views of Pool prices.

However, while some may argue over the relative importance of each of the sub markets, it is absolutely vital that the Power Pool works in a reasonable fashion. What does a 'reasonable fashion' mean in this context? The relevant standard for the AESO is that the market is fair, efficient and openly competitive.

2 Features of the Alberta electricity market

The Power Pool is a wholesale market through which generators and retailers/loads trade electricity. By virtue of electrical interconnections (called interties) with British Columbia and Saskatchewan power can be both exported and imported to and from outside regions. A new intertie is being constructed connecting to Montana that is scheduled to be in service in 2011.

The design of the Alberta wholesale market reflects the physical characteristics of electricity:

- Production (generation) must exactly match consumption (load) at all times since electricity cannot be economically stored. This balancing act requires very close coordination of the electrical system components by the AESO in order to maintain system reliability.
- Once electrical energy is generated, one MWh is indistinguishable from another.² The use of a common trading pool (the Power Pool) obviates the need to try to track individual units of consumption back to a particular source of generation.

The Power Pool is mandatory, meaning that all wholesale electrical energy must flow through it. There is no formal day-ahead market in which AESO facilitates financial or physically binding purchases and sales. Similarly, the AESO does not facilitate any other form of forward arrangements for buying and selling electrical energy.³ However, such activities are not precluded by the existence of the Power Pool⁴ and a significant amount of hedging does take place such that the MSA believes that only a modest (but unknown) portion of total physical flow is exposed to Pool price.⁵

Unlike many other electricity markets, Alberta does not pay generators for the availability of their capacity.⁶ Alberta is referred to as an 'energy only' market. One of the consequences of this is that, from the generators' perspective, Pool prices over the long term must be sufficiently high overall to pay them all operating costs as well as recovery of capital costs - plus profits to shareholders.

² There is an emerging trend toward the development of projects producing 'green' energy, which becomes a distinguishing characteristic. However, this is not recognized in the Power Pool which only deals with dispatching and establishing the price for the energy component.

³ Net Settlement Instructions are used to register forward physical transactions at the AESO, but the volumes are relatively small.

⁴ See Section 5(b) of the Alberta Electric Utilities Act.

⁵ The MSA routinely collects forward trading data from brokers that operate in the Alberta market. However, that data is not sufficient to calculate the net exposure to real-time Pool price.

⁶ The AESO does pay generators and some loads to provide contingency reserves. This is a form of capacity payment but only applies to a small segment of the market and payments to generators are essentially compensation for withdrawing from the energy market.

Alberta has incorporated a suite of ISO rules, Guidelines and Regulations to ensure that the market operates in a fair, efficient and openly competitive manner.

The basic rules governing the operation of the Power Pool have remained largely unchanged since 1996. Refinements have been made over the years, but in comparison with other electricity markets Alberta has been consistent in its design philosophy. The most recent set were implemented in December 2007 and collectively called the 'Quick Hits' rules. Key features of the Quick Hits changes were:

- Must offer to the market, must comply with dispatch requirements for generators. This means that generators must offer all available capacity to the market and, when dispatched by the system controllers they must comply. Note that generators are free to choose offer prices (between the floor [\$0/MWh] and the cap [\$999.99/MWh]).⁷
- Lockdown on price changes of offers 2 hours ahead of real time. This means that participants are free to make their own marketing decisions but those changes are not allowed within 2 hours of real time. The rationale for this is to provide some time separation between market activity and the actual delivery of electricity through the grid to customers.
- Creation of the Dispatch Down Service price reconstitution process. The use of Transmission Must Run service in Alberta has a depressing effect upon Pool price. The Dispatch Down Service market was created to help correct for this effect. Participants are compensated for 'stepping out' from the energy market, thus offsetting the Transmission Must Run units that are required to 'step in'.
- Uplift payments to suppliers on the margin when Pool price settles below the suppliers' offer price. In some hours, situations arise where a generator offers at a particular price, receives dispatch from the system controller, generates energy and ultimately receives a Pool price that is *less* than the dispatched offer. This is caused by a lack of alignment between the time interval of dispatching (minute by minute) and settlement (hourly). Generators that produce dispatched energy at offer prices that are higher than Pool price receive an uplift payment to keep them whole.

The Alberta market has a single price across the whole province for both the generators and load whereas most other electricity markets have regional or 'locational' prices. For Alberta to be able to have the single price across the province, the transmission system has to be sufficiently robust that under most conditions all generators can compete to serve all loads. This is one of the features of the Alberta transmission policy of providing a strong transmission grid – it promotes competition. When the loading on a transmission line reaches its safe operating limit congestion occurs, and the normal economic dispatch in the merit order has to be adjusted. This results in more expensive generation being dispatched ahead of less expensive alternatives that are on the downstream side of the congested line.

There are a few areas of congestion in Alberta that are managed by the AESO using special Transmission Must Run contracts (TMR). The use of Transmission Must Run causes generating units to be running when otherwise they would not. It interrupts the normal merit order. Occasionally, other areas can become congested for brief periods and a similar process is used to ensure units are running to maintain reliability and to meet the load. The fact that out-of-merit units are running to meet load (due to transmission constraints) puts downward pressure on Pool prices and the Dispatch Down Service market

⁷ Note that wind generation does not currently make offers to the Pool, but comes in as 'negative' load.

was created as a mechanism to correct for this effect. In the Dispatch Down Service market, in-merit generators compete to be paid to 'step out' of the energy market to help correct Pool price for the effects of TMR.

3 How the ISO's spot market works

This section describes the mechanics of how the Power Pool spot market works. It is done in a stylistic way as a complete description including all the minutiae would not be helpful in terms of providing the reader a broad overview.

The spot market operates 24 hours a day, seven days a week and is facilitated at the AESO's System Coordination Centre (SCC) by system controllers. Their job is to coordinate the operation of the electric system so that it is safe and reliable, and that the spot market is operated in a fair, efficient and openly competitive manner.

