



2010 Annual Market Statistics



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Executive Summary

As an independent system operator, the AESO leads the safe, reliable and economic planning and operation of Alberta's interconnected power system. The AESO also facilitates Alberta's fair, efficient and openly competitive wholesale electricity market. In 2010, the Alberta market had about 175 participants and approximately \$5 billion in annual energy transactions.

The annual market statistics report provides a summary of key market information from 2010 and describes historic trends in Alberta's wholesale electricity market. For the first time, the AESO is also publishing an accompanying [data file](#) to provide stakeholders access to the information behind the metrics presented in this summary report.

The annual average pool price for wholesale electricity was \$50.88/MWh in 2010, an increase of six per cent over the 2009 average pool price of \$47.81/MWh. The annual average AECO/NIT natural gas price remained relatively unchanged, averaging \$3.76/GJ in 2009 and \$3.79/GJ in 2010. The increase in pool price contributed to a four per cent increase in the market heat rate, from 13.15 GJ/MWh in 2009 to 13.69 GJ/MWh in 2010. Pool prices were relatively low for all months in 2010 and comparable to those observed in 2009, with the exception of the month of May 2010 which had a monthly average pool price of \$134.69/MWh. During the month of May various planned and unplanned transmission and coal-fired unit outages resulted in a reduction of available supply. Tight supply and demand balance contributed to the high pool prices that occurred during the month.

In 2010 Alberta Internal Load (AIL) grew 2.6 per cent over 2009, the highest annual average growth observed since 2006. The primary factors that led to this growth were an increase in demand in major urban centres in the province, economic recovery impacting demand growth in several industries, and high industrial demand growth in northeastern Alberta.

There were nearly 270 MW of new generation capacity added to the Alberta grid in 2010, with the majority of the additions comprised of three new wind power facilities totaling 214 MW. The last remaining unit at the Wabamun coal power plant was retired in 2010. The 279 MW Wabamun 4 coal-fired plant initially commissioned in 1967 was officially retired on March 31, 2010.

2010 Annual Average Pool Price, \$50.88/MWh

In Alberta's competitive wholesale market electricity prices fluctuate based on the principles of supply and demand. During instances of supply surplus and low to moderate demand prices are low, while times of supply scarcity and high demand drive higher prices. The wholesale electricity price, known as the pool price, ranges from the price floor of \$0/MWh to the price cap of \$999.99/MWh. In 2010, pool price averaged \$50.88/MWh, a six per cent increase over 2009. On-peak and off-peak pool prices averaged \$66.13/MWh and \$31.42/MWh respectively. Table 1 summarizes the historical price statistics from 2000 to 2010. In 2010, prices were similar to those observed in 2009 due to robust supply in the province, as well as continued low natural gas prices. Natural gas prices averaged \$3.79/GJ in 2010.

TABLE 1 – ANNUAL POOL PRICE STATISTICS – 2001 TO 2010

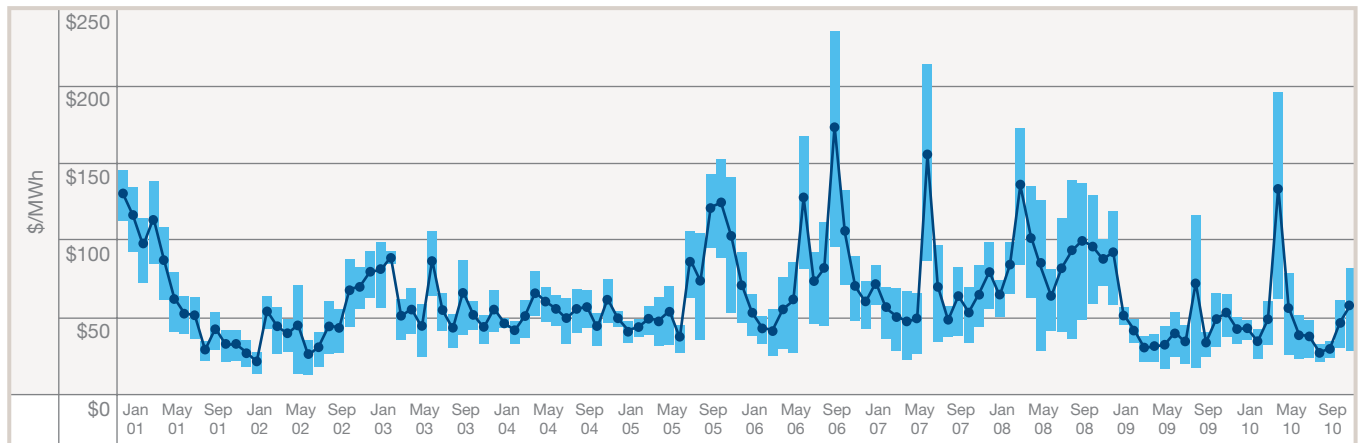
Pool Price (\$/MWh)	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Average hourly pool price	71.29	43.93	62.99	54.59	70.36	80.79	66.95	89.95	47.81	50.88
Off-peak average pool price	53.14	28.47	46.97	41.88	49.28	50.15	41.86	54.45	30.26	31.42
On-peak average pool price	85.51	56.04	75.54	64.53	86.86	104.97	86.61	117.73	61.56	66.13
Maximum hourly pool price	879.20	999.00	999.99	998.01	999.99	999.99	999.99	999.99	999.99	999.99
Minimum hourly pool price	5.82	0.01	7.07	0.00	4.66	5.42	0.00	0.00	0.10	0.00

Note: On-peak hours refer to hour ending 08:00 through to hour ending 23:00, Monday through Saturday excluding holidays. Off-peak hours refer to hour ending 01:00 through hour ending 07:00, as well as hour ending 24:00, Monday through Saturday, all day Sunday and all day on North American Electric Reliability Corporation (NERC) defined holidays.

As seen in Figure 1, with the exception of May 2010, pool prices were relatively low and flat throughout the year. During the month of May, unplanned and planned transmission outages significantly reduced the supply availability of certain coal-fired units. Coal-fired generators typically offer most of their energy at lower prices. The reduction in availability of low priced coal-fired generation during May resulted in high pool prices during the month. Excluding May 2010, the pool price averaged \$43.10/MWh throughout the rest of the year.

In conditions of supply shortfall the system controllers use a series of mitigation steps to help alleviate the situation. These steps are documented in Operating Policy and Procedure (OPP) 801. In 2010 there were four separate supply shortfall events during which the price cap of \$999.99/MWh was reached, all occurring during the month of May. These events occurred from May 16 to 18 due to high levels of planned and unplanned outages to coal-fired units, with an average hourly amount of 2,016 MWh of coal unavailable during these days.

In 2010, the pool price dropped to the price floor of \$0/MWh on July 4, 2010 in hour ending 7. This was the first time since June 2008 that the pool price settled at the price floor. On July 4, 2010, the system marginal price remained at the price floor for 83 minutes from 5:37 a.m. to 7:00 a.m. This was due to a number of factors, including high wind generation, low system demand and high coal availability.

FIGURE 1**Monthly Average Hourly Pool Price From 2001 to 2010 with On/Off Peak Averages (\$/MWh)**

The Alberta pool price is determined by the highest priced generator dispatched to meet the demand for electricity. Generators submit hourly offers to the AESO that include the amount of energy they will provide at a specific price. The AESO's automated Energy Trading System arranges all the hourly offers from the lowest to the highest price. Starting at the lowest priced offer, the AESO system controllers dispatch generating units until the demand requirement is satisfied. The highest priced unit that is dispatched is said to be on the margin, and sets the system marginal price. The pool price is set based on the hourly average of all system marginal prices in the hour.

Natural gas-fired generators are on the margin a significant portion of the time, particularly during on-peak periods. The offer prices made by natural gas-fired generators in the middle of the energy market merit order tend to fluctuate reflecting changes in the price of their underlying fuel. When natural gas prices rise, offers tend to reflect the higher cost, which tends to result in an increase in pool price.

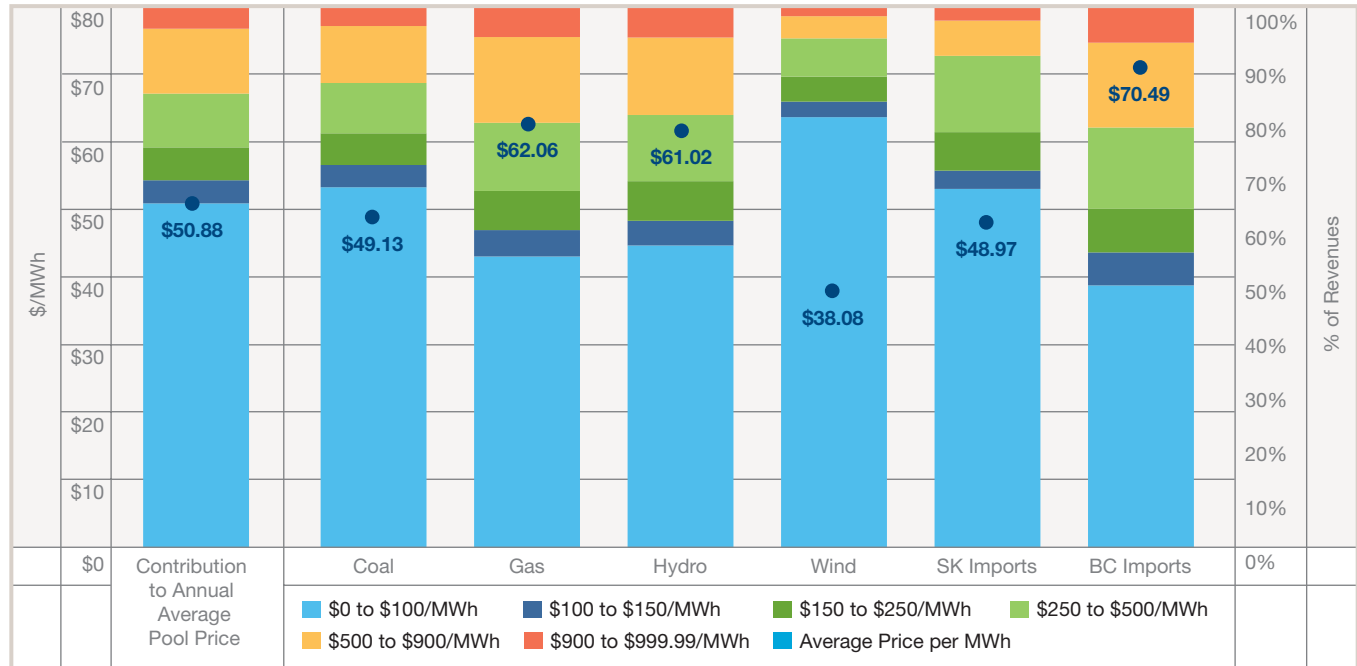
Figure 2, on the following page, presents the breakdown of revenue by pool price range for different asset types. As seen in the graph, the per cent contribution to the annual average pool price was highest in the \$0/MWh to \$100/MWh range.

