ALBERTA
ELECTRIC
SYSTEM
OPERATOR

2011 Annual Market Statistics

AESO Market Stats
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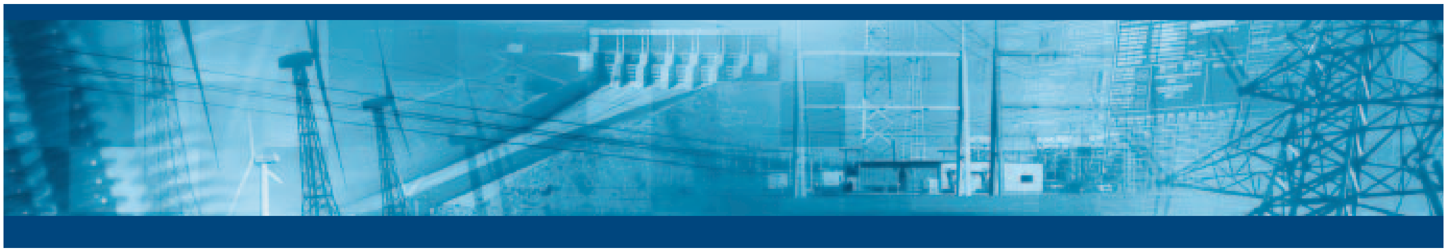
February 16, 2012



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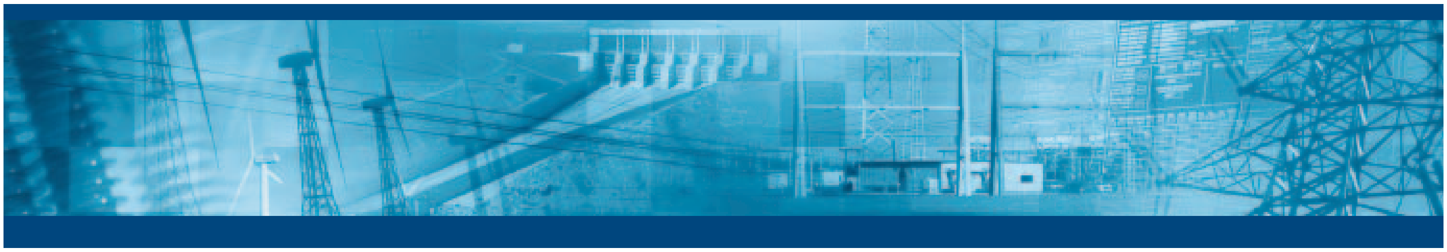


Executive Summary

As an independent system operator, the AESO leads the safe, reliable and economic planning and operation of the Alberta Interconnected Electric System. The AESO also facilitates Alberta's fair, efficient and openly competitive wholesale electricity market. In 2011, the Alberta market had 164 participants and approximately $8 billion in annual energy transactions.

The annual market statistics report provides a summary of key market information from 2011 and describes historic trends in Alberta's wholesale electricity market. An accompanying **data file** is provided to give stakeholders access to the information behind the metrics presented in the summary report. The AESO is committed to continuous improvement in the quality, timeliness and utility of the market data that we provide.

In 2011 there was continued strong growth in demand as observed in the previous year, with Alberta Internal Load (AIL) growth of 2.6 per cent over 2010. A new summer peak record for AIL was set on July 18, with load reaching 9,552 MW in hour ending 16.

The annual average pool price for wholesale electricity was $76.22/MWh in 2011. The annual average AECO/NIT natural gas price decreased slightly, averaging $3.44/GJ in 2011. This resulted in a market heat rate average of 22.39 GJ/MWh in 2011, which is the highest annual heat rate observed in the past decade. The increase in the heat rate was driven by a higher average pool price coupled with lower average gas prices. The highest monthly average pool price for the year occurred in August 2011, averaging $126.36/MWh. During August, high load and periods of supply scarcity were the primary factors driving high prices.

Imports from Alberta's two interties served almost five per cent of the total load in 2011. Total net imports on the B.C. intertie increased by 107 per cent over the previous year and net imports from the Saskatchewan intertie increased by 60 per cent.

Transmission must-run (TMR) dispatches increased one per cent over 2010, from 792 GWh to 801 GWh. There was an increase in unforeseen TMR primarily due to inflow restrictions limiting flows into the Fort McMurray region which required TMR to serve the local load in that area. Constrained down generation (CDG) decreased over the previous year, primarily due to lower levels of major constraints. During 2011, 142 GWh of CDG was recorded by the AESO's system controller.

In 2011 nearly 670 MW of generation capacity was added to the Alberta grid including the 450 MW Keephills 3 coal-fired unit. Two large coal units, Sundance 1 and 2, were removed from service at the end of 2010 and remained offline throughout 2011.

Pool Prices Increased in 2011

Alberta's competitive wholesale market electricity prices fluctuate due to 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 2011, pool prices averaged $76.22/MWh. On-peak prices were 62 per cent higher in 2011, while off-peak prices declined nine per cent from 2010. Prices were higher for most of the year with the exception of May and December. Table 1 summarizes the historical price statistics from 2002 to 2011. Higher pool prices in 2011 were mainly due to lower availability of coal-fired units, as well as strong load growth throughout the province.

TABLE 1 – ANNUAL POOL PRICE STATISTICS, 2002 TO 2011

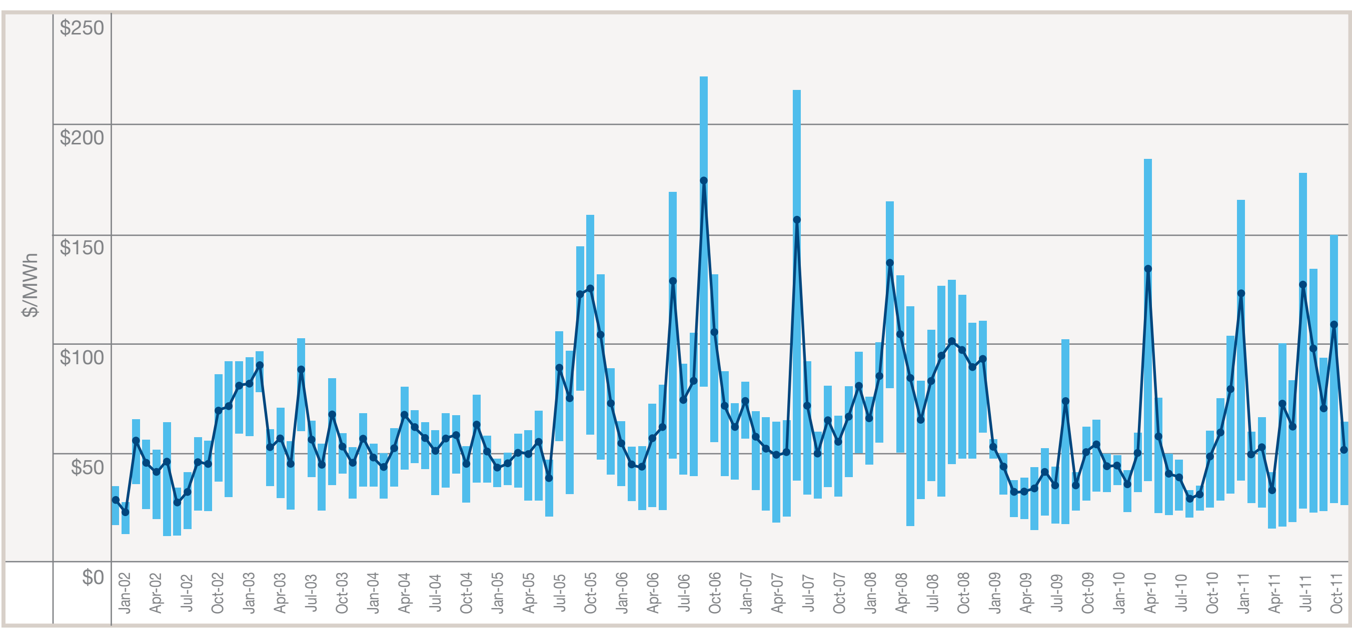
Pool Price *($/MWh)*	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Average hourly pool price	43.93	62.99	54.59	70.36	80.79	66.95	89.95	47.81	50.88	**76.22**
Off-peak average pool price	21.61	42.15	35.72	40.37	39.54	32.11	43.92	27.36	26.67	**24.22**
On-peak average pool price	55.09	73.41	64.03	85.35	101.41	84.37	112.97	58.04	62.99	**102.22**
Maximum hourly pool price	999.00	999.99	998.01	999.99	999.99	999.99	999.99	999.99	999.99	**999.99**
Minimum hourly pool price	0.01	7.07	0.00	4.66	5.42	0.00	0.00	0.10	0.00	**0.00**

Note: On-peak hours refer to hour ending 08:00 through to hour ending 23:00, Monday through Sunday inclusive. Off-peak hours are all other periods.

The highest monthly average pool price of $126.36/MWh occurred in August due to periods of tight supply coupled with high demand during the month. Figure 1 shows the monthly distribution of prices during 2011 as compared to the past ten years.

FIGURE 1

Monthly Average Hourly Pool Price From 2002 to 2011 with On/Off Peak Averages *($/MWh)*

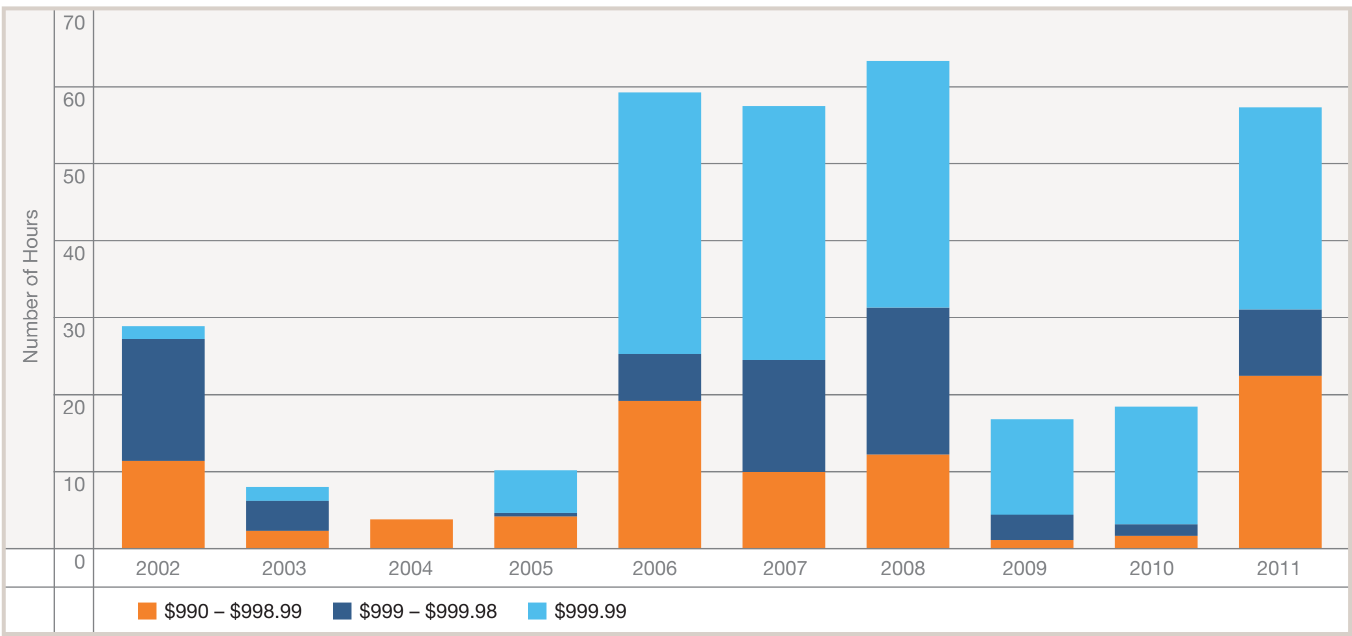


In conditions of supply shortfall the system controllers use a series of mitigation steps to help alleviate the situation. These steps are documented in Operating Policy and Procedure (OPP) 801. In 2011 there were 11 separate supply shortfall events during which the price cap of $999.99/MWh was reached, as compared to three events in the previous year. An OPP 801 event occurred during a total of 23 hours in 2011. Figure 2 illustrates there has been an increase in the number of hours where system marginal price (SMP) has exceeded $990/MWh as compared to the previous two years, but was comparatively lower than the 2006 to 2008 timeframe.

