Q4/13 Quarterly Report

Oct. – Dec. 2013

January 31, 2014

Wholesale Market

The average pool price in Q4/13 was $48.59/MWh ($61.04/MWh on-peak, $23.73/MWh off-peak), $30.12 lower than in Q4/12.

		2012	2013	*Change*
Avg. Pool Price ($/MWh)	Oct.	91.36	64.56	-29.33%
	Nov.	87.41	28.34	-67.58%
	Dec.	57.62	52.26	-9.30%
	Q4 Total	**78.71**	**48.59**	**-38.27%**
Avg. Load (MW)	Oct.	8544	8639	1.11%
	Nov.	9076	9350	3.02%
	Dec.	9453	9821	3.89%
	Q4 Total	**9024**	**9269**	**2.71%**
Avg. Outage (MW)	Oct.	3343	3195	-4.41%
	Nov.	3310	2475	-25.23%
	Dec.	2482	2190	-11.77%
	Q4 Total	**3042**	**2622**	**-13.82%**
Avg. Supply Cushion (MW)	Oct.	1388	1623	16.93%
	Nov.	1183	1715	44.97%
	Dec.	1643	1592	-3.10%
	Q4 Total	**1407**	**1643**	**16.77%**

During this quarter, there was no week with an average pool price greater than $100/MWh. There were four weeks with an observed average pool price below $30/MWh (the highlighted area in the next figure). The relatively low price was a result of ample supply cushion, despite the fact that average load increased 2.71% over Q4, 2012. Of interest, the quarter had more than 400 hours with a load greater than 10000 MW and 55 hours with a load greater than 10609 MW, the previous record in 2012.

In comparison to 2012, average wind speeds measured at Lethbridge and average wind generation were substantially higher in 2013, which is shown in the next table. From 2012 to 2013, the major newly added wind capacity was the 150MW Halkirk wind power facility.

	Wind Speed (km/h)		Wind Generation (MWh)	
Year	2012	2013	2012	2013
October	19.41	23.90	289	371
November	19.30	26.38	345	448
December	17.94	32.23	396	460

October

By late September both the SD1 and SD2 had returned from their long outages and increased supply by approximately 560 MW. This in combination with high winds, SD3, 4, 5 and 6 with their minimum stable generation point equal to their available capacity combined to keep prices low.

November

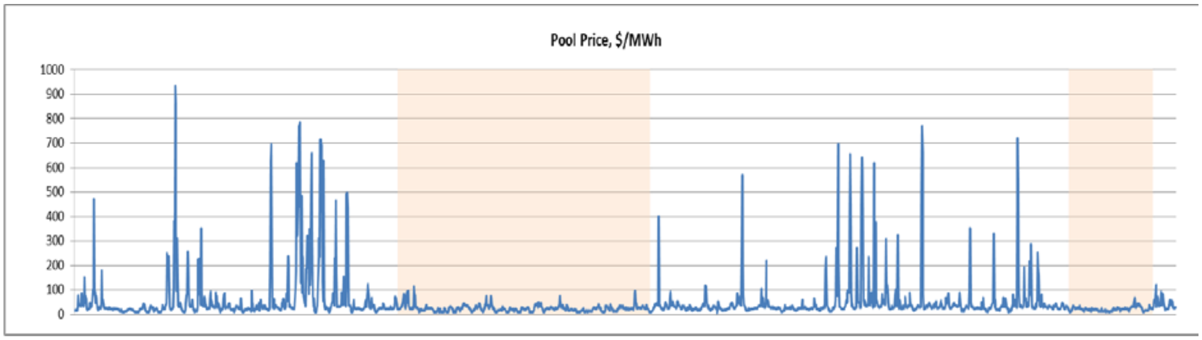
While the average load in November was 274 MW higher than the previous year, both a reduction in outages in part due to the return of SD1 and SD2 as well as increased wind generation contributed to a supply cushion that averaged over 1700 MW. High levels of supply typically mean reduced pool prices and in November 2013 pool price fell by 68% over the same period of last year.

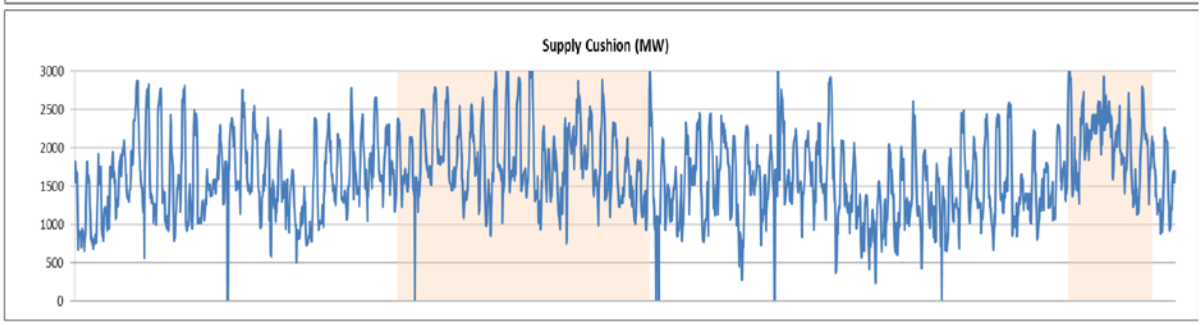
December

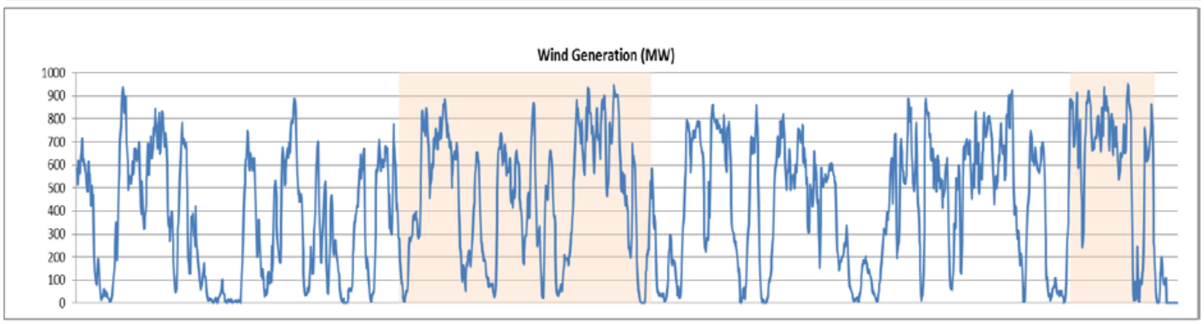
The load flirted with historical highs in December with the average load more than 370 MW higher than the previous December and the peak milestone climbed to 11139 MW at HE 18, Dec. 2, 530 MW more than the last year's high of 10609 MW in Jan. 16, 2012.

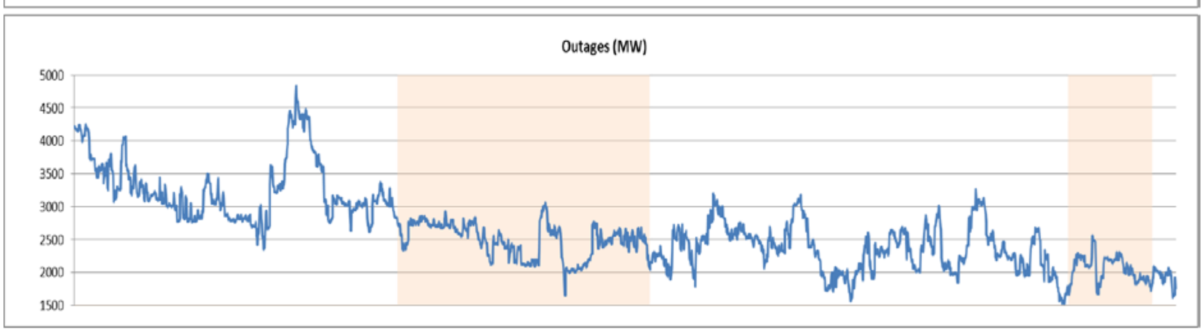
The total energy demand for December was 7,307 GWh in comparison to a December 2012 energy demand of 7,033 GWh was 3.7% higher in 2013.

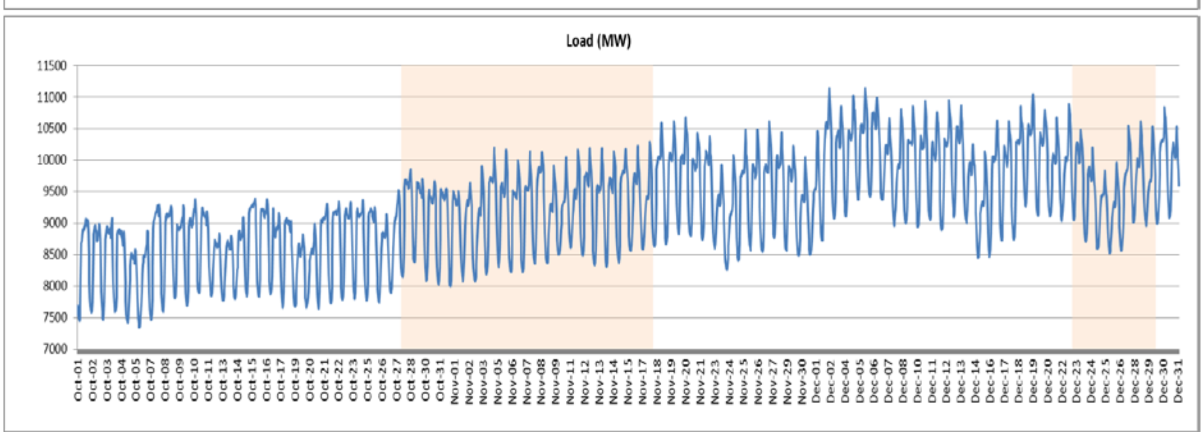
The following chart presents the hourly pool price, supply cushion, wind generation, generator outage and load from Oct. 1 to Dec. 31, 2013.


Pool Price, $/MWh
1000
900
800
700
600
500
400
300
200
100
0


Supply Cushion (MW)
3000
2500
2000
1500
1000
500
0


Wind Generation (MW)
1000
900
800
700
600
500
400
300
200
100
0


Outages (MW)
5000
4500
4000
3500
3000
2500
2000
1500


Load (MW)
11500
11000
10500
10000
9500
9000
8500
8000
7500
7000

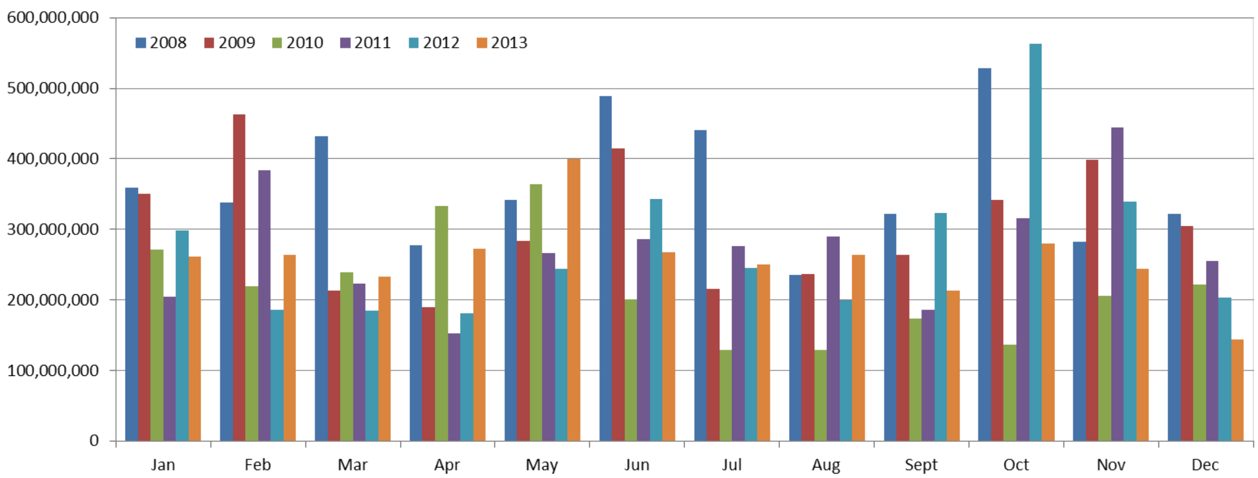
Wholesale Forwards

Trading Activity

The Q4/13 continued to observe a deep plummet in total traded MWh: there were approximately 11 TWh of forward trades, which was 38.06% lower than in Q4/12. All three months experienced a drop in liquidity over the same period of the previous year.

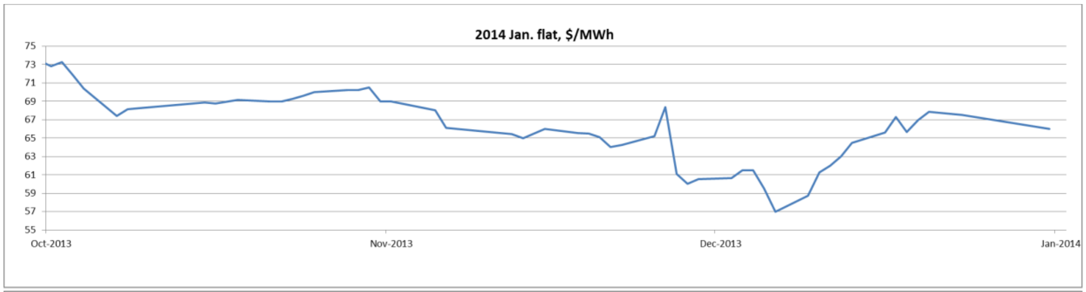
	TWh Traded		
	2012	2013	*% Change*
Oct.	9.56	4.75	-50.27%
Nov.	5.64	4.19	-25.69%
Dec.	3.30	2.51	-23.87%
Q4 Total	**18.50**	**11.46**	**-38.06%**

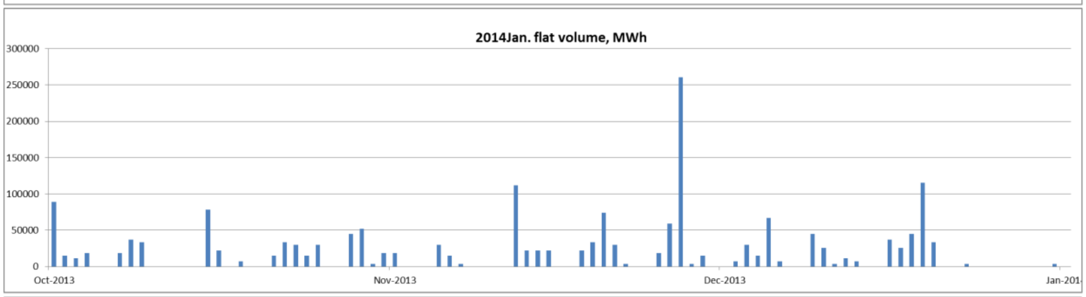
Recently we are seeing forward volumes dropping. The next figure plots monthly forward volumes from Jan. 2008 to Dec. 2013. The recent drop may be due to lower forward prices signalling less opportunity in the forward market to profit. But we welcome comments by others on the reasons for the falling liquidity.

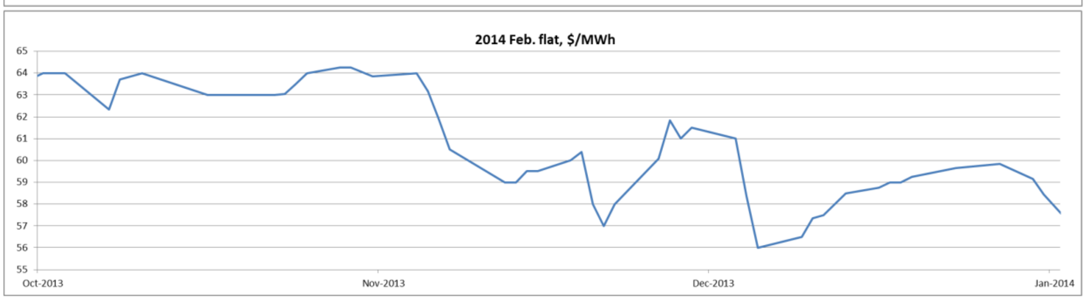


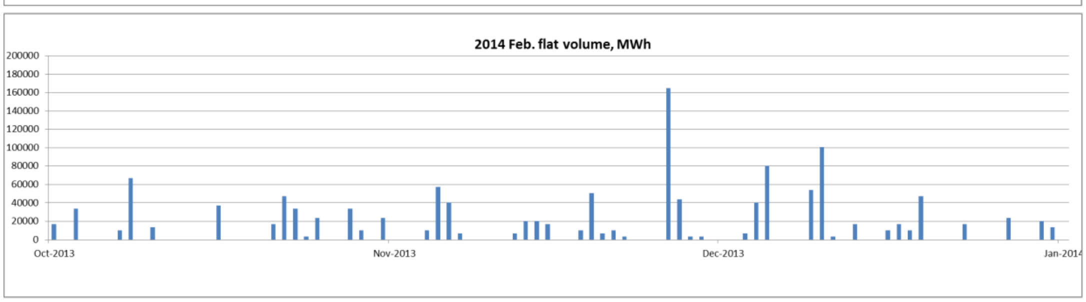
The price drop in late November for the January contract was due to the cancellation of a coal unit that was planned out for all of January 2014. On December 12 another coal unit outage was added to the outage chart for the first 15 days of January 2014.

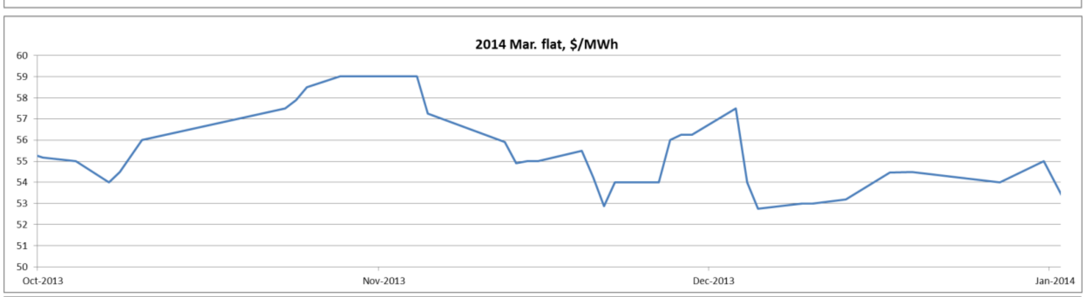
In early December forward prices for January, February and March fell, in reflection of the fact that while winter peak demand had reached 11,139 MW, the supply cushion was still 1592 MW. The high supply cushion is a reflection of the return of SD1 and SD2 plus winter winds. This seems to be an example of the effect of spot price on forward prices.

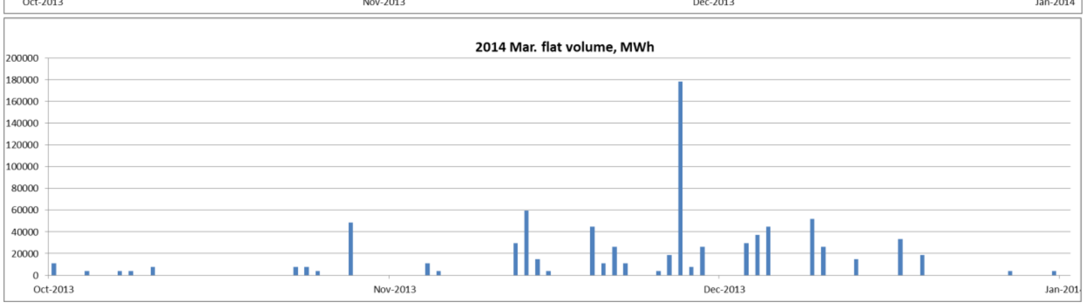

2014 Jan. flat, $/MWh
75
73
71
69
67
65
63
61
59
57
55
Oct-2013
Nov-2013
Dec-2013
Jan-2014


2014Jan. flat volume, MWh
300000
250000
200000
150000
100000
50000
0
Oct-2013
Nov-2013
Dec-2013


2014 Feb. flat, $/MWh
65
64
63
62
61
60
59
58
57
56
55
Oct-2013
Nov-2013
Dec-2013
Jan-2014


2014 Feb. flat volume, MWh
200000
180000
160000
140000
120000
100000
80000
60000
40000
20000
0
Oct-2013
Nov-2013
Dec-2013


2014 Mar. flat, $/MWh
60
59
58
57
56
55
54
53
52
51
50
Oct-2013
Nov-2013
Dec-2013
Jan-2014


2014 Mar. flat volume, MWh
200000
180000
160000
140000
120000
100000
80000
60000
40000
20000
0
Oct-2013
Nov-2013
Dec-2013

Constrained Down Generation and the Cost of Congestion

Background

In its April 5, 2013 Decision on Real Time Transmission Constraint Management[1] the AUC came to the conclusion that:
the AESO's single clearing price for energy in Alberta is intended to be established by the intersection of the unconstrained supply curve and the demand curve for energy as reflected through the EMMO.[2]

As a consequence, Constrained Down Generation (CDG)[3] might cause a distortion as higher priced energy downstream of a constraint is dispatched up to ensure generation matches load and used to set the pool price. The AUC directed that ISO rules be changed in accordance with the following:

(1) include the principles of the RTMR proposal outlined in paragraph 191 in the EMMO/pro-rata mechanism;
(2) increase the use of TMR in conjunction with DDS in an effort to minimize price distortion in the market, particularly to address foreseen occurrences of congestion;
(3) monitor and report the cost of using the TCM Rule on at least an annual basis;

In this section we report on the amount of congestion in the past two years and its impact upon pool price and its associated cost.

Transmission Must Run (TMR) and Constrained Down Generation

While the AESO plans and directs the operation of the Alberta transmission system to minimize congestion there are always occasions when forced and planned transmission outages cause congestion, albeit infrequently. When generation is prevented from reaching the market due to transmission constraints it is necessary for the AESO to reduce output above the "bottleneck", typically called "Constrained Down Generation" (CDG) and in turn increase generation downstream of the bottleneck to ensure that generation matches load.

The AESO has two mechanisms to manage this congestion.[4] The first is a combination of Transmission Must Run (TMR) and Dispatch Down Service (DDS) to address transmission constraints by directing generators to constrain on and constrain off. This is typically used by the AESO where the constraint is small or it is necessary to raise generation in a bottlenecked area. At its simplest, the mechanism will not cause a distortion in pool price if there are matching amounts of constrained on (above the pool price) and constrained off generation (below the pool price). A distortion may occur if the existence of TMR and DDS causes market participants to alter offer behaviour from what would have been the case absent the constraint. Further, no DDS is used when the system marginal price is above the TMR "reference

[1] ISO Rule 302.1.
[2] AUC Decision 2013-135, para 148.
[3] Constrained Down Generation is the MW difference of a generating unit between the lower directed MW output and the in merit MW output, as a result of a direct by the system controller.
[4] This does not include transmission congestion that causes a reduction in imports. It has been discussed previously in Q2 2011 report.

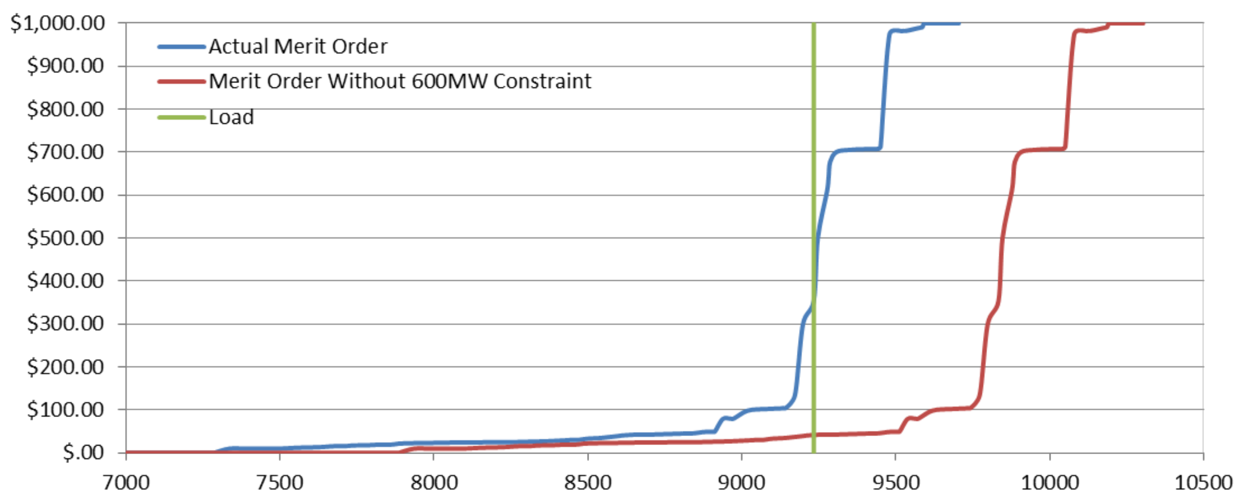
price".[5] The payments for generators constrained on by TMR are either based on contract or for unforeseen TMR based on Article 11 of the AESO tariff. The costs of TMR are paid by load customers. The costs associated with DDS are paid for by generators providing electric energy during that settlement interval. Both costs for TMR and DDS are costs over and above what would have occurred in an unconstrained system.

The second mechanism available to the AESO is CDG. In merit generation upstream of a bottleneck is directed to a lower MW output to ensure the relevant transmission line is not overloaded. Transmission congestion may be the result of

- Insufficient transmission capacity with all elements in service, too much generation not enough transmission, presently a rare event in Alberta.
- Due to planned and/or forced outages restricting transmission capability or
- Reliability constraints

Unlike the TMR/DDS mechanism, when generation is constrained down replacement energy is found from the merit order, which results in a higher pool price than would have been the case with an unconstrained supply curve. This is illustrated in the Figure 1 below, where with an unconstrained supply curve the SMP would have been $42.41/MWh. However, due to 600 MW constrained down generation, the offer curve shifts left 600 MW, resulting a SMP at $353.69/MWh.

Figure 1 - Illustration of CDG's Impact on Pool Price



The costs of CDG will derive from higher pool price and any subsequent impact on forward prices. There may also be transfers between market participants, with some generators unable to run due to the constraint.

The two mechanisms for dealing with congestion can also interact. In undertaking these calculations the MSA at times observe hours where both CDG and TMR is implemented.

[5] Reference price is the price in $/MWh that is calculated and determined by the ISO in accordance with Rule 201.6.

Identification of CDG in 2012 and 2013

Identifying the amount of CDG and its source is not a simple exercise using the AESO's current systems. While the AESO does track CDG, it is primarily though manual entry by the system operators. The manual entry system also does not record which units were constrained or the cause. Isolating the cause of congestion is interesting in that it may shed light on the nature of constraints both now and in the future. To determine the likely cause of the constraint the MSA consulted operators' shift logs and manually matched that to the constrained down MW that had been recorded elsewhere. While the shift logs record the initiating event they do not record the end of the event. It was necessary at times to manually review the data to isolate overlapping events. We performed the above procedure for both years 2012 and 2013. While not precise it does provide what we feel is a representative answer of both the constraints and their magnitude.

The Figure 2 plots the CDG in MWh by constraints and years. In 2012 there were 160 GWh with 14% of hours impacted (1241 hours). In 2013 there appears to have been less congestion, 126 GWh with 19 % of hours impacted (1678 hours). So while there has been less CDG volume in 2013 the number of hours has increased. What this means is simply that in 2012 for example there was 160 GWh of in-merit generation that could not be delivered to the market due to transmission congestion. In comparison to the total Alberta load of roughly 65 TWh (excluding behind-the-fence load) the actual congestion in terms of volume in 2012 and 2013 is roughly 0.2%, a very small number. In other words roughly 99.8% of all MWh that were economic were delivered to the market.[6] Our numbers compare well to the AESO's as we calculated 160 GWh of congestion in 2012 versus their published 164 GWh for 2012.[7] If we sum the calculated congestion of the Leismer, Fort McMurray and Ruth Lake Cutplanes we find 97 GWh of congestion versus the 98 GWh at Fort McMurray published by the AESO.

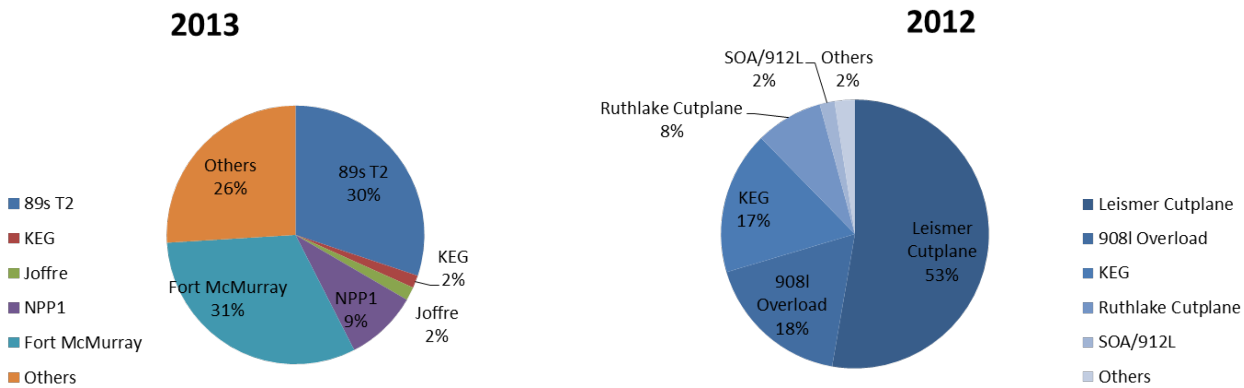
In 2012, the constraint due to the Leismer cutplane, 908L overload and KEG [8] accounted for about 88% percent of total CDG. The 2013 constraints due to 89s T2 and Fort McMurray accounted for about 61% of total CDG. The constraints at 89sT2 appear to have been due to a transformer at Ellerslie that was taken out of service and bottled KEG generation over a few days in April, May and June due to the construction of the Heartland Project.

[6] The Transmission Regulation Standard is actually 95%.

[7] See http://www.aeso.ca/downloads/AESO_24-Month_Reliability_Outlook_2013-2014_FINAL.pdf . Our number is slightly smaller due to the removal of some small hours with incomplete data in the analysis.

[8] One might consider the 908L and KEG as cut from the same cloth as both constraints reduced generation in the Keephills-Ellerslie-Genesse (KEG) area.

Figure 2: CDG in MWh by Constraints, 2013 Total 126 GWh, 2012 Total 160 GWh



Cost of CDG

To assess the CDG's impact on pool price versus an unconstrained transmission system, we determined the theoretical 'unconstrained' system marginal price (SMP) by matching the CDG MW data with the energy merit order at the middle of each hour. The unconstrained SMP is the offer price of the last dispatched MW by moving the offer curve right by the amount of CDG MW. Essentially, it is a reverse procedure of the aforementioned illustration in Figure 1. This method does not incorporate how the market may respond to congestion. Factors like the actions of price responsive loads or increased imports might moderate the impact of CDG on pool price. The presence of CDG may also increase economic withholding by some market participants that find they have increased market power as a result of the constraint.

After calculating the unconstrained SMP, we estimate the impact of the constraint as the difference between the actual SMP minus the unconstrained SMP multiplied by the load in the Alberta Interconnected Electric System in a given hour.[9] One can say that this is not entirely accurate as certain loads in the hour may have purchased forward contracts. However, expectations of congestion that increases pool price will feed through to forward prices. The number calculated is not precise but representative of the cost caused by congestion. It is a simplistic analysis in that:

1. It does not factor in the impact on price responsive load that directionally should mitigate some of the price impact as load would have consumed. At the same time that potential consuming load isn't accounted for in the cost calculation.
2. It does not factor in the potential impact of imports that potentially could respond to pool price, and directionally lower the impact.
3. CDG is added back into the merit order at $0/MWh and thus does not account for CDG generation that was offered at higher prices and would influence the final calculated price effect, reducing the impact.
4. The calculation does not account for roughly 500 MW of Operating Reserve that would attract a cost as it is typically priced as a discount to pool price, which makes the calculation conservative.
5. The analysis used the 30 minute SMP and merit order to discern the price impact of CDG but was then applied to the hourly price. At times when pool price was lower than the SMP the impact was larger than it should be and vice versa. The impact was limited in both cases by using the largest potential impact as the pool price.

[9] AIES load is used rather than Alberta Internal Load since the former does not include behind-the-fence generation.

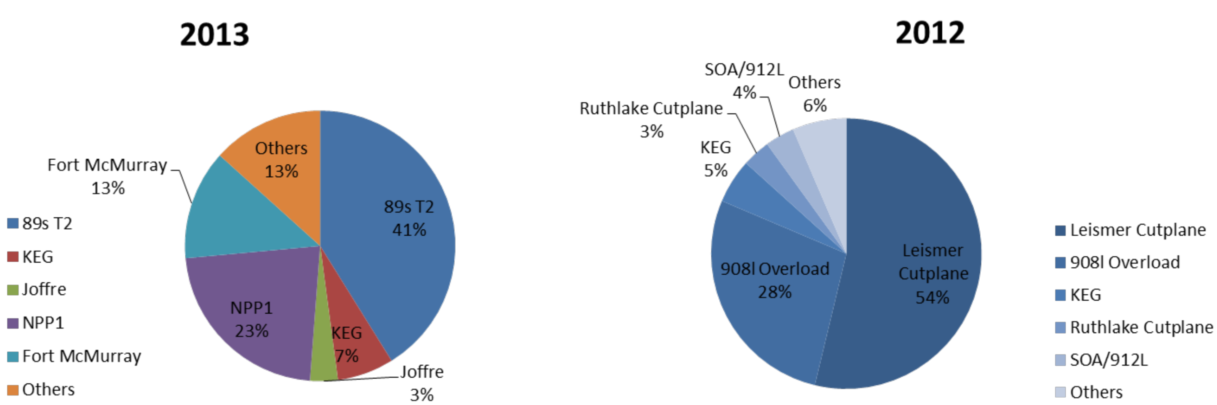
6. While TMR and CDG are discreet events, they sometimes occur in the same hour and their price impact is directionally opposite in that TMR tends to lower pool price while CDG raises pool price. As a sensitivity analysis these MW effects are combined to determine the price impact of the combination. The pool price is lower but not substantially so and we have provided those results in the next table.

	Average Annual Pool Price, $/MWh[10]	Unconstrained Pool Price without CDG, $/MWh	Unconstrained Pool Price without CDG/TMR, $/MWh	Cost due to CDG, Million Dollar	Cost due to CDG/TMR, Million Dollar
2012	64.31	60.99	61.44	210	180
2013	80.19	75.00	75.07	323	318

What we found is that:

- The price impact of CDG is not evenly distributed; some CDG events have a substantially higher price impact than others. For example, in 2013, KEG accounted for only 2% of all CDG MWh while it was responsible 7% of the total cost. In 2012, the cost due to the Leismer cutplane and the 908L overload constraint accounted for 82% of the total cost. In 2013, the cost due to the 89s T2 constraint for construction of the Heartland project alone accounted for 41% of the total,, approximately $132 million.[11]
- Small levels of congestion may have little to no price effect as the offer curve shows little change in small steps. For example moving 20 MW along the offer curve may typically show only pennies of price change.
- When comparing the relative congestion at 0.2% of total load in 2013 the impact in terms of cost was close to 5%.

Figure 3 CDG's Impact on Cost by Constraints, 2013 Total $323M, 2012 Total $210M



[10] The number can be slightly different with other sources due to the missing of some hours in the analysis.
[11] The named constraints are based on the AESO's system controller logs. For example Keg and 89sT2 are effectively both the same constraint, but we have not attempted to simplify the outcome. [make clear what you mean]

Conclusion

The intent of the pool price in Alberta is to be generally reflective of an unconstrained system. In 2013, 126 GWh of congestion or 0.2% is reflective of a system that is 99.8% uncongested by volume. But the present derivation of the pool price is based upon the price of the highest downstream generator dispatched and thus can amplify the relatively small impact of congestion on loads. The pool price is paid by all loads both upstream and downstream of the constraint. For example in 2013 while congestion by volume is only 0.2%, the price impact on loads was over 5% of their total energy payment, the pool price itself was approximately $5 higher than it otherwise would have been.[12]

We do not claim this analysis on price outcomes to be complete due to the competing effects but we do believe that it is in the right order of magnitude in terms of cost.

While there are a considerable number of hours where CDG may be occurring, in 2012 over 14%, in many of those hours the actual CDG amount is small and has little impact on the total dollar cost of CDG itself. For example in the two years there were 928 events with a CDG of less than 20 MW, 32% of total CDG events but accounted for only 12% of the pool price impact.

We have found that the congestion that is impacting pool price is typically focused in a few very discreet events caused by planned or forced outages to transmission elements rather than a continual small amount of congestion. In 2012 and 2013 there are 430 events with CDG greater than 200 MW, 15% of all events, yet they produce 57% of the price effect across the two years.

As well CDG events tend to cluster in the spring and fall months, likely due to those months being both the major transmission planned outage period and major generator outage window. Close to 79% of all the CDG MWh in these two years occurred in the March through May and September through November period accounting for 82% of the price effect across the two years.

In a way the CDG effect on price is a misfortune of circumstances. If CDG simply occurred in periods of high supply cushion the impact both on price and its cost would be small and this issue would likely not be under discussion. But the simple fact of having an abbreviated outage season both for generation and transmission tends to make the supply cushion tight in times of CDG which 'amplifies' the price effect due to the congruence of events on the system.

[12] We have not reviewed other possible market mechanisms to deal with the impacts of CDG and there should be recognition that there would be costs associated with those mechanisms.

The Performance of MATL and Allocation of Available Transmission Capacity (ATC)

The MATL has been on commercial operation since Sept. 18, 2013. Until Dec. 31, 2013, the MATL had imported (exported) a total of 128,483 MWh (2369 MWh), which represents an hourly average import (export) of about 50 MWh (0.9 MWh). In contrast, during the same period, the total import (export) ATC was 189 MW (220 MW). The next table[13] presents the average import ATC by curtailment reasons and its associated number of hours. Among the total 2521 hours in the Quarter, 1431 hours observed a curtailment due to the MATL series compensation out-of-service,[14] resulting in an average ATC of 233 MW at these hours. There have been two Market Participants using MATL.

MATL Import ATC by Curtailment Reasons

	Average ATC	Hours
MALT Series Compensation out-of-service	233	1431
System Normal	295	456
MATL Outage	0	338
1201L and other TX outages	15	49
Alberta Reliability and ISO Rule Constraints15	28	28
Others	60	244
Grand Total	189	2521

ISO Rule 203.6 - Available Transfer Capacity and Transfer Path Management - sets out the requirements and protocols for allocation of ATC among transfer paths, and curtailing interchange transactions to alleviate constraints identified across transfer paths.

Generally, the rule has achieved its objective. However, the MSA also noticed there are some hours where the ATC was not efficiently allocated between the MATL and BC lines, i.e., one path was allocated more ATC than it can actually flow due to external transmission limits. Consider a hypothetical example and assume at one hour, the total ATC at T-2 on BC\MATL was 600 MW. The MATL and BC offered 300 and 600 MW respectively. By the ISO Rule, the MATL and BC were allocated 200 and 400 MW at T-2. Due to a transmission constraint on the Montana side, the MATL was only capable of transferring 100 MW at real time. As a result, 100 MW ATC allocated to MATL were not utilized while the BC path wanted more ATC.

To address the issue requires that the AESO look into neighbouring jurisdictions in real time and on a forward basis. Currently the AESO does not account for the BC or Montana external transmission limit unless the limit is the binding constraint on transfer capacity. However, the MSA notices that recently the AESO has done so in some hours by taking account of MATL Series Compensation into the ATC allocation process. It is our understanding that this Series Compensation scheme is in Montana. In a

[13] The original data of this table can be found at the *Historical Intertie Capability Report* of the AESO's website.

[14] Our understanding is the series compensation is to increase the capability of the Transmission line to transmit power. In the case of MATL the series compensation facilities are in Montana

[15] Mainly ISO Rule 302.1 due to 911L outage.

recently updated Information Document,[16] the AESO determined the Alberta-Montana transfer path import total transfer capability at the Alberta-Montana border is in the range of 256 MW to 267 MW depending on Alberta internal load.

The MSA is actively watching this process and will update the market once it has more data to assess the magnitude and impact. Presently this has been a rare occurrence.

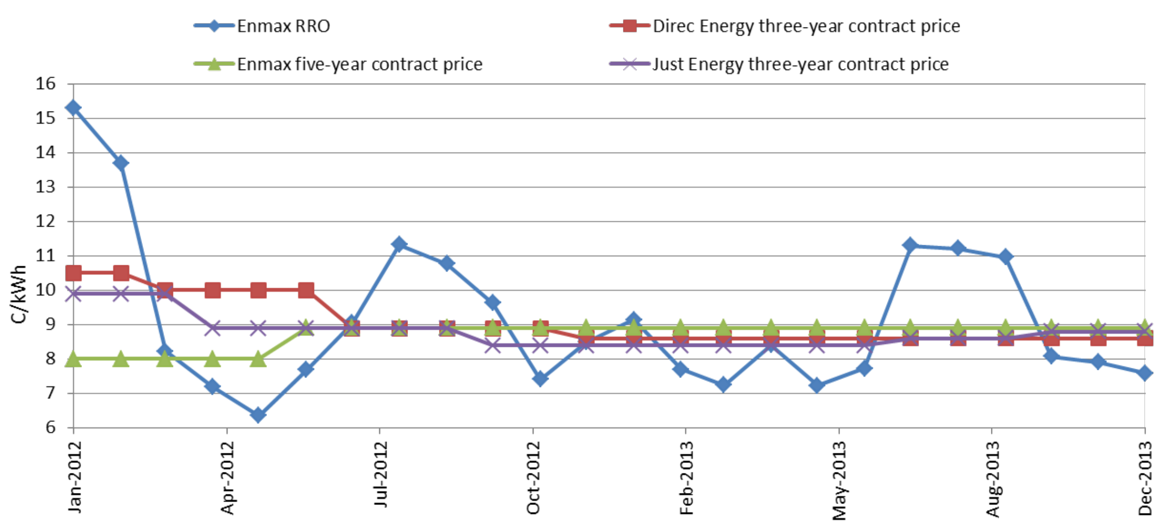
[16] http://www.aeso.ca/downloads/Updated_ID_2011-001R_Available_Transfer_Capability_and_Transfer_Path_Management_to_be_posted_to_AESO_Website.pdf.

Retail Rates for Electricity and Natural Gas

Alberta consumers can choose competitive contracts or to stay on default rate for electricity and natural gas. Over the past years, switching from the regulated rate in both electricity and natural gas for residential customers has gradually increased. At the end of November 2013, the switching rates for both electricity and natural gas were at about 43%. This means that 43% of customers are on competitive contracts of some form for both electricity and natural gas.

Though many factors can influence the decision in switching away from the default rate, price is an important consideration. The next figure compares the default and competitive electricity rates for 2012 and 2013. As the default rates vary only slightly across different providers, the ENMAX RRO rate is chosen as the benchmark default rate. The figure also includes long-term competitive fixed-price rates for ENMAX, Direct and Just Energy, the three largest mass market retailers in Alberta. During this two-year period, the average ENMAX RRO rate was 9.14 c/kWh. There was a fair spread in the competitive contract rates in early 2012 but the rates since then have been quite tightly grouped around 9 c/kWh. By design, the default rate changes from month to month. The volatility of default rate means in some months it was lower than the competitive rates and in others it was higher.

Default and Competitive Rates: Electricity[17]

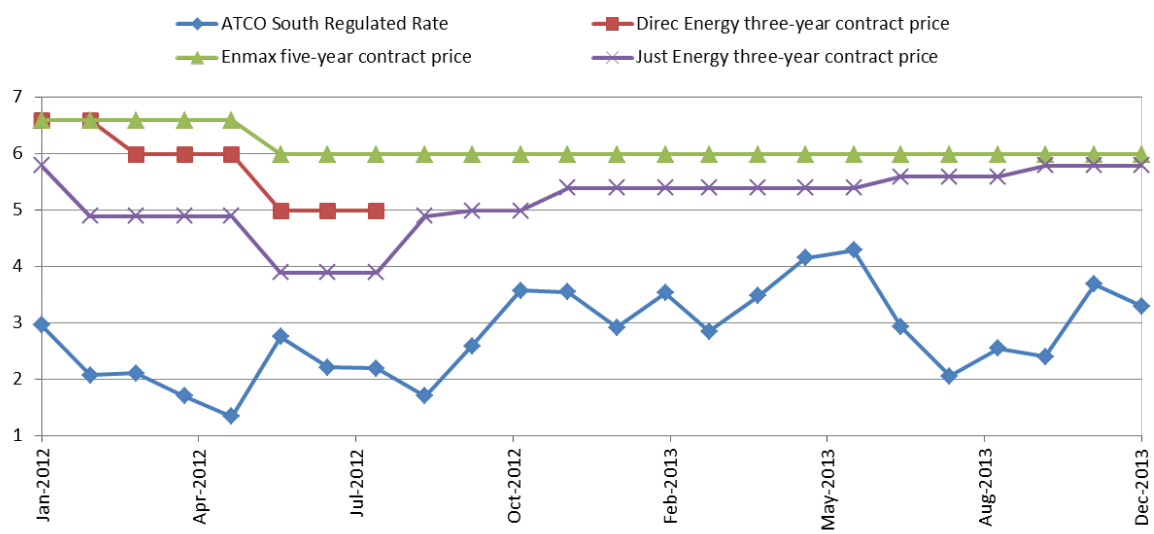


Similarly, the next figure shows the natural gas default rate versus competitive rates[18]. ATCO South is chosen as the benchmark default rate. As for default electricity, the price changes each month. The competitive residential natural gas providers are the same three firms that provide electricity. Over the period, the average natural gas default rate was $2.78/GJ which is below all of the competitive rates in all months. One of the main reasons for this is the mechanism that sets the natural gas default rates. Essentially, the final price is set at a rate that is very low and does not include some of the cost elements that face a competitive retailer, such as customer acquisition.

[17] All of the data can be found at Utilities Consumers Advocate, http://www.ucahelps.alberta.ca/historic-rates.aspx.

[18] Since Sept. 2012, Direct Energy stopped offering natural gas at a fixed rate, but a flex through option.

Default and Competitive Rates: Natural Gas



Since the natural gas competitive rates seem to be higher than the default rates, why do consumers switch away from the default rate? Firstly, some consumers are quite prepared to pay a premium to remove the uncertainty of the changes in monthly prices that exist in the default rates. Also, for some time the competitive offerings have included floating rates and the MSA is of the view that possibly a significant portion of consumers on competitive natural gas contracts are on them. The MSA will be requesting data from competitive retailers on this and other items in the near future. In February we hope to publish a report on switching rates, market shares and other items of interest in the retail area.

Retail Market Review Committee (RMRC) - Implementation

The MSA is an active member on three of the sub-committees formed to assist the MLA committee in its implementation of the RMRC report recommendations. In particular, the MSA is undertaking a survey of Alberta consumers with a view to estimating the effects of co-branding on consumer choices when deciding whether to switch and to which company for electricity and natural gas. Combined with information on regional switching rates and market shares, we believe this will assist the sub-committee in considering various options to deal with co-branding in the Alberta retail market.

MSA Activities and Releases

Market reporting

MSA 2013 Third Quarter Report (11/20/13) - Page 20 Graph Updated

MSA 2013 Third Quarter Report (11/20/13)

Presentations

"No Market is an Island Entire of Itself" - MSA Speaking Notes for the 14th Annual Alberta Power Summit (11/13/13)

Consultations

Notice re Market Harm Draft Comments (12/19/13)

Notice re Framework for the Assessment of Market Harm - Draft (11/07/13)

Notice re MSA Stakeholder Meeting - Looking Back, Looking Forward (10/04/13)

Other

Notice RFP to Design and Conduct a Customer Survey (12/13/13)

Notice re MSA 2014 Budget (12/10/13)

Notice re Market Statistics - Amendment (11/07/13)

Notice re Retail Market Statistics (10/31/13)

October 2013 Market Surveillance Administrator (MSA) Newsletter (10/22/13)