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DECISIONS

REGULATORY
LAW CHAMBERS

ENERGY REGULATORY REPORT

Regulatory Law Chambers *is a Calgary-based energy boutique law firm dedicated to excellence in energy regulatory matters. We have expertise in oil and gas, electricity, renewable energies, climate change, tolls and tariff, commercial electricity, compliance and environmental related matters. We frequently represent clients in proceedings before the Alberta Energy Regulator ("AER"), the Alberta Utilities Commission ("AUC"), the National Energy Board ("NEB") and the Courts, and in energy related arbitrations and mediations.* ***Our advice is practical and strategic. Our advocacy is effective.***

This monthly report summarizes matters under the jurisdiction of the AER, the AUC and the NEB and proceedings resulting from AER, AUC and NEB decisions. For further information, please contact Rosa Twyman at Rosa.Twyman@RLChambers.ca or 403-930-7991 or Vincent Light at Vincent.Light@RLChambers.ca or 403-930-7994.

IN THIS ISSUE:

ALBERTA ENERGY REGULATOR

Play Based Regulation Pilot Project Extended (AER Bulletin 2014-35)
AER Bulletin – Play-Based Regulation Pilot Project Extended

The AER has extended its Play-Based Regulation Pilot Project established under Manual 009: *Play-Based Regulation Pilot Application Guide*, to allow sufficient time for oil and gas operators in the pilot area (North of Edson, Alberta) sufficient time to prepare applications and solicit feedback through stakeholder engagement.

The deadline has been extended to March 31, 2015, and the project will end on June 30, 2015.

Temporary Surface Water Pipelines for the Energy Resource Industry (AER Bulletin 2014-38)
AER Bulletin – Temporary Surface Water Pipelines

The AER released Bulletin 2014-38 to reiterate and clarify existing rules for temporary surface pipelines such as lay-flat polyurethane hose, polypropylene hose, and aluminum irrigation pipe for transferring water for energy resource development. The Bulletin notes that these surface water pipelines do not need a pipeline licence, provided that they comply with the rules under section 3(3) of the *Pipeline Rules*. The Bulletin also states that, while pipeline licences may not be required, the following approvals may be necessary for temporary surface water pipelines:

- Landowner consent is required to place temporary pipelines on privately owned lands;
- Consent is required from occupants on public land, before applying for an authorization under the *Public Lands Act*; and
- Approvals may be required from other authorities (e.g., municipal approval for road crossings).

Further clarification may be obtained by contacting the AER or its *Directive 056* help line.

Change in Business process Relating to Preapplication Statements of Concern (Bulletin 2014-39)
AER Bulletin – Statements of Concern

The AER released Bulletin 2014-39 advising that, effective immediately, it will no longer accept statements of concern for a project until the application associated with that project is received.

ALBERTA UTILITIES COMMISSION

Revision of Rule 019 – Specified Penalties for Contravention of ISO Rules (AUC Bulletin 2014-16)
AUC Bulletin – Amendment to Rule 019

The AUC released Bulletin 2014-16 advising that it had approved amendments to AUC Rule 019: *Specified Penalties for Contravention of ISO Rules*, which becomes effective on January 1, 2015.

AUC Rule 002: Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors (AUC Bulletin 2014-17)
AUC Bulletin – Amendment to Rule 002

The AUC released Bulletin 2014-17 advising that it had approved changes to Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors*, on December 2, 2014, to be effective on January 1, 2015. The amended rule can be viewed on the AUC website, or by clicking on this link.

The AUC noted that consultations for revisions under this rule are ongoing, with the next meeting scheduled for April 2015.

Administrative amendments to Rules 001, 005, 007, 009, 020 and 022 to coincide with and support the implementation of the Alberta Utilities Commission's new information technology regulatory filing system (AUC Bulletin 2014-18)
AUC Bulletin – Rule Amendments

The AUC released Bulletin 2014-18 advising that it had approved administrative amendments to the following rules to reflect the implementation of its new eFiling system, which is slated to become operational on January 5, 2015:

(a) Rule 001: *Rules of Practice* ("*Rule 001*");

(b) Rule 005: *Annual Reporting Requirements of Financial and Operational Results*;

(c) Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments*;

(d) Rule 009: *Rules on Local Intervener Costs*;

(e) Rule 020: *Rules Respecting Gas Utility Pipelines*; and

(f) Rule 022: *Rules on Intervener Costs in Utility Rate Proceedings.*

The AUC noted that the amendments to these rules were approved independent of any current ongoing stakeholder consultations, as the amendments are administrative in nature. However, the AUC noted the following three amendments to *Rule 001* that have implications for participants in AUC proceedings:

(a) Section 15 sets out new requirements for parties filing revisions or updates to documents previously filed in a proceeding;

(b) Section 29 sets out new requirements for filing information requests; and

(c) Section 30 sets out new requirements for providing responses to information requests.

Commission-initiated Review: Electric Transmission Access Charge Deferral Accounts – Quarterly Applications (Decision 2014-328)
Transmission Access Charge Deferral Account Rider Applications

The AUC initiated a proceeding regarding transmission access charge ("TAC") deferral account rider applications by distribution facility owners ("DFO"). The DFOs submitted a joint application requesting approval of a standardized schedules template for use in quarterly Alberta Electric System Operator ("AESO") demand transmission service ("DTS") deferral account rider applications.

Throughout several TAC deferral account rider applications this year, several DFOs have suggested refinements to the previous standard methodology established in Decision 2012-304. In each of these applications, the AUC deferred consideration of any refinements to this proceeding.

The AUC considered the purpose of the proceeding it initiated as follows:

(a) To review and adopt agreed-upon refinements to standardized templates and common approaches to quarterly AESO DTS deferral account rider filings; and

(b) Determine any opportunities to harmonize the content and structure of the DFOs annual TAC deferral account applications, to develop a common approach to the same.

The AUC published this decision to set out its findings in respect of the first purpose (a) set out above.

One of the refinements proposed by the DFOs was a "carryover provision" for true-up amounts in the event that an AESO DTS deferral filing impacted a customer's bill by more

than 10 percent, constituting a rate shock. The AUC held that the carryover provision did not constitute a double counting of deferral amounts, and that limiting the effects of a potential rate shock would reduce volatility and maintain rate stability for customers.