A supply surplus event occurs when there is excess supply and low system demand. These events typically occur during the early morning hours, when demand is low. In 2011, the pool price reached the price floor of $0/MWh for six hours during the month of May, and AIL was below 7,000 MW for all of these hours. This is the highest number of hours since 2004, which saw six instances where pool price reached the floor during the month of December. In 2010, pool price was $0/MWh for one hour in July.

FIGURE 2

Number of Hours System Marginal Price (SMP) Exceeded $990/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 controller dispatches 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.

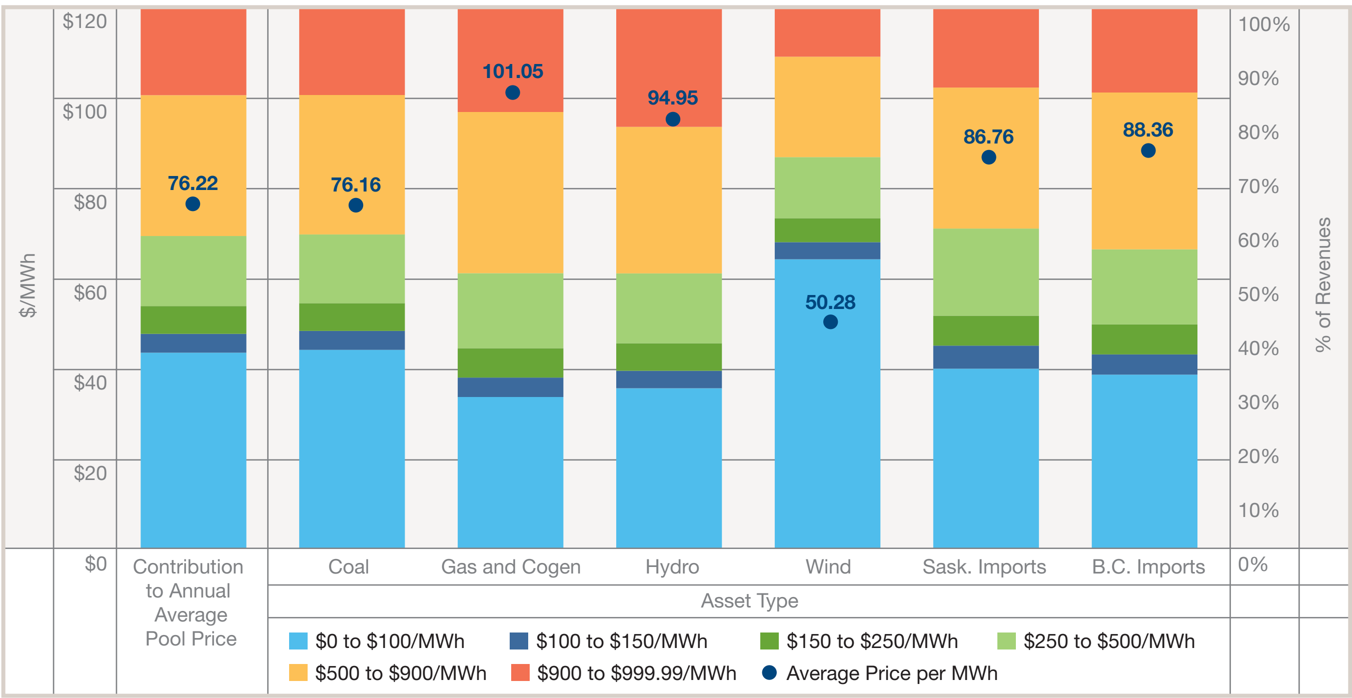
Figure 3 presents the breakdown of revenue by pool price range for different asset types. As seen in the graph, the per cent contribution to the annual average pool price was highest in the $0/MWh to $100/MWh range.

The numbers shown within the bars represent the average pool price received by asset type. For example, gas-fired generators and cogenerators received $101.05/MWh on average over all hours, 33 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 priced at $0/MWh), tends to receive lower prices per megawatt hour because it displaces higher cost gas generation and reduces the pool price. In 2011, wind generators on average received $50.28/MWh, a 34 per cent discount to the annual average price.

FIGURE 3

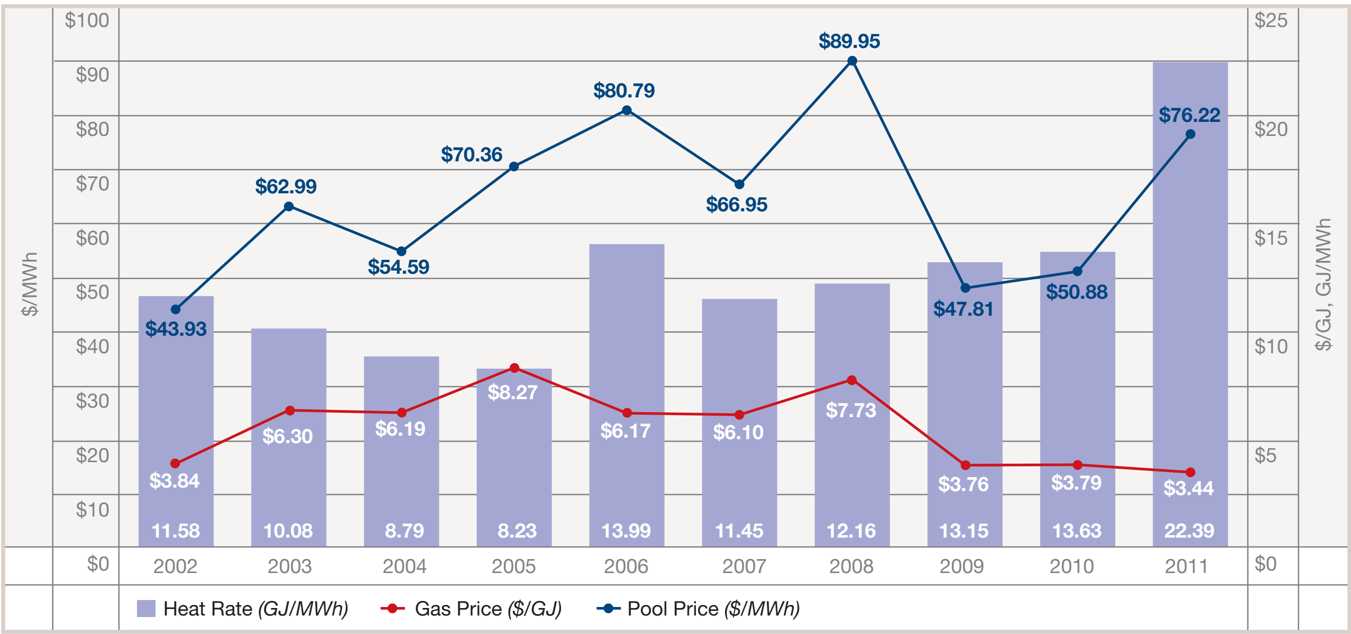
Pool Price Contribution to Total Revenue by Asset Type and Pool Price Range

Average Revenues = 2011 Hourly Pool Price Multiplied by Metered Volumes



In 2011, natural gas prices were fairly stable, declining nine per cent over the 2010 annual average of $3.79/GJ. Figure 4 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. The market heat rate averaged 22.39 GJ/MWh in 2011, which is the highest heat rate seen in the past decade. This is due to higher average pool prices coupled with lower average gas prices.

FIGURE 4
Annual Average Pool Price, AECO Natural Gas Price and Heat Rate



Strong Load Growth in 2011

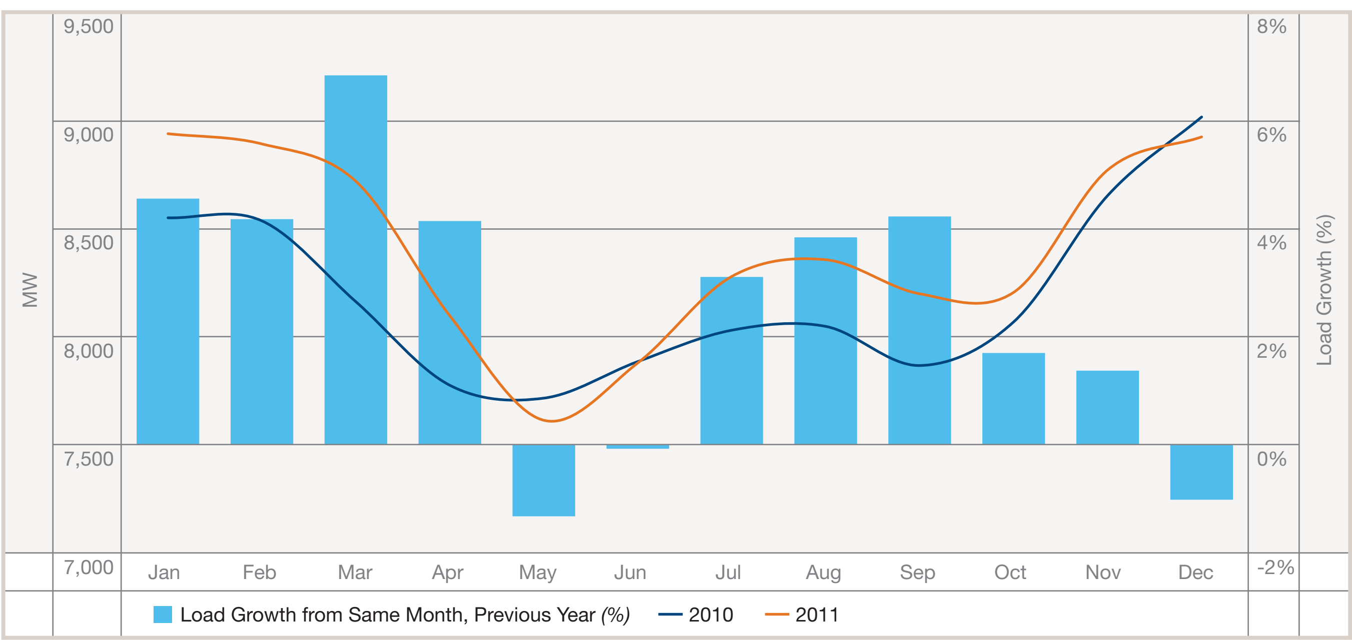
Alberta Internal Load (AIL) grew 2.6 per cent in 2011, continuing the strong growth trend seen in the previous year. Increased demand in major urban centres such as Calgary and Edmonton and oilsands demand growth in northeastern Alberta were the primary contributors to this growth. The highest monthly year-over-year load growth of 6.9 per cent occurred in March 2011. December saw a 1.1 per cent decrease in year-over-year load growth. This is primarily due to warmer temperatures in comparison to the previous year. December 2011 was nine degrees warmer on average than December 2010. Table 2 gives annual system demand statistics for the past ten years.

