

2009  
Annual Market Statistics



# Table of Contents

<b>Continued growth in 2009</b>	1
<b>Pool price down 47 per cent</b>	1
Table 1: Price Summary Statistics – 2000 to 2009	1
Figure 1: Monthly Average Hourly Pool Price From 2000 to 2009 with On/Off Peak Averages	2
Figure 2: Pool Price Contribution to Total Revenue by Asset Type and Pool Price Range	2
<b>Low cost of fuel is reflected in the pool price</b>	3
Figure 3: 30-Day Rolling Average Pool Price and Natural Gas Price (AECO-C) 30-Day Rolling Average Heat Rate	3
Figure 4: Monthly Average Natural Gas Price and Pool Price vs. Weighted Average Coal and Gas Offer Prices in the EMMO Above \$0 and Below \$100/MWh	4
<b>Continued growth in wind generation</b>	5
Figure 5: Monthly Average Wind Capacity Factor with Minimum/Maximum Range	5
<b>Price setting and generation share in the market</b>	6
Figure 6: Energy Production by Fuel Type / Price Setters by Fuel Type	6
<b>Few instances of supply scarcity</b>	6
Figure 7: Hours SMP Has Been Above \$900/MWh	6
<b>Low demand growth in 2009</b>	7
Table 2: Demand Statistics – 2000 to 2009	7
Figure 8: Monthly Average Load and Load Growth – 2008 to 2009	8
<b>Slight decline in imports in 2009</b>	8
Table 3: Intertie Statistics – 2005 to 2009	8
Table 4: Intertie Available Transfer Capability Statistics	9
Figure 9: Import-Export Utilization on B.C. Intertie 2005 – 2009	9
<b>Constrained Down Generation</b>	10
Figure 10: Monthly Total Constrained Down Generation	10
<b>Dispatch down service (DDS)</b>	11
Figure 11: Average DDS Offers and DDS Dispatched Compared to TMR Dispatches	11
<b>Payments to suppliers on the margin (PSM)</b>	12
Figure 12: Monthly Total Payments to Suppliers on the Margin Compared to the Average Range Between the Maximum SMP and the Settled Pool Price	12
<b>Lower reserve prices track the decline in pool price</b>	13
Table 5: Operating Reserve Costs – 2005 to 2009	13
Table 6: Average Price/MWh – 2005 to 2009	13
<b>Market share of reserves continue to be stable</b>	14
Figure 13: Market Share of Active Regulating Reserve by Fuel Type	14
Market Share of Active Spinning Reserve by Fuel Type	14
Market Share of Active Supplemental Reserve by Fuel Type	14
Figure 14: D-1 On-Peak Active Operating Reserve Market Liquidity	15
<b>In summary</b>	16

# 2009 Alberta Wholesale Market Statistics

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, which, in 2009, had about 200 participants and approximately \$5 billion in annual energy transactions.

For the first time, the annual market statistics from the past year are being published in a stand-alone report in order to share information that supports a transparent market and provides long-term value to market participants.

## Continued growth in 2009

The Alberta wholesale electricity market saw continued growth in overall power consumption and installed capacity in 2009. The growth in power consumption is largely due to growth in demand for power at a number of oilsands extraction and upgrading sites. Other sectors experienced declines as a result of the economic downturn.

The market saw the addition of approximately 600 MW of supply to the system, including both new generation and increases in maximum capabilities of existing generation. Retirements to the Rossdale generating units resulted in a reduction in installed capacity of approximately 200 MW. Overall the net increase in capacity in 2009 was approximately 400 MW.

## Pool price down 47 per cent

Alberta's competitive wholesale market electricity prices fluctuate based on the principles of supply and demand. During instances of supply surplus prices are low, while times of supply scarcity 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 2009, pool price averaged \$47.81/MWh, the lowest annual average since 2002, and a 47 per cent decrease over 2008. On-peak and off-peak pool prices averaged \$61.56/MWh and \$30.26/MWh respectively. Table 1 summarizes the historical price statistics from 2000 to 2009. The decline in pool price was predominantly due to low natural gas prices, as well as a higher per cent of time that coal-fired generators set price compared to 2008. Natural gas price averaged \$3.76/GJ in 2009, a 51 per cent decline over 2008.

**TABLE 1: PRICE SUMMARY STATISTICS – 2000 TO 2009**

Pool Price (\$/MWh)	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Average hourly pool price	133.22	71.29	43.93	62.99	54.59	70.36	80.79	66.95	89.95	47.81
Off-peak average pool price	72.52	53.14	28.47	46.97	41.88	49.28	50.15	41.86	54.45	30.26
On-peak average pool price	181.08	85.51	56.04	75.54	64.53	86.86	104.97	86.61	117.73	61.56
Maximum hourly pool price	999.99	879.20	999.00	999.99	998.01	999.99	999.99	999.99	999.99	999.99
Minimum hourly pool price	5.84	5.82	0.01	7.07	0.00	4.66	5.42	0.00	0.00	0.10

*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 and all day on Sunday and all day on North American Electric Reliability Corporation (NERC) defined holidays.*

As seen in Figure 1, January 2009 saw the highest monthly pool price for the year at \$92.97/MWh. This occurred as a result of cooler temperatures and a significant number of coal outages from January 21 – 23. September 2009 saw higher pool prices in comparison to other months in 2009. This was due to a number of periods of supply scarcity during the month. The remainder of the year saw relatively stable pool prices.