The AUC summarized each of the changes proposed in a table outlining the refinements and additions proposed and agreed upon by all of the DFOs participating in the proceeding. The AUC noted that no party to the proceeding objected to any of the proposed refinements and approved the schedules template for the DFOs' standardized quarterly AESO DTS deferral account filings, as filed.

The AUC approved the changes, to become effective for the Q1 2015 filings.

Suncor Energy Products Inc. 80-MW Hand Hills Wind Power Project (Decision 2014-331)

Wind Power Project Application

Suncor Energy Products Inc. ("Suncor") applied to the AUC to construct and operate the Hand Hills Wind Power Project (the "Project"), to be located in the Delia area, 27 kilometres northeast of Drumheller, Alberta.

The Project is to consist of 54 1.62 megawatt ("MW") rated General Electric turbines, for a total capacity of 80MW, a collector system, and the Hand Hills 605S substation. Suncor indicated that, if the Project were approved, a separate application from ATCO Electric Ltd. would be required to connect the Project to the Mother Mountain 2055S substation, which is currently before the AUC.

Five participants were granted standing, as the AUC determined that they may be directly and adversely affected by the AUC's decision on the Project.

With respect to siting matters, Suncor indicated that all of the turbines were located on lands zoned as "agricultural district" and were not expected to significantly alter current land-use by landowners. Suncor anticipated that effects on vegetation and wildlife habitat would be low or minimal, as less than one percent of the Project would be located on native pasture. Suncor also submitted that two of its turbines would be located within 300 metres of Highway 851, one of which had been approved by Alberta Transportation. Suncor noted that it was developing a traffic accommodation strategy for the remaining turbine.

Suncor submitted that its noise impact assessment predicted a maximum cumulative noise level of 39 dBA at night at the receptor most impacted by the Project, in accordance with AUC Rule 012: *Noise Control* ("*Rule 012*"). Suncor submitted that the project contribution noise levels had a maximum noise level of 38 dBA at night. Suncor also submitted an analysis of low-frequency noise, which concluded that an audible tone below 250 hertz would be unlikely. Suncor committed to conducting post-construction sound level surveys at receptor points that were predicted to be the most impacted.

With respect to environmental impacts, Suncor submitted an environmental evaluation report, which acknowledged that the Project may potentially impact various wildlife groups. The environmental evaluation report noted that, with the implementation of proposed mitigation measures, the impacts arising from the Project would be low to medium in magnitude and importance. The report noted that the only medium impacts would be caused by construction.

On matters relating to future decommissioning, Suncor proposed to remove all above grade facilities (including concrete foundations) to a depth of one metre below grade and to backfill with natural grade. However, Suncor proposed to leave approximately 52 kilometres of cable buried in place to minimize land disturbance.

Suncor's consultation program consisted of holding two open houses, the establishment of a toll free hotline, personal consultation with landowners within 800 meters of the Project, and notification for landowners within 2,000 meters of the Project. Suncor submitted that it had not initially consulted with First Nations, as the Project would be located entirely on private lands, but did meet with the Siksika First Nation to discuss the Project.

As part of the consultation program, the AUC noted that Suncor made participants aware of the decommissioning plans to leave de-energized and buried cable on the Project lands.

The AUC held that the Project was in the public interest, noting that:

(a) The noise impact assessment provided a reasonable prediction of Project noise, and noted that post-construction surveys would assist in ensuring compliance with *Rule 012*;

(b) The Project had received sign-off from Alberta Environment and Sustainable Resource Development, this being strong evidence that the environmental impacts were acceptable; and

(c) Project consultation had met the requirements of AUC Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments*, and were adequate given the scope of the Project.

Accordingly, the AUC approved the Project, and issued the following orders:

(a) Power Plant Approval No. U2014-509 to construct and operate the Hand Hills Wind Power Plant; and

(b) Substation Permit and Licence No. U2014-510 to construct and operate the Hand Hills 605S substation.

ENMAX Energy Corporation 2012-2014 Regulated Rate Option Non-energy Tariff Compliance Filing and Non-energy Rate Rider Application (Decision 2014-332)
Compliance Filing – Rate Rider Application

ENMAX Energy Corporation ("ENMAX") filed the compliance filing for its 2012-2014 regulated rate option ("RRO") non-energy tariff pursuant to Decision 2014-138. ENMAX also requested approval to collect an RRO non-energy rate rider from residential and commercial customers.

Later in the proceeding, ENMAX also requested that any final 2014 rates approved in this decision be applied as interim refundable rates for 2015.

The AUC held that ENMAX's filing complied with the AUC's directions 1 through 6, 8, and 11 through 15 as set out in Decision 2014-138. The AUC therefore limited its discussion in this decision to outstanding directions 7, 9, 10, 17, and 18.

With respect to directions 9 and 10, the AUC had provided direction to ENMAX that the shared services costs for its RRO non-energy application must reflect a reduced number of site counts for 2012-2014. ENMAX, in its compliance filing, submitted that shared service costs were calculated independently of site counts, noting that shared service costs (such as office space) do not typically vary by the number of customers, and thus bore no correlation to them in allocating costs. The Consumers' Coalition of Alberta suggested that the allocation factors used by ENMAX were based on gross profit, which naturally varies with the number of site counts, and therefore should be further reduced due to the drop in site count.

The AUC accepted ENMAX's submissions that there should be no further reduction to the shared services costs, as shared services costs did not adequately correlate to site counts. Therefore the AUC approved ENMAX's allocation of shared service costs based on its previously approved methodology.

ENMAX submitted that it would provide additional information and its most recent actuarial studies in its next non-energy tariff application. As a result, the AUC held that no further information was required with respect to its previous directions to file updated actuarial studies with the current application.

ENMAX also submitted adjustments to its non-energy revenue requirements pursuant to AUC directions 17 and 18 for the years 2012 through 2014, with final amounts as follows:

(a) 2012 – $ 19,890,000;

(b) 2013 – $ 18,141,000; and

(c) 2014 – $ 16,541,000.

The AUC held that ENMAX had adequately responded to the AUC's direction, and therefore approved the adjusted revenue requirements as filed.