The numbers shown within the bars represent the average pool price received by asset type. For example, gas-fired generators received \$62.06/MWh on average over all hours, 22 per cent higher than the average pool price. This is because gas-fired generators typically offer to run at higher prices than baseload coal-fired generation. Wind generation, which is a price taker (meaning that wind generation is effectively offered at \$0/MWh), tends to receive lower prices per megawatt hour because it displaces higher cost gas generation and reduces the pool price. In 2010, wind generators on average received \$38.08/MWh, a 25 per cent discount to the annual average price.

FIGURE 2

Pool Price Contribution to Total Revenue by Asset Type and Pool Price Range

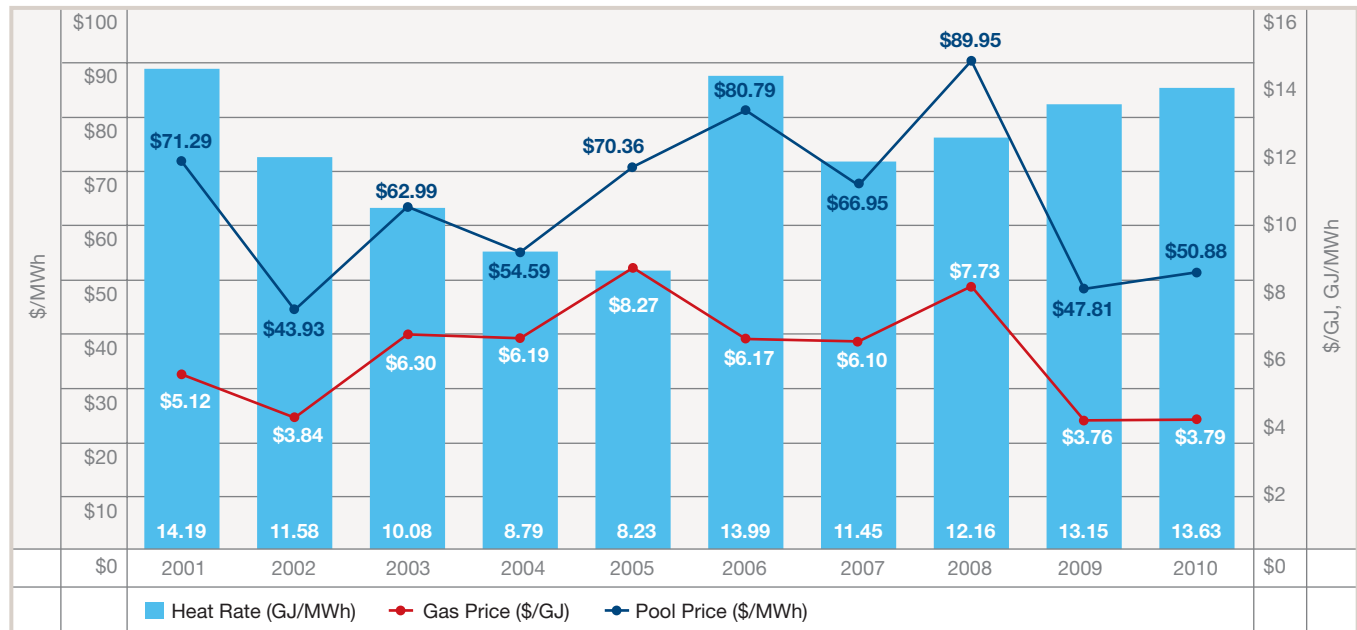
Average Revenues = 2010 Hourly Pool Prices Multiplied by Metered Volumes



Natural gas prices continued to be low in 2010. Figure 3 shows the historic relationship between natural gas prices and the pool price. The market heat rate refers to the market price of electricity expressed as a function of the market price of the underlying fuel used to produce electricity. In Alberta's case, this fuel is natural gas.

FIGURE 3

Annual Average Pool Price, AECO Natural Gas Price and Heat Rate



2.6 Per Cent Demand Growth in 2010

After three years of relatively flat load growth, total Alberta internal load (AIL) grew 2.6 per cent in 2010. The highest monthly year-over-year load growth of 6.5 per cent occurred in November 2010 and only March 2010 saw a monthly year-over-year decline, with load declining 0.2 per cent compared to March 2009. Increased demand in major urban centres and industrial demand growth in northeastern Alberta were the primary contributors to this growth.

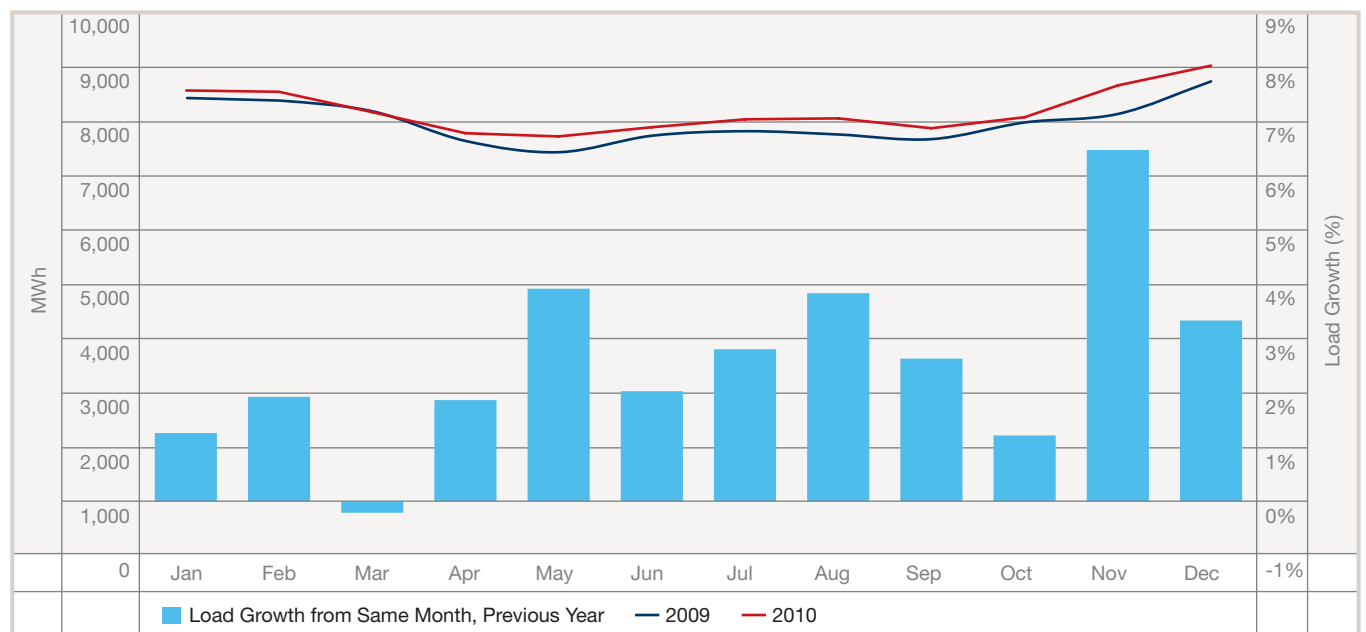
TABLE 2 – ANNUAL SYSTEM DEMAND STATISTICS

Year	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Total energy (GWh)	54,464	59,428	62,714	65,260	66,267	69,371	69,661	69,947	69,914	71,723
Average hourly load (MWh)	6,217	6,784	7,159	7,429	7,565	7,919	7,952	7,963	7,981	8,188
Maximum hourly load (MWh)	7,934	8,570	8,786	9,236	9,580	9,661	9,701	9,806	10,236	10,196
Minimum hourly load (MWh)	5,030	5,309	5,658	6,017	6,104	6,351	6,440	6,411	6,454	6,641
Year-over-year load growth (%)	0.8	9.1	5.5	4.1	1.5	4.7	0.4	0.4	0.0	2.6
Year-over-year load growth (adjusted for leap year effect) (%)	1.0	9.1	5.5	3.8	1.8	4.7	0.4	0.1	0.2	2.6
Load factor (%)	78.4	79.2	81.5	80.4	79.0	82.0	82.0	81.2	78.0	80.3

Primary load growth in Alberta's northeast was due to the continuing expansion of oilsands in the Fort McMurray and Cold Lake areas.

Large urban centres such as Calgary and Edmonton also contributed to Alberta's overall load growth. Both cities initiated and/or completed large commercial projects in 2010. Calgary's average load for 2010 was 1,090 MWh (a growth of about 1.3 per cent over 2009) while Edmonton load averaged 864 MWh for 2010 (a growth of about 1.1 per cent over 2009).

FIGURE 4
Monthly Average AIL and Load Growth



The AESO's 2009 forecast of demand¹ closely forecast the actual demand observed in 2010. The 2009 forecast, published in late 2009, forecast total AIL energy for 2010 to be 72,459 GWh. Actual energy consumption for the year was 71,723 GWh, resulting in a forecast error of -1 per cent. Peak demand was forecast at 10,170 MWh and actual peak demand was only 26 MWh higher at 10,196 MWh, resulting in a forecast error of 0.3 per cent. For reference, the highest recorded peak load in Alberta in 2009 was 10,236 MWh.

A key feature in the growth observed in 2010 was the close to 200 MWh increase in the minimum load after three years where the minimum was around 6,450 MWh. This is indicative of the strong baseload growth observed in 2010. Another key indicator of load growth in the province has been the increase and regularity of hours where demand has exceeded 10,000 MWh. In December 2009, AIL eclipsed 10,000 MWh for the first time. A total of five hours in December 2009 saw AIL above 10,000 MWh, while in November and December 2010, AIL was above 10,000 MWh for a total of 25 hours.

¹ *Future Demand and Energy Outlook (2009 – 2029)*

Temperatures Drive Peak Demand in Summer and Winter

There was no new peak demand set in 2010, although there were substantially more hours where AIL was greater than 10,000 MWh in November and December 2010 as a result of cold weather. Demand typically peaks between 5 p.m. and 6 p.m. in the winter months. The highest demand observed in 2010 of 10,196 MWh occurred during this hour on December 16th, 2010. Temperatures across the province in 2010 were relatively low, averaging -14 degrees Celsius. In comparison, the temperature averaged -30 degrees Celsius in December 2009 when the winter peak reached an all-time record of 10,236 MWh.

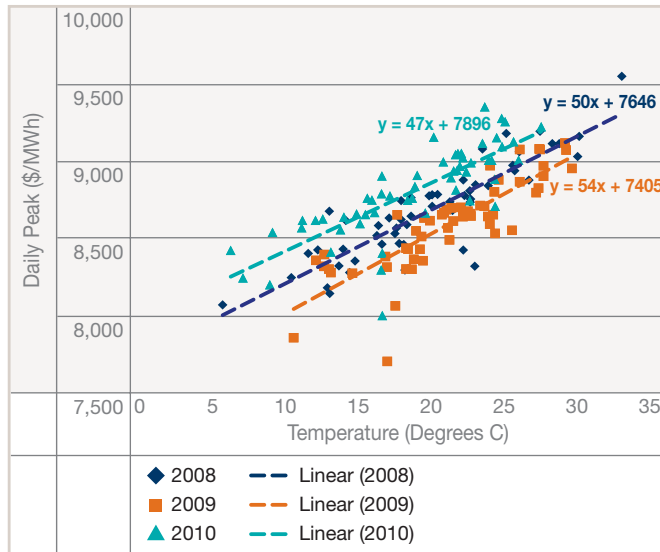
For the second summer in a row, a new summer peak was not set. The peak demand during the summer of 2010 was 9,343 MWh, set on July 29 between 1 p.m. and 2 p.m. Summer peak demand, like winter peak demand is driven in part by temperature. The lack of a new summer peak is primarily attributable to the second summer in a row with very few days where temperatures exceeded 30 degrees Celsius. Average temperatures during July and August 2010 were 16 and 15 degrees Celsius respectively.