Each day, all generators submit their offers to the Power Pool for the following seven days. For each generating unit, they may use up to 7 price-quantity pairs to make their offers. All available capacity must be offered – all capacity that is physically able to generate must be offered to the market. This is required under the AESO's 'Must Offer' provisions.⁸ The AESO makes available a 7-day assessment of how tight the market will be in terms of the volume of supply relative to the demand. This is done by comparing the forecast of demand with the forecast of supply. It provides a signal to the market on how tight the market looks given the information that the AESO has at the time. It does not provide a forecast of Pool price beyond two hours out, but there is a relationship between Pool price and the tightness of the market.

Generators are free to make changes to their offer prices (but not their offered volumes) closer to real time as the market unfolds. Two hours before real time all price changes must stop and the only allowable changes are those associated with operational issues at the units. This procedure is meant to provide some time separation between market activity and the physical delivery of energy to customers.

Loads may choose to make bids to the market but have not done so for several years. Most load acts as a 'price taker' – meaning that it will pay whatever price the market dictates. A modest amount (200-300 MW) of load does directly participate in the real-time market by monitoring conditions and choosing to reduce consumption in the face of high Pool prices.⁹ Since these loads do not make bids, they operate outside the market by responding to price without a dispatch. This is a rational choice for such loads. If the avoided costs by not consuming are greater than the profits to be derived by continuing to consume it makes sense to not consume. In practice, this is not a straightforward decision due to limitations on industrial processes and the lack of predictability of the hourly price. Note that some loads participate in the operating reserves market selling reliability products to the AESO.

In real time, it is the job of the system controllers to manage the electric system and facilitate the market. This is an extremely important and complicated job. Keeping the lights on for all Albertans is crucial, while the operation of the wholesale spot market is also important. The balancing act facing the system controllers is, *whilst maintaining a high level of reliability of the system*, to operate the wholesale Power Pool

⁸ Generators can offer at a price such that dispatch is unlikely.

⁹ Although modest, by comparison with other markets, Alberta's spontaneous 200-300 MW is quite high.

in such a way that the price truly reflects the outcome from a fair, efficient and openly competitive market.

Unlike many other electricity markets, Alberta does not have a real-time security-constrained market model as such, in the sense that there is no mathematical computer program or algorithm that optimizes a series of dispatches across the offers from the generators and over future time frames. Rather, the Alberta market can be described as a pure dispatch market which affords (or requires) participants a high degree of freedom to manage their affairs through their offers. The Alberta market does not formally recognize generator start times and ramp rates. Obviously, the system controllers have to be aware of these factors in making their dispatch decisions. In general, generating units are not committed by the system controllers and participants manage their participation in the market through their offers.¹⁰

Generators are allowed to offer their energy at any price between \$0 and \$999.99/MWh. There are many factors that influence the selection of offer prices. For example, generating units that use coal as the primary fuel typically have a minimum level at which they can safely operate, which is often about 50% of total unit capacity. They cannot generally operate at a level lower than this. Since the re-start costs associated with coal units are quite high, they do not want to be dispatched off the system should Pool prices happen to be low for a brief period. The Alberta market does not feature multi-part bidding and associated optimization. Hence, offering the minimum stable generating capacity at \$0/MWh is a mechanism for ensuring that the plant is not dispatched off.¹¹ Co-generating plants are often intimately tied to the operation of a host with electrical and/or steam requirements that are paramount. For these plants, the electricity output is a must-run obligation that causes such energy to be priced at \$0/MWh. Hydro units typically have a limited amount of water and its use is 'rationed' through a combination of \$0/MWh offers for must-run energy and higher prices for that which has a potentially high future value. By ISO rule, imports and exports are price takers and must price into the market at \$0/MWh and \$999.99/MWh, respectively.

For each generating asset, up to seven price-quantity pairs are available to be offered to the Power Pool. The following is a hypothetical example of a unit with capacity 320 MW:

Block	Volume (MW)	Price (\$/MWh)
0	150	0
1	150	10
2	20	300

In the above example, the minimum stable generation capacity of 150 MW is offered at \$0/MWh to avoid being dispatched off even at low Pool prices. Most of the remaining energy (150 MW out of 170 MW) is offered at \$10/MWh (reflecting the low variable cost for this asset) and a small portion (20 MW) is offered at a higher price of \$300/MWh. Note that only three of the available seven price-quantity pairs were used.

There are a wide variety of offers to the Power Pool reflecting the diversity of size and cost structure, operational features as well as any market offer strategy that a participant may use.

¹⁰ In rare situations, where the system controller is able to foresee an emergency shortage of generation that could be relieved by committing idle but available generating plant he may do so (OPP705).

¹¹ In fairly infrequent situations, SMP may fall to \$0/MWh and the system controller must implement provisions contained in the Supply Surplus Protocols, currently being refined by the AESO.

In real time, the system controllers observe all offers to the Power Pool ranked from lowest to highest in offer price in the form of the system merit order. Essentially the system controllers go up and down the merit order as required whilst keeping all key reliability parameters within bounds. Dispatches occur when as needed and the highest priced dispatched energy block sets the current price called the System Marginal Price, or SMP). Often System Marginal Price will change through the hour as dispatches are required due to changes in the supply demand balance. The time-weighted value of the System Marginal Prices for an hour is Pool price, which is the wholesale settlement price.

Some observers have questioned why all generators are paid the clearing price and wondered if it would be cheaper for load if generators were paid according to their offers. If a generator offered at \$20/MWh and was dispatched then the generator would receive \$20/MWh, even though some generators might receive a higher price. This is termed a 'pay as bid' market. This is the arrangement in the Mid C market that operates in the Pacific NW area. In that market, buyers and sellers seek each other out and transactions are bilateral. There is no pool as we have here in Alberta. Generators are paid the agreed price by the counterparty loads. In Alberta, consistent with the idea that energy is a commodity, paying all generators the clearing price provides the most efficient price signal. Suppose generators in the Pool were paid as bid. Logically, all generators who expect to generate in a given hour will seek to 'guess' the price of the most expensive offer that is needed – on the basis that they would not wish to sell for less than others at that time. Essentially the pay as bid model and single price pool model should yield the same price in any given situation. Alberta has adopted the pool concept with a single price clearing model.