Finally, ENMAX requested approval to collect $230,618 from customers through an RRO non-energy rate rider, for the difference between interim refundable rates and the final rates for 2012 through 2014. ENMAX proposed to collect these amounts effective January 1, 2015 through March 31, 2015, based on a daily rate for residential and commercial customers. The AUC held that this amount was reasonable, and approved it as filed. However, the AUC ordered ENMAX to file a true-up application to reflect actual site counts for its rate rider, either as a separate application, or as part of its next RRO non-energy application.

The AUC made the following orders in accordance with its findings above:

(a) ENMAX's RRO non-energy tariff revenue requirements and daily rates for the years 2012 to 2014 were approved as filed;

(b) ENMAX's RRO non-energy rates for 2015 were approved for the purpose of setting the 2015 RRO non-energy tariff on an interim refundable basis effective January 1, 2015;

(c) ENMAX's RRO non-energy tariff final rates rider will be collected from January 1, 2015 to March 31, 2015; and

(d) ENMAX was directed to file a true-up application for its rate rider as a separate application, or as part of its next RRO non-energy application.

ATCO Pipelines, a division of ATCO Gas and Pipelines Ltd. Review and Variance of Decision 2014-090 Costs Award (Decision 2014-333)
Review and Variance – Cost Award

ATCO Pipelines, a division of ATCO Gas and Pipelines Ltd. ("ATCO") was granted a review of the costs awarded in Decision 2014-090.

Following Decision 2014-090, ATCO was granted a review and variance of the costs decision in Decision 2014-237 on the basis that it had inadvertently missed an invoice from

Bennett Jones LLP ("Bennett Jones"), and that there was a computation error in a spreadsheet submitted with its costs application. ATCO submitted $7,550.77 in costs for legal fees for the preparation of the review and variance application granted in Decision 2014-237.

The AUC held that the time spent by Bennett Jones in preparing the review and variance application was not recoverable, in light of the tasks described in the costs claim. The AUC cited Utility Cost Order 2003-037 by the Alberta Energy and Utilities Board, which held that costs related to the preparation of costs claims are not recoverable.

The AUC also noted that the time spent by Bennett Jones was similar in nature to the preparation of the initial costs claim issued in Decision 2014-090. In noting the scope of the present application, the AUC also held that even if the claim were recoverable, the time spent was not reasonable given that the scope of work consisted of the inclusion of a missed invoice and a calculation error in a spreadsheet. Therefore, the AUC concluded that the basis for the review request did not require the amount of time and legal fees claimed.

The AUC therefore denied the costs claim in its entirety.

Total E&P Canada Ltd. Joslyn North Mine Project – Cogeneration Power Plant (Decision 2014-338)
Cogeneration Power Plant

Total E&P Canada Ltd. ("Total") applied to the AUC to construct and operate a 170-MW cogeneration power plant as part of its proposed commercial scheme for the recovery of oil sands, called the Joslyn North Mine Project (the "Project") located approximately 70 kilometres north of Fort McMurray.

The environmental, socio economic, and other impacts of Total's application for the Project was before a joint panel of the Energy Resources Conservation Board and the Canadian Environmental Assessment Agency, which conditionally approved the Project in 2011.

Total had originally applied for one 85-MW cogeneration unit as part of the Project. However, as a result of changes to the Project filed before the AER, Total applied to the AUC for a second 85-MW cogeneration unit, and had also filed amendments to its approval from the joint panel with the AER, which have yet to be decided on. Total noted that it had submitted an integrated application for environmental approval of the Project to Alberta Environment and Sustainable Resources Development ("ESRD").

TransCanada Energy Inc. ("TransCanada") had concerns about the Project, in respect of interconnecting the cogeneration power plant to the Alberta Interconnected Electric System ("AIES"), submitting that the Project may impact the operation of TransCanada's MacKay River generator nearby. TransCanada later withdrew its concerns after being advised that Total was not planning on interconnecting the Project to the AIES immediately.

No other concerns were raised by stakeholders or the public in respect of the Project.

After reviewing Total's submissions, the AUC held that:

(a) The Project would have a negligible impact on air quality;

(b) The Project would have a minimal incremental disturbance on the land apart from the impacts created on the mine site;

(c) The Project, through the use of mitigation measures, complied with the requirements of AUC Rule 012: *Noise Control*; and

(d) The Participant Involvement Program for the Project was consistent with AUC Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments*.

Accordingly, the AUC held that the Project was in the public interest. However, the AUC granted the approval subject to three conditions:

(a) The approval is conditional upon any related approvals from ESRD. Total must advise the AUC of any such approvals within 30 days of their receipt;

(b) The approval is conditional on approval for the Project from the AER. Total must advise the AUC of any such approvals within 30 days of their receipt; and

(c) Total may not commence construction until it has received approvals from ESRD and the AER and filed confirmation of the same with the AUC.

EPCOR Distribution & Transmission Inc. 2013-2014 Transmission Facility Owner Tariff Compliance Filing: Interim Rates (Decision 2014-339)
Compliance Filing - Interim Rates

EPCOR Distribution & Transmission Inc ("EDTI") applied to the AUC requesting approval of:

(a) Its 2013-2014 transmission facility owner ("TFO") tariff compliance filing, including an interim amount of $6.54 million for December 2014;

(b) Its transmission function revenue requirements for 2013 and 2014, its TFO tariffs, terms and conditions; and

(c) Its 2013 and 2014 true-up amounts of $4.38 million and $11.53 million respectively, on a final basis by December 17, 2014 in order to settle the amounts with the Alberta Electric System Operator ("AESO").

EDTI requested alternatively, that the AUC approve the amounts requested on an interim, refundable basis if it was unable to do so prior to December 17, 2014.

Due to scheduling requirements, the AUC was not able to provide an approval on a final basis.

The AUC approved the 2013 and 2014 true-up amounts on an interim basis, to be collected effective December 1, 2014. The AUC ordered that the true-up amounts be collected with the December 2014 interim amount, for a total TFO rate of $22,452,144 effective December 1, 2014. The AUC also approved the interim rates of $6.54 million per month, previously approved in Decision 2013-373, to be effective January 1, 2015.