**FIGURE 1**

**Monthly Average Hourly Pool Price From 2000 to 2009 with On/Off Peak Averages (\$/MWh)**

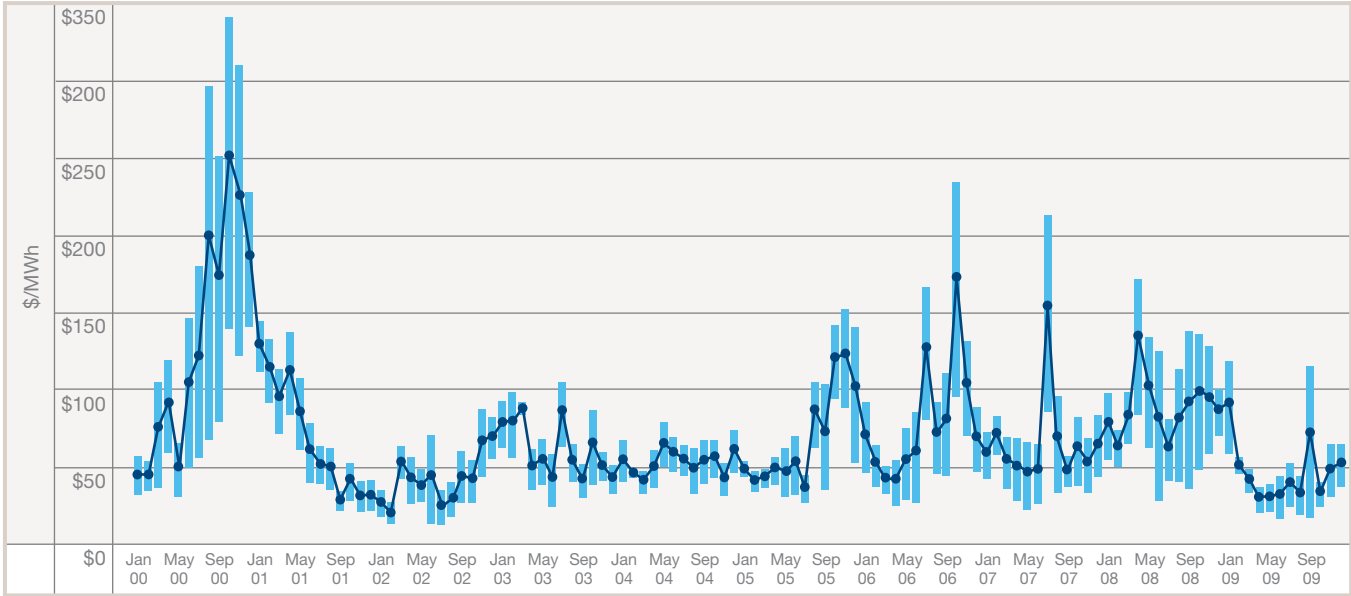


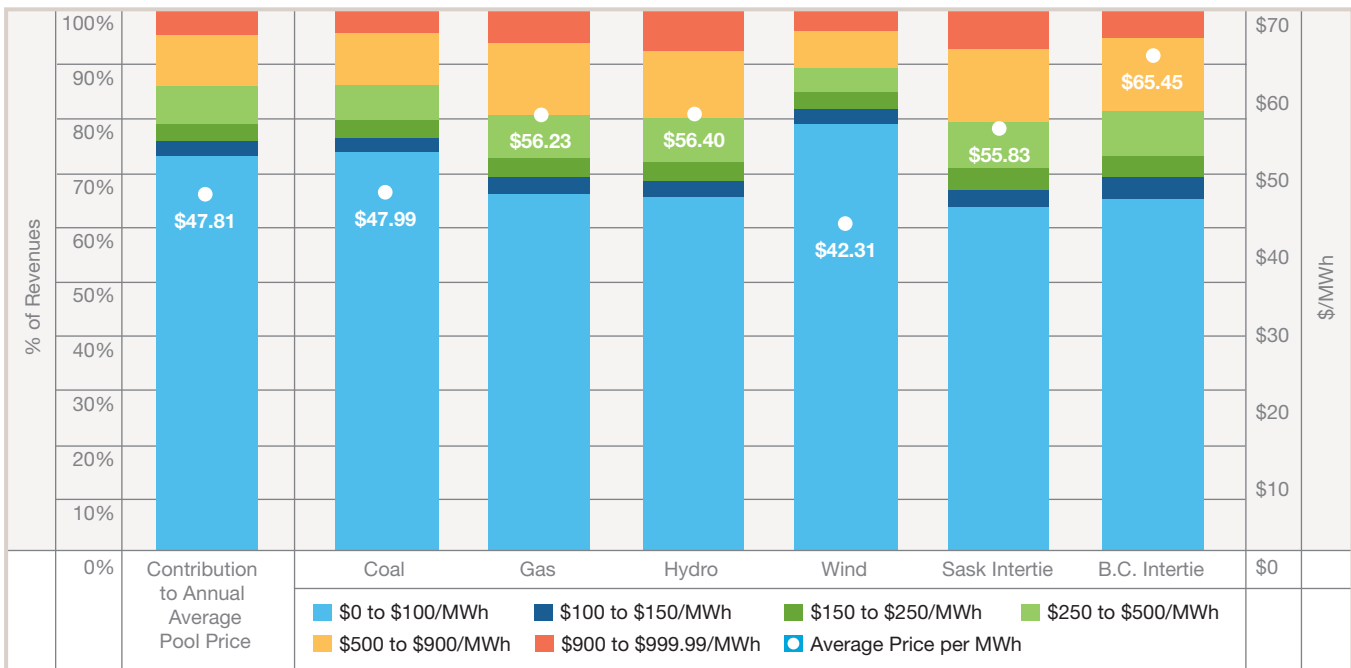
Figure 2 presents the breakdown of revenue by pool price range for different asset types. As seen in the graph, the per cent contribution to the annual average pool price was highest in the \$0/MWh to \$100/MWh range. Over all asset types, units earned at least 60 per cent of their revenues in the \$0/MWh to \$100/MWh range in 2009.

The numbers placed within the bars represent the average price received by asset type. For example, gas-fired generators received \$56.23/MWh on average over all hours.