Figure 5 illustrates the relationship between temperature and daily peak demand in summer and winter respectively. On average, an increase of 1 degree Celsius will see an increase in the AIL peak of 50 MWh during summer months, and in winter months, a decrease of 1 degree Celsius will see AIL peak increase by 30 MWh.

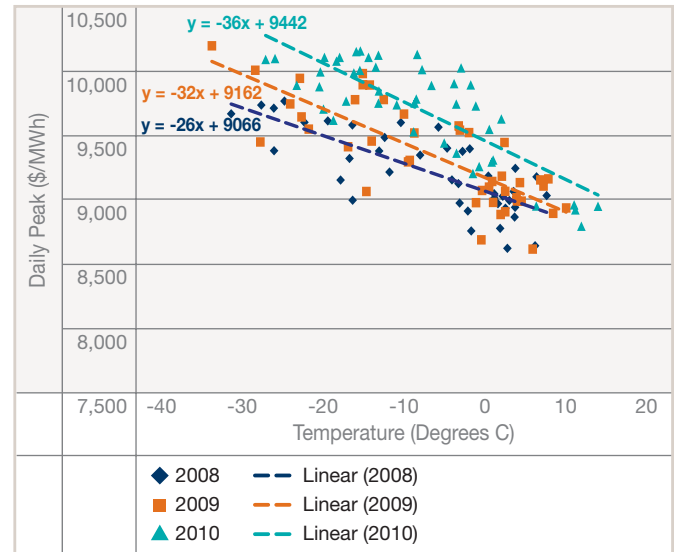
FIGURE 5

Summer and Winter Peak Demand vs. Temperature

Daily Weekday Summer Peaks vs. Mean AB Temperature at the Time of Peak



Daily Weekday Winter Peaks vs. Mean AB Temperature at the Time of Peak



Supply Adequacy Drives Prices

In a well functioning energy-only electricity market, supply adequacy is the key driver of market price and a motivator of investment decisions. During instances of supply surplus, prices are typically low, while times of supply scarcity tend to drive prices higher.

The supply cushion is an indicator of supply adequacy and the market's ability to meet demand. The supply cushion measures the undispached energy in the energy market merit order using merit order snapshots at the midpoint of the hour. The detailed calculation of supply cushion is as follows:

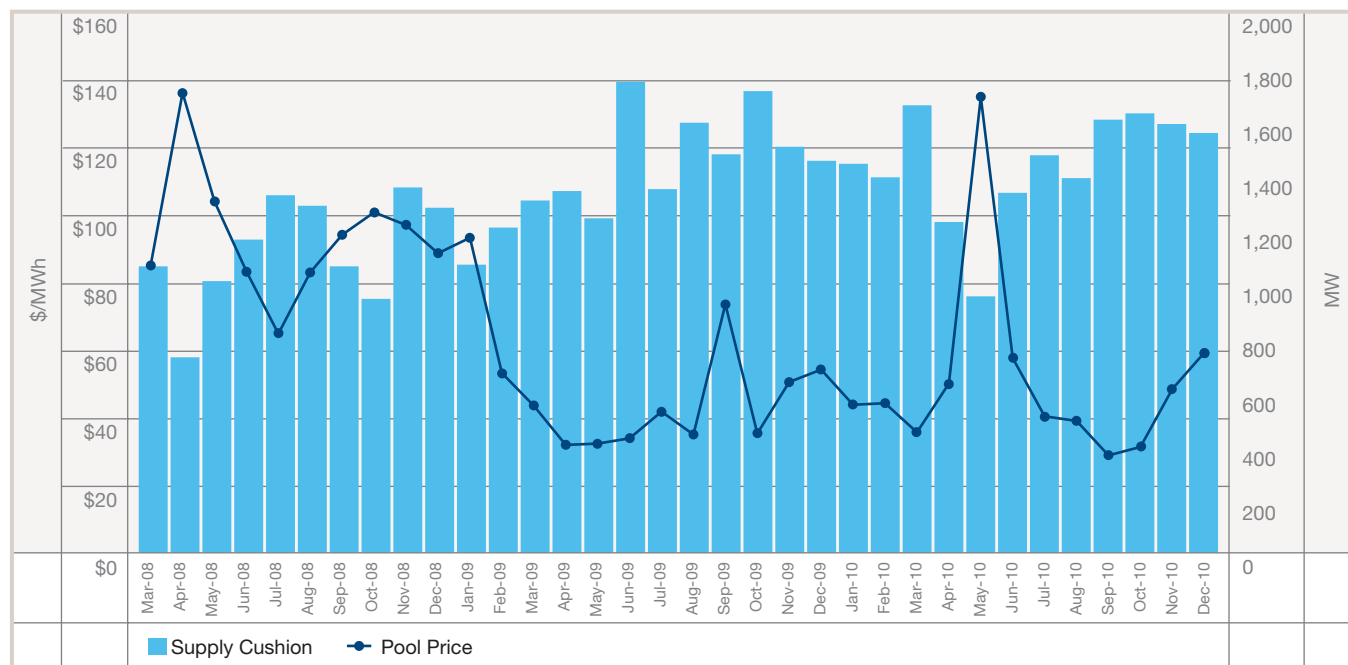
$$\text{Supply Cushion} = \sum_1^n (\text{Available MW} - \text{Dispatched MW}) + \text{DDS Dispatched} - \text{TMR Dispatched}$$

Note: In the equation, DDS stands for dispatch down service and TMR stands for transmission-must-run. Both concepts are explained in the "Dispatch Down Service" section on page 18 of this report.

Figure 6 displays the monthly average supply cushion compared with the monthly average pool price. Months where the supply cushion was low (indicating a tight supply and demand balance) corresponds with high monthly average pool prices. Typically the supply cushion will decrease when there are planned and unplanned outages that affect supply.

FIGURE 6

Monthly Average Supply Cushion and Pool Price



In May 2010, instances of supply scarcity represented by a low monthly average supply cushion drove prices higher, averaging \$134.69/MWh for the month. A significant amount of supply from coal-fired generation was unavailable to the market during this time due to unplanned transmission maintenance in southeast Alberta and planned maintenance in the Keephills/Ellerslie/Genesee (KEG) area.

On April 14, 2010, a spring storm in southeast Alberta caused several transmission line outages that resulted in significant constraints to the coal-fired generators in the area and the curtailment of Saskatchewan interconnection imports to manage the constraint. Repair of the impacted lines was completed in June, 2010. In addition to the southeast constraints, the KEG area underwent several planned transmission outages within the same time period, in particular during the months of May and June.

The reduction in coal generation due to the significant constraints on the system resulted in high pool prices during the time frame, with an average pool price of \$106.50/MWh from April 14 to June 1 (in comparison to an average price of \$42.26/MWh during the rest of the year not including this period). During this timeframe, there were 1,096 hours (93 per cent of all hours in the period) with constraints to generation, resulting in an average hourly amount of constrained energy of 443 MWh for those hours with constrained generation.

FIGURE 7

Impact of System Constraints on Prices – April and May 2010

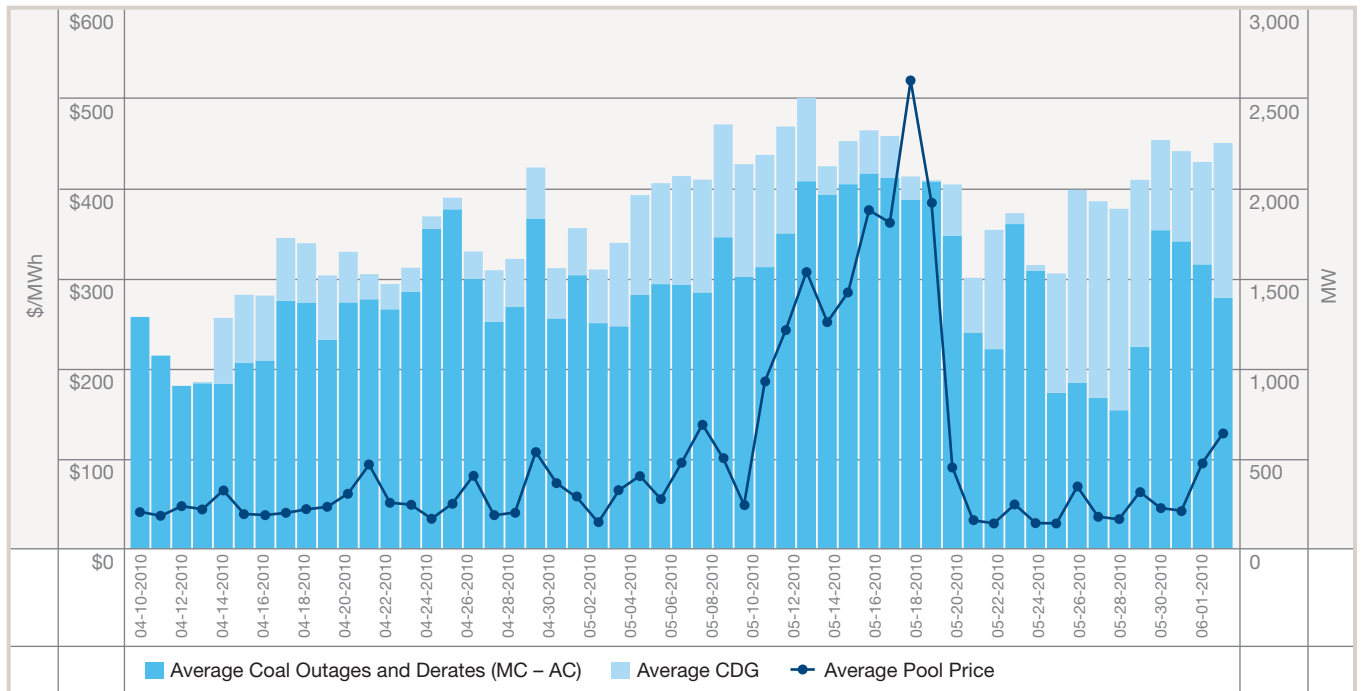
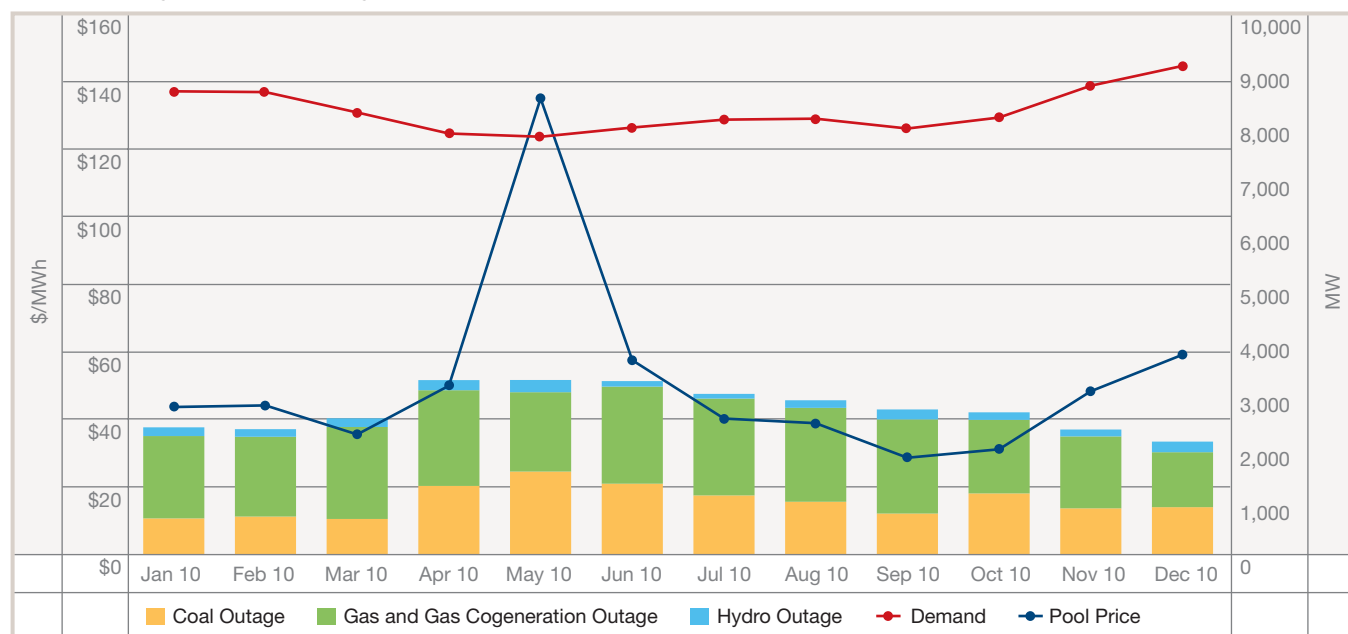