MidAmerican (Alberta) Canada Holdings Corporation Request to Remove Obligation to Conduct Itself as if Designated as an Owner of a Public Utility (Decision 2014-344)

Owner of Public Utility Designation

MidAmerican (Alberta) Canada Holdings Corporation ("MC Alberta"), pursuant to the AUC's direction in Decision 2014-326, was ordered to conduct itself as if it had been designated as an owner of a public utility under the *Public Utilities Act* until such time as a new corporation is identified as the designated owner of the public utility, is incorporated, and MC Alberta's representations made in the application are transferred to the new corporation.

MC Alberta notified the AUC on December 1, 2014 that the new corporation was incorporated as BHE AltaLink Ltd. ("BHE AltaLink"), and that all of MC Alberta's representations on the record of Proceeding No. 3250 had been transferred to BHE AltaLink. MC Alberta also provided a copy of BHE AltaLink's certificate of incorporation and a copy of the agreement between MC Alberta and BHE AltaLink confirming the transfer of representations.

The AUC accepted the submissions of MC Alberta and ordered that MC Alberta is relieved of the requirement to act as if it is a designated owner of a public utility as set out in the *Public Utilities Act*.

Decision on Request for Review and Variance of AUC Decision 2013-386 Medicine Hat Transmission Project (Decision 2014-345)

Review and Variance

The AUC received requests to review Decision 2013-386 from 10 parties pursuant to AUC Rule 016: *Review of Commission Decisions* (the "Review Requests").

In Decision 2013-386, AltaLink Management Ltd. ("AltaLink") had received approval to construct approximately 51 kilometres of new 138-kilovolt transmission line along an alternate route, identified as Route 1A in that proceeding. The Review Requests were held in abeyance by the AUC, as AltaLink advised that it was considering an amendment to the facilities.

Among the concerns raised in the Review Requests the applicants (the "Dunmore Group") relied mainly on the following grounds of review:

(a) That the notice on them by AltaLink was not effective, as AltaLink did not anticipate that the alternate Route 1A would be approved;

(b) That the applicants were denied procedural fairness, as AltaLink advised them that their rights would not likely be affected;

(c) That each of the applicant landowners did not attend the original hearing in reliance on these assurances from AltaLink;

(d) That no evidence was presented at the original hearing with respect to the impacts of alternate Route 1A; and

(e) That new facts, changes in circumstances, and facts not previously placed in evidence would be presented with respect to the potential impacts of alternate Route 1A.

The Dunmore Group submitted that their participation in the hearing could have lead the AUC to a materially different conclusion than it had made in Decision 2013-386.

AltaLink opposed the Review Requests, noting, among other points, that its consultation program was found to be adequate in Decision 2013-386, and that the Dunmore Group could have participated in the hearing but chose not to. AltaLink's letter submission was supported by various other landowner groups that participated in the Decision 2013-386 hearing.

The AUC held that while the Dunmore Group and the other applicants had clearly outlined their concerns with the notice provided, such notice was consistent with common law rules of natural justice and procedural fairness, as well as the AUC's own statutory requirements for the service of a notice.

The AUC reviewed the contents of the Notice of Hearing for the Decision 2013-386 proceeding, noting that it described the preferred and alternate routes in the application on a map, explained how interested parties could participate, stated where the hearing would be held, and provided contact information if any further information was needed. The AUC accordingly determined that the notice described in detail the process it would use to consider the application, and provided sufficient information to allow a potentially-affected person to understand that the alternative routes were under consideration as part of the hearing.

With respect to the outstanding concerns and "new evidence", the AUC held that these concerns were not new facts or changes in circumstances. The AUC held that these concerns and facts were, or could have been, raised in the hearing, and were addressed by the hearing panel in Decision 2013-386.

As a result, the AUC held that none of the review applications raised any substantial doubt as to the correctness of the decision of the original panel, and therefore dismissed the review and variance applications.

ATCO Electric Ltd. 2013-2014 Transmission General Tariff Application Second Compliance Filing (Decision 2014-348)

Compliance Filing – General Tariff Application

ATCO Electric Ltd. ("ATCO") submitted its second compliance filing for its transmission general tariff application ("GTA") in response to directions given by the AUC in Decision 2014-167.

No parties objected to the compliance application.

The AUC held that ATCO had complied with, and provided satisfactory responses to directions 1 to 3 and 5 to 10 from Decision 2014-167. Direction 4 and any other outstanding matters from Decision 2013-358 were intended to be considered in future ATCO GTA applications, and therefore were not addressed by the AUC in the decision.

The AUC did, however, provide clarification with respect to defined benefit plan costs for 2013 and 2014 as set out in direction 10 from Decision 2014-167. The AUC noted that it had denied ATCO's request for its existing deferral account to flow-through the impact of changes between actual and forecast defined benefit payments. The AUC noted in this decision that it still considers that the existing defined benefit deferral account allows ATCO to recover the actual defined benefit plan special payment costs.

The AUC also noted that the ATCO I-Tek rates for 2013 and 2014 would be determined as part of the ATCO Utilities Evergreen Compliance Filing proceeding, and that the forecast volumes would not be subject to placeholder treatment. Therefore, the AUC considered that the amounts are approved as final for the 2013 and 2014 test years.

ATCO submitted that the true-up amounts necessary to account for interim and final tariffs for 2013 and 2014 were $2.45 million and $6.45 million, respectively, for a total of $8.9 million. Given the size of the total adjustment relative to the total revenue requirement, the AUC ordered ATCO to collect the total true-up amount of $8.9 million for adjustments to the 2013 and 2014 test years in January 2015.

The AUC approved as final ATCO's proposed revenue requirements for 2013 and 2014 in the amounts of $484.6 million and $579.0 million, respectively.

FortisAlberta Inc. 2015 Annual PBR Rate Adjustment Filing (Decision 2014-351)

PBR Rate Adjustment

FortisAlberta Inc. ("FAI") filed an application for its annual performance-based regulation ("PBR") rates adjustment filing, as provided for in the PBR framework set out in Decision 2012-237. As part of the application, FAI requested approval of its 2015 rates, option and riders schedules, to be effective January 1, 2015 on an interim basis. FAI also included proposed updates to its customer and retailer terms and conditions of electric distribution service to be effective January 1, 2015.