The system controllers have regulating range as one of their operating reserves that serves as a tool to help balance the system. It is comprised of two parts: Automated Generation Control (AGC) and ramp rate range. AGC is a mechanism by which small moment to moment changes are accommodated in the system with no direct action by the system controllers. It automatically maintains the near instantaneous supply demand balance and the schedule on the intertie, and avoids the system controllers from having to dispatch up and down the merit order continuously for very small volumes. Basically, absent AGC every time the supply demand balance changes by as little as 1 MW, the system controller would need to dispatch the merit order by the same amount. Whilst it might be argued that the absence of AGC would provide better price fidelity¹², the wear and tear on generators (and system controllers) would be significant. At any given time, several units in the system are providing AGC, these units having been successful sellers in the operating reserves market. The balance of the regulating range is used by the system controllers to help manage the system ramps. Such ramps occur for several reasons including the early morning when Albertans get up and go to work thus increasing the load on the system.

A lot of information is available on the AESO's web site describing the current state of the market such as SMP, Pool price, and generation output by unit required to meet the demand. In Alberta, the degree of transparency of market operations is very high. Figures 3.1 and 3.2 are just examples of the wealth of data that the AESO puts out to the market, both updated very close to real time.

Figure 3.2 is the AESO's trading page and shows various items:

- **Event Log** – Items that have a significant effect on the market as noted by the system controllers.

¹² 'Price fidelity' is a term referring to the degree that market prices (Pool price in the case of the wholesale market) relate strongly to the fundamentals of the market. A high degree of price fidelity is desirable.

- **System Marginal Price** – The values of SMP and the size of the associated offer block over the past few hours.
- **TMR Reference Price** – This is associated with the price reconstitution that AESO does in connection with TMR.
- **DDS Market** – This provides an indication of the number of MW offered to the DDS market that too is associated with price reconstitution.
- **Pool Price** – Calculated Pool price, 30-day rolling average Pool price and system demand for the past several hours.

Figure 3.2 shows generation by unit for virtually all units in the system greater than 5 MW. In addition, there are rolled up values of generation, net intertie flow, and contingency reserves to protect the system.

Figure 3.1 AESO Trading Page

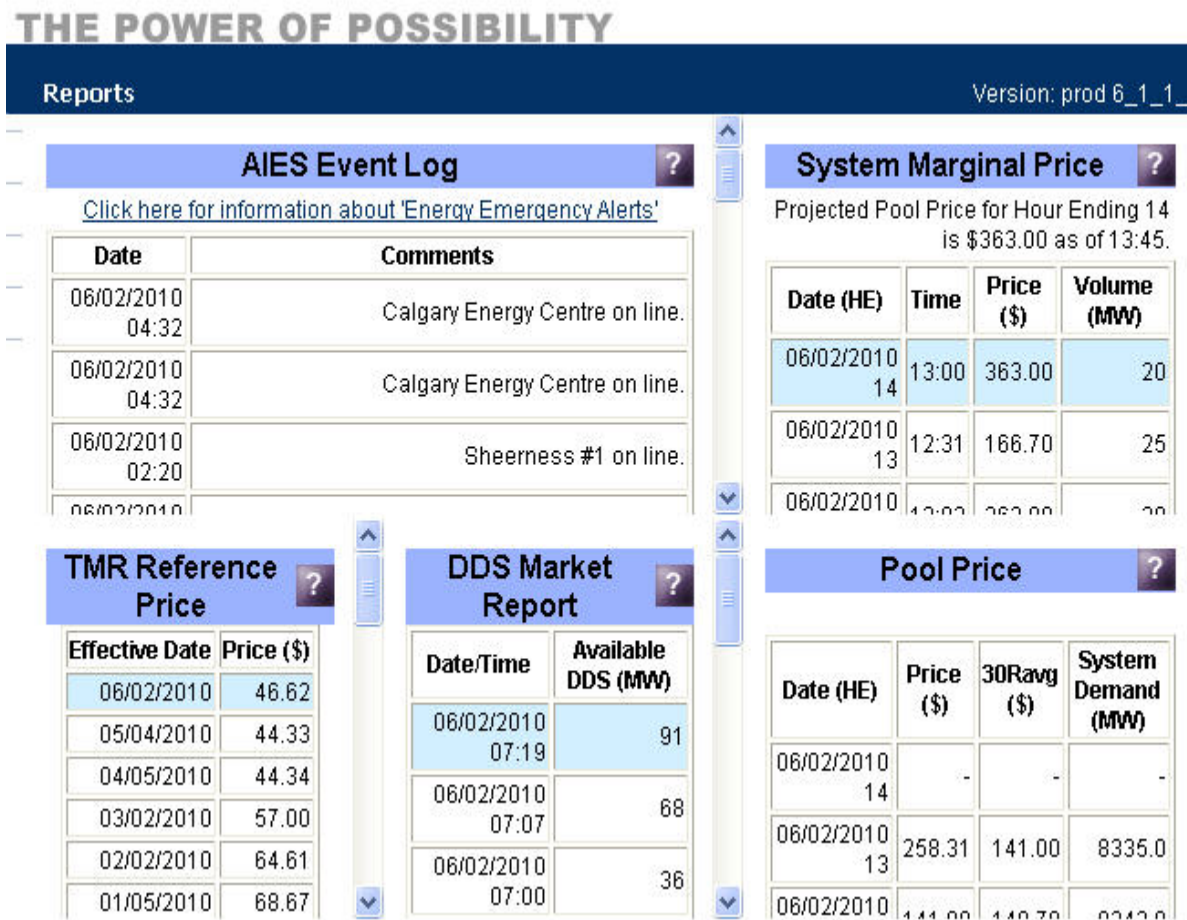
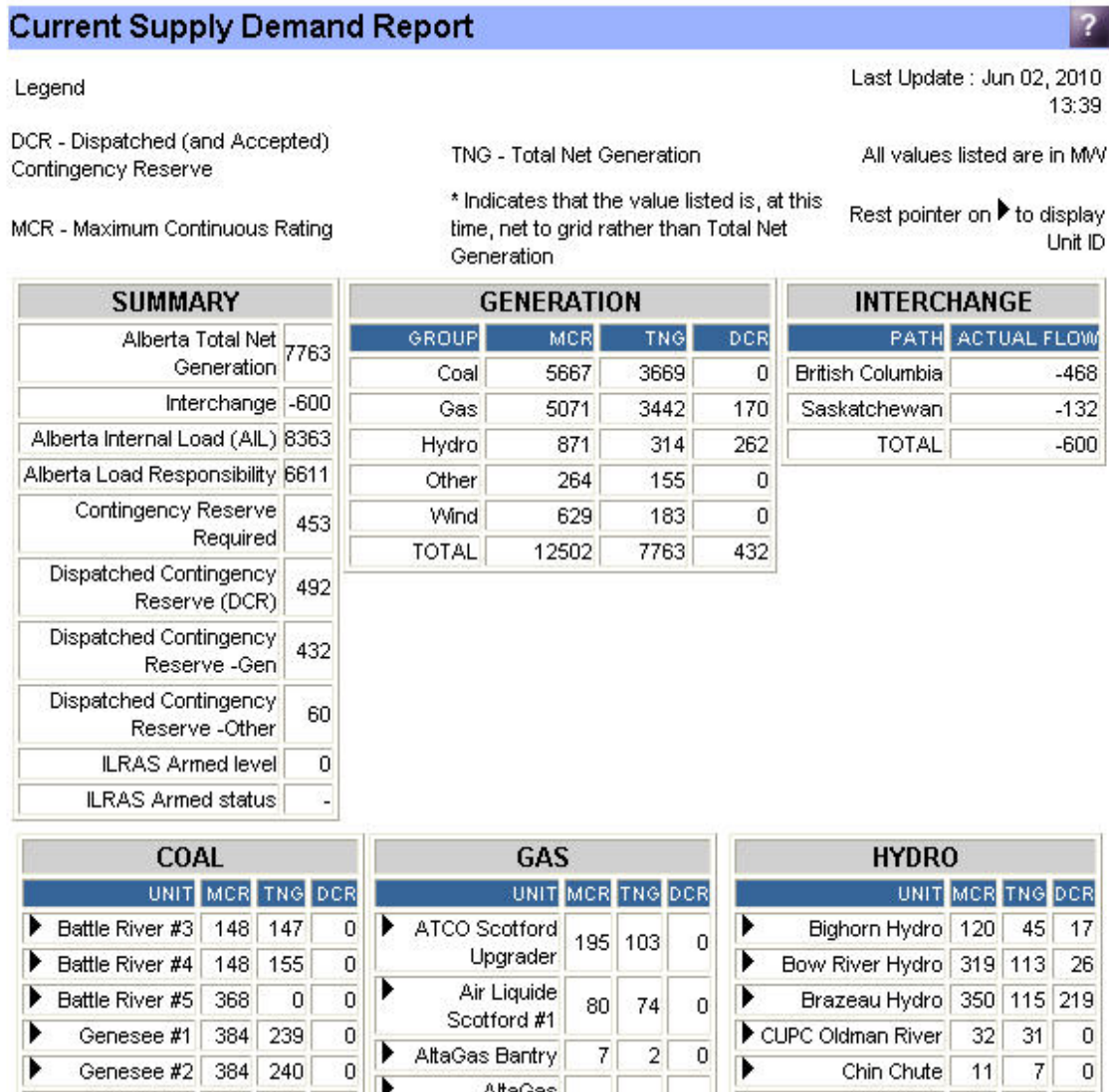


Figure 3.2 AESO Current Supply and Demand Page



4 Demand and supply

The Power Pool is the physical real-time market where the needs of the load are met by the various suppliers. The characteristics of the two sides of the market are important and are discussed in this section.

4.1 DEMAND CHARACTERISTICS

Demand, or load as it is commonly called, has notable features. The average hourly shape of demand is depicted in Figure 4.1 using data for 2009. The load shape in Alberta has a very high system load factor defined as the average divided by the peak. This is due to Alberta's high industrial load that tends to run more constantly than small consumers. The high system load factor has a bearing on the choices of

generation. The high system load factor notwithstanding, it is evident in Figure 4 that there is a ramp up of demand in the morning hours and again a secondary ramp up in the evening hours, with the ramping down taking place through the night.

Figure 4.1 Average Demand by Hour of the Day

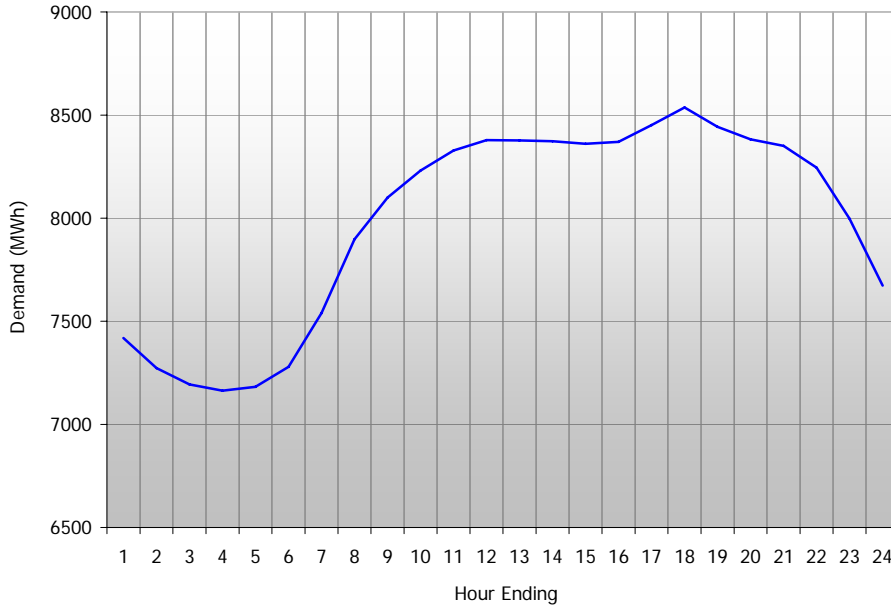
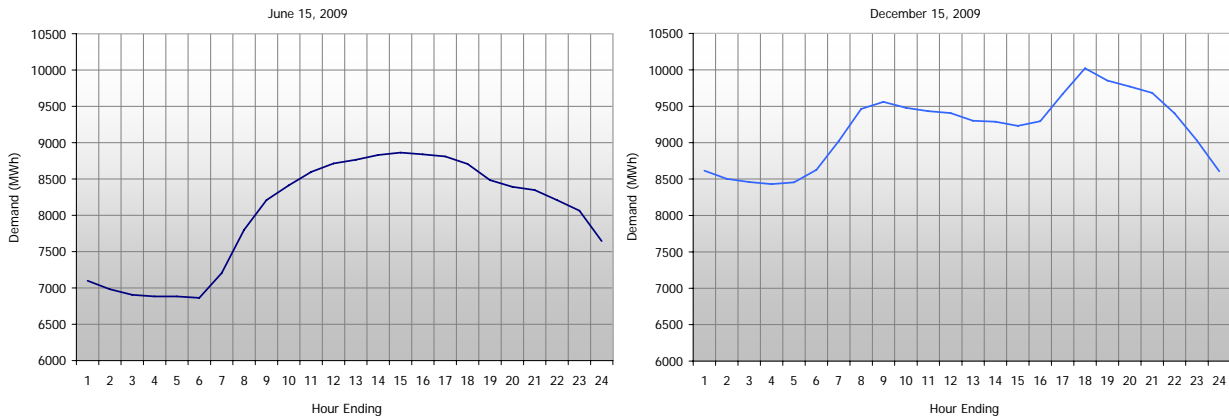


Figure 4.1 shows the average for the year. However, there is significant variability within the year as can be seen in Figure 4.2. The profile on the left is a typical day in mid June corresponding to late-spring or early-summer conditions (probably snowing!) and the one on the right is a typical early winter day likely including the effects of the load from Christmas lights in the evening hours. Both examples show the load ramps that the AESO has to manage and that these ramps are greater than that indicated in Figure 4.1 (due to the effects of averaging). Also note the much higher average level of demand on the December day compared with the June case.

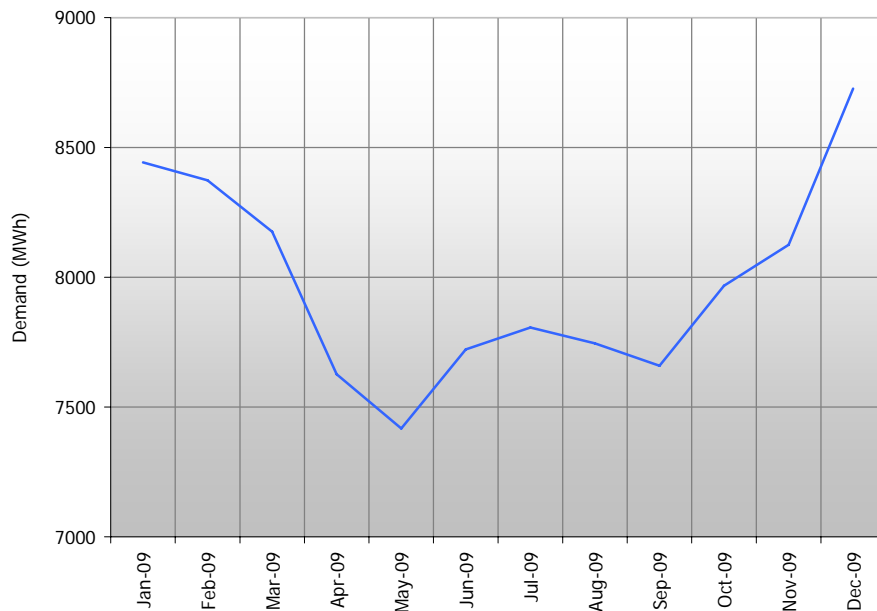
Figure 4.2 Typical Daily Demand Profiles



Looking at the pattern of average demand through the year (see Figure 4.3) it is apparent that there is a strong seasonal pattern. Typically spring and fall have the lowest average demand, summer has somewhat higher demands and winter exhibits the highest levels. Although not shown, the daily peaks show a similar pattern except that some summer days will have peak levels of demand approaching the winter peaks (not in 2010). Over time, the daily peaks on the hottest days of summer are beginning to approach those of the winter peaks, in part due to the increasing use of air conditioning in the Alberta residential sector.

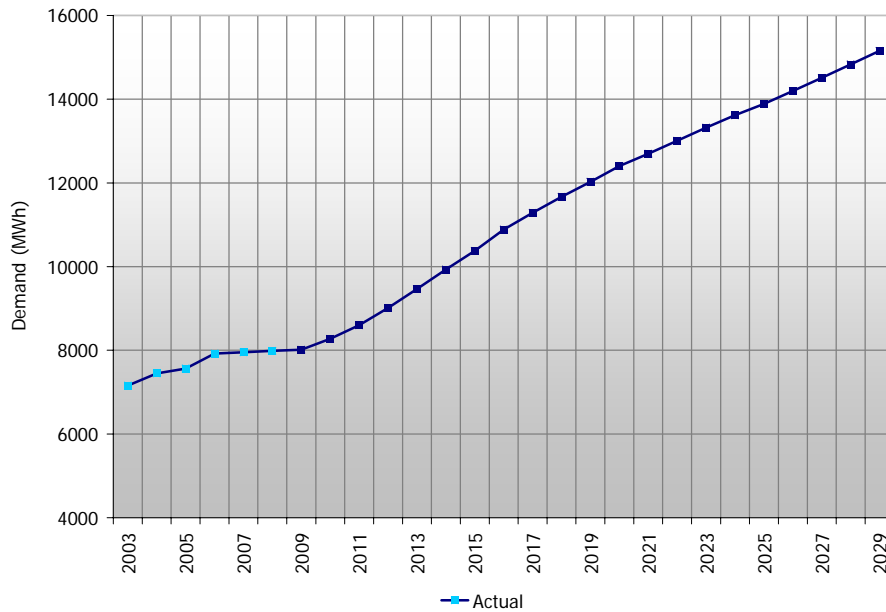
Overall, load is comprised about 78% industrial and commercial, 18% residential and 4% farm. Most of this can be characterized as passive in the electricity market under the current market design. What do we mean by passive? Basically, most consumers use electricity without considering, ‘what’s the market price at the moment’? In most cases they have arrangements in place that provide them an average price for each kWh of consumption. Most in-province load behaves in this way. There is a small, but important, subset of load which is not passive in terms of participating in the market. These loads actively participate in selling supplemental reserves to the AESO and reduce consumption in the face of high Pool prices. Typically these loads are large, are able to fairly easily shut down parts of their industrial processes thereby reducing consumption and are electricity costs are important to the viability of the business.

Figure 4.3 Average Monthly Demand Through the Year



The rate of growth in demand is fairly moderate in mature electricity jurisdictions such as ours. Figure 4.4 shows the most recent AESO forecast of demand growth to 2029. The implications of this forecast are that the system will need to nearly double in size over the next 20 years.

Figure 4.4 Long-Term Forecast Growth of Energy Demand



4.2 SUPPLY CHARACTERISTICS

As of June 2010, the system comprises some 12,500 MW of capacity plus import capability from BC and Saskatchewan. The in-province mix at this time is as shown on Table 4.1. Historically, the coal-burning plants have been the workhorse in Alberta, providing a high level of ‘baseload’ generation. Natural gas-fuelled generation expanded significantly since 1996 and now provides more than 5000 MW to the system.

Hydro is the third largest category of supply although wind is expanding rapidly and will soon surpass it. Both these categories are characterized by having limited ‘fuel’. In the case of hydro, water is generally not available in sufficient quantity to run the plant at full capacity. In many cases, there are limitations on the operations of hydro plants such that the flexibility is extremely limited.

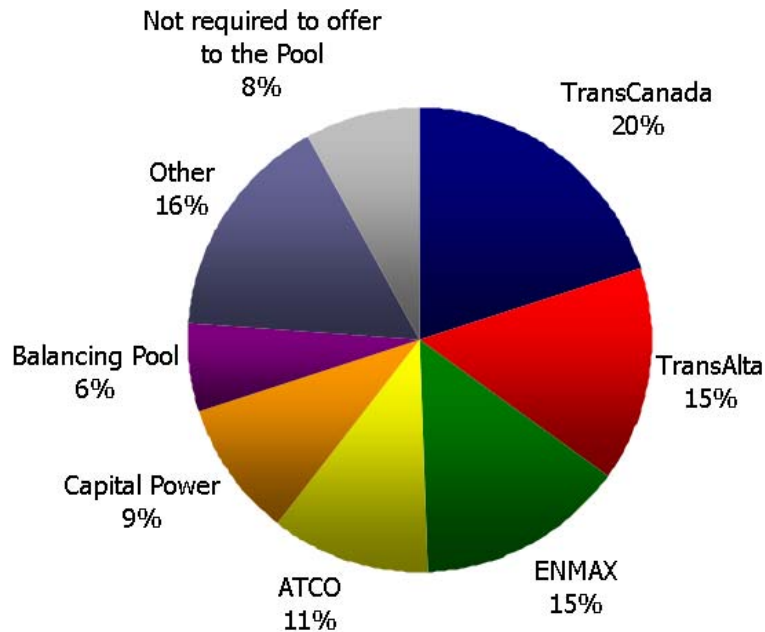
The wind plants are ‘fueled’ by the wind and it is generally highly variable. These types of plants generate when the wind blows and are idle otherwise.

Table 4.1 Alberta Generation Mix - June 2010

Generation Type	Installed Capacity (MW)	Installed capacity (%)
Coal	5670	45
Natural Gas	5070	41
Hydro	870	7
Wind	630	5
Biomass	130	1
Other	130	1
Total	12,500	100

It is relevant to know about the larger market participants on the supply side of the market. Due to the existence of the PPAs and other commercial arrangements, it is more important to look at whom actually controls the assets from a market perspective rather than who owns them. Control here by and large means being commercially responsible for marketing the plant output. Figure 4.5 is drawn from publicly available information, and provides an approximate assessment of the position on control.

Figure 4.5 Offer Control in Alberta



4.3 LONG-TERM ADEQUACY

In Alberta, the development of new generation projects is not centrally controlled by an agency but occurs spontaneously from the market as participants see opportunities to build projects and make profits. The AESO monitors the development of new projects, the retirements of older projects and the growth of demand and publishes the results to the market.¹³ The purpose of this process is to provide the maximum amount of information to the market to assist participants in making development decisions as well as providing an indication of the likelihood of any remedial actions that the AESO may have to take to protect reliability. In the event that there is a forecasted shortfall in generation projects the AESO will, under a strict set of conditions, make temporary arrangements to maintain reliability through the shortfall period. Note that this is an action that has never yet been exercised by AESO.

The most important metric that the AESO uses in the reliability assessment is the ‘Two-Year Probability of Supply Adequacy Shortfall’ (2YrPSAS). This is a calculation that looks at the potential shortfall over the next two years and includes any new generation that is scheduled to come into service. As of August 2010 the AESO’s latest assessment indicated a 2YrPSAS of 7 MWh, considerably less than the ‘trigger’ value of 1,600 MWh.

¹³ AESO Long-Term Adequacy metrics can be found on the AESO’s website.

4.4 SUPPLY OFFER CURVE

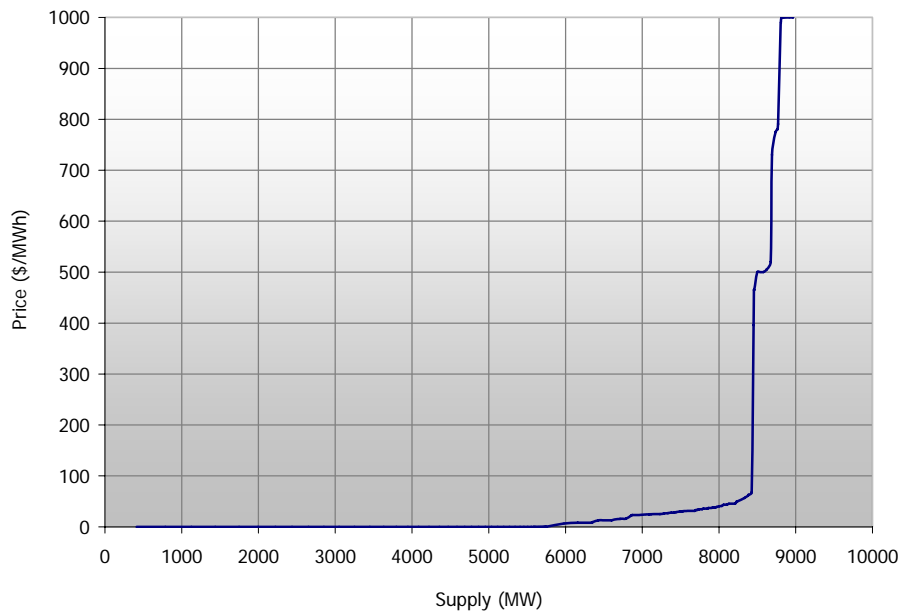
A typical supply curve for the Alberta market is shown in Figure 4.6. For this purpose we have not shown the assets that correspond to the individual offers. For those interested, the AESO publishes the information 60 days after the fact on their web site. The supply curve has some interesting features. A significant volume of energy is offered at zero dollars, in this example, some 5,700 MW. This does not necessarily mean that the sellers are hoping to receive \$0 for their production.

At the upper end of the supply curve it can be seen that there is about 500 MW that is priced above \$500/MWh. In some cases these offers are from the 'emergency' capacity of plants and reflect anticipated higher maintenance costs in the event that they are called on to generate. In others, it simply reflects a preference not to run unless the spot price goes to a sufficiently high level.

Between these two we see the normal 'price-setting' zone since they set the System Marginal Price most of the time. Accordingly, units in this zone will tend to be dispatched up and down more frequently than those priced outside this zone.

Although not displayed in Figure 4.6, the demand curve is essentially a vertical line, with the exception of the aforementioned price-responsive load (200 – 300 MW) that often reduce consumption at high prices.

Figure 4.6 Typical Hourly Offer Curve



5 Imports and exports

Alberta is a small electricity market compared with most other jurisdictions. Imports provide energy to Alberta and compete with native Alberta generators to serve the demand. Similarly, exports provide an opportunity for Alberta generators to sell energy outside Alberta that would otherwise be 'shut in'.

Alberta currently has fairly low import and export capability although the AESO is actively engaged in finding ways to improve the situation. Actual available import and export capacity varies with system conditions both in Alberta and outside. In 2009, average import capacity was about 600 MW and export capacity was 360 MW, although the values varied with the season and operational conditions.

The drivers for imports and exports are potential profits from arbitrage opportunities. In normal operation, energy from a lower value market should flow to a higher value market, making profits for the shipper of the power and also tending to 'close the arb'. The expression 'closing the arb' refers to the fact that the act of profit taking by importers and exporters tends to reduce the price difference between the two markets and ultimately remove the profit opportunity - an efficient outcome.

There are a number of difficulties facing potential importers and exporters that can hamper the efficient closing of the arb. One is that Pool price is unknown until after the hour so that a shipper (importer/exporter) is forced to make a forecast or to form an expectation of what Pool price will be in making the decision to flow energy. Given the (T-2) market rules in Alberta, this means forecasting out at least 3, more likely 4 hours. Another problem is that imports and exports are not allowed to offer to the market at a price. This is because the current rules do not allow for inter-hour dispatch for energy on the interties and accordingly such flow must be as a 'price taker' (meaning imports offer at \$0/MWh and exports bid at \$999.99/MWh).

In Alberta, we currently have interconnections with two jurisdictions: British Columbia and Saskatchewan. Shortly, a new line will be added with Montana, the Montana Alberta Transmission Line (MATL). The MATL line is a merchant line, meaning that it is being built with private funds and will charge a tariff to its users.

By far, the largest users of Alberta's interties are Powerex and NorthPoint, crown corporations in British Columbia and Saskatchewan, respectively. The second largest group of users is the companies with generating assets in Alberta. The smallest group is traders who study market data to try to spot arbitrage opportunities. The relative market (overall use of interties) shares of these groups are 78%, 14% and 8%, respectively.

6 Pool prices

Alberta Pool prices have been volatile for the past 10 years and it is a feature of the market structure. Prices can go for extended periods below the all-in long-run cost of generation, and then go to very high levels for (usually) shorter periods. The range of hourly Pool prices in a given month can often be close to the maximum range - \$0 to \$999.99/MWh.

Interestingly, load is not the most important driver of Pool prices. The daily and seasonal cycles of load are well understood and fairly predictable. Normal plant maintenance is planned to coincide with the periods when load is lower than average. What can occur and does drive Pool prices to high levels are the unplanned (or forced) unit outages that are not predictable but have to be accommodated.

Figure 6.1 shows a typical sequence of Pool prices and shows the volatility discussed above. Another way of showing the same Pool prices is in the form of a duration curve. Figure 6.2 shows the duration curve of the same set of Pool prices in Figure 6.1. The horizontal axis is the probability of exceedence corresponding to the value of Pool price on the vertical axis.

As noted in Section 2, although the AESO does not facilitate forward contracting, most loads avoid direct exposure to Pool price volatility by hedging. The upside of price volatility (from the generator's perspective) is averaged into the price of the forward contract.

Figure 6.1 Typical Sequence of Hourly Pool Prices (May 1-9, 2010)

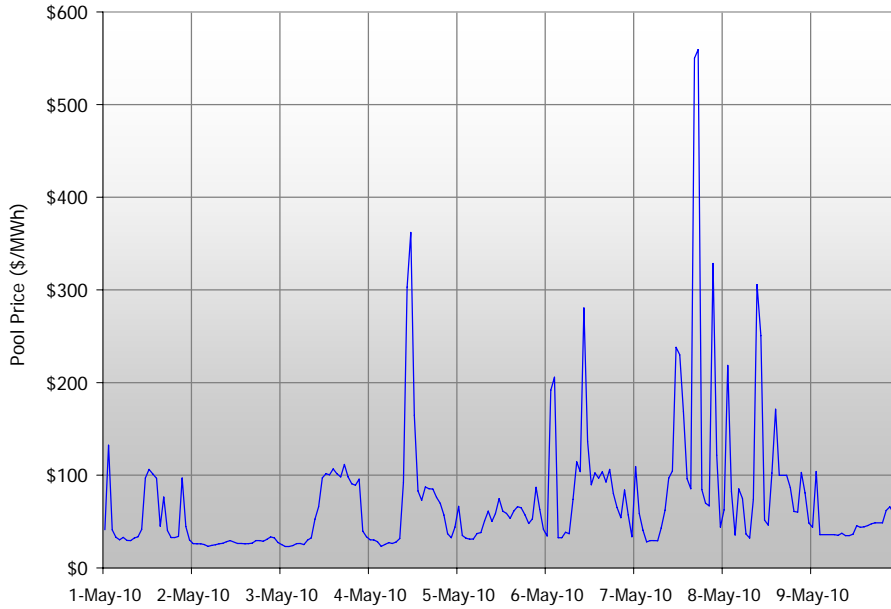
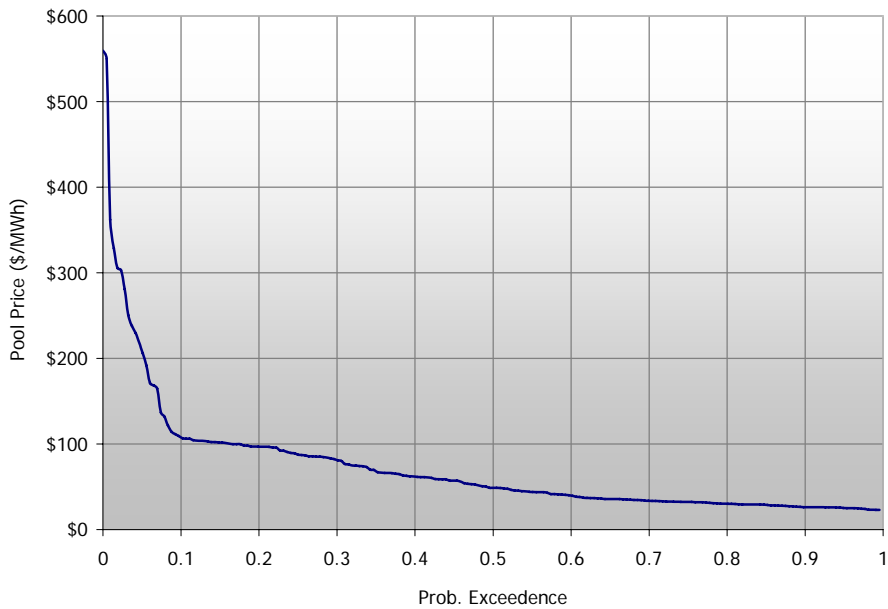


Figure 6.2 Pool Price Duration Curve (May 1-9, 2010)



7 Interpretation of events in the wholesale market

Pool prices are influenced by many factors, some of which are easily discernable and others less so. For example, in Alberta, Pool prices tend to increase following a unit outage reflecting the tightening of the market. However, that doesn't always happen. Sometimes, importers respond to the signal provided by the unit outage and situations can arise where a 300 MW unit outage is replaced by 500 MW of imports and price then drops below the pre-outage level – a somewhat counter-intuitive outcome.

In the MSA's quarterly reports, analysis is provided of some of these types of unusual outcomes in the market. Such analysis can be helpful in identifying issues associated with market rules or participants' behaviours in the market. Factors that often feature in these market events are:

- Unanticipated unit outages or derates (as noted above)
- Unusual levels of transmission congestion
- Morning ramp rates, particularly in winter
- Supply surplus conditions whereby the system controllers have more offers at \$0/MWh than the level of demand
- Emergency conditions, arising primarily in situations of energy shortage
- Offer strategies.

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Alberta Electric System Operator

Supply Surplus Protocols, currently being refined by the AESO.

http://www.aeso.ca/downloads/Supply_Surplus_discussion_paper-April_29.pdf

AESO Trading Page - <http://ets.aeso.ca>

AESO Current Supply and Demand Page -

http://ets.aeso.ca/ets_web/ip/Market/Reports/CSDReportServlet

AESO Long-Term Adequacy metrics are posted at <http://www.aeso.ca/market/21311.html>



The Market Surveillance Administrator is an independent enforcement agency that protects and promotes the fair, efficient and openly competitive operation of Alberta's wholesale electricity markets and its retail electricity and natural gas markets. The MSA also works to ensure that market participants comply with the Alberta Reliability Standards and the Independent System Operator's rules.