Figure 7 gives the daily average pool price, daily average coal outages and daily average constrained down generation (CDG). Note that the CDG value includes all constraints entered by the system controller, and may include more units than those impacted due to transmission constraints in the KEG and southeast areas, for example constraints to wind generation. As seen in Figure 7, although the latter portion of May had high CDG, prices were lower than those observed from May 3 through May 18. This was due to a number of factors, including higher availability of overall supply (partly due to increased hydro availability during normal spring runoff), and higher availability of coal units.

All generating assets submit a maximum capability (MC) representing the maximum quantity of megawatts the generating asset is physically capable of generating under optimal operating conditions. The available capability (AC) is set to the MC. Each asset must offer its entire MC to the market unless there is an acceptable operational reason (AOR) for reducing AC to a level lower than the MC. The majority of supply in the market is from baseload assets that run nearly all the time. Most baseload assets are coal-fired units, which offer the majority of their energy into the market at \$0/MWh to ensure they are dispatched and because they do not have the operational flexibility to be dispatched below a unit's minimum generation level. When these baseload assets are unavailable due to planned or unplanned outages, prices tend to increase as generation from gas-fired units and hydroelectric facilities, which tend to have a higher offer price, are required to meet demand.

Figure 8 illustrates the relationship between outages (defined as the difference between the MC and AC) by fuel type and the pool price. In addition to planned and unplanned outages, there are a few periods when a generating asset is available to run based on its operational situation but is constrained from providing all its available generation to the market due to transmission maintenance. As seen in the figure, in May 2010 there was approximately 1,500 MWh of coal-fired generation unavailable, and the pool price averaged \$134.69/MWh.

FIGURE 8
Monthly Average Generation Outages and Derates



Nearly 270 MW of New Supply Added in 2010

In 2010, nearly 270 MW of new supply was added to the system. This included three new wind generators adding 214 MW to the existing wind installed capacity of 563 MW. Also, a 15 MW cogeneration unit was connected to the grid in 2010. The last remaining unit at Wabamun coal power plant, Wabamun 4, was retired in 2010. The 279 MW coal-fired plant initially commissioned in 1967 was officially retired on March 31, 2010.

FIGURE 9
Generation Additions and Retirements, 2001 to 2010

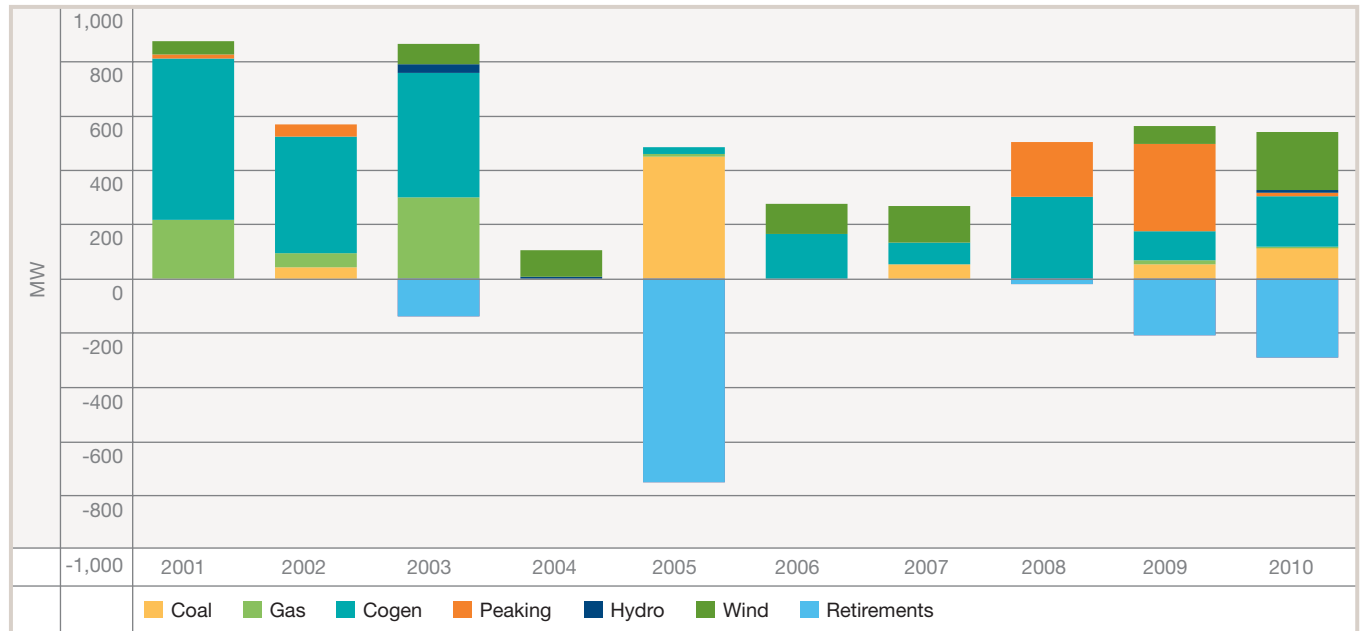


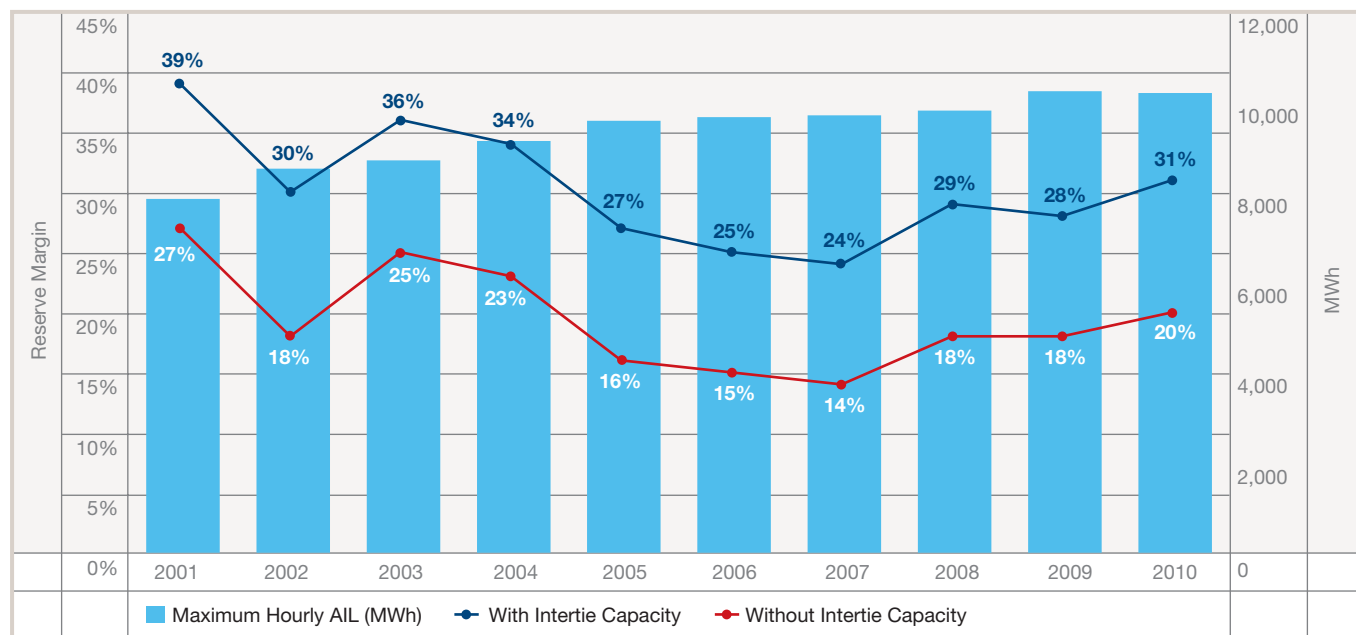
Figure 9 above indicates that there has been continued growth in new supply in 2010. The reserve margin is a metric that can be used to assess if supply has been adequate in meeting demand. The reserve margin estimates the amount of firm generation capacity at the time of system peak that is in excess of annual peak demand, expressed as a percentage of the system peak. Firm generation is defined as installed generation capacity, adjusting for seasonal hydro capacity and behind-the-fence demand and generation, and excludes wind capacity.

The metric is graphed with and without intertie capacity since full import capability may not always be available at the time of system peak demand.² Figure 10 shows that 2010 saw a healthy reserve margin indicating that there was adequate supply to meet demand. The reserve margin including intertie capacity increased from 28 per cent in 2009 to 31 per cent in 2010. The increase in reserve margin is in response to generator additions, a slight decline in peak load, and changes to the capacity values used to perform the calculation.³

² The reserve margin statistics here are based on the quarterly Long Term Adequacy (LTA) Metrics that include annual reserve margin with a five year forecast period.

³ On Nov. 1, 2010 the AESO updated the Current Supply and Demand report capacity values to reflect maximum capability as the capacity. Prior to that date capacity values were based on the generating unit's maximum continuous rating.