The PBR framework essentially provides a formula mechanism to adjust rates annually, using inflation (I Factor) less an offset (X Factor) to reflect the productivity improvements the utility can expect to achieve during the test period. However, the PBR framework also requires certain adjustments, including amounts to fund necessary capital expenditures (K Factor), flow-through costs to be recovered directly from the consumer (Y Factor), and material events for which the company has no other reasonable cost recovery mechanism (Z Factor).

Decision 2012-237 set the I Factor as a weighted average composed of 55 percent based on the Alberta average weekly earnings index, and 45 percent based on the Alberta consumer price index for the previous July through June period. FAI submitted that the updated I Factor was calculated at 2.65 percent for the 2015 PBR period. FAI also proposed to continue the use of the 1.16 percent X Factor approved in Decision 2012-237, resulting in an I-X index value of 1.49 percent for 2015.

As no party had objected to the I-X index value, and noting that FAI's submissions were consistent with previous AUC decisions and directions, the AUC held that FAI's proposed I-X index value was reasonable.

FAI proposed a Y Factor refund of 1.3 million to customers, composed mostly of AUC assessment fees, property taxes, and transmission credits. The AUC held that FAI's proposed Y Factor amounts consisted entirely of previously approved cost categories set out in Decision 2012-237. In addition, the AUC also noted that FAI's proposed Y Factor costs were less than, or equal to the forecasted amounts. Accordingly, the AUC determined that these figures were within a reasonable range of the amounts approved as forecasts in FAI's last PBR adjustment filing.

FAI requested a K Factor placeholder for 2015 in the amount of $68.9 million, which is equal to its revised K Factor amount included in its 2013-2015 capital tracker application currently before the AUC in Proceeding 3220. FAI requested that the amount be included on an interim basis. The Utilities Consumer Advocate ("UCA") requested that the AUC treat the K Factor placeholder in a similar manner to other interim rate increase requests, by approving only 60 percent of the requested increase.

The AUC agreed with the UCA's request to determine the interim rate in a similar manner to other interim rate increase requests, and determined that an amount less than 100 percent should be granted. However, the AUC noted its concerns of rate stability and rate shock, and the fact that FAI and the UCA agreed that a K Factor placeholder equal to 90 percent of the proposed amount would be a reasonable compromise. Accordingly, the AUC approved a K Factor placeholder of $62.0 million for 2015.

FAI did not propose any amount for a Z Factor in its 2015 PBR adjustment application.

FAI proposed to continue using the previously approved methodology for forecasting its billing determinants. While the matter was not addressed by the intervenors in argument, the AUC noted that the approved methodology allows for some application of judgment in forecasting, and that FAI had satisfactorily described its reasons for forecasting:

(a) A decline in the number of oil and gas service customers in 2015, based on declines from the last quarter in 2012; and

(b) New load additions, existing load reductions and terminations, and the volume and nature of customer requests, based on forward-looking information.

The AUC therefore approved the proposed 2015 billing determinants, and directed FAI to provide information on the variance from forecast to actual billing determinants by rate class larger than 5 percent for 2013 and 2014 in its 2016 annual PBR rate adjustment filing.

FAI did not apply for any new rate riders in 2015, and proposed to continue using its existing riders as previously approved. The AUC approved the continued use of rate riders as being reasonably necessary to recover or refund flow-through items relating to Y Factor amounts.

For transmission cost forecast, FAI proposed to use the actual average of pool prices from 2013 and 2014 to calculate the operating reserve percentage and pool price, as the Alberta Electric System Operator had not provided a forecast at the time of the application. The AUC noted that the figures used by FAI were accurately calculated and that no party objected to or raised concerns in respect of the calculations. The AUC therefore approved the transmission cost forecast as filed.

FAI proposed to allocate its Z, Y and K Factors consistent with previously approved allocation methodologies as set out in Decision 2014-018. The AUC held that, after review, the proposed allocation was consistent with previous findings and directions, and approved them as filed.

The AUC accordingly approved FAI's rates as applied for. However, the AUC approved these rates on an interim basis until such time as the placeholders noted have been approved by the AUC.

Lastly, the AUC approved the revised terms and conditions proposed by FAI and the proposed increase in service fees according to the updated I-X index value.

Warwick Rural Electrification Association Application for Permission to Cease and Discontinue Operations; ATCO Electric Ltd. Sale and Transfer of the Warwick Rural Electrification Association (Decision 2014-359)

Cease/Discontinue Operation – Sale, Transfer and Operation of Assets

The Warwick Rural Electrification Association (the "Warwick REA") applied for approval to cease and discontinue operation of its electric distribution system pursuant to section 29(1) of the *Hydro and Electric Energy Act* ("*HEEA*"). The Warwick REA owns and operates an electric distribution system in rural east-central Alberta. The Warwick REA made the application as its assets were to be sold and transferred to ATCO Electric Ltd. ("ATCO") pursuant to section 32 of the *HEEA*. Accordingly, ATCO applied simultaneously to the AUC for approval of the sale, transfer and operation of the Warwick REA assets under section 32 of the *HEEA*.

The AUC considered the application in two stages: deciding first on whether the sale was in the public interest; and then considering the prudence of the sale itself.

The Warwick REA submitted that it had obtained all necessary approvals and permits for the transfer from the Rural Utilities Division of Alberta Department of Agriculture

and Rural Development. The Warwick REA also held a special general meeting of the Warwick REA members on August 20, 2014. At this meeting, ATCO presented its purchase offer, which 75% the Warwick REA members voted to accept. A memorandum of agreement was executed between ATCO and the Warwick REA on August 27, 2014, and indicated a purchase price of $4,263,954.00, based on the replacement costs, new less depreciation (RCN-D), formula previously approved by the AUC.

The AUC held that the Warwick REA had complied with the governance requirements to be followed under section 23 of the *Rural Utilities Act* by passing an extraordinary resolution authorizing the sale of its entire works to a utility company. The AUC also held that the Warwick REA was wholly within ATCO's service area, and relied on ATCO's commitment to continue to provide service to the members served by the Warwick REA.