**FIGURE 2**

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

Average Revenues = 2009 Hourly Pool Prices Multiplied by Metered Volumes

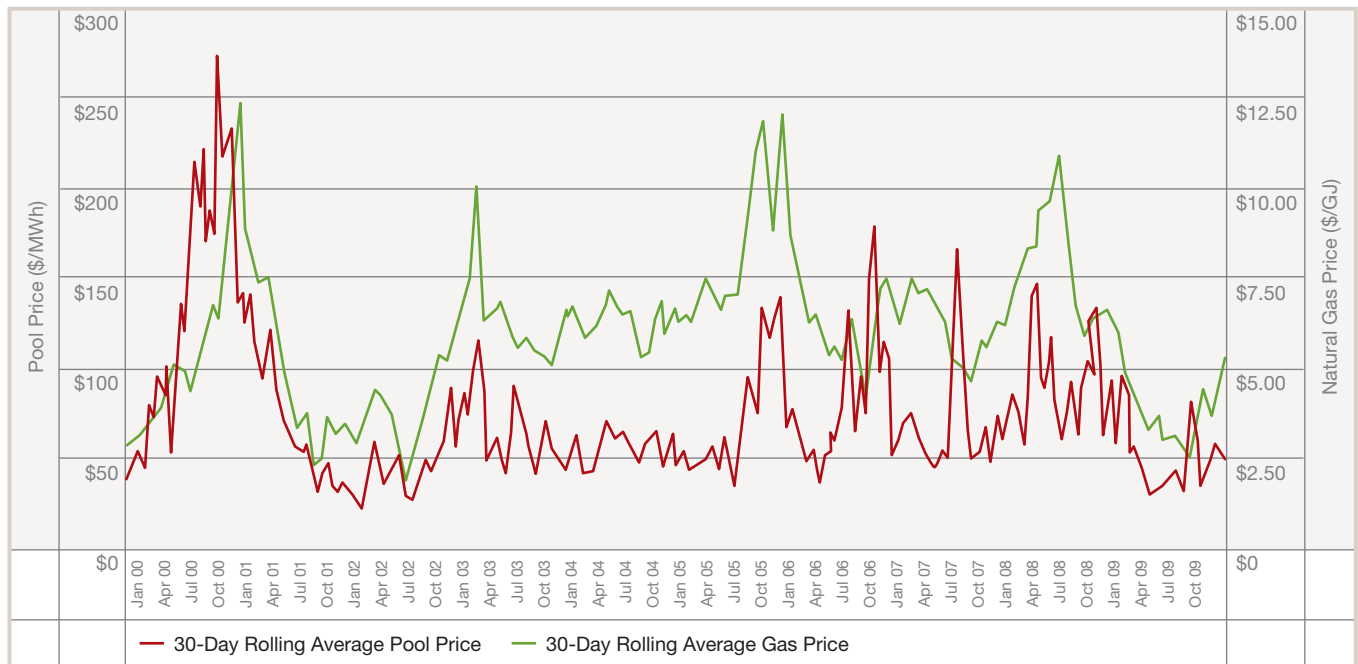


## Low cost of fuel is reflected in the pool price

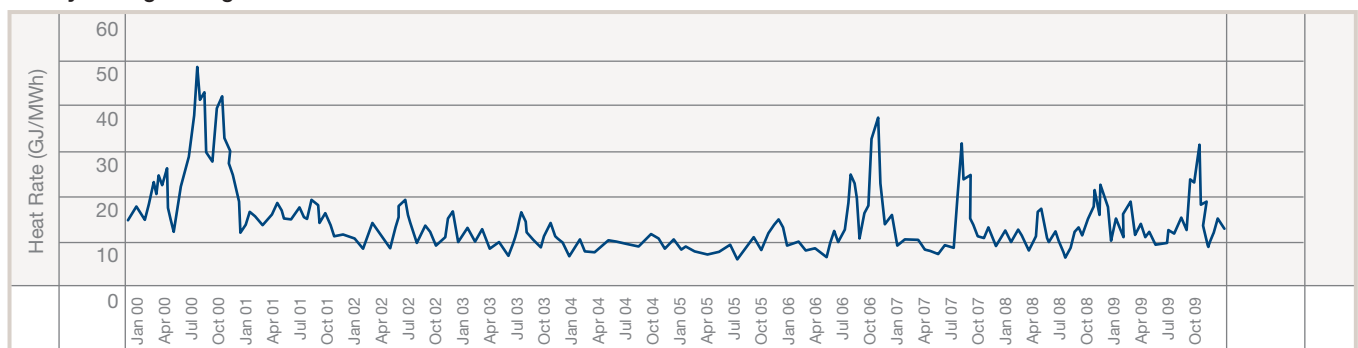
The Alberta pool price is determined by the highest priced generator that is dispatched to meet the demand for electricity. Generators submit hourly offers to the AESO that include the amount of energy they will provide at a specific price. An automated system at the AESO arranges all the hourly offers from the lowest price to the highest price. Starting at the lowest priced offer, the AESO system controllers dispatch generating units until the demand requirement is satisfied. Natural gas-fired generators are on the margin a significant portion of the time, particularly during on-peak periods. The price of offers made by natural gas-fired units fluctuates to reflect changes in the price of the underlying fuel. When natural gas prices rise, offers tend to reflect the higher cost, which tends to result in an increase in pool price.

In 2009, lower natural gas prices contributed to the decline in pool prices. 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 an underlying fuel used to produce electricity. In Alberta's case this fuel is natural gas. As seen in Figure 4, the offer prices of gas-fueled generation tend to track the price of natural gas. The offer prices of coal-fired generation are relatively stable over time and generally independent of the cost of natural gas.

**FIGURE 3**  
**30-Day Rolling Average Pool Price and Natural Gas Price (AECO-C)**

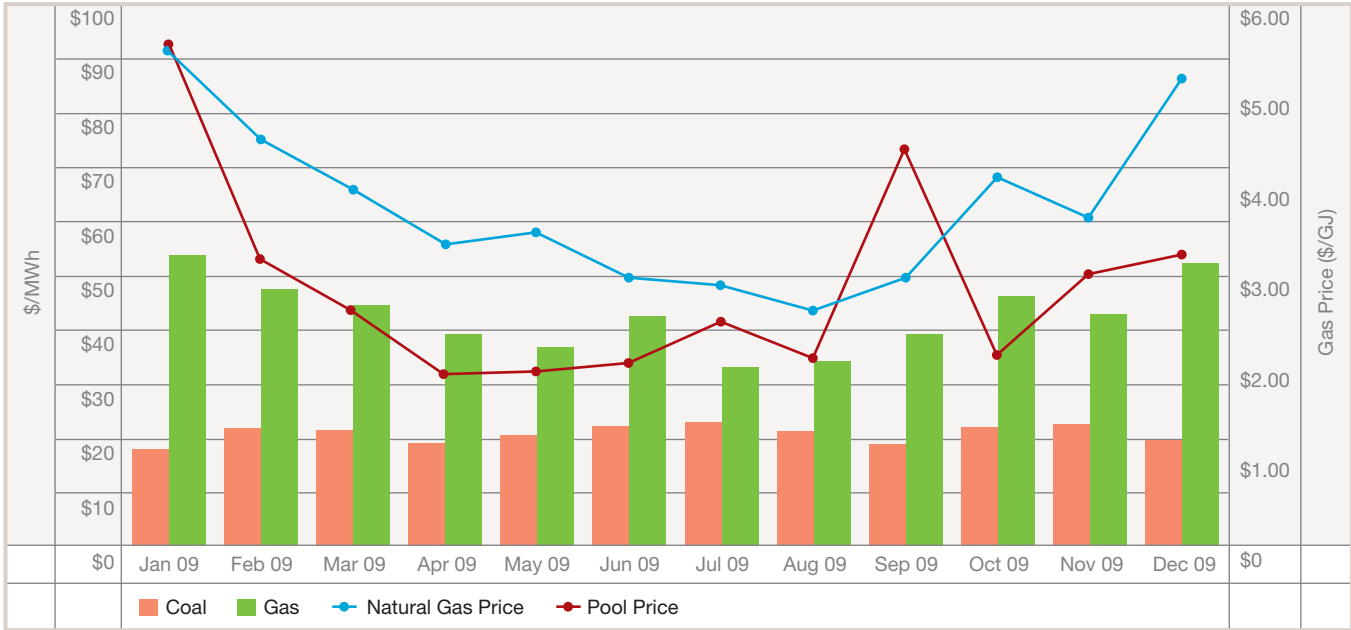


## 30-Day Rolling Average Heat Rate



**FIGURE 4**

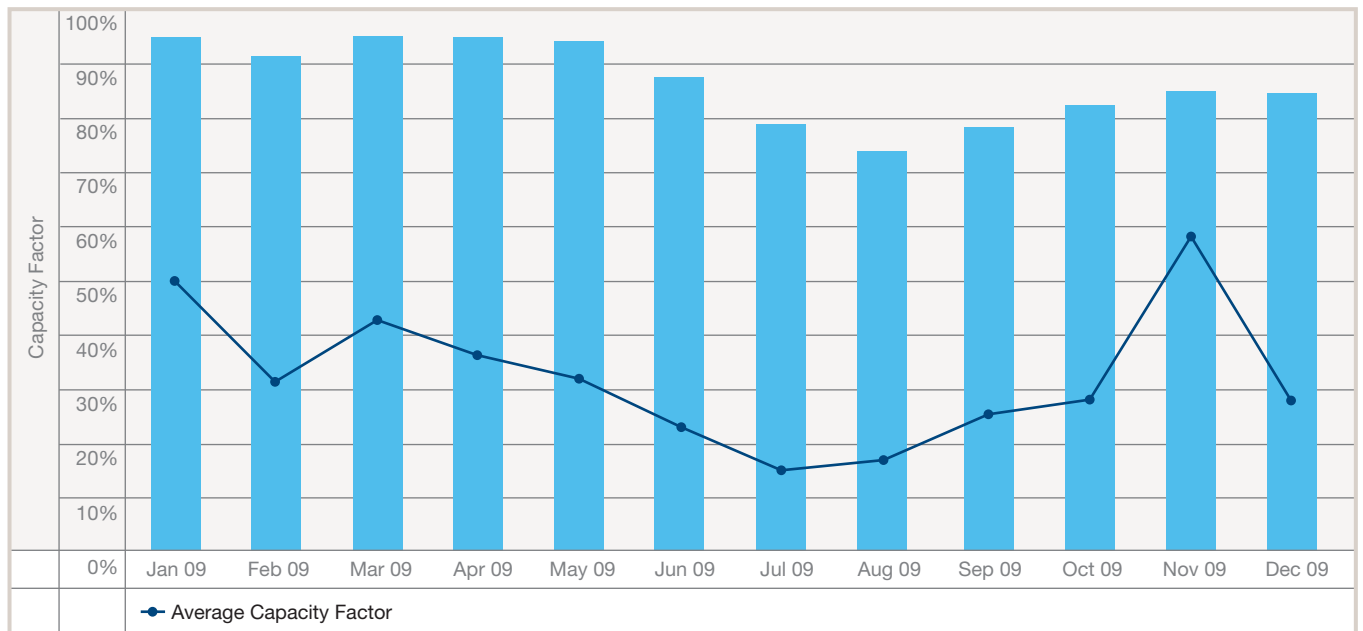
**Monthly Average Natural Gas Price and Pool Price vs. Weighted Average Coal and Gas Offer Prices in the EMMO Above \$0 and Below \$100/MWh**



## Continued growth in wind generation

TransAlta's Blue Trail wind farm commenced operations in 2009, adding 66 MW to the province's existing 497 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. As seen in Figure 5, wind generation in the province continues to be strong, with an aggregate annual average capacity factor of 32.1 per cent in 2009 that is well above the capacity factors observed in other jurisdictions across North America, which average around 20 per cent<sup>1</sup>. The previous year's annual capacity factor was 35.3 per cent.

**FIGURE 5**  
**Monthly Average Wind Capacity Factor with Minimum/Maximum Range**



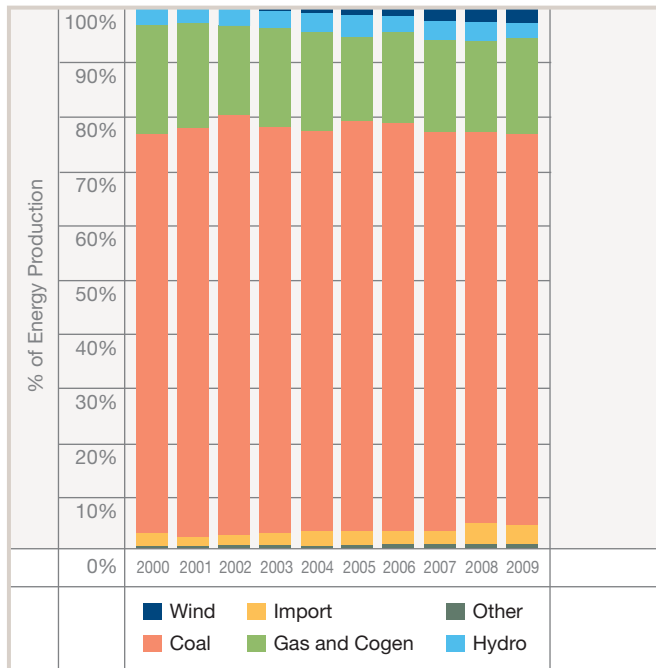
<sup>1</sup> ISO/RTO Council: 2009 State of the Markets Report

## Price setting and generation share in the market

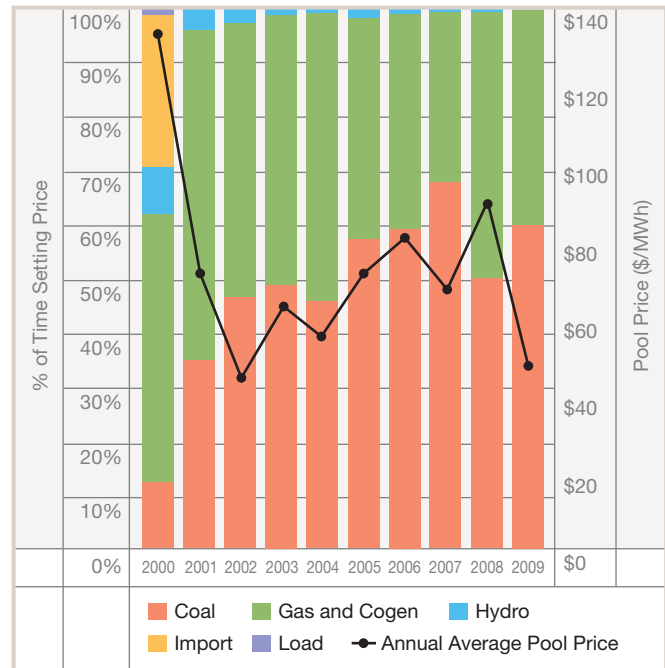
Coal-fired generation typically provides electricity at a low cost relative to gas generation. In 2009 coal-fired generation set price 60 per cent of the time, an increase of 10 per cent over 2008. Gas and cogeneration units set price for most of the remaining time. Hydroelectric generation set price under one per cent of the time in 2009.

FIGURE 6

Energy Production by Fuel Type



Price Setters by Fuel Type



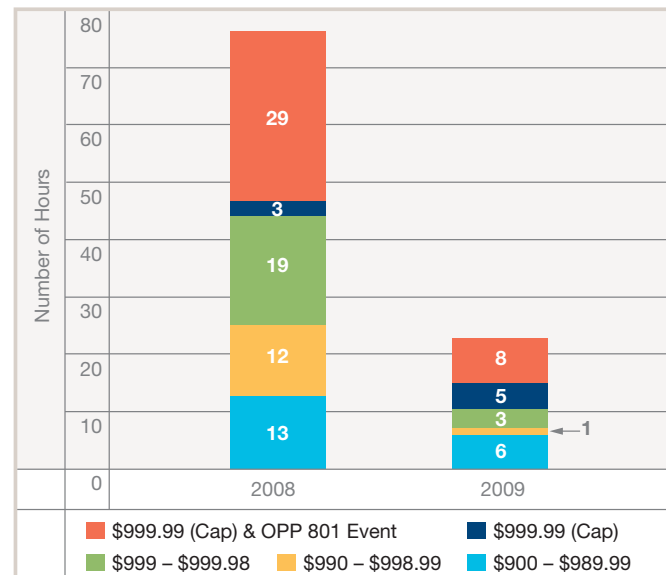
## Few instances of supply scarcity

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 2009 there were fewer instances of supply shortfall, with only three separate events that occurred in comparison to 14 events in 2008.

Figure 7 illustrates that there has been a significant reduction in the number of hours that the system marginal price was above \$900/MWh from 2008.

FIGURE 7

Hours SMP Has Been Above \$900/MWh



## Low demand growth in 2009

During 2009, load growth continued the trend from the previous two years of fairly flat growth at 0.2 per cent. The highest monthly year-over-year growth of 2.9 per cent occurred in October 2009 and the highest decline in growth of -2.8 per cent occurred in August 2009. Declines in industrial load (without oilsands) were offset by increases in the residential, farm, and oilsands sectors resulting in a positive growth overall.

**TABLE 2: DEMAND STATISTICS – 2000 TO 2009**

Alberta Internal Load (AIL)	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Total AIL (GWh)	54,053	54,464	59,428	62,714	65,260	66,267	69,371	69,661	69,947	69,914
Average hourly load	6,154	6,217	6,784	7,159	7,429	7,565	7,919	7,952	7,963	7,981
Maximum hourly load	7,785	7,934	8,570	8,786	9,236	9,580	9,661	9,701	9,806	10,236
Minimum hourly load	4,999	5,030	5,309	5,658	6,017	6,104	6,351	6,440	6,411	6,454
Year-over-year load growth		0.8%	9.1%	5.5%	4.1%	1.5%	4.7%	0.4%	0.4%	0.0%
Year-over-year load growth (corrected for leap year effect)		1.0%			3.8%	1.8%			0.1%	0.2%
Load factor	79.0%	78.4%	79.2%	81.5%	80.4%	79.0%	82.0%	82.0%	81.2%	78.0%

The slowdown in load growth is due to a number of factors, including lower load in a number of chemical, forestry, and natural gas plants. Transmission and distribution losses also declined by approximately 12 per cent over 2008 levels. This is due to a reduction in AIES load as well as the impact of the Keephills-Ellerslie-Genesee (KEG) conversion project in 2008. Positive growth in load at a number of oilsands extraction and upgrading sites contributed to the positive growth in overall load.

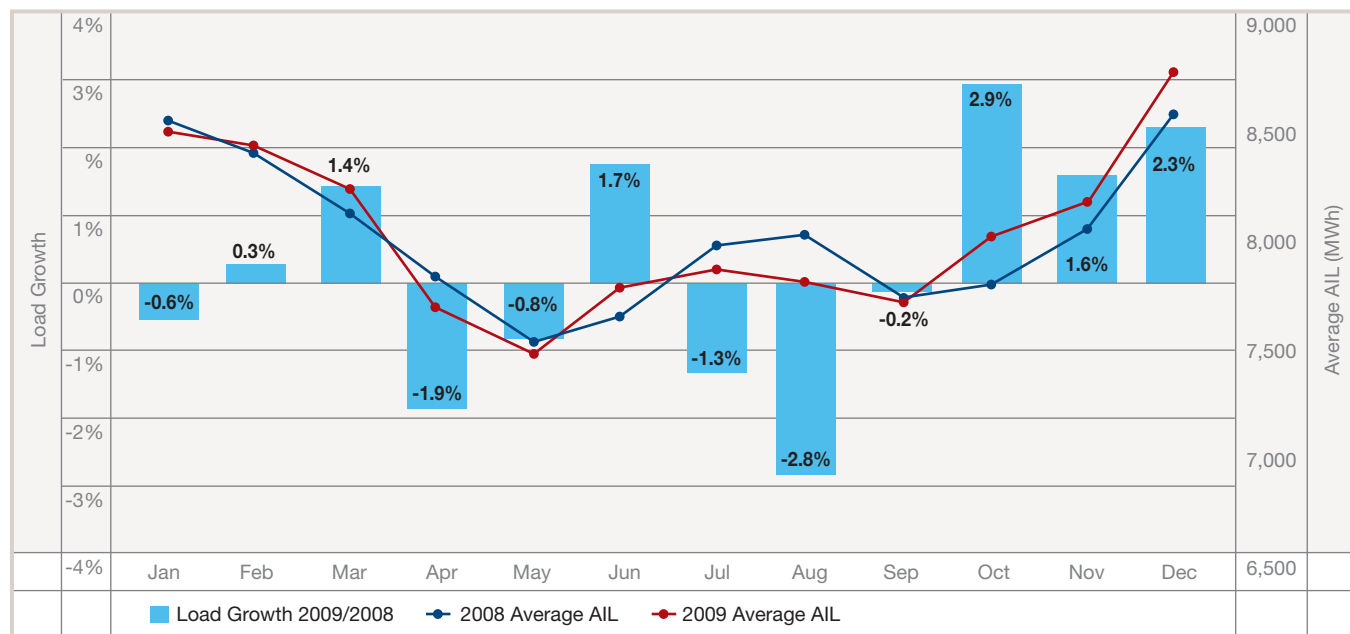
A new Alberta Internal Load (AIL) peak of 10,236 MW was set in hour ending (HE) 18 on December 14. The peak occurred due to colder temperatures throughout the province, with temperature averaging -26 degrees C on December 14, as well as increases in industrial load in the later months of 2009. Despite high demand during the day, price did not increase significantly. This was due to high coal availability, as well as a high level of imports on both the Saskatchewan (Sask) and British Columbia (B.C.) tie line. Price responsive load did not go offline due to the stable low price signal, keeping overall demand high.

Summer peak load reached its lowest level since 2006, with the peak of 9,108 MW occurring late in the summer months on September 2 in HE 17. Summer peaks are generally caused by high temperatures over a sustained period of time that result in high air conditioning load. There were few periods of high temperatures during the summer months. In both July and August 2009 temperatures were quite moderate with average Alberta temperatures of 17 degrees C and 16 degrees C respectively.

Alberta's peak load growth continues to be stronger than overall load growth, averaging 2.1 per cent per year over the past five years as compared to 1.5 per cent growth in average load. Peak load growth in 2009 was 4.4 per cent.

FIGURE 8

Monthly Average Load and Load Growth – 2008 to 2009



### Slight decline in imports in 2009

Lower prices in 2009 contributed to a decline in overall imports and exports on the Sask and B.C. tie lines. Import and export decisions are made based on the price of power in neighbouring jurisdictions. If the prices in neighbouring jurisdictions are consistent with those observed in Alberta, there is less incentive for participants to import or export electricity if they receive similar prices for the electricity within Alberta. In 2009, prices in Alberta were consistent with those in neighbouring jurisdictions, resulting in lower imports and exports overall. Total imports declined 10 per cent over 2008, and exports declined eight per cent. Table 3 displays yearly import and export statistics.

TABLE 3: INTERTIE STATISTICS – 2005 TO 2009

Intertie statistics (MWh)	2005	2006	2007	2008	2009
Imports on B.C. intertie	1,070,848	1,101,207	927,108	1,574,370	1,344,024
Imports on Sask intertie	463,726	415,828	540,113	673,748	674,583
<b>Total imports</b>	<b>1,534,574</b>	<b>1,517,035</b>	<b>1,467,221</b>	<b>2,248,118</b>	<b>2,018,607</b>
Year-over-year growth (%)	2.9%	-1.1%	-3.3%	53.2%	-10.2%
Exports on B.C. intertie	987,581	460,050	885,551	518,453	487,793
Exports on Sask intertie	50,493	29,415	87,666	40,306	25,369
<b>Total exports</b>	<b>1,038,074</b>	<b>489,465</b>	<b>973,217</b>	<b>558,759</b>	<b>513,162</b>
Year-over-year growth (%)	-2.2%	-52.8%	98.8%	-42.6%	-8.2%
<b>Net yearly imports</b>	<b>496,500</b>	<b>1,027,570</b>	<b>494,004</b>	<b>1,689,359</b>	<b>1,505,445</b>

The available transfer capability (ATC) is the amount of electricity that can flow on the interties. In 2009, the maximum B.C. import ATC declined 25 MW, while the maximum B.C. export ATC and both export and import ATC on the Sask intertie remained relatively unchanged. On average, the B.C. export ATC declined which partly explains the reduction in overall exports on the B.C. tie.

**TABLE 4: INTERTIE AVAILABLE TRANSFER CAPABILITY STATISTICS**

Year	B.C. export ATC		B.C. import ATC		Sask export ATC		Sask import ATC	
	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average
2005	735	187	715	604	69	52	153	139
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

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 reserves being provided over the intertie divided by the ATC;

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

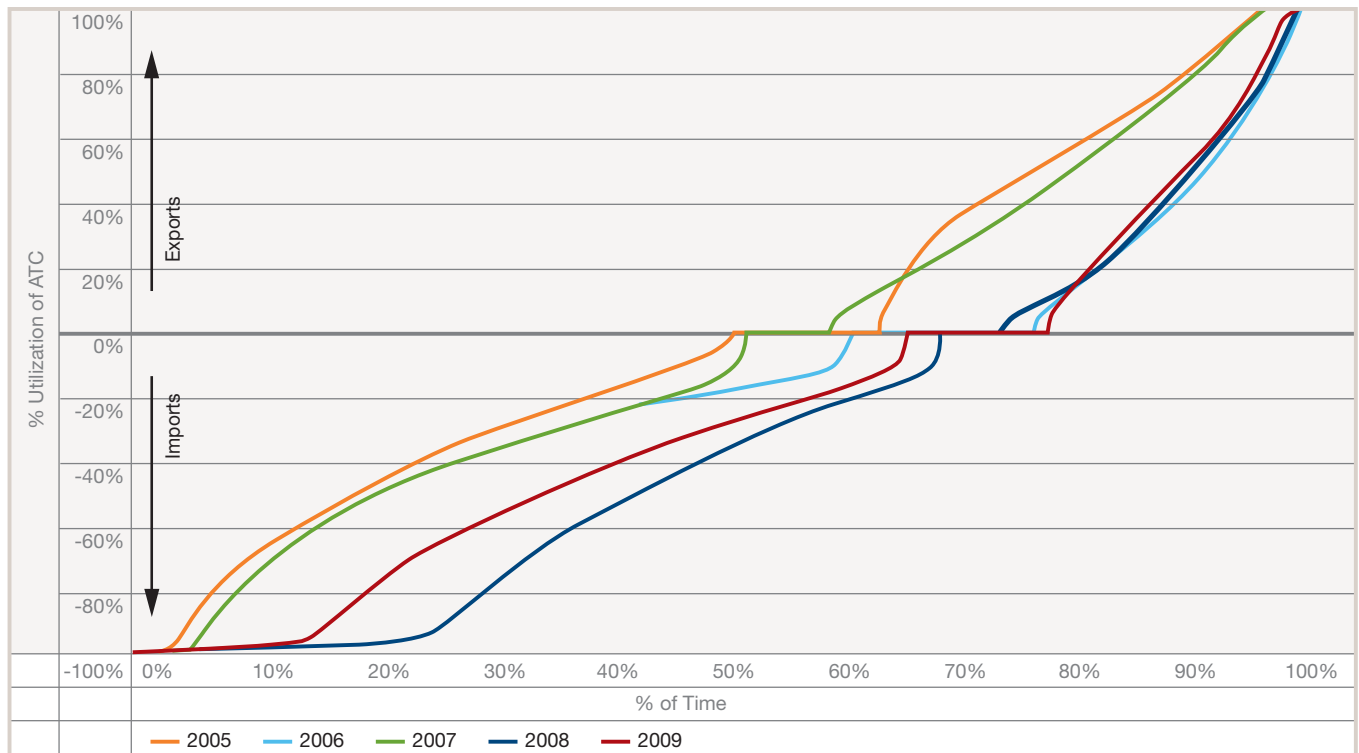
The export utilization is the export amount net of any imports divided by the export ATC;

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

In 2009, there was a decrease 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 9**

**Import-Export Utilization on B.C. Intertie 2005 – 2009**  
**Import Utilization Adjusted to Account for Reserves Provided on the Intertie**



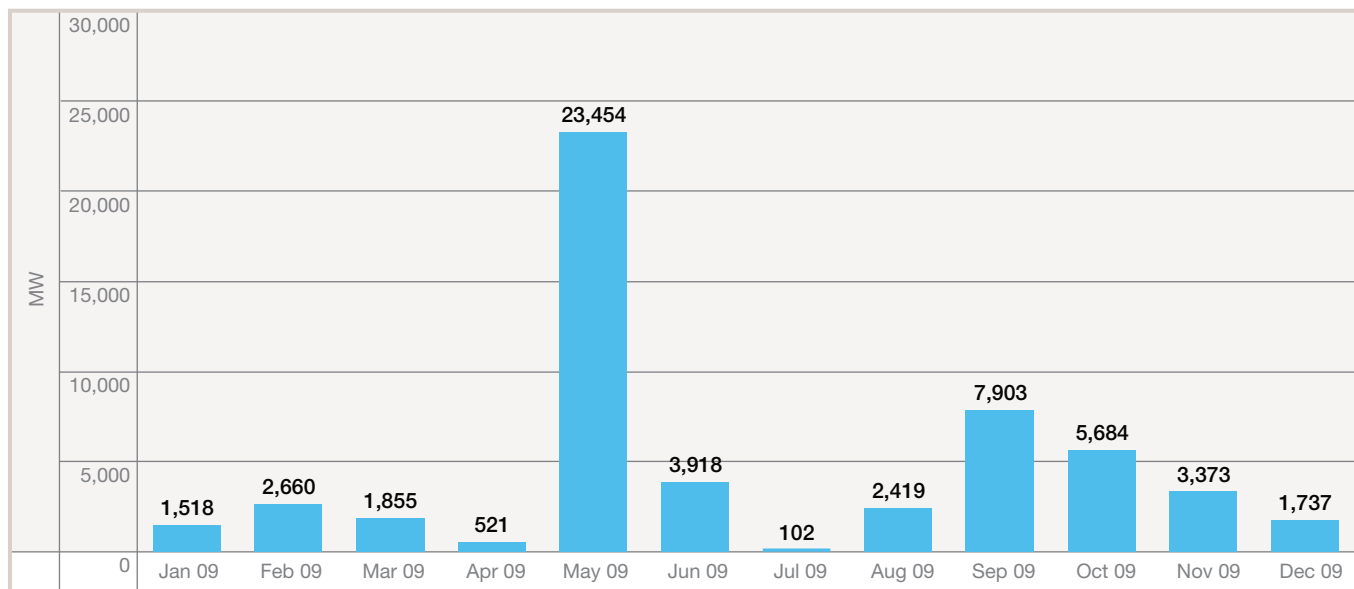
## Constrained Down Generation

In 2009 there was approximately 55.1 GWh of constrained down generation recorded by the system controller. Of the constrained down occurrences approximately 80 per cent involved curtailments to wind generation. Figure 10 displays constrained down generation by month.

There were significant constraints in May due to an outage on 190L from May 11 – 15, where generation was curtailed at Keephills and Genesee. Later in the month there were constraints in the Fort McMurray region and in the KEG area which resulted in further constrained down generation.

**FIGURE 10**

**Monthly Total Constrained Down Generation**



## Dispatch down service (DDS)

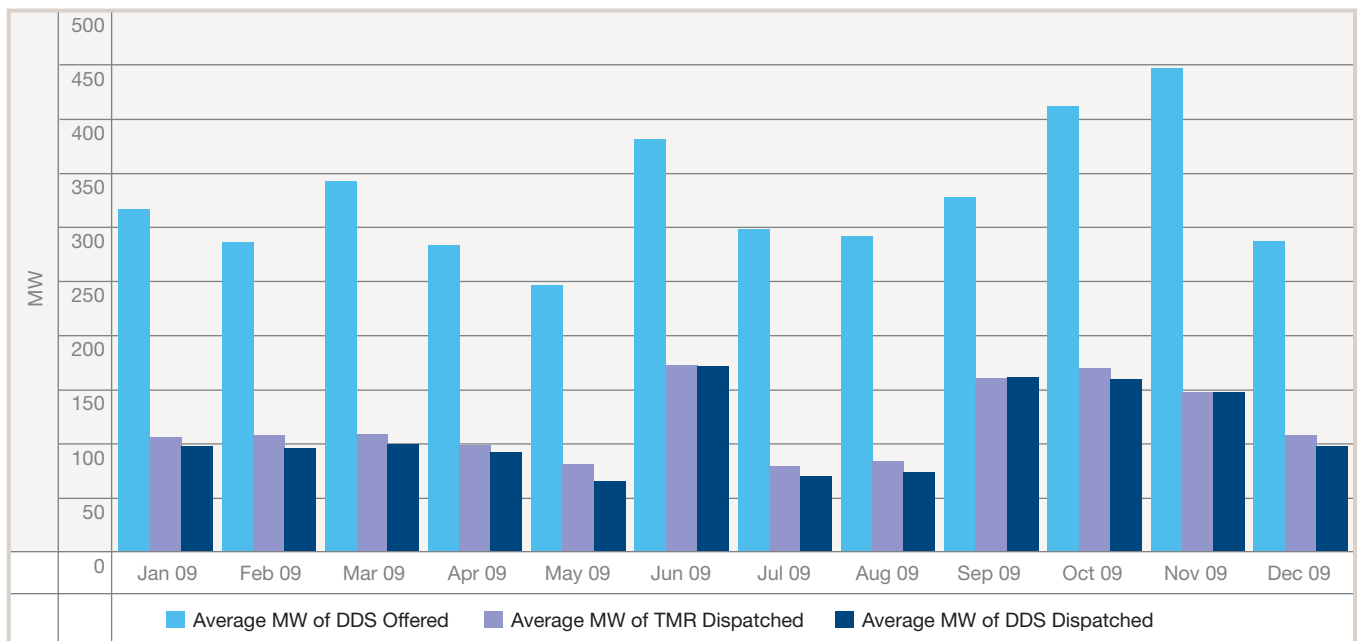
Figure 11 illustrates that DDS is continuing to be used to reconstitute the pool price during times when transmission must run (TMR) is dispatched. There have been sufficient DDS offers in nearly all hours. The month of May 2009 saw the lowest DDS dispatched for the year. This is due to a number of constraints that occurred in the month.

The months of June, September, October, and November saw the highest volumes of DDS dispatched due to outages of the Langdon static VAR compensator (SVC). As per OPP 510, when the SVC is out of service, ENMAX Calgary Energy Centre (CAL1) must be online if it is available. Thus, these months saw high volumes of TMR dispatched, as well as high volumes of DDS to offset the TMR.

DDS payments in 2009 totaled \$13.3 million for 810,326 MWh of DDS dispatched. The total payment for 2009 is 52 per cent lower than that of 2008 (\$27.5 million for 724,921 MWh of DDS dispatched), despite the increase in dispatch volumes. This is primarily due to lower pool prices and lower reference prices in 2009 over 2008.

**FIGURE 11**

**Average DDS Offers and DDS Dispatched Compared to TMR Dispatches**

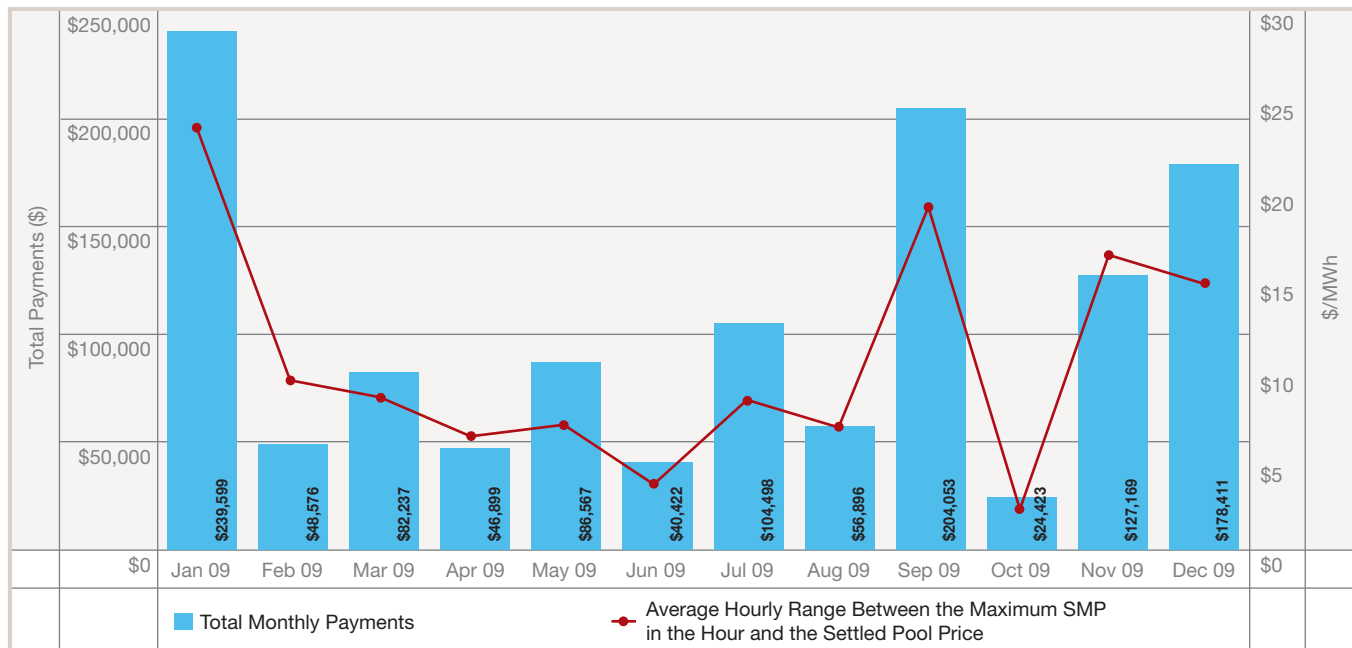


## Payments to suppliers on the margin (PSM)

The second year of the PSM rule saw even lower payments to suppliers on the margin than in 2008. In 2009, uplift payments totaled \$1.2 million, a 65 per cent decrease over the 2008 total of \$3.4 million. Much of this is due to lower overall pool prices, and a low range on average between the pool price and the maximum SMP. As seen in Figure 12, the monthly value of PSM tracks the range between the maximum SMP in the hour and the pool price.

**FIGURE 12**

**Monthly Total Payments to Suppliers on the Margin Compared to the Average Range Between the Maximum SMP and the Settled Pool Price**



## Lower reserve prices track the decline in pool price

The AESO procures operating reserve for the AIES to ensure ongoing reliability of the transmission system. There are three types of operating reserves: regulating reserve, spinning reserve and supplemental reserve. Each type of operating reserve has two products: active and standby.

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. 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 is purchased from either the ancillary services exchange or through over-the-counter contracts. The majority of operating reserve offer prices are indexed to the pool price. During the past five years, there has been a noticeable correlation between pool price and the average price paid for all three types of reserves. In 2009, pool prices decreased 47 per cent over the previous year, and the average price paid for all three reserve types dropped as well. The overall cost including both active and standby cost declined 62 per cent over the previous year. Tables 5 and 6 illustrate this relationship.

**TABLE 5: OPERATING RESERVE COSTS – 2005 TO 2009**

Total Costs (\$)	2005	2006	2007	2008	2009
Active cost	\$ 113,487,713	\$ 172,006,439	\$ 167,651,829	\$ 244,094,240	\$ 89,458,552
Standby premium	\$ 6,445,992	\$ 8,842,956	\$ 11,169,250	\$ 14,204,745	\$ 9,510,486
Standby activation	\$ 4,447,722	\$ 5,031,119	\$ 6,624,174	\$ 11,365,431	\$ 4,576,024
Total Cost	\$ 124,381,427	\$ 185,880,515	\$ 185,445,253	\$ 269,664,416	\$ 103,545,063

**TABLE 6: AVERAGE PRICE/MWH – 2005 TO 2009**

Average price (\$/MWh) rounded	2005	2006	2007	2008	2009
Pool price	\$ 70	\$ 81	\$ 67	\$ 90	\$ 48
Active regulating reserve	\$ 29	\$ 35	\$ 34	\$ 52	\$ 23
Active spinning reserve	\$ 22	\$ 30	\$ 30	\$ 44	\$ 16
Active supplemental reserve	\$ 15	\$ 29	\$ 26	\$ 38	\$ 11

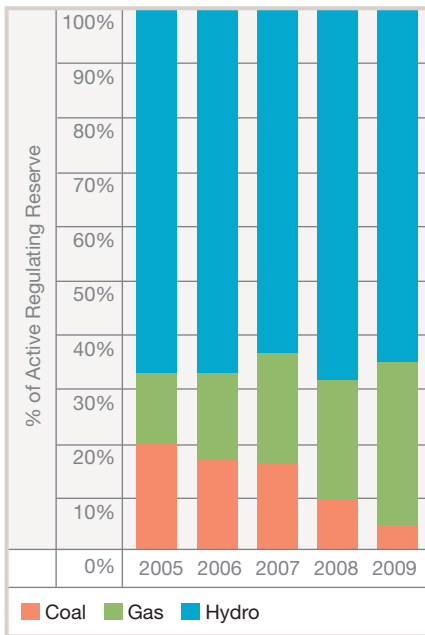
## Market share of reserves continue to be stable

In 2009, nearly 65 per cent of regulating reserve was provided by hydroelectric generators, a decline of five per cent from 2008.

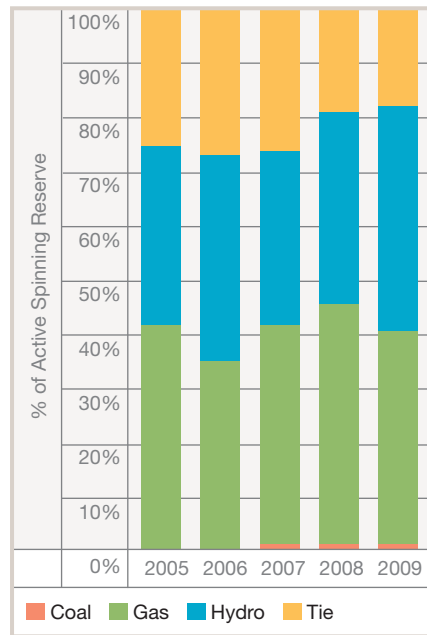
The share of hydroelectric generation in the provision of both spinning and supplemental reserve has increased by seven per cent. Gas-fired generators provided five per cent less spinning reserve, and four per cent less supplemental reserve in 2009 over 2008 levels. Load participates in the supplemental market and over the past four years consistently provided around 10 per cent of the active reserve.

**FIGURE 13**

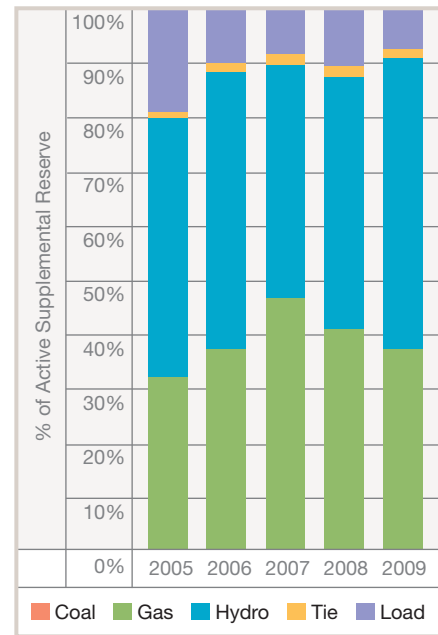
**Market Share of Active Regulating Reserve by Fuel Type**



**Market Share of Active Spinning Reserve by Fuel Type**



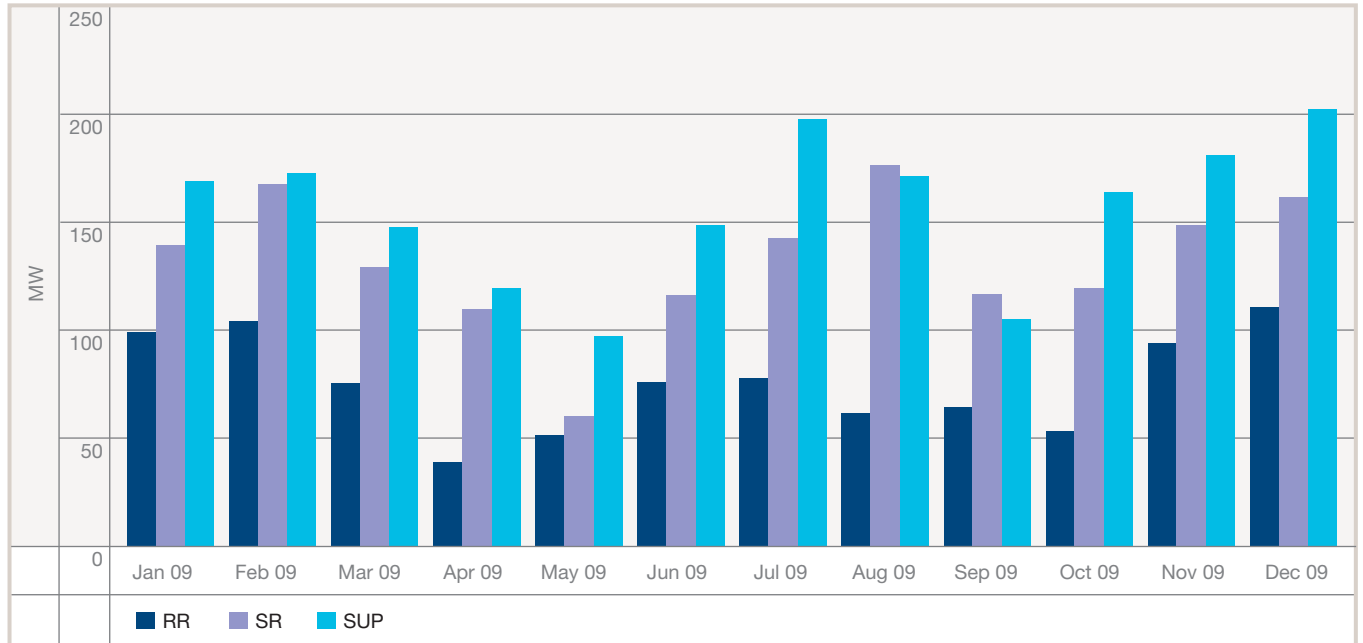
**Market Share of Active Supplemental Reserve by Fuel Type**



Operating reserve market liquidity is measured by comparing the offers and bids for operating reserve products and determining the average MW remaining in the active market. The liquidity measures have indicated that there is sufficient liquidity across all products. As seen in Figure 14, April and May 2009 displayed the lowest level of liquidity, with average MW remaining in the active market below 100 MW for all reserve types.

**FIGURE 14**

**D-1 On-Peak Active Operating Reserve Market Liquidity**  
Daily Average MW Remaining in Active Market



## In summary

---

The following are the key highlights of the Alberta wholesale electricity market in 2009:

- The market saw continued growth in both supply and demand from previous years.
- Lower natural gas prices and coal-fired generation setting the price a high percentage of the time contributed to a decline in the pool price in 2009 compared to 2008.
- In the past five years there has been a noticeable relationship between the price of operating reserve and the pool price. In 2009, there was a 47 per cent decline in pool price over the previous year, and the average price paid for all three types of operating reserve declined as well.
- 2009 saw fewer instances of supply scarcity compared to 2008.
- Growth in power consumption continued the slowdown observed from the previous two years.
- Lower imports and exports on the B.C. and Saskatchewan interties were observed in 2009, and are primarily due to Alberta prices being consistent with those observed in other jurisdictions.



*This report is for general information purposes only. Under no circumstances will the Alberta Electric System Operator, its members, officers, employees, contractors or agents, or any of their respective affiliates, be liable for any errors or omissions in, or any losses, damages or claims whatsoever, whether in contract, tort or otherwise, arising from use of or reliance upon, this report or any information contained herein. Parties using or relying on this report do so solely at their own risk, and all information contained herein should be independently verified.*

[www.aeso.ca](http://www.aeso.ca)

**Alberta Electric System Operator**

2500, 300-5th Avenue SW  
Calgary, Alberta T2P 0L4  
403-539-2450