FIGURE 10
Annual Reserve Margin and Peak Alberta Internal Load (AIL)

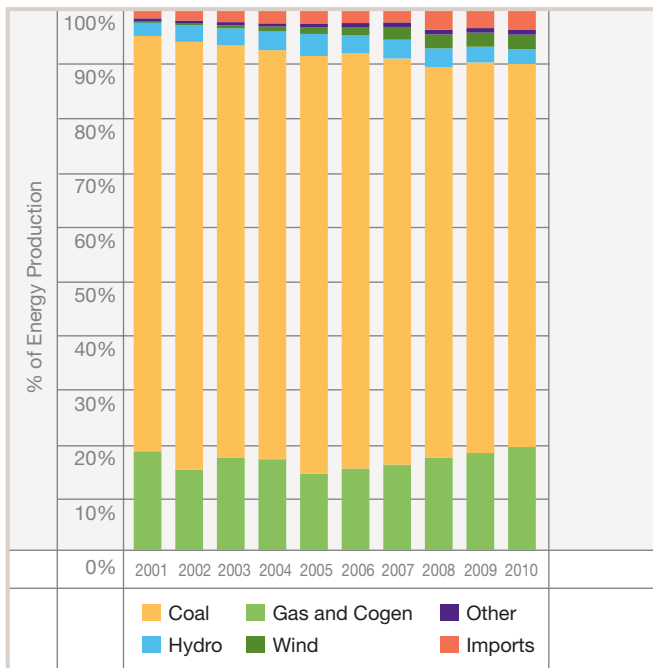


Price Setting and Generation Share in the Market

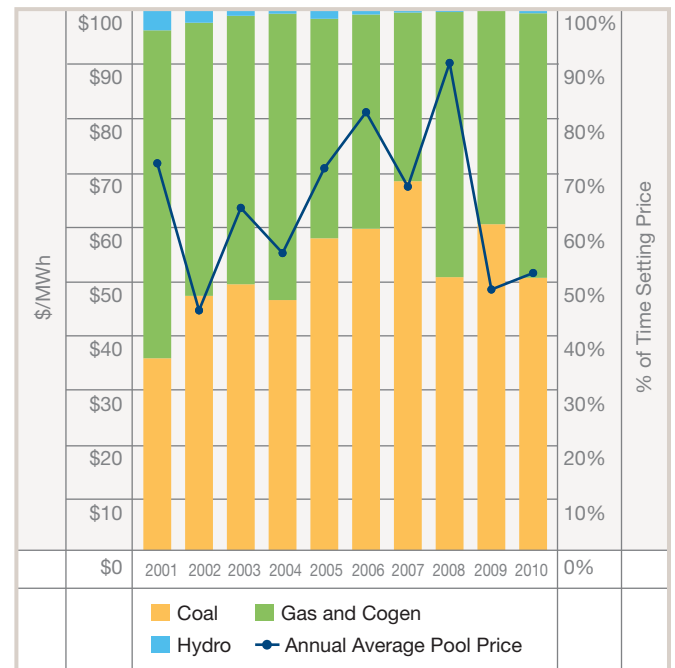
Coal-fired generation production provides the majority of the energy required by Alberta's market. In 2010, coal-fired generators provided 71.1 per cent of the energy consumed. This represents a 1.4 per cent reduction from 2009 due to increased coal-fired unit outages and derates in 2010 and the retirement of Wabamun 4. Gas and cogeneration units provided 18.7 per cent of the energy consumed and wind generation provided 2.8 per cent, an increase of one per cent and 0.2 per cent over 2009 respectively. The amount of energy provided by hydroelectric generation declined 0.2 per cent year-over-year, from 2.9 per cent in 2009 to 2.7 per cent in 2010.

Coal-fired generating units set price 50 per cent of the time in 2010, a 10 per cent decrease from 2009. The amount of time that natural gas-fired units set price increased from 39 per cent to nearly 50 per cent of the time in 2010. The offer prices of natural gas-fired generation typically track the price of the underlying fuel, natural gas. Higher gas prices result in higher offer prices by natural gas-fired units. In 2010, natural gas prices continued to be low, which led to a reduction in the offer prices of natural gas-fired units. Therefore, the annual average pool price was relatively low despite the increased amount of time that natural gas-fired units were on the margin.

FIGURE 11
Production and Price Setting Share
Energy Production by Fuel Type



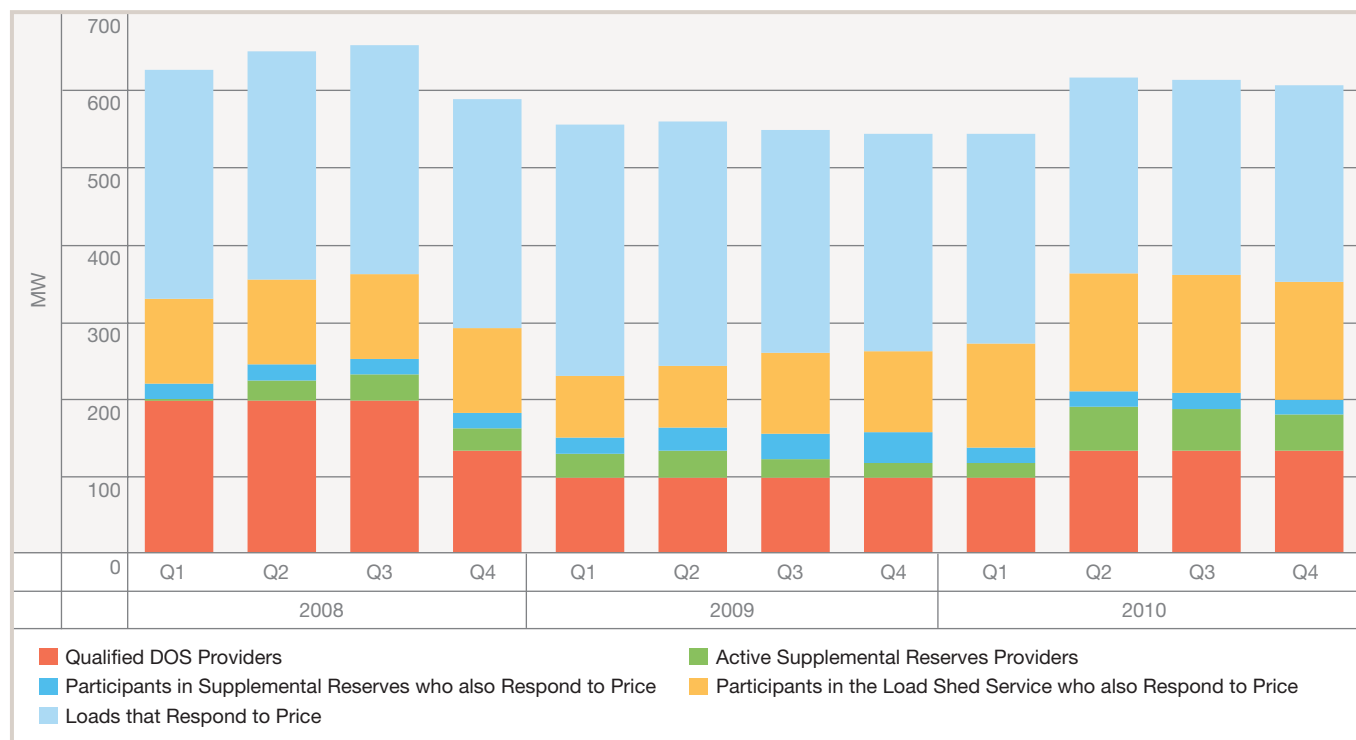
Price Setters by Fuel Type



Demand Participation Increases

The AESO has a particular interest in examining how demand response programs can assist in managing reliability and contribute to a fair, efficient and openly competitive electricity market. In Alberta, large industrial customers are directly connected to the transmission system and may be exposed to the hourly volatility of pool price. Many of these customers participate in some form of demand response varying from voluntarily reducing consumption when prices increase to providing some form of reliability product to the AESO. In 2010 there was an increase in the amount of load that qualified for demand opportunity service, which is a temporary, interruptible class of transmission service. There was also an increase in the amount of loads participating in the supplemental reserves market.

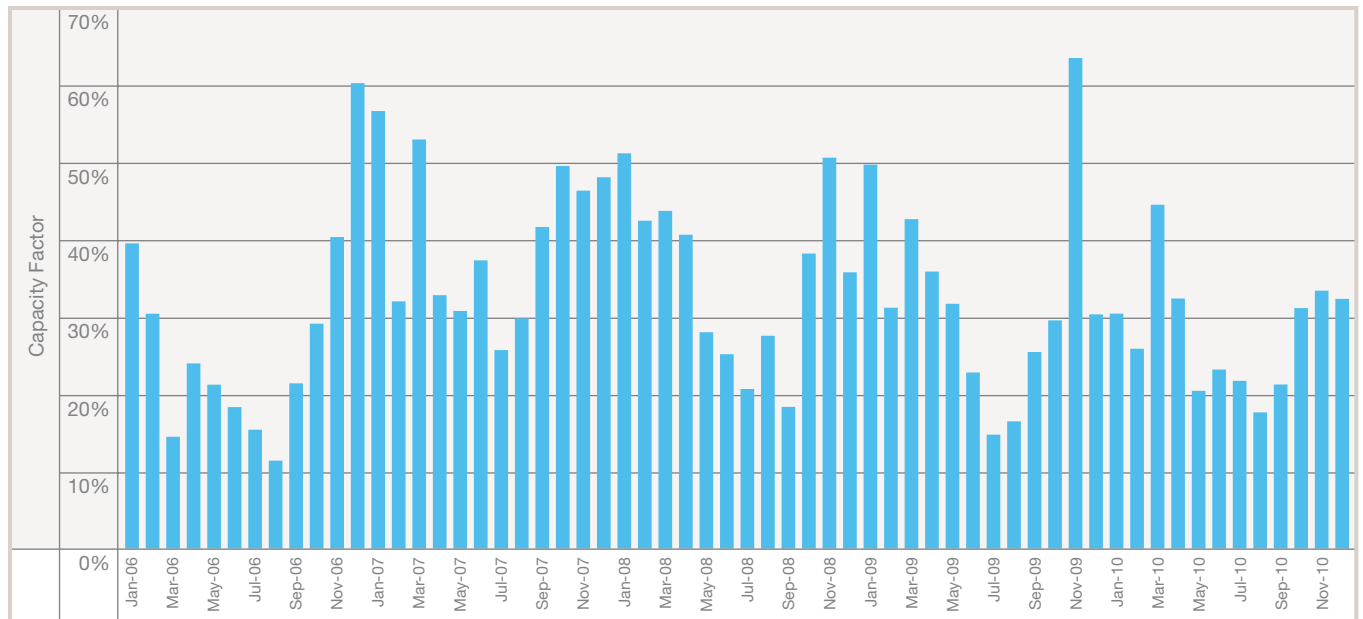
FIGURE 12
Load Participation in Demand Response Programs



Wind Generation

In 2010 there was continued growth in wind installed capacity with the addition of three new wind farms. The addition of Summerview II, Ardenville and Ghost Pine wind farms added 214 MW to the province's existing 563 MW of wind installed capacity in southern Alberta. The aggregate capacity factor for wind power facilities compares the total energy production over a period of time with the amount of power the plant would have produced at full capacity. Wind capacity factor in 2010 averaged 28 per cent, which is lower than the 2009 average of 33 per cent.

FIGURE 13
Monthly Average Wind Capacity Factor



Imports and Exports

Alberta has interties to both provincial neighbors. These interties allow energy to be imported during times of tight supply and exported during periods of energy surplus. During the course of the year the amount of imports and exports will vary depending on the limitations of the interties, market prices for electricity in other jurisdictions, and other factors. Total imports on the B.C. intertie increased in 2010 by 37 per cent as compared to the previous year.

TABLE 3 – ANNUAL INTERTIE STATISTICS

Intertie statistics (GWh)	2006	2007	2008	2009	2010
Imports on B.C. intertie	1,101	927	1,574	1,344	1,846
Imports on Sask. intertie	416	540	674	675	358
Total imports	1,517	1,467	2,248	2,019	2,205
Year-over-year growth (%)	-1.1%	-3.3%	53.2%	-10.2%	9.2%
Exports on B.C. intertie	460	886	518	488	411
Exports on Sask. intertie	29	88	40	25	48
Total exports	489	973	559	513	459
Year-over-year growth (%)	-52.8%	98.8%	-42.6%	-8.2%	-10.5%
Net yearly imports	1,028	494	1,689	1,505	1,745

The available transfer capability (ATC) is the amount of electricity that can flow on the interties. In 2010, both the maximum B.C. import ATC and average B.C. import ATC increased over 2009. The Saskatchewan maximum import ATC remained unchanged at 153 MW, while the average import ATC declined 32 MW due to the spring storm in southeast Alberta that caused various transmission constraints in the area. To manage the constraints, the Saskatchewan intertie import ATC was set to zero. In 2010 both the maximum and average export ATC on the Saskatchewan intertie increased as compared to 2009.

TABLE 4 – INTERTIE ANNUAL ATC STATISTICS (MW)

Year	B.C. export ATC		B.C. import ATC		Sask. export ATC		Sask. import ATC	
	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average
2006	735	188	700	607	60	38	153	141
2007	735	333	675	517	60	47	153	146
2008	735	387	625	468	60	35	153	148
2009	735	322	600	449	61	37	153	146
2010	735	389	650	507	153	88	153	114

Utilization of the import ATC on the B.C. intertie is defined as the import amount net of any exports for each hour, plus any operating reserves being provided over the intertie divided by the ATC:

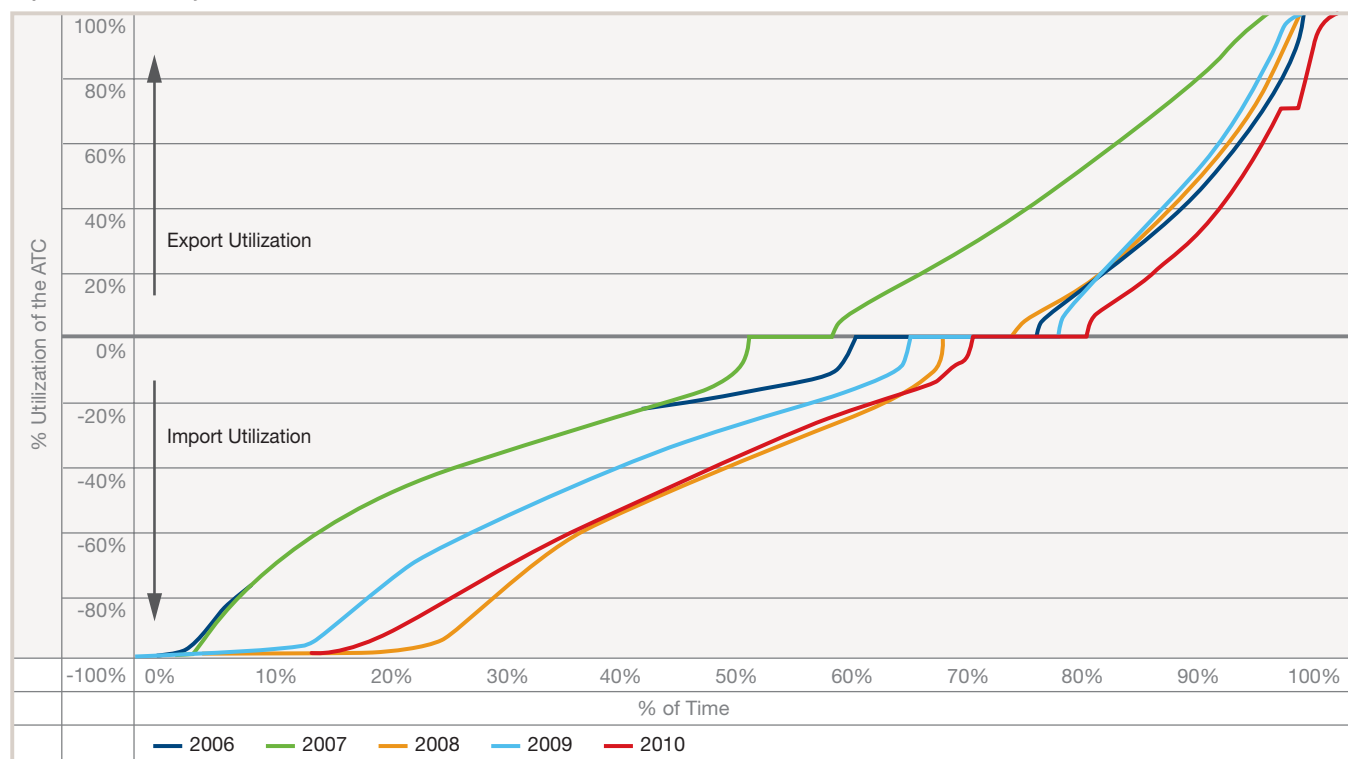
$$\text{Import utilization} = \frac{(\text{import}_h - \text{export}_h) + \text{reserves}}{\text{ATC}}$$

The export utilization is the export amount net of any imports divided by the export ATC:

$$\text{Export utilization} = \frac{(\text{export}_h - \text{import}_h)}{\text{ATC}}$$

In 2010, there was an increase in the amount of time that the B.C. intertie was highly utilized (greater than 80 per cent utilization). Imports flow in response to market opportunities in Alberta and in doing so, enhance system reliability in times when there is insufficient supply within the province to meet demand. Figure 14 illustrates the amount of time the B.C. intertie was utilized over the past five years. During 2010 imports on the B.C. intertie occurred 67 per cent of the time, and 27 per cent of the time import utilization of ATC exceeded 80 per cent. Exports on the B.C. intertie occurred 22 per cent of the time, with export utilization exceeding 80 per cent four per cent of the time.

FIGURE 14
Import and Export Utilization on the B.C. Intertie – 2006 to 2010
Import Utilization Adjusted to Account for Reserves on the Intertie



Dispatch Down Service

Transmission-must-run (TMR) dispatches occur when a generator is constrained on to operate at a minimum specified MW output level in order to maintain system security. Dispatching TMR displaces in merit energy and results in a downward effect on the pool price. The dispatch down service (DDS) is a price adjustment mechanism that negates the downward effect TMR dispatches have on the pool price. This service was introduced in December 2007 and is intended to improve the pool price signal.

DDS payments in 2010 totaled \$8 million for 538 GWh of DDS dispatched. This service was used to offset 792 GWh of TMR dispatches. The total DDS payment in 2010 was 42 per cent lower than in 2009 (\$13 million) due to reductions in the amounts of TMR and DDS dispatched. Total TMR dispatched in 2010 was reduced 22 per cent from 2009, and total DDS dispatches reduced 34 per cent year over year.

TABLE 5 – DDS ANNUAL STATISTICS

Year	TMR Dispatched (GWh)	DDS Dispatched (GWh)	Average DDS Charge per MWh (\$/MWh)	Total DDS Payments (\$ millions)
2008	983	731	0.46	28
2009	1,018	810	0.23	13
2010	792	538	0.13	8

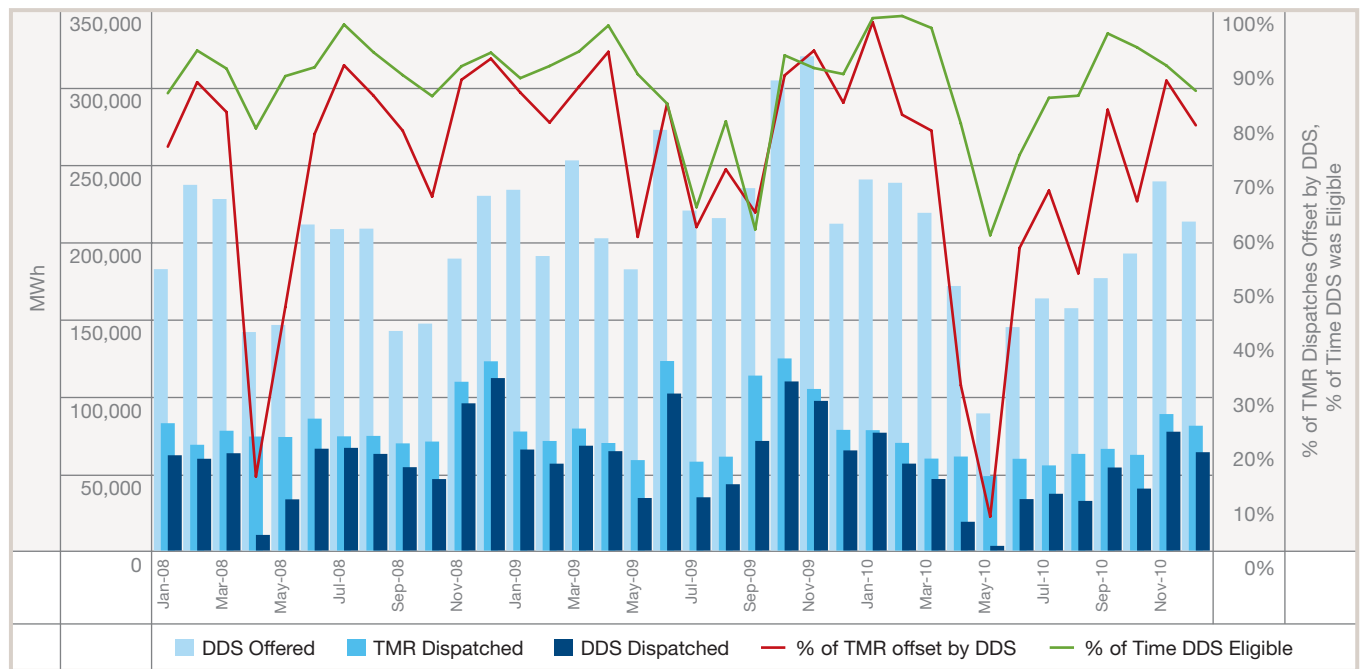
The costs of providing the DDS service are allocated to suppliers (generators and imports) by metered volumes in a manner that is effectively a “financial pro-rata” among suppliers who generated during a settlement interval. In 2010, the average DDS charge was \$0.13/MWh, down 10 cents from 2009.

The amount of DDS required is directly related to the amount of TMR on the system. Eligibility for dispatching DDS is also determined by the system marginal price. If the system marginal price is greater than the TMR reference price, then no DDS is dispatched. Furthermore, any system constraints that result in generation being constrained down offset the need for DDS.

Due to system constraints in April, May, and June of 2010, and the resulting generation that was constrained, the amount of DDS required was significantly lower than the amount of TMR dispatched during the same period. In 2010, the system marginal price was less than the TMR reference price 86 per cent of the time. The combined effect of the amount of time the DDS was eligible and the amount of generation constrained down resulted in 68 per cent of TMR dispatches being offset by DDS dispatches.

FIGURE 15

Total DDS and TMR Dispatched with Total DDS Offers

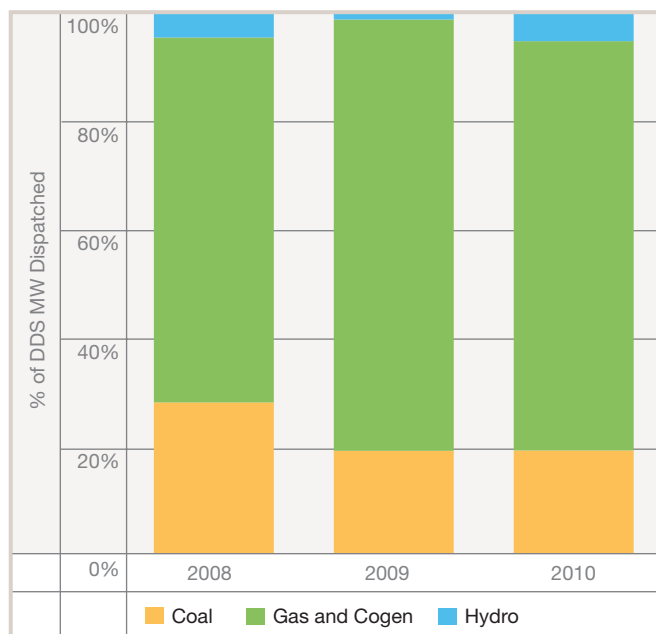


There continues to be sufficient interest in the DDS market with nearly all hours having surplus DDS offers to offset the amount of TMR dispatched. A total of 10 participants offered into the DDS market in 2010, unchanged from the year before. Gas-fired units continue to be the predominant provider of DDS, receiving 75 per cent of the dispatches in 2010.

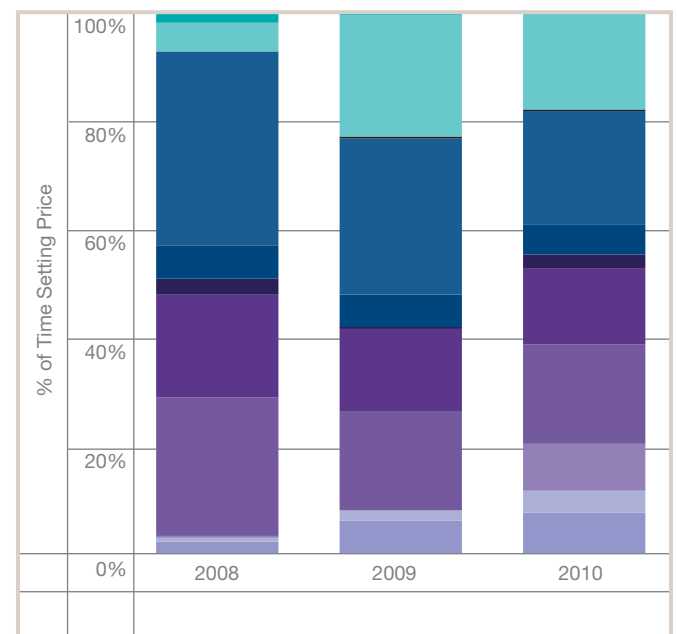
FIGURE 16

Dispatch Down Service Participation

Per Cent of DDS Dispatched by Fuel Type



Per Cent of DDS Dispatched by Participant



Payments to Suppliers on the Margin

Payments to suppliers on the margin, also known as uplift, is a settlement rule intended to address the discrepancy between the dispatch and settlement intervals. The payment provides generators the opportunity to receive payments based on their actual offer prices instead of the settled pool price, which may have settled lower than their offer that received a dispatch in a particular settlement interval.

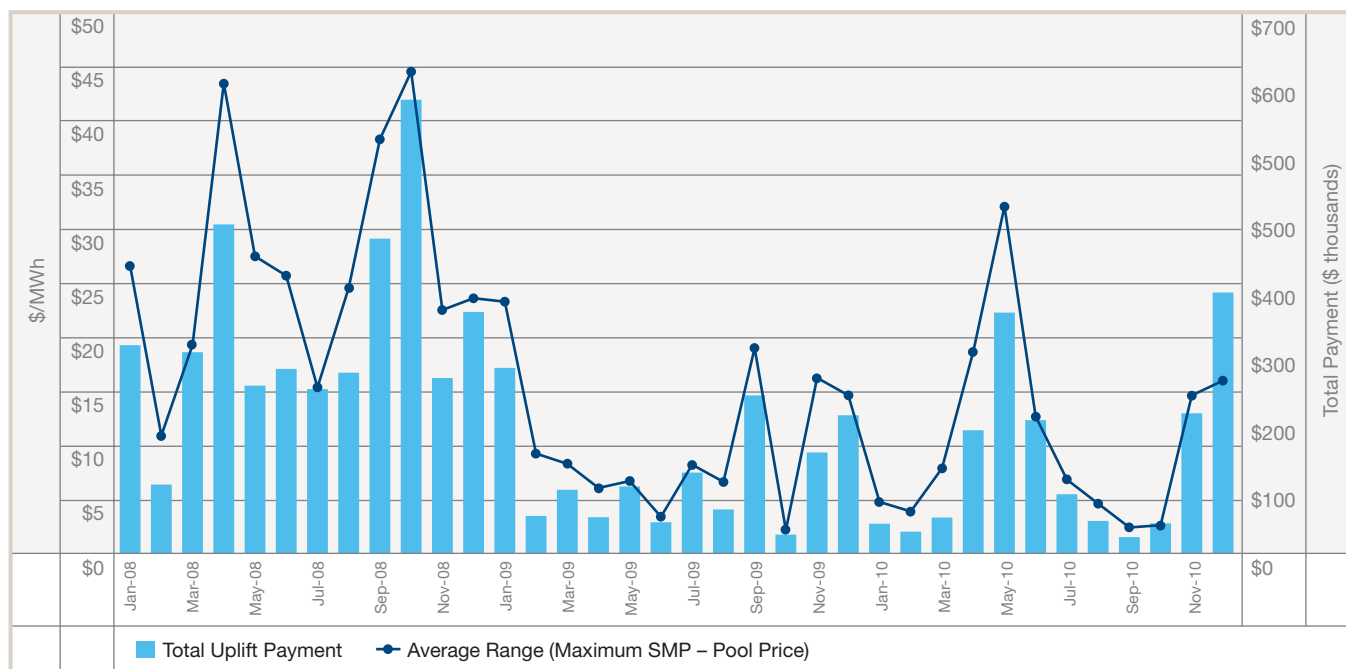
TABLE 6 – ANNUAL PAYMENTS TO SUPPLIERS ON THE MARGIN STATISTICS

Year	Total Uplift Payments (\$ millions)	Average Range between the maximum SMP and the pool price (\$/MWh)	Average Charge (\$/MWh)	Total Market Value* (\$ millions)	% of Market Value
2008	3.5	26.81	0.06	5,178	0.07
2009	1.2	10.29	0.02	2,734	0.05
2010	1.5	10.60	0.03	2,884	0.05

* Total market value equals the sum of AIES load metered volumes multiplied by pool price

In 2010, uplift payments totaled \$1.5 million, a 17 per cent increase over the 2009 total of \$1.2 million. This increase is partially due to a slight increase in the average pool price, but is also due to an increase in the average range between pool price and the maximum system marginal price in the hour, which is a measure of intra-hour volatility and a driver of uplift payments (as seen in figure 17). In 2010, the difference between the maximum SMP in a settlement interval and the pool price averaged \$10.60/MWh, while in 2009 the difference averaged \$10.29/MWh.

FIGURE 17
Total Uplift Payments and the Average Range between Maximum SMP and the Pool Price



Operating Reserve Markets

The prices paid to providers of operating reserve (OR) are indexed to pool price. Therefore, the prices in the operating reserve market trend closely to changes in pool price. The AESO procures active and standby reserve. The purpose of active reserve is to meet the requirements of the AIES under normal operating conditions and the purpose of standby reserve is to provide replacement or additional reserve should there be a need. All active reserve is priced based on an index to pool price. Standby pricing involves both a premium and activation price. The premium price is the price paid to the OR provider which gives the AESO the option to call on the reserve if required. The activation price is the price paid to the provider if the option is dispatched.

In 2010, prices in the OR markets increased from the previous year in part due to the overall increase in pool price, as well as the constraints caused by the storm damage in southeastern Alberta as discussed on page 9. OR costs for May alone were \$47 million or 34 per cent of the total 2010 OR costs. Table 7 provides a historical summary of prices in both the active and standby markets. Regulating reserve is used for real-time balancing of supply and demand and requires automatic control of generation levels to ensure the grid is operated reliably. Due to the significant requirements of this product, it is priced higher than the other two types of reserves. Spinning reserve and supplemental reserve are used to maintain the balance of supply and demand when an unexpected system event occurs. Spinning reserve must be synchronized to the grid. Both of these products are priced lower than regulating reserve, with spinning reserve priced slightly higher than supplemental reserve.

TABLE 7 – ANNUAL AVERAGE OPERATING RESERVE PRICES (\$/MW)

	Active			Standby premiums			Standby activation			Total OR Cost (\$ million)
	RR	SR	SUP	RR	SR	SUP	RR	SR	SUP	
2006	34	30	29	4	4	3	84	85	84	186
2007	34	29	26	5	4	4	101	101	96	185
2008	51	43	38	7	5	5	163	151	133	270
2009	23	16	11	5	4	3	96	85	69	104
2010	27	21	16	7	4	4	141	115	91	137

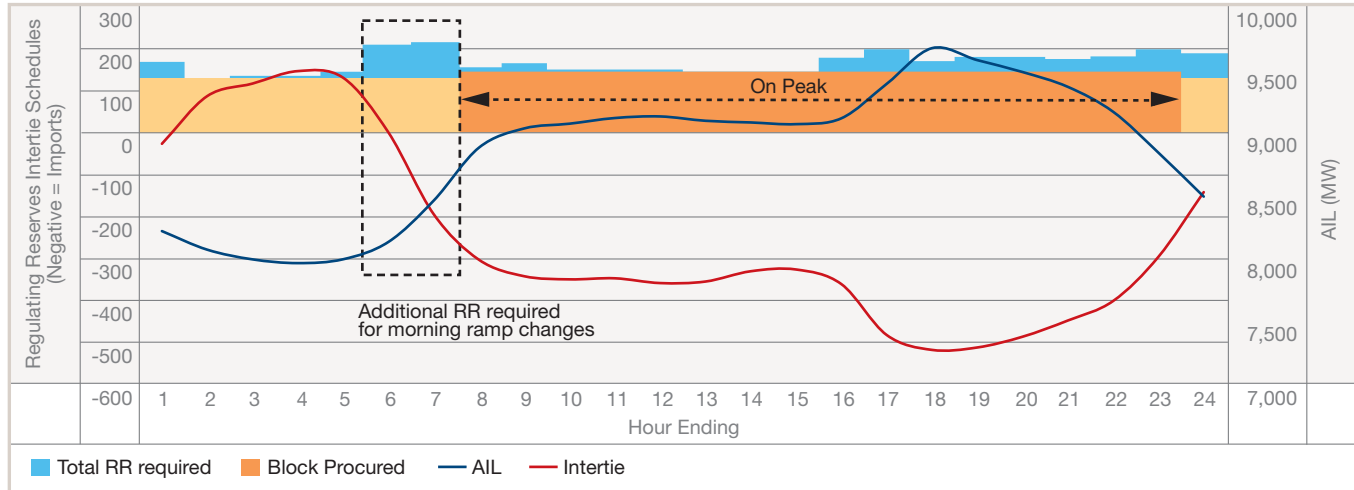
The amount of active OR varies depending on the reserve type and also the time of day. The regulating reserve requirement is influenced primarily by changes to intertie schedules and the short-term AIL forecast. Both spinning and supplemental reserve are used for contingency purposes and the criteria for determining the requirement is primarily based on the load levels in Alberta. Figure 18 on the following page illustrates typical reserve requirements.

The AESO procures the majority of active reserve using an online exchange called Watt-Ex. On Watt-Ex the AESO procures OR using on and off-peak blocks. The amounts of these blocks are based on the minimum amount of reserve required in each period. In figure 18 on the following page, the yellow area of the graph represents the off-peak volumes procured over Watt-Ex, while the orange area represents on-peak volumes procured. The remainder of the OR requirement is then procured using over-the-counter contracts (OTC). In 2010, six per cent of the active OR requirement was procured using OTC.

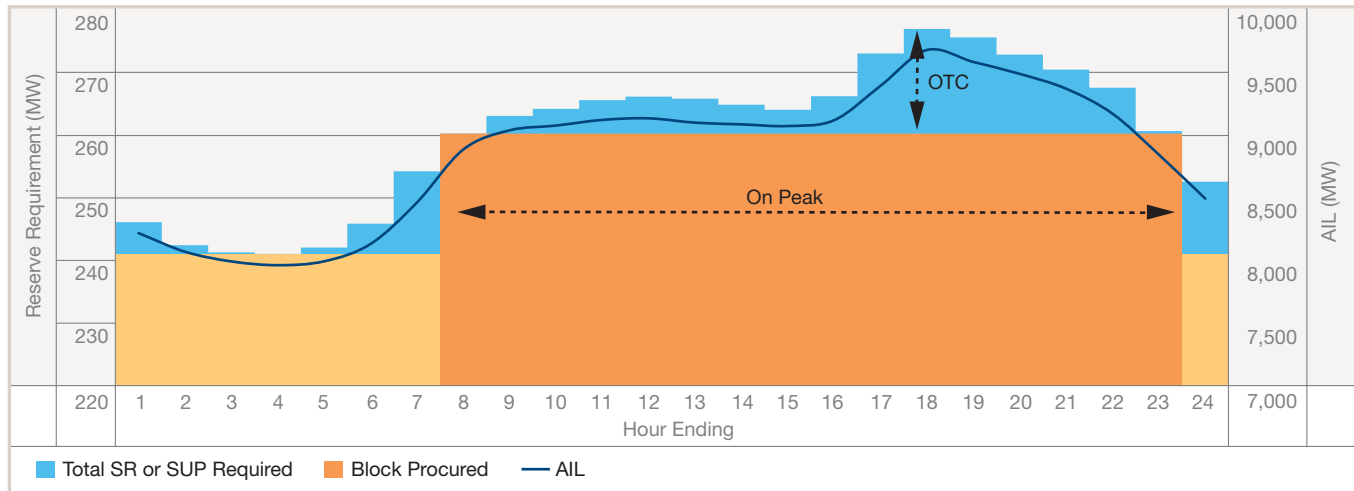
FIGURE 18

OR Reserve Requirements

Regulating Reserve Requirements



Spinning and Supplemental Reserve Requirements



Move to D-1 does not Impact Market Liquidity

Operating reserve is procured one day in advance of when it is required. This timing is referred to as “day minus one” or “D-1”. Prior to July 2010, operating reserve was procured up to five days in advance of delivery. However, the procurement period was reduced to D-1 procurement after July 2010 as part of the AESO’s ongoing efforts to improve the design of the operating reserve market.

Operating reserve market liquidity can be measured by comparing the amount of offers to the AESO’s bid for OR products to determine the MW remaining in the active market. The liquidity measures for all on and off-peak active markets on D-1 indicate that there has been little difference between the time the AESO moved to 100 per cent D-1 procurement (July 2010) and before.

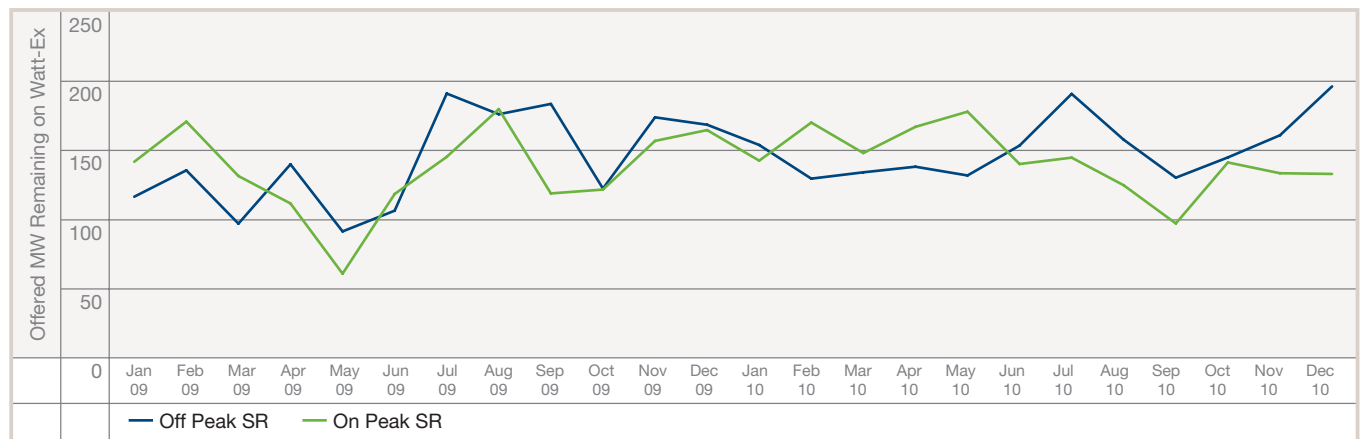
FIGURE 19

Day Minus One Market Liquidity

Regulating Reserve Day Minus One Market Liquidity



Spinning Reserve Day Minus One Market Liquidity



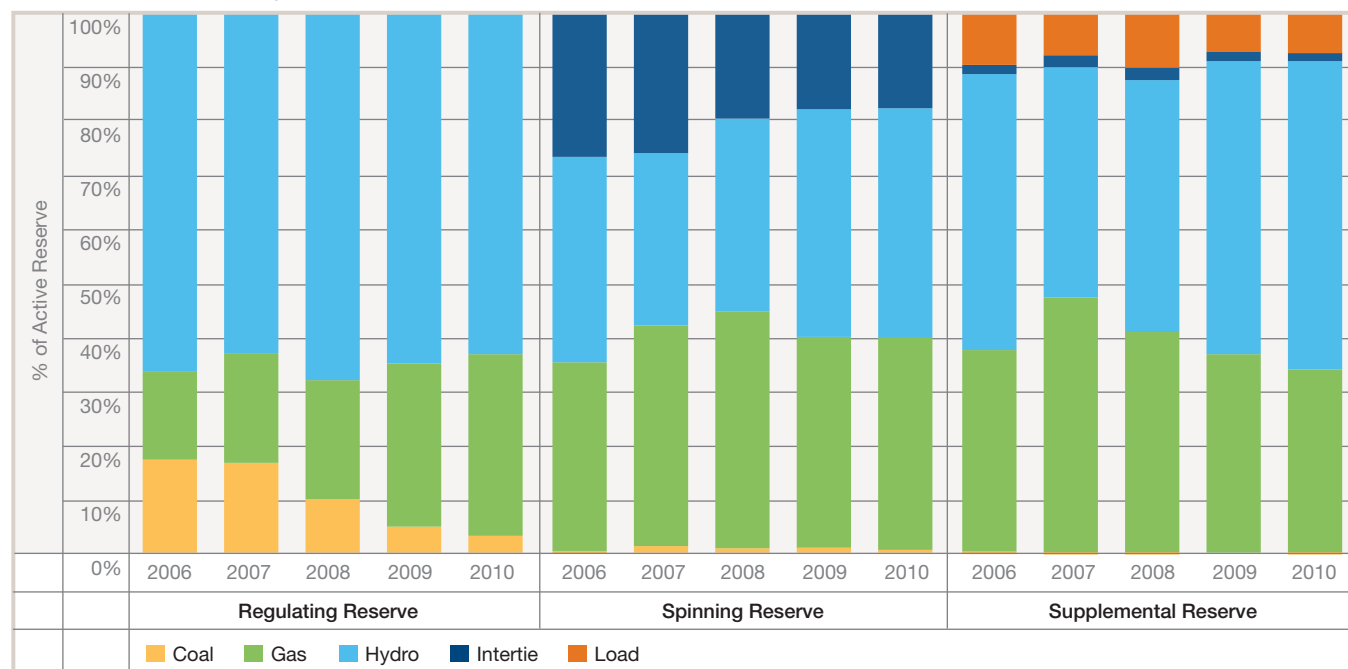
Supplemental Reserve Day Minus One Market Liquidity



Market Share of Reserves Remain Stable

In 2010, 63 per cent of active regulating reserve required was provided by hydroelectric generators. Hydro assets also provided 57 per cent of supplemental reserve and 43 per cent of spinning reserve. Gas-fired generation provided almost all of the remaining regulating reserve and coal-fired units provided three per cent of regulating reserve. Spinning reserve market share was unchanged from the previous year with gas, hydro, and inertia capacity providing the majority of spinning reserve. Generators and loads are able to participate in the supplemental reserve market. In 2010, load increased its market share in the supplemental market from eight per cent in 2009 to nine per cent in 2010.

FIGURE 20
Market Share of Operating Reserve by Fuel Type



Final Notes and Market Monitoring in 2011

As the market evolves throughout 2011 and beyond, the AESO will continue to monitor, analyze, and report on market outcomes. As part of this monitoring process, the AESO provides real-time, historical and forecast reports and metrics on the market. These include daily and weekly reports outlining energy and operating reserve market statistics and a broad selection of historical datasets. The AESO appreciates comments and questions from stakeholders on this report.

Should market participants have any questions on this report, or have a market analysis question, please contact **market.analysis@aeso.ca**



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