Taking into account the above findings, and noting that the Warwick REA approached ATCO for the offer of sale and that the majority of Warwick REA members approved the sale, the AUC held the sale of Warwick REA to ATCO to be in the public interest, and directed the Warwick REA to sell, and ATCO to purchase and operate, the Warwick REA assets.

Having approved the purchase and sale, the AUC considered the prudence of the transaction, and any impacts it may have on ATCO's rates. The AUC held that the RCN-D methodology for valuing the Warwick REA assets was consistent with prior approvals by the AUC, and therefore held that the purchase price to be paid by ATCO was prudent.

The AUC did not make any findings with respect to rate impacts, as it noted that ATCO had not yet applied for any rate adjustments.

In order to give effect to the above findings, the AUC made the following orders:

(a) Discontinuance of Distribution System – Approval No. U2014-555 to Warwick REA to cease to operate in its service area;

(b) An order transferring the service area of the Warwick REA to ATCO under section 32(1) of the *HEEA*;

(c) An order rescinding REA Approval No. HE 77126 upon the closing of the Sale of Distribution System and Termination of Services Agreement between Warwick REA and ATCO; and

(d) Sale and Transfer of Distribution System – Approval No. U2014-557.

ENMAX Power Corporation 2014 Formula-based Ratemaking Annual Rates and Technical Report (Decision 2014-367)

Annual Rates and Technical Report

In Decision 2009-035, the AUC required ENMAX Power Corporation ("EPC") to file an annual rates and technical report ("ART Report"). EPC applied for its performance based regulation ("PBR") rate adjustment concurrently with the filing of its ART Report. As part of its application, EPC requested:

(a) A distribution access service adjustment rider to collect a shortfall of $7.871 million to true-up EPC's 2013 distribution tariff;

(b) Z Factor amounts totalling $0.182 million, to be effective October 1, 2014 to December 31, 2014;

(c) 2013 loss factors, effective October 1, 2014;

(d) A line loss rate adjustment for 2013 in the amount of $1.782 million through a rate adjustment to the distribution system usage charge, to be effective October 1, 2014 to December 31, 2014;

(e) An interim distribution tariff rates schedule, to be effective October 1, 2014;

(f) A determination on transmission capital prudence;

(g) A one-time collection of $5.563 million for a true-up of balances related to I factor, flow-through costs and Z Factor amounts from 2013 transmission rates, effective October 1, 2014; and

(h) An interim transmission tariff, effective October 1, 2014.

EPC stated that its transmission return on equity and the resulting 2013 earning sharing calculation are subject to its upcoming transmission reopener compliance filing, and EPC will request approval of the final earning sharing calculation as part of that filing, including final transmission rates for 2010 to 2013.

EPC proposed to collect its 2013 rates true-up between October 1, 2014 and December 31, 2014. The Utilities Consumer Advocate ("UCA") did not take issue with the amount, but submitted that the timeline for collection was not achievable and argued for a six month collection period beginning 30 days after the AUC's decision.

The AUC approved EPC's 2013 rate true-up, to be collected over a three-month period. However, due to timing problems with the requested collection period, the collection period was approved effective January 1, 2015.

In submitting its 2014 rates report, EPC requested the continued application of the FBR formula approved in Decision 2009-035. The AUC approved the FBR formula, and associated costs as filed, except as discussed below.

EPC applied for pass-through treatment of $933,000 in costs associated with a 69-kV conversion project, directed by the Alberta Electric System Operator ("AESO") as part of a needs identification document, which was later cancelled. The UCA opposed the inclusion of these costs on the basis that EPC had a duty to provide input to the AESO providing better alternatives, which the UCA submitted EPC had failed to do by waiting for direction from the AESO.

The AUC rejected the UCA's argument on the basis that EPC was obligated to incur costs in assisting the AESO to prepare a needs identification document, pursuant to section 35 of the *Electric Utilities Act*. The AUC also held that section 40 of the *Transmission Regulation* entitles a TFO to include in its transmission tariff, costs and expenses incurred by the TFO in assisting the AESO in preparing needs identification documents. Therefore the AUC approved the flow through of costs in EPC's tariff. However, the AUC reduced the amount approved by $246,160 of the $933,000 requested. The AUC held that these expenses had been incurred after the AESO had given notice of the cancellation of the needs identification document application.

EPC also provided business cases and supporting documentation in respect of its 2013 transmission capital expenditures, with explanations for variances within each project. After review, the AUC approved these expenditures as prudent, and noted that none of the interveners raised any issues in respect of the prudence of EPC's 2013 transmission capital expenditures.

The AUC further held that this decision would not affect EPC's interim approved rate schedules for 2015 approved in Decision 2014-311.

The AUC therefore ordered that:

(a) EPC collect its shortfall amount of $7.871 million to true-up EPC's distribution tariff rates from July 1, 2013 to December 31, 2013;

(b) EPC's various FBR true-up balances in the amount of $0.182 million will be incorporated into the 2015 rates true-up application;

(c) EPC's loss factors and line loss rate adjustment true-up of $1.782 million will be incorporated into the 2015 rates true-up application; and

(d) A one-time collection of $5.563 million for July 1, 2013 to December 31, 2013 transmission rates, with the exception of the disallowed amount of $246,160, will be incorporated in the 2015 rates true-up application.

TransAlta Corporation, as Manager of the TransAlta Generation Partnership 2015-2016 Interim Tariff Application (Decision 2014-369)

Interim Tariff Application

TransAlta Corporation, as Manager of the TransAlta Generation Partnership ("TransAlta") requested approval for an interim refundable transmission facility owner ("TFO") tariff effective January 1, 2015. TransAlta applied to continue its tariff, approved in Decision 2013-418, from January 1, 2015 until December 31, 2016 on an interim refundable basis. TransAlta proposed to continue its approved TFO terms and conditions on a final basis until otherwise directed.

TransAlta's current approved TFO tariff has a rate of $371,345 per month net of goods and services tax.

The AUC approved the interim tariff as filed, but noted it did not need to make a determination with respect to TFO terms and conditions. The AUC held that once terms and conditions are approved, they remain in effect until any changes are approved by the AUC.

AltaGas Utilities Inc. 2014-2015 Capital Tracker Application and 2013 Capital Tracker True-up Application (Decision 2014-373)

Capital Tracker Projects and Programs – K Factor

AltaGas Utilities Inc. ("AltaGas") applied for its proposed 2014 and 2015 capital tracker projects and programs, pursuant to directions given in Decision 2013-435. Capital tracker projects and programs were established in Decision 2012-237 as a supplemental funding mechanism in addition to the revenue requirement associated with approved amounts to be collected from ratepayers through an adjustment to the annual performance based regulation ("PBR") rate-setting formula ("K Factor").

Projects or programs are eligible for capital tracker treatment, provided that they meet the following three criteria:

(a) The project must be outside the normal course of on-going operations;

(b) Ordinarily, the project must be for replacement of existing capital assets, or the project must be required by an external party; and

(c) The project must have a material effect on the company's finances.

In order to qualify as "outside the normal course of on-going operations", the AUC noted that the increase in associated

revenue provided by the PBR formula, must be insufficient to recover the entire revenue requirement associated with the prudent capital expenditures for the capital tracker program or project in question. The AUC noted that it viewed this test as more accounting oriented than engineering oriented, although such applications generally must be supported by an engineering study and business case to assess the reasonableness of the request.

In order to qualify as being required by a third party under the second criterion, a growth related project must demonstrate that customer contributions and incremental revenues are insufficient to offset the revenue requirements associated with a project for a given year.

The materiality threshold in the third criterion requires that each project must individually affect the revenue requirement by four basis points. On an aggregate level, all proposed capital trackers must have a total impact on revenue requirement of 40 basis points.

The Utilities Consumer Advocate ("UCA") did not object to AltaGas' proposed grouping of capital tracker projects. The Consumers' Coalition of Alberta ("CCA") proposed that the AUC take into account the revenues and costs associated with the assets being retired as part of the materiality assessment. The AUC declined to consider the CCA's proposal, noting that the matter would be more properly addressed with respect to depreciation in a general rate application. Accordingly, the AUC held that the projects were properly grouped by AltaGas, consistent with previous directions regarding the same.

AltaGas provided a business case together with an engineering study for each of its programs and projects, consistent with the AUC's previous directions in Decision 2013-435. AltaGas submitted that each of the three programs was necessary in order to maintain safe and reliable service, and that such service may be compromised in the absence of these programs.

AltaGas specifically stated that the pipe replacement program is required to prevent deterioration in safety and service standards, and that the risks would persist until the replacements are complete.

With respect to station refurbishments, AltaGas submitted that the stations slated for refurbishment have aged to the point where maintenance is either no longer possible or no longer effective. The refurbishments are necessary to maintain operability and serviceability within acceptable safety parameters.

With respect to gas supply projects, AltaGas noted that these projects arise from third party suppliers, or that deterioration of the volume or quantity of supply would compromise safety and service quality if the program is not undertaken.

The UCA objected, generally, to the inclusion of some projects that were deferred from previous years, citing the deferment itself as evidence that the replacements were not necessary to maintain safe and reliable service. The AUC dismissed this objection, holding that other business reasons may vary the timing of a series of proposed projects, including changing priorities and risk levels. The AUC held that the bare fact that a project was deferred was not sufficient to demonstrate that the project was not necessary.

The UCA also objected to the substitution of projects within a program as an inappropriate "bucket of costs", noting that such a framework was not conducive to creating efficiency incentives. AltaGas submitted in reply that it needs the flexibility to manage overall pipeline risk while responding to emerging priorities and risks as they arise, and cannot simply follow a pre-determined order.

The AUC agreed with AltaGas, citing flexibility as a key need for companies regulated under the PBR framework, and noted that the nature of the K Factor as requiring a true-up, means it does not represent a "bucket of costs" but rather an amount of revenue requirement not adequately funded by the PBR mechanisms.

Pipeline Replacement Program

AltaGas applied for capital tracker treatment for its pipeline replacement program, which was previously approved as a multi-year initiative in Decision 2012-091 for the 2010-2012 test period and for 2013 in Decision 2013-435. The project proposes to replace all polyvinylchloride (PVC) pipe, non certified polyethylene (PE) pipe, and pre-1957 steel pipe in AltaGas' service areas. AltaGas noted that the pipe types identified currently exceed risk tolerances, have high leak frequencies, or are beyond their useful lives. AltaGas proposed to continue this project as follows:

(a) Replacement of 76.5 km of PVC pipe in 2014, at a cost of $4.0 million;

(b) Replacement of 51.0 km of PVC pipe in 2015, at a cost of $3.6 million;

(c) Replacement of 26.7 km of non-certified PE pipe in 2014, at a cost of $5.6 million;

(d) Replacement of 34.1 km of non-certified PE pipe in 2015, at a cost of $6.1 million;

(e) Replacement of 17.4 km of pre-1957 steel pipe in 2014, at a cost of $4.9 million; and

(f) Replacement of 27.0 km of pre-1957 steel pipe in 2015, at a cost of $7.7 million.

AltaGas also requested a true up for any variance amounts for projects completed as part of this program in 2013. The AUC approved the 2013 true-up amounts, consisting of:

(a) A credit of $55,853 for all PVC pipe replacement projects as filed, noting that the variances were less than 10 percent of the approved amounts, and were adequately explained;

(b) A collection of $87,981 for all non-certified PE pipe replacement projects as filed, noting that the variances were adequately explained as a result of external circumstances, such as adverse ground conditions, and existing third party service lines that were not previously identified; and

(c) A collection of $426,705 for pre-1957 steel pipe replacement projects as filed. Cost variances were described as partially due to a cost estimate error by AltaGas for Leduc (downtown) pipe replacement based on similar work undertaken in Calmar.

AltaGas also noted that two pre-1957 steel pipe replacement projects were not fully completed due to funding constraints and cost overruns. The AUC voiced its concern that AltaGas was unable to secure sufficient funding, or allocate the resources necessary to complete all of these projects in 2013, given the risks identified by AltaGas. The AUC stated that AltaGas has an obligation to provide safe and reliable service, and that this obligation was not altered or displaced by the existence of the PBR regime. However, the AUC found that the costs incurred were prudently incurred, and approved them as filed.