TABLE 2 – ANNUAL SYSTEM DEMAND STATISTICS

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Total energy *(GWh)*	59,428	62,714	65,260	66,267	69,371	69,661	69,947	69,914	71,723	**73,600**
Average hourly load *(MW)*	6,784	7,159	7,429	7,565	7,919	7,952	7,963	7,981	8,188	**8,402**
Maximum hourly load *(MW)*	8,570	8,786	9,236	9,580	9,661	9,701	9,806	10,236	10,196	**10,226**
Minimum hourly load *(MW)*	5,309	5,658	6,017	6,104	6,351	6,440	6,411	6,454	6,641	**6,459**
Year-over-year growth in total energy *(%)*	9.1	5.5	4.1	1.5	4.7	0.4	0.4	0.0	2.6	**2.6**
Year-over-year average load growth (adjusted for leap year effect) *(%)*	9.1	5.5	3.8	1.8	4.7	0.4	0.1	0.2	2.6	**2.6**
Load factor *(%)*	79.2	81.5	80.4	79.0	82.0	82.0	81.2	78.0	80.3	**82.2**

As seen in Figure 5, load growth was positive for most months in 2011, with the exception of May, June and December. On July 18, 2011, AIL reached a new summer seasonal record high of 9,552 MW in hour ending 16. This is 0.1 per cent higher than the previous record of 9,541 MW set in August 2008. Province-wide high temperatures were a major factor contributing to the high demand. The typical drivers of peak demand during the summer months are high temperatures over a sustained period of time that result in increased air conditioning load.

FIGURE 5
Monthly Average Alberta Internal Load (AIL) and Load Growth

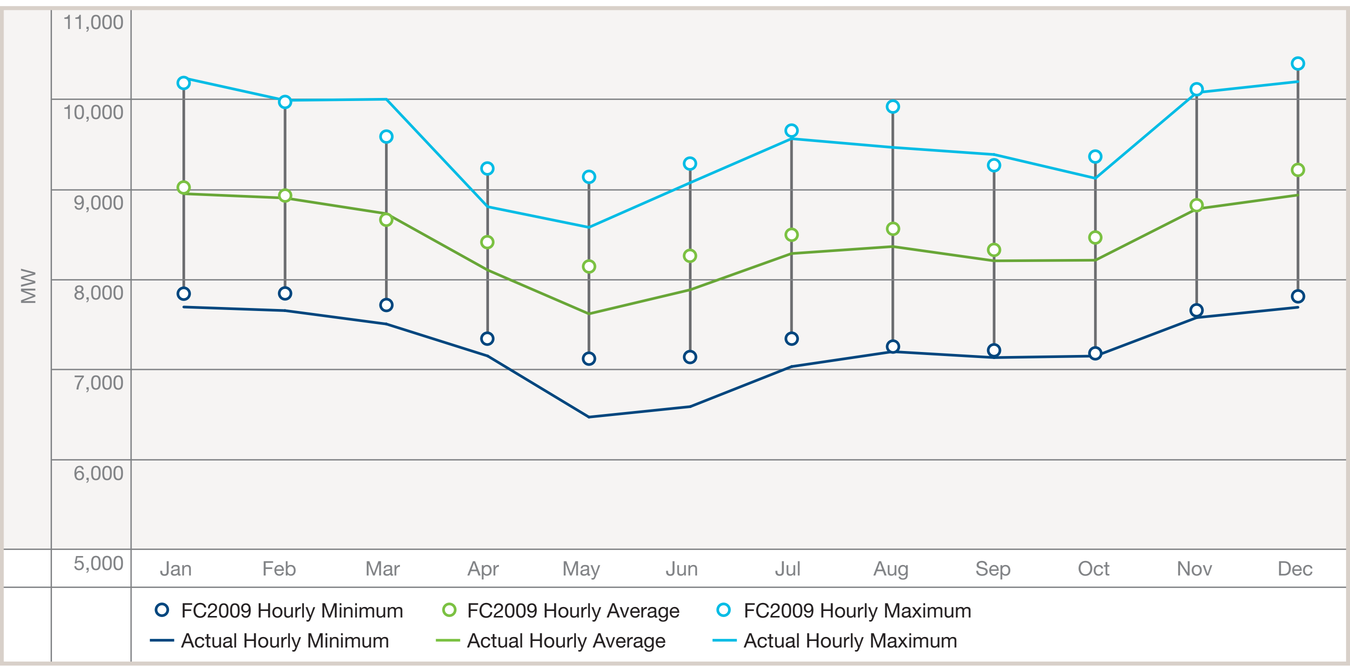


The AESO produces long-term load forecasts for the long-term planning process. These forecasts are continuously assessed against Alberta's actual demand and electricity usage to verify methodology and identify variances that could impact the forecast. The last long-term load forecast was prepared in 2009. The AESO will be releasing our 2012 Long-term Outlook in the first quarter of 2012.

Figure 6 compares monthly forecast to actuals for hourly minimum, peak and average demand. The 2009 long-term forecast of monthly average demand was within 1.7 per cent and 2.4 per cent of actuals for 2010 and 2011 respectively. Note that it is more difficult to predict demand levels further out, which explains the slight reduction in accuracy from 2010 to 2011.

FIGURE 6

Forecast versus Actual System Demand based on the 2009 Long-term Forecast *(MW)*



Imports Serve Almost Five Per Cent of Total Load in 2011

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. As seen in Table 3, total net imports increased by 107 per cent on the B.C. intertie, and increased by 60 per cent on the Saskatchewan intertie as compared to the previous year. Total exports decreased 83 per cent on the B.C. intertie, and were unchanged on the Saskatchewan intertie.

TABLE 3 – ANNUAL INTERTIE STATISTICS

Intertie statistics *(GWh)*	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Total scheduled imports										
Imports on B.C. intertie	922	903	1,073	1,071	1,101	927	1,574	1,344	1,846	**3,047**
Imports on Saskatchewan intertie	240	429	418	464	416	540	674	675	358	**544**
Total imports	1,161	1,332	1,492	1,535	1,517	1,467	2,248	2,019	2,205	**3,591**
Total imports as a percent of total AIL *(%)*	2.0	2.1	2.3	2.3	2.2	2.1	3.2	2.9	3.1	**4.9**
Total scheduled exports										
Exports on B.C. intertie	468	1,194	968	988	460	886	518	488	411	**71**
Exports on Saskatchewan intertie	106	34	93	50	29	88	40	25	48	**48**
Total exports	574	1,228	1,061	1,038	489	973	559	513	459	**119**
Total exports as a percent of total AIL *(%)*	1.0	2.0	1.6	1.6	0.7	1.4	0.8	0.7	0.6	**0.2**
Net imports (imports minus exports)										
Net B.C. imports	454	-291	105	83	641	42	1,056	856	1,435	**2,976**
Net Saskatchewan imports	134	395	325	413	386	452	633	649	310	**496**
Total net imports	588	104	430	497	1,028	494	1,689	1,505	1,745	**3,473**
Total net imports as a percent of total AIL *(%)*	1.0	0.2	0.7	0.7	1.5	0.7	2.4	2.2	2.4	**4.7**
Market size (total demand)										
Alberta Internal Load (AIL)	59,428	62,714	65,260	66,267	69,371	69,661	69,947	69,914	71,723	**73,600**

The available transfer capability (ATC) is the amount of electricity that can flow on the interties. Table 4 provides annual intertie ATC statistics for the past five years. In 2011, the average B.C. import ATC increased by 17 MW over 2010, while the maximum import ATC decreased by 25 MW. The average Saskatchewan import ATC increased 23 MW and the maximum import ATC remained unchanged over 2010. The maximum export ATC remained unchanged and the average export ATC increased for both the B.C. and Saskatchewan interties. The Saskatchewan ATC increases are a result of transmission reinforcement in southeastern Alberta which fully restored the intertie's capability.

TABLE 4 – ANNUAL INTERTIE ATC STATISTICS *(MW)*

	B.C. export ATC		B.C. import ATC		Saskatchewan export ATC		Saskatchewan import ATC	
Year	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average
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
2011	**735**	**421**	**625**	**525**	**153**	**134**	**153**	**137**

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:

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

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

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

In 2011, there was a substantial increase in the amount of time 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 at times when there is insufficient supply within the province to meet demand. Figures 7 and 8 illustrate the amount of time the B.C. intertie and the Saskatchewan intertie were utilized over the past five years. During 2011 the B.C. intertie was fully utilized 39 per cent of the time, and imports on the B.C. intertie occurred 92 per cent of the time. Exports on the B.C. intertie occurred nearly four percent of the time, with export utilization exceeding 80 percent less than one per cent of the time. On the Saskatchewan intertie, the amount of time the intertie was highly utilized (greater than 80 per cent utilization) for imports was 25 per cent in 2011 and eight per cent in 2010. Exports on the Saskatchewan intertie occurred 19 per cent of the time.

FIGURE 7

Import and Export Utilization on the B.C. Intertie, 2007 to 2011

Import Utilization Adjusted to Account for Reserves on the Intertie

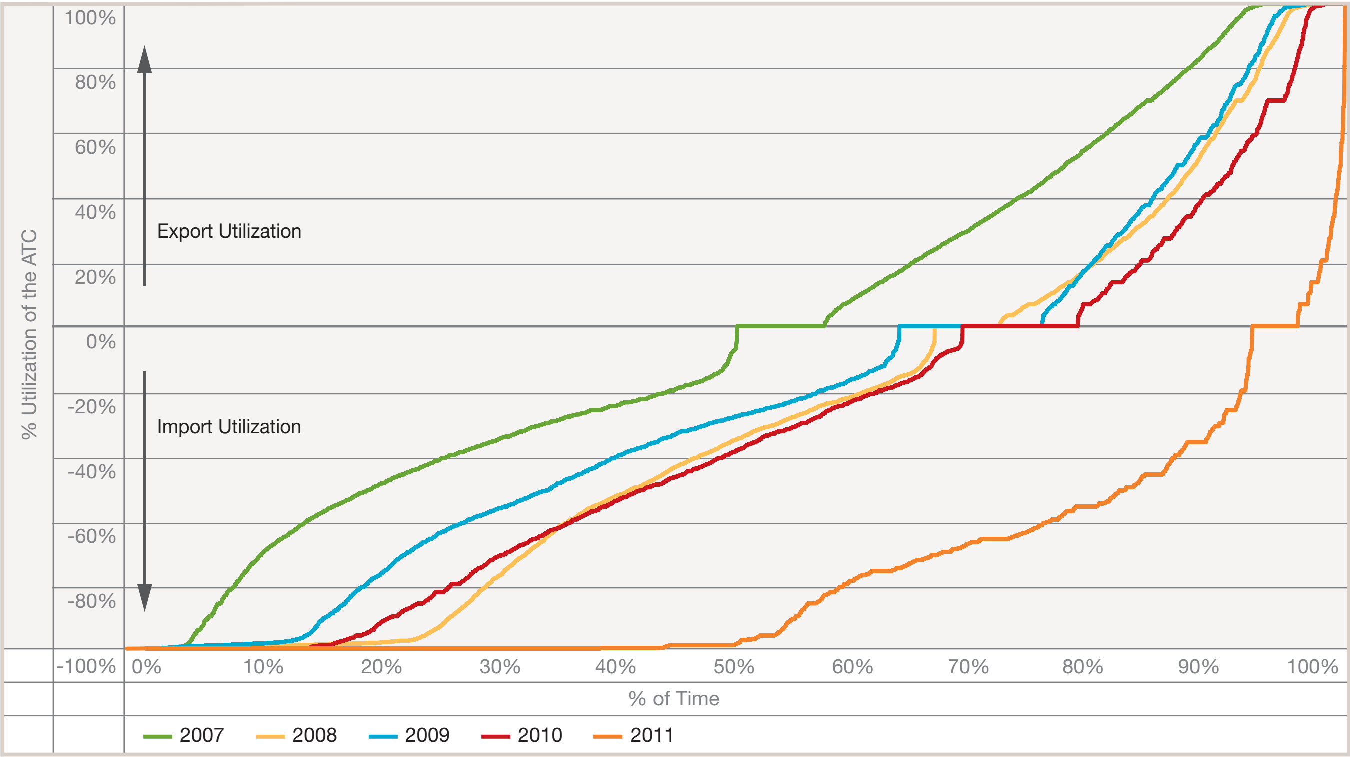
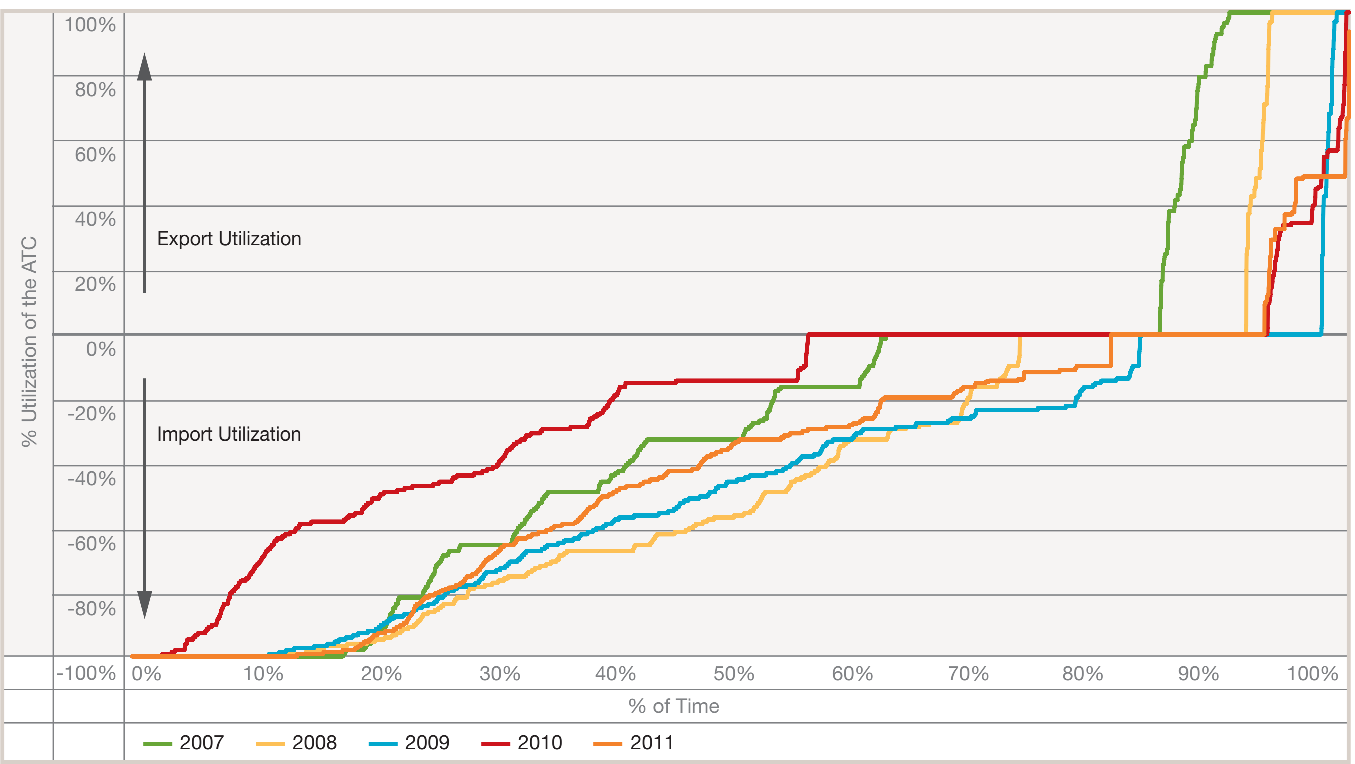


FIGURE 8

Import and Export Utilization on the Saskatchewan Intertie, 2007 to 2011

Import Utilization Adjusted to Account for Reserves on the Intertie



Supply Adequacy

Supply Cushion

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 undispatched 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:

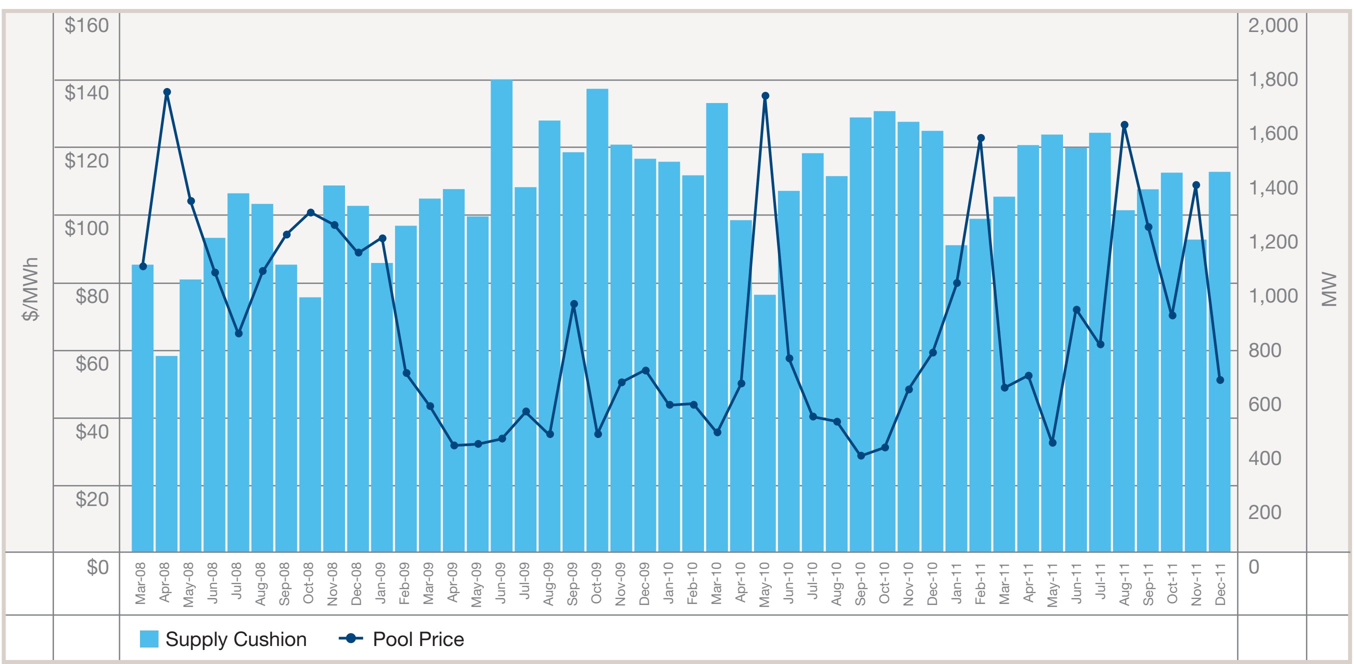
$$\text{Supply Cushion} = \sum_{1}^{n} (\text{Available MW} - \text{Dispatched MW}) + \text{DDS Dispatched} - \text{TMR Dispatched}$$

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 23 of this report.

Figure 9 displays the monthly average supply cushion as compared to average pool price. Typically the supply cushion will decrease when there are planned and unplanned outages that affect supply. At the end of 2010 two large coal units, Sundance 1 and 2, were removed from service, remaining offline throughout 2011. Sundance 1 and 2 have a combined Maximum Capability of 576 MW, which represents approximately nine per cent of the current Alberta coal fleet. This reduced supply availability resulted in an approximate seven per cent decrease in the annual average supply cushion. The Keephills 3 coal-fired unit came into service in May 2011, adding 450 MW to the coal fleet and lessening the impact of the Sundance unit outages.

FIGURE 9

Monthly Average Supply Cushion

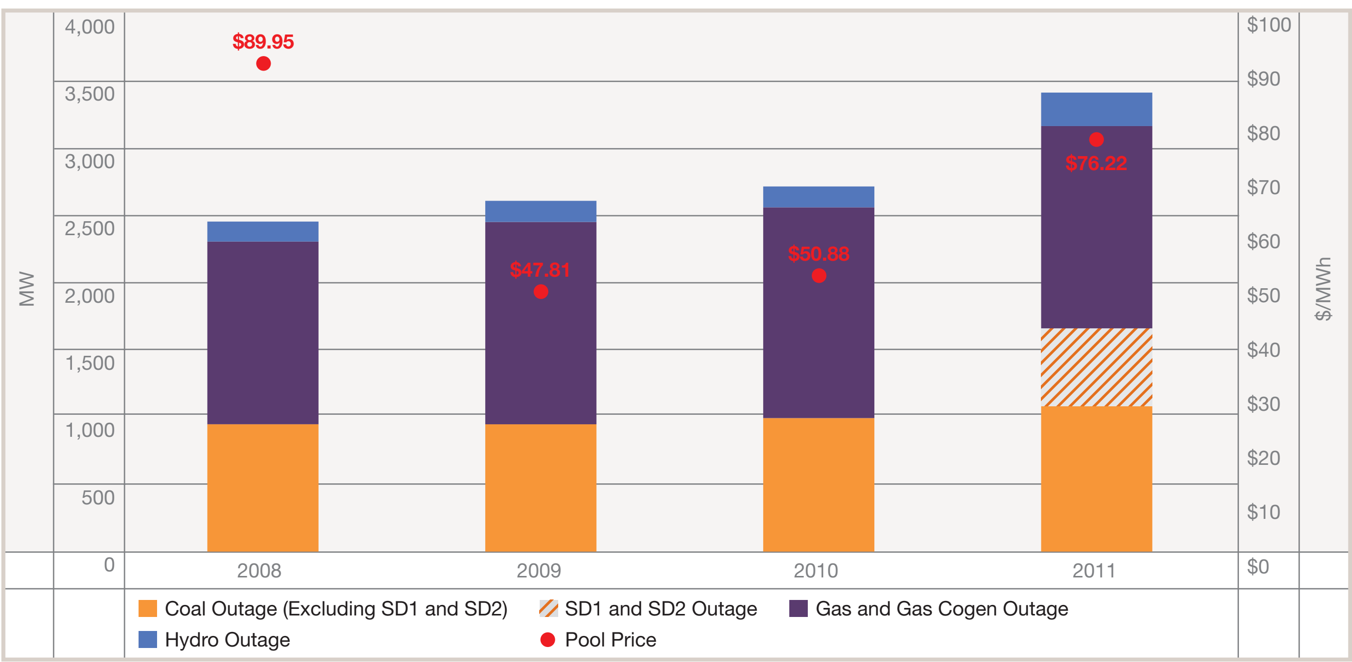


Generation Outages

All generating assets submit a Maximum Capability) 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 generating assets that run nearly all the time. Most baseload generators are coal-fired and cogeneration units, which offer the majority of their energy into the market at $0/MWh to ensure that they are dispatched and because they do not have the operational flexibility to be dispatched below a unit's minimum stable generation level. When these baseload generators 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 10 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, 2011 saw a nine per cent increase in the levels of coal-fired generation on outage or derates over 2010 (without including the SD1 and SD2 outages). The reduced availability of low priced coal-fired generation drove higher pool prices in 2011 than in previous years. The exception to this is 2008, which saw higher gas prices coupled with periods of high demand and supply scarcity.

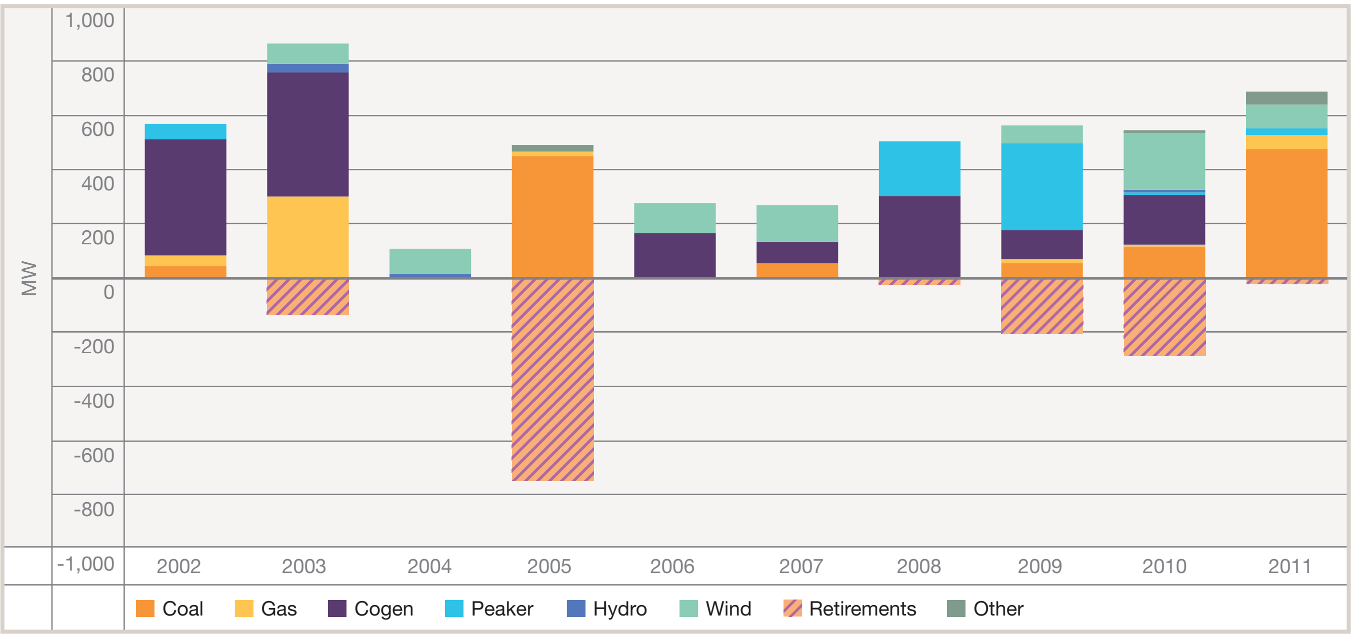
FIGURE 10
Annual Average Generation on Outage and Derates versus the Pool Price



Generation Additions

In 2011 approximately 670 MW of supply was added to the system, which includes new additions as well as any changes to the capacity of existing units. This includes the following new additions: the Keephills 3 coal-fired facility (450 MW), the Daishowa gas-fired asset (52 MW), the Weyerhaeuser biomass asset (48 MW), and the Suncor Wintering Hills wind power facility (88 MW). Figure 11 provides the annual generation additions and retirements for the past ten years.

FIGURE 11
Generation Additions and Retirements, 2002 to 2011

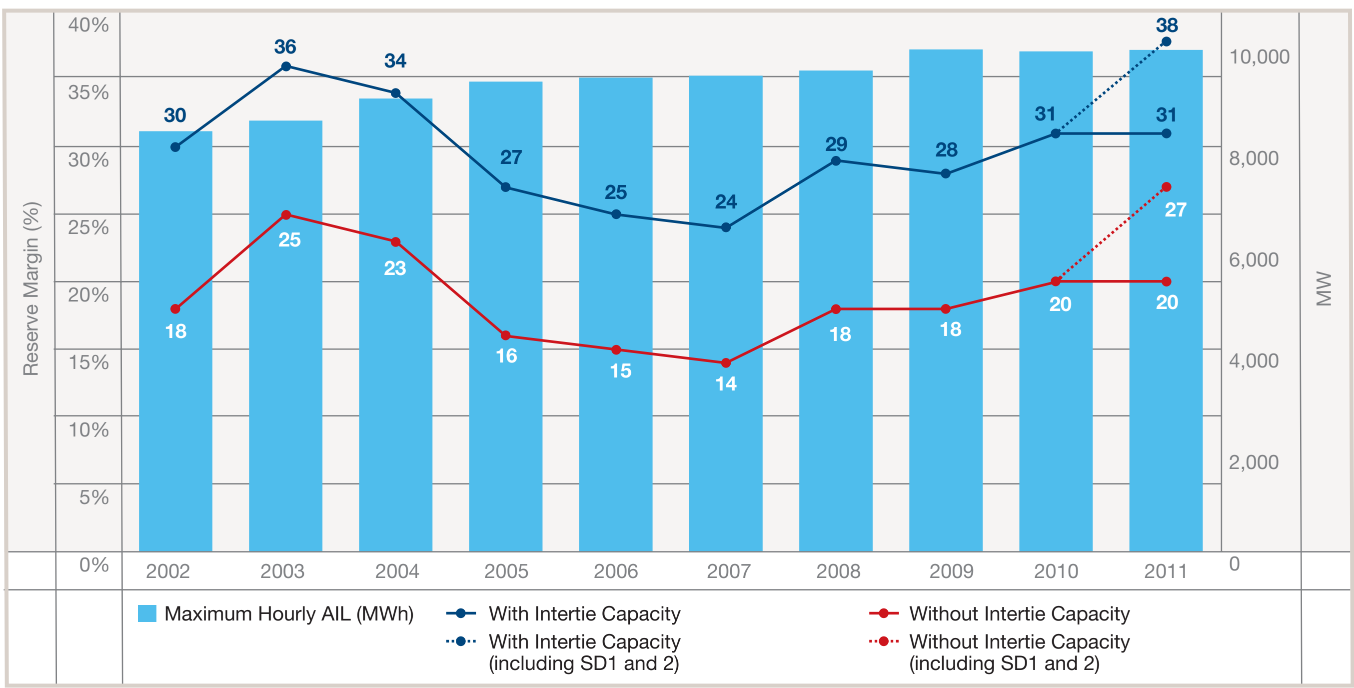


Reserve Margin

The reserve margin is a metric that can be used to assess whether 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. Figure 12 gives annual reserve margin with and without intertie capacity since full import capability may not always be available at the time of system peak demand.[1]

Reserve margins remained unchanged year-over-year due to the slight increase in installed capacity with the new generator additions, along with a slight increase in peak demand. In 2011, reserve margin was 31 per cent including intertie capacity, and 20 per cent without intertie capacity and excluding Sundance 1 and 2 in the overall capacity. Also presented in Figure 12 are 2011 values for reserve margin including the Sundance 1 and 2 units. The reserve margin including these units was 38 per cent with intertie capacity, and 27 per cent without.

FIGURE 12
Annual Reserve Margin and Peak Alberta Internal Load (AIL)



1 *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.*

Transmission Constraints

Constraints on the transmission system in Alberta may result in instances where generation is stranded, making it unavailable to the market. In addition, constraints may occur in some parts of the province if there is insufficient transmission capacity to serve local load. In these cases local generation may be required to run even if it is not in merit due to the need to meet local demand.

Transmission Must-Run

When generators are constrained "on" this is known as transmission must-run (TMR) service, where the AESO contracts for the right to use local generation to meet local demand in areas where there is insufficient local transmission capacity to support local demand and system reliability. TMR services are required in the Rainbow Lake area, northwest Alberta and at times in Calgary to maintain system reliability. The AESO plans for this requirement and enters into contracts with generators in the appropriate region to provide this service. In 2011, a total of 764 GWh of contracted TMR was required from these generators, down slightly from the 791 GWh dispatched in 2010.

In areas that the AESO has not foreseen the need for TMR there are occasional events where, due to transmission maintenance and or system constraints, unforeseen TMR is required to maintain reliability in the region. In 2011 unforeseen TMR increased to 37 GWh from one GWh in 2010, primarily due to inflow restrictions which limited the flow into the Fort McMurray Region. TMR was required in the Fort McMurray area to serve local load due to transmission limitations. Overall, TMR dispatches increased in 2011.

TABLE 5 – ANNUAL TOTAL TMR DISPATCHED

GWh	2008	2009	2010	2011
Unforeseen TMR	0	0	1	**37**
Contracted TMR	983	1,018	791	764
Total TMR	983	1,018	792	**801**

Constrained Down Generation

Constrained Down Generation (CDG) occurs when generators are constrained "off". This includes generation that is prevented from reaching the market due to either small levels of constraint that occur at varying locations across the entire transmission system or due to significant contingencies such as storms or outages, the effects of which are exacerbated by an insufficient transmission capacity margin.

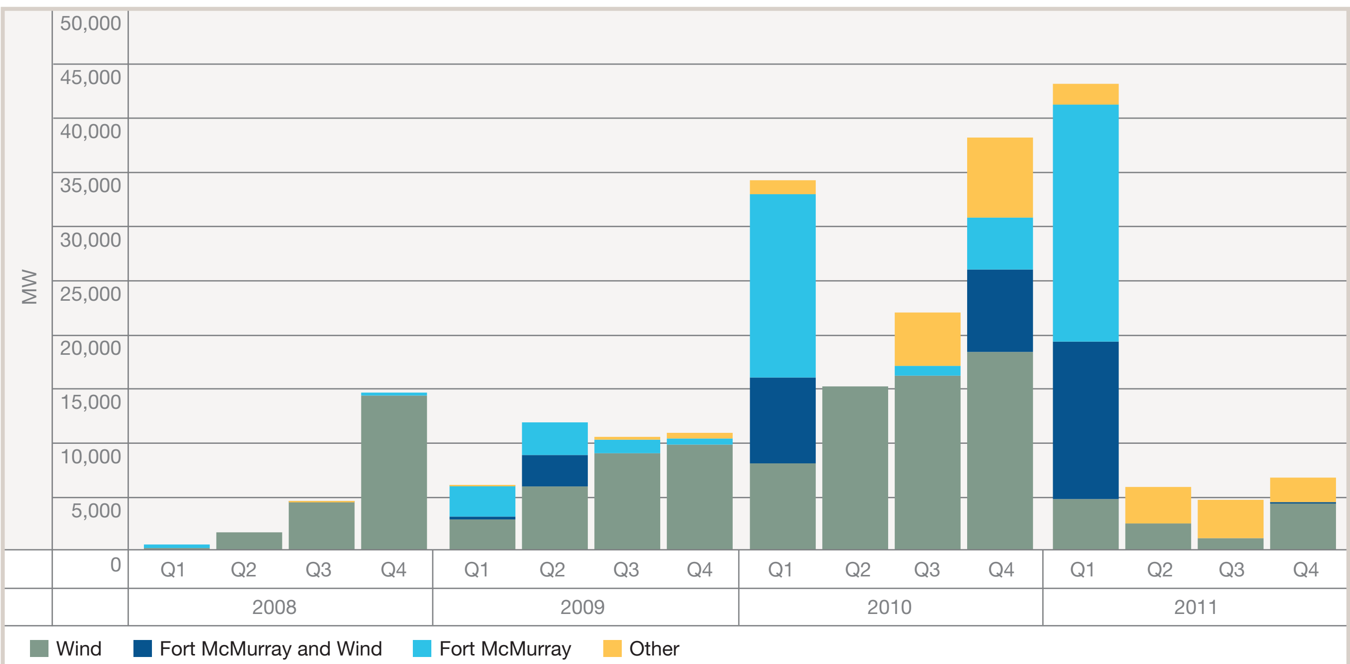
In 2011, the primary sources of CDG were in the Keephills-Ellerslie-Genesee (KEG) area as a result of transmission upgrades in this region. Other instances of constrained cogeneration occurred in the Fort McMurray area, and to wind generation in the south. The CDG is comprised of both major and typical constraints. Major constraints are those that have a significant impact on the market, such as constraints to KEG area generation. Conversely, typical constraints describe constraints that occur on a regular basis. Examples of the latter are constraints to wind generation and Fort McMurray area generation. Figure 13 displays the total megawatts of typical constraints on a quarterly basis.

As seen in Table 6, in 2011 142 GWh of CDG was recorded by the system controller, compared to the previous year's amount of 700 GWh. A sharp reduction in the amount of major constraints (82 GWh in 2011 as compared to 591 GWh in 2010) contributed to the lower CDG values. In 2010, major planned and unplanned constraints during the month of May resulted in higher overall constraints for the year. In addition, the amount of typical constraints relating to wind generation was at a four year low of 13 GWh.

TABLE 6 – ANNUAL TOTAL CONSTRAINED DOWN GENERATION *(GWh)*

			Typical constraint types			
Year	Total CDG	Major constraints	Wind	Fort McMurray	Wind and Fort McMurray	Others
2008	295	274	20	1	0	0
2009	55	16	27	8	3	1
2010	700	591	57	23	16	14
2011	**142**	**82**	**13**	**22**	**15**	**11**

FIGURE 13
Amount of Typical Constrained Generation by Quarter



In 2011 there were both Constrained Down Generation and TMR in the Fort McMurray region due to transmission capacity limitations in and out of the region. When generation was constrained down in Fort McMurray there was not enough transmission capacity to transfer all of the in-merit generation in the region to the rest of the market. When there were TMR requirements in Fort McMurray, local area generators were directed on to meet local area needs, meaning that there was not enough transmission capacity to bring in-merit market based generation into the region. In 2011, outflows from the Fort McMurray region to the rest of the grid occurred 93 per cent of the time and the region brought power in seven per cent of the time. The amount of inflows was up substantially from 2010, where Fort McMurray drew power in from the grid 0.5 per cent of the time. As seen in Figure 13, the Fort McMurray area experienced outflow restrictions primarily during the first quarter of 2011, during which time generators within the Fort McMurray region were constrained down.

Wind Generation

As of the end of 2011, there were 865 MW of installed wind capacity in Alberta. The Suncor Wintering Hills 88 MW wind power facility was added to the system in October of 2011. The aggregate capacity factor for wind power facilities compares the total energy production over a period of time with the amount of power the aggregate wind facilities would have produced at full capacity. The wind capacity factor in 2011 averaged 33 per cent, compared to the 2010 average of 28 per cent. As seen in Figure 14, the highest monthly average capacity factor of 51 per cent occurred in December 2011, and is the highest monthly capacity factor seen since November 2009.

Table 7 below gives annual summary statistics for wind generation. The 2011 peak demand was reached in January, and the wind capacity factor during the peak averaged 13 per cent. Typically during the annual winter peak demand, wind generation is low due to cold weather which results in low wind speeds.

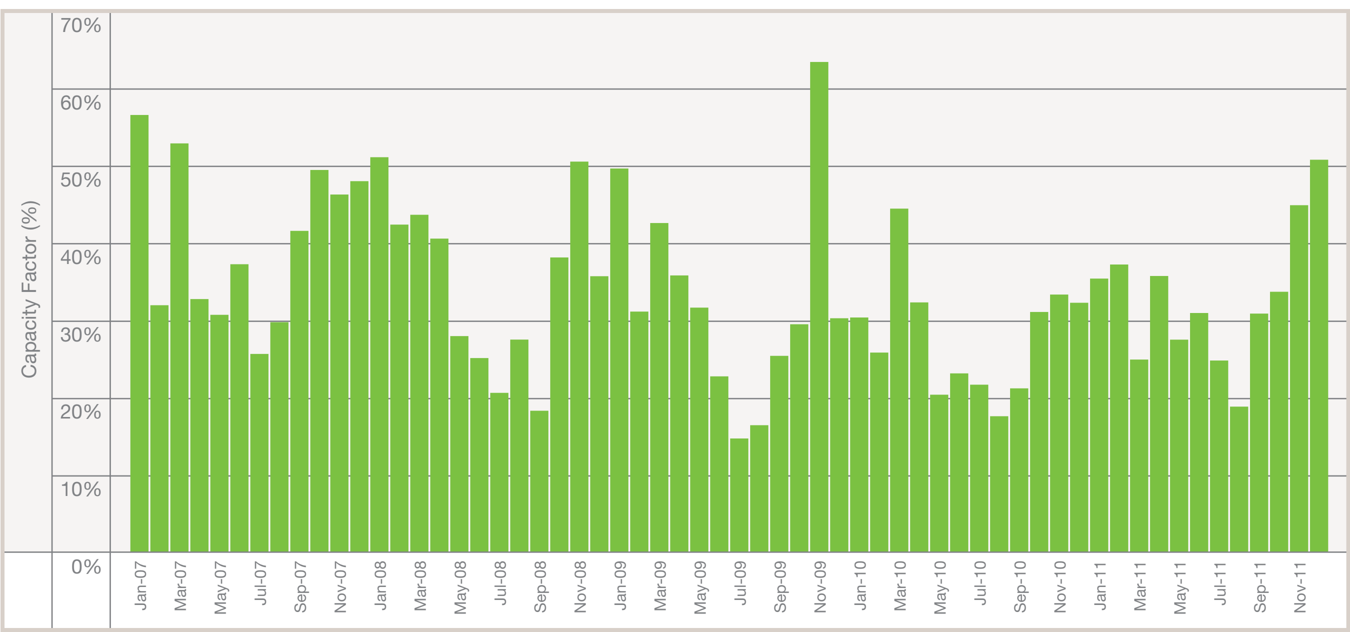
TABLE 7 – WIND GENERATION STATISTICS

Year	2007	2008	2009	2010	2011
Average hourly capacity factor *(%)*	40.5	35.3	32.9	27.9	**33.0**
Maximum hourly capacity factor *(%)*	97.0	97.8	95.1	97.3	**87.6**
Installed wind capacity (at year end) *(MW)*	497	497	563	777	**865**
Total wind generation *(GWh)*	1,427	1,539	1,503	1,552	**2,323**
Wind generation as a per cent of total energy (AIL) *(%)*	2.05	2.20	2.15	2.16	**3.16**
Wind capacity factor during annual peak demand *(%)*	35	12	3	0	**13**

FIGURE 14

Average Hourly Wind Capacity Factor

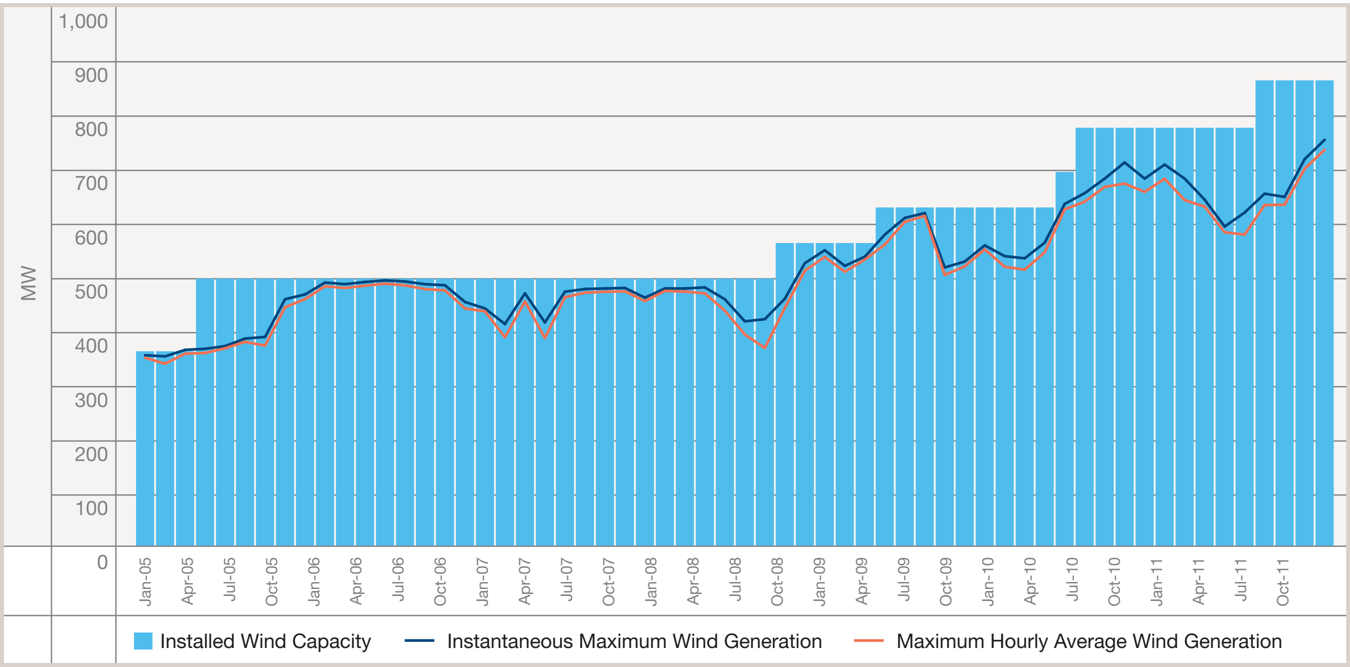
Total Wind Generation *(MW)* / Installed Wind Capacity *(MW)*



With new additions to wind capacity, the maximum level of wind generation has risen over the past five years. Figure 15 below gives installed wind capacity with instantaneous and hourly maximum wind generation. In the past two years, there has been greater locational diversity of wind in the province. There are two facilities in the Hanna region totaling 170 MW, whereas the majority of Alberta's wind generation is located in the South (695 MW). The AESO expects that there may not be as many coincident occurrences where all wind generation is at a high capacity factor due to this diversification of wind across the province. In Table 7, the maximum hourly wind capacity factor has declined nearly ten per cent from 2010 to 2011. This is mainly due to the geographic diversification of wind.

FIGURE 15

Installed Wind Capacity with Instantaneous and Hourly Maximums



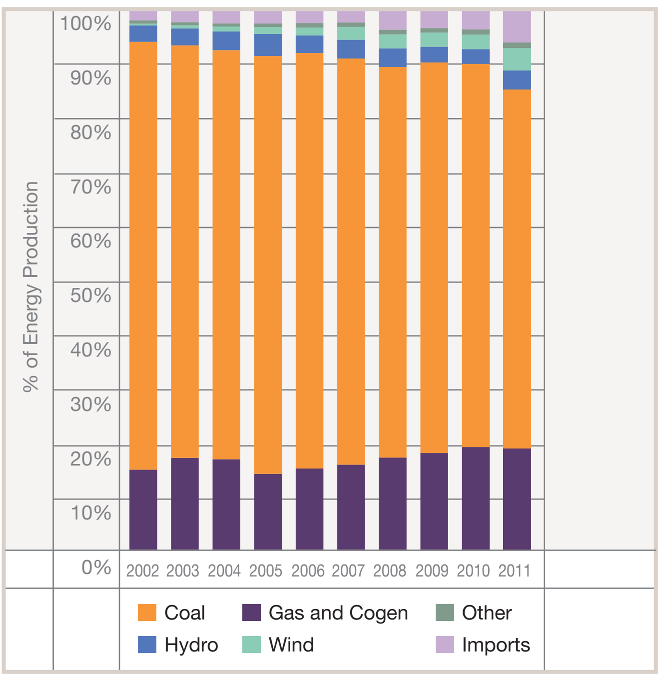
Price Setting and Generation Share

Coal-fired generation production provides the majority of the energy required by Alberta's market. In 2011 coal-fired generators provided 67 per cent of the energy consumed. This represents a four per cent reduction from 2010 due to increased coal-fired unit outages and derates in 2011, and the removal of Sundance 1 and 2 from service. The generation share of gas and cogeneration units was stable, providing 19 per cent of the energy consumed for both 2010 and 2011. Wind generation provided four per cent in 2011, an increase of one per cent over 2010. The amount of energy provided by hydroelectric generation increased 0.7 per cent year-over-year, from 2.7 per cent in 2010 to 3.4 per cent in 2011.

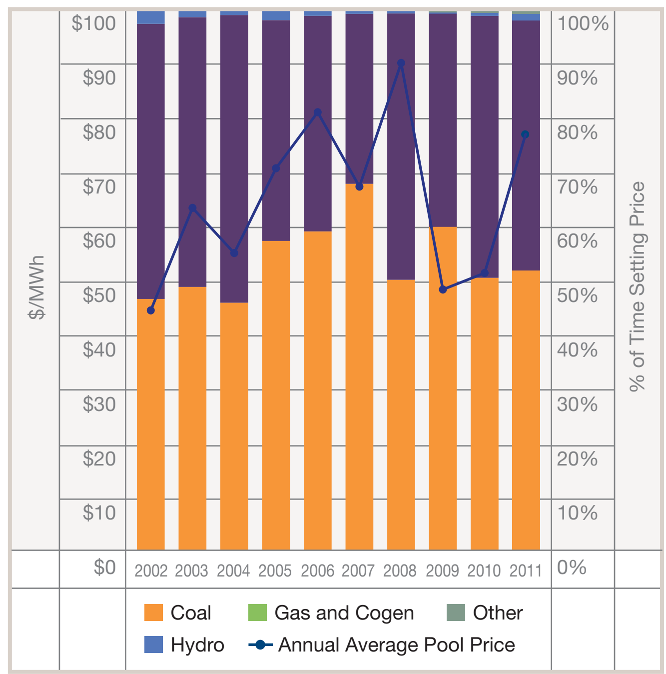
Coal-fired generating units set price 52 per cent of the time in 2011, a two per cent increase from 2010. The amount of time that natural gas-fired units set price decreased from 49 per cent to 46 per cent of the time in 2011. Figure 16 gives the annual production and price-setting share by fuel type from 2002 to 2011.

FIGURE 16
Production and Price Setting Share

Energy Production by Fuel Type



Price Setters by Fuel Type



Demand Response

The AESO has an interest in examining how demand response can assist in managing reliability and contributing 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. Figure 17 gives an estimate of the value for loads who voluntarily respond to changes in pool price by reducing their consumption in response to high prices. In 2011 loads that responded to price would have received a pool price savings of approximately 40 per cent over those loads that did not respond to price.

As seen in Figure 18, from 2010 to 2011 there has been an increase in total load participation in demand response programs. The majority of this increase comes from the introduction of the Load Shed Service for imports (LSSi) program. LSSi replaced the Load Shed Service (LSS) program in 2011, nearly tripling the volume of the previous service. A portion of the load that participates in the LSSi program is also price responsive. The amount of load that qualified for demand opportunity service (DOS) remained unchanged from 2010 to 2011. DOS is a temporary, interruptible class of transmission service. There was a decrease in the amount of loads participating in the supplemental reserve market.

FIGURE 17
Value to Loads for Participating in Demand Response

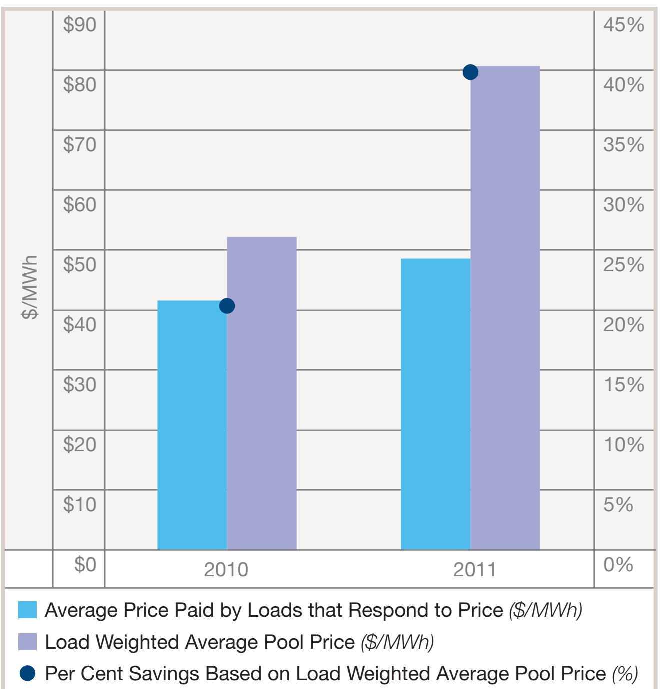
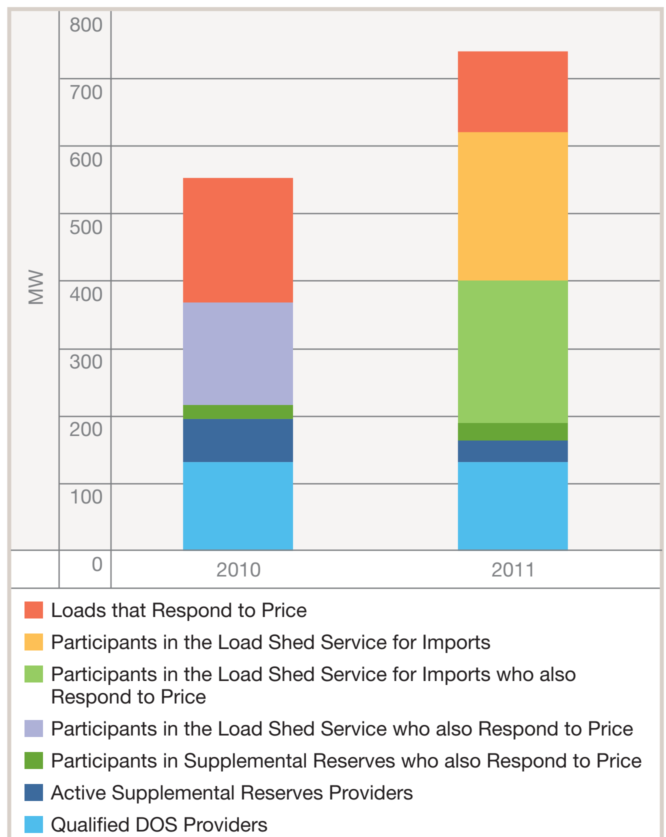


FIGURE 18
Load Participation in Demand Response Programs



The LSSi program was implemented in 2011 and is a market service that enables an increase in import capacity on the B.C. intertie by mitigating potential frequency dips caused by the sudden loss of the intertie during periods of high imports. Loads that provide LSSi are designed to trip off when frequency drops below a specified threshold, which helps restore the frequency to normal levels following the loss of the interconnection.

LSSi replaced the former Load Shed Service (LSS) in 2011 to address the limitations of LSS. The previous service was not armable, resulting in possible reliability threats under export conditions. The new LSSi service can be dispatched on or off by the system controller (armable), meaning that loads can only react to frequency dips and then consequently trip only in the “on position”, effectively eliminating the risk of an unexpected trip.

The first load contract for LSSi was set up on November 1, 2011. The AESO contracts with various loads in the province to provide this service and loads must meet certain operational requirements in order to be eligible to provide this service. As of the end of 2011, the AESO procured a total of 432 MW of load to provide LSSi.

Operating Reserve

The prices paid to providers of operating reserve (OR) are indexed to the pool price. Therefore, prices in the operating reserve market trend closely to changes in the pool price. The AESO procures active and standby reserve with the purpose of active reserve being to meet the requirements of the Alberta Interconnected Electric System (AIES) under normal operating conditions. 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 reserve pricing involves both a premium and activation price. The premium price paid to the OR provider 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 called upon.

In 2011, prices in the OR market increased from the previous year due to the overall increase in the pool price. Table 8 provides a historical summary of prices in both the active and standby markets. Regulating reserve (RR) is used for real-time balancing of supply and demand and requires automatic control of generation levels to ensure the grid is operated reliably. Spinning reserve (SR) and supplemental reserve (SUP) are used to maintain the balance of supply and demand when an unexpected system event occurs. SR must be synchronized to the grid.

TABLE 8 – ANNUAL AVERAGE OPERATING RESERVE PRICES *($/MW)*

	Active			Standby premiums			Standby activation			Total OR Cost	Average hourly pool price
	RR	SR	SUP	RR	SR	SUP	RR	SR	SUP	*($ millions)*	*($/MWh)*
2007	34	29	26	5	4	4	101	101	96	185	66.95
2008	51	43	38	7	5	5	163	151	133	270	89.95
2009	23	16	11	5	4	3	96	85	69	104	47.81
2010	27	21	16	7	4	4	141	115	91	137	50.88
2011	**55**	**57**	**51**	**6**	**8**	**7**	**98**	**121**	**95**	**328**	**76.22**

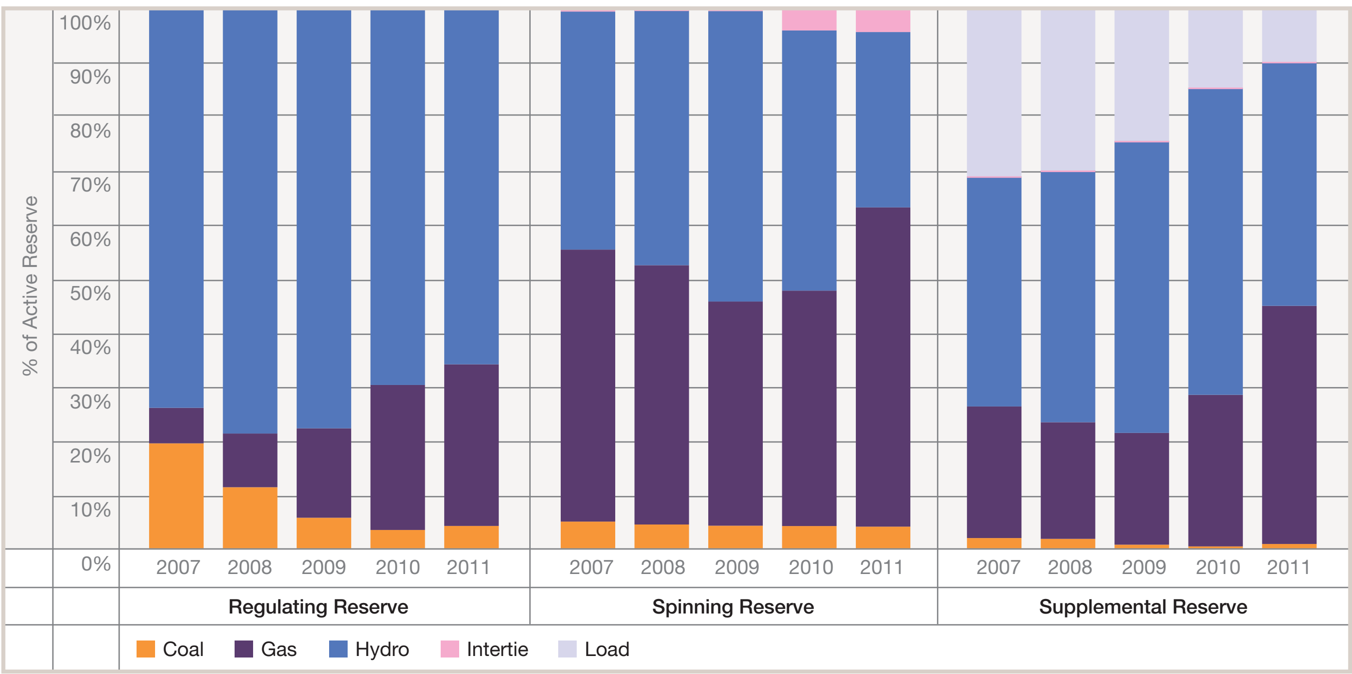
Note: OR costs and prices are preliminary and may change.

Market Share of Reserve

In 2011, nearly 66 per cent of active regulating reserve required was provided by hydroelectric generators, a decline of four per cent share from 2010. Hydroelectric generation's share of the provision of spinning and supplemental reserve declined by 16 per cent and 12 per cent respectively. The share of operating reserve provided by gas-fired generation has increased over all three reserve types from the previous year.

Generators and loads are able to participate in the supplemental reserve market. Load decreased its market share of the supplemental market from 15 per cent in 2010 to ten per cent in 2011. Figure 19 gives the annual market share of operating reserve by fuel type.

FIGURE 19
Market Share of Operating Reserve by Fuel Type



Operating Reserve Redesign Improves Function of the Market

Through consultation with stakeholders, the AESO has implemented several initiatives to reduce the AESO's influence in the operating reserve market with the goals of improving transparency, creating better alignment with the energy market and simplifying the overall design. In August 2011, phase two of the operating reserve (OR) market redesign was implemented. In the former design, OR was procured over two platforms: Watt-Ex and through over-the-counter (OTC) contracts. As of December 12, 2011, procurement through the OTC platform was discontinued as part of the OR market redesign.

In early 2012, the AESO will conduct a further in-depth analysis of the OR market, including a review of fundamentals and the impacts of changes made to the OR market.

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 reliability. Dispatching TMR displaces in-merit energy and results in a downward impact on the pool price. The dispatch down service (DDS) is a price adjustment mechanism that negates the downward effect that TMR dispatches have on the pool price. This service was introduced in December 2007 with the intention of improving the pool price signal.

As seen in Table 9, DDS payments in 2011 totaled $6 million for 537 GWh of DDS dispatched. This was used to offset 801 GWh of TMR dispatches. The total DDS payment in 2011 was 16 per cent lower than in 2010 ($8 million). Total TMR dispatched in 2011 increased 12 per cent over 2010, while total DDS dispatched decreased slightly by 0.1 per cent.

TABLE 9 – ANNUAL DISPATCH DOWN SERVICE STATISTICS

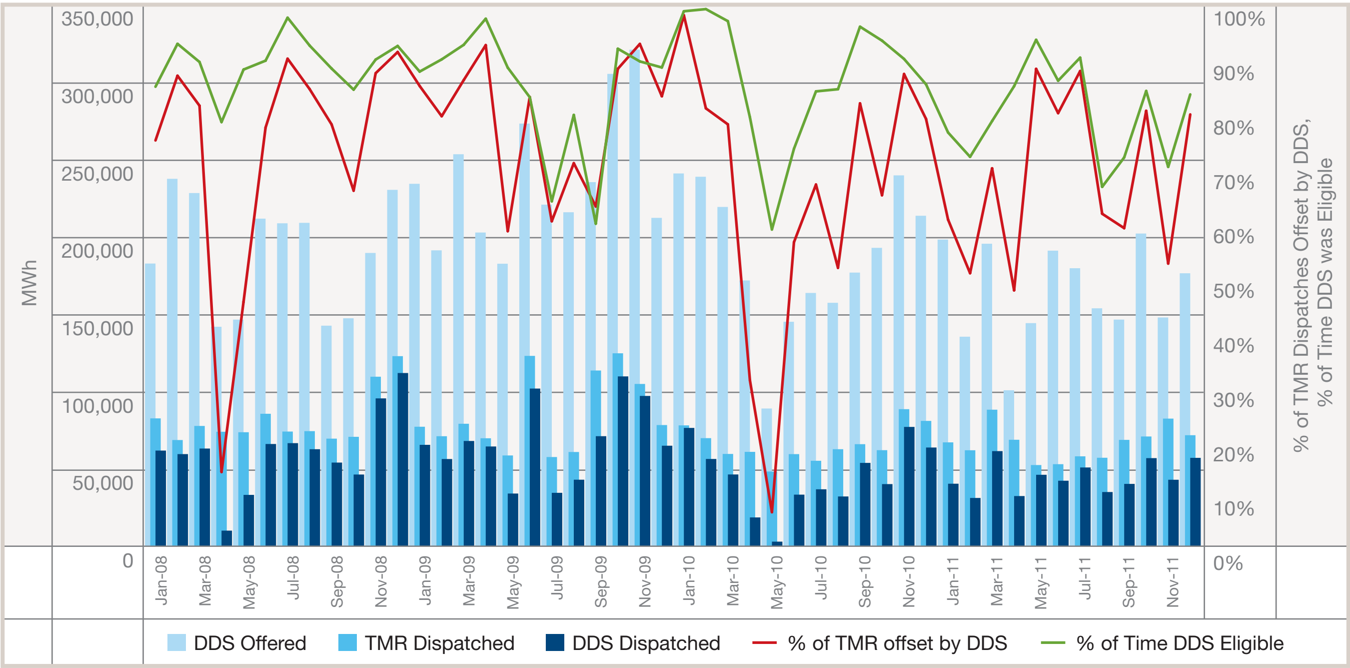
Year	TMR dispatched *(GWh)*	DDS dispatched *(GWh)*	Average DDS charge per MWh *($/MWh)*	Total DDS payments *($ millions)*
2008	983	731	0.46	28
2009	1,018	810	0.23	13
2010	792	538	0.13	8
2011	**801**	**537**	**0.11**	**6**

The cost of providing DDS service is 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 2011, the average DDS charge was $0.11/MWh, down two cents from 2010.

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.

Despite a year-over-year increase in TMR dispatched, DDS dispatched decreased slightly year-over-year, from 538 GWh in 2010 to 537 GWh in 2011. As seen in Figure 20, during the year, higher pool prices resulted in more instances where the SMP exceeded the TMR reference price, resulting in a slightly lower DDS eligibility in comparison to the previous year. The system marginal price was less than the TMR reference price 80 per cent of the time in 2011 and 86 per cent of the time in 2010. The combined effect of the amount of time the DDS was eligible and the amount of generation constrained down resulted in 67 per cent of TMR dispatches being offset by DDS dispatches.

FIGURE 20
Total DDS and TMR Dispatched with Total DDS Offers



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 10 gives annual payments to suppliers on the margin statistics for the past five years.

TABLE 10 – ANNUAL PAYMENTS TO SUPPLIERS ON THE MARGIN STATISTICS

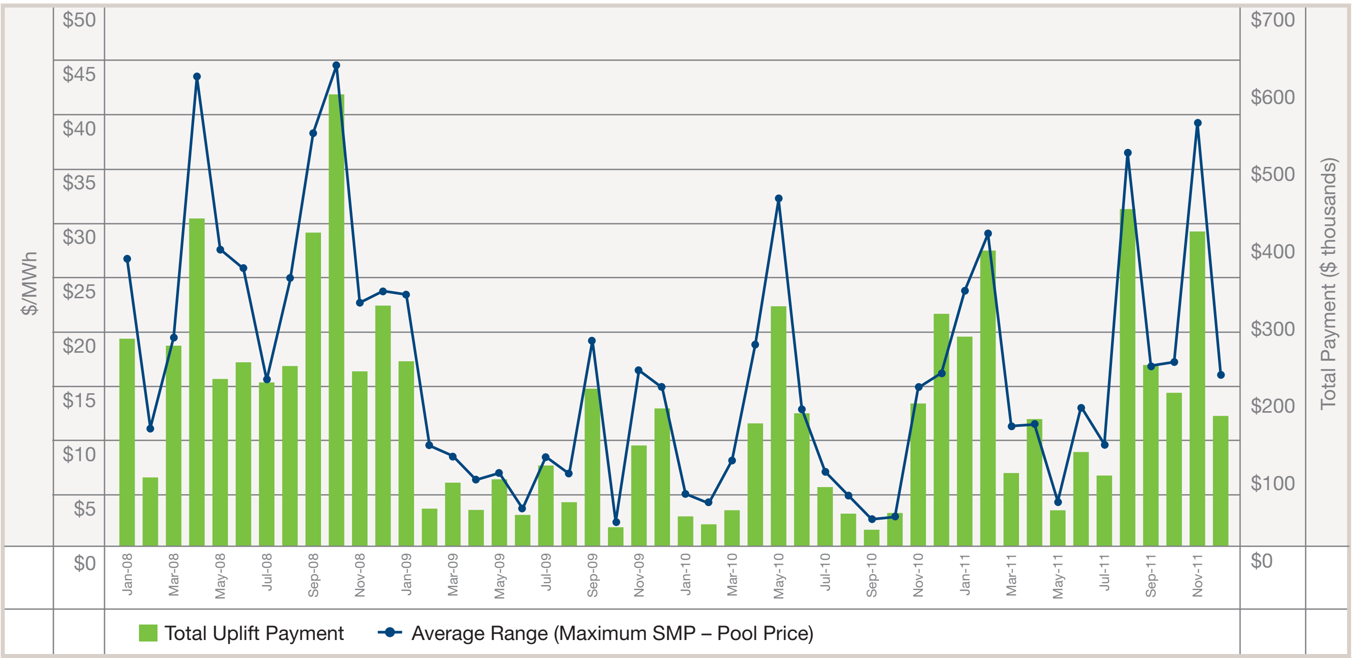
Year	**Total uplift payment** *($ millions)*	**Average range between the maximum SMP and the pool price** *($)*	**Average charge** *($)*	**Market value** *($ millions)*	**% of market value**
2008	3.5	26.81	0.06	5,178	0.07
2009	1.2	10.29	0.02	2,734	0.05
2010	1.4	10.60	0.02	2,896	0.05
2011	**2.6**	**18.72**	**0.04**	**4,580**	**0.06**

** Market value is determined by the pool price multiplied by the AIES load in the hour.*

In 2011, higher pool prices resulted in higher uplift payments in comparison to the previous year. In addition, the average range between the maximum SMP and the pool price increased from $10.60/MWh to $18.72/MWh in 2011. As seen in Figure 21, the total uplift payment closely tracks the trend in average range between the maximum SMP and the pool price. Total uplift payments increased 86 per cent from 2010 to 2011. Despite this increase, uplift continues to hold a small share of overall market value, representing 0.06 per cent of the total market value in 2011.

FIGURE 21

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



Final Notes and Market Monitoring in 2012

As the market evolves throughout 2012 and into the future, 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 encourages stakeholders to send any comments or questions on this report, or any other market analysis questions to **market.analysis@aeso.ca**. Your input is appreciated.

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