With respect to 2013 projects that were not approved for capital tracker treatment from Decision 2013-435, but were undertaken by AltaGas, the AUC held that:

(a) Non-certified PE pipe replacement projects near Morinville, Pincher Creek, and Stettler had insufficient evidence on the record to conclude that costs for the particular projects were prudent. The AUC therefore did not approve those projects for capital tracker treatment; and

(b) The pre-1957 steel pipe replacement project in downtown Drumheller was prudently undertaken in 2013, though not approved for capital tracker treatment. However, the AUC held that given the cost overruns and lack of evidence on the record, it could not conclude that the costs for the project were prudent. The AUC therefore did not approve this project for capital tracker treatment.

Station Refurbishment Program

AltaGas applied for capital tracker treatment for its station refurbishment program, which was previously approved as a multi-year initiative in Decision 2012-091 for the 2010-2012 test period and for 2013 in Decision 2013-435. AltaGas noted that approximately 30 percent of its 700 stations throughout Alberta were installed in the 1950s, 1960s and 1970s, many of which are currently equipped with obsolete parts, or do not conform to new pipe configurations. The program aims to refurbish purchase meter stations (PMS), town border stations (TBS) and post regulator stations (PRS). AltaGas proposed to continue this project, and applied for a true-up for variances from its 2013 approved forecast costs.

AltaGas applied for the following projects under its station refurbishment program, at a total cost of $6,548,800:

(a) Refurbishment of six PMS stations in 2014, at a cost of $1,803,800;

(b) Refurbishment of five TBS stations in 2014, at a cost of $795,700;

(c) Refurbishment of five PRS stations in 2014, at a cost of $297,000;

(d) Refurbishment of six PMS stations in 2015, at a cost of $1,877,000;

(e) Refurbishment of four TBS stations in 2015, at a cost of $1,478,500; and

(f) Refurbishment of 17 PRS stations in 2015, at a cost of $296,800.

While no party was opposed to any of the projects, the CCA voiced its concern over the lack of transparency and explanations provided by AltaGas in respect of the variability of costs from one project as compared to a standard station in its forecasts. The AUC therefore found that it was difficult to assess the reasonableness of the costs, and directed AltaGas to provide a detailed table showing the build-up of project costs for each station and comparing it to that of a standard station, along with an explanation for the variance from a standard station. Despite these findings, the AUC held that it was prepared for the purposes of the decision to approve AltaGas' forecasts for station refurbishments for 2014 and 2015.

The AUC approved the 2013 true-up amounts as filed. When netted against other projects approved, but not completed, the variance amounted to a credit of $48,102. Reasons provided for the variance, were due in part to actual costs incurred in 2012 as work in progress, but not reflected in 2013 forecast capital additions. As this was a forecasting oversight, the AUC directed AltaGas to include such work in progress forecast capital additions in the future.

With respect to 2013 projects that were not approved for capital tracker treatment from Decision 2013-435, but were undertaken by AltaGas, the AUC held that:

(a) Station refurbishment projects coded as PMS station MN032 and PRS station LE069 had insufficient evidence on the record to conclude that costs for the particular projects were prudent. The AUC therefore did not approve those projects for capital tracker treatment; and

(b) Station refurbishment project coded as PMS Station MN017 did not appear to be included in the calculation of total costs applied for, and was directed to identify the costs associated with it and demonstrate the prudence of the costs incurred. The AUC therefore did not approve this project for capital tracker treatment.

Gas Supply Program

AltaGas applied for continued capital tracker treatment for its gas supply program, which due to its unique nature, AltaGas submitted it manages on a project-by-project basis. Usually the customer requesting the gas supply lines may require certain types of pipe construction/installation, station work provided by specially trained crews, welding requirements, and other requirements. AltaGas proposed a gas supply amount of:

(a) $3,640,000 for 2014, partly as a result of a proposed connection to an existing pipeline to serve St. Paul customers; and

(b) $531,000 for 2015, consisting of mostly direct costs, with a 6.2 percent overhead amount, based on the average cost of previous gas supply projects completed since 2010.

AltaGas also proposed a 2013 true-up amount for its gas supply program for a credit of $234,697, resulting from costs coming in below forecast.

The AUC approved the proposed gas supply program projects and amounts for 2014 and 2015, noting that no parties objected to the program, and that the forecasts were reasonable based on historical data.

AUC Findings

The AUC found that:

(a) The scope, timing, level and costs for each pipe replacement project, station refurbishment project and gas supply programs to be reasonable, and satisfied the first criterion from the three part test described above;

(b) Each of the three capital tracker programs continued to satisfy the requirements of the second criterion from the three part test described above; and

(c) All of the projects approved by the AUC in AltaGas' application met the materiality thresholds for K Factor treatment, in the third criterion from the three part test describe above.

The AUC also approved AltaGas' trailing 2012 costs from previously approved projects in the amount of $118,790, on the basis that the amounts were prudently incurred, and that the individual amounts for each project were largely immaterial.

The AUC held that consequential changes to the revenue requirement, such as weighted average cost-of-capital, and updated inflation figures, would be applied consistent with the AUC's decisions on those matters in separate proceedings, and would be applied once determined by the AUC.

In accordance with the findings described above, the AUC ordered as follows:

(a) Approval of the 2013 K Factor adjustment as applied for, for its three capital tracker programs, as a credit of $188,287. The AUC directed AltaGas to file an application for a rate rider F reflecting the same in a compliance filing to this decision; and

(b) The AUC directed AltaGas to update its 2014 and 2015 K Factor adjustment forecasts for its capital tracker programs consistent with the findings set out in this decision in a compliance filing to this decision.

ENMAX Power Corporation Formula-Based Ratemaking Transmission Re-opener Compliance Filing to Decision 2014-100 (Decision 2014-378)

Compliance Filing – Negotiated Settlement Agreement

ENMAX Power Corporation ("ENMAX") requested approval of its compliance filing to Decision 2014-100, including the recovery of the following amounts:

(a) A revised 2010-2013 G Factor remedy in the amount of $13.50 million, which is net to the customer share of earnings (at $1.59 million);

(b) Carrying costs in the amount of $0.85 million; and

(c) The collection of the total amount of $14.34 million from the Alberta Electric System Operator, via a lump sum payment.

Since the compliance filing was developed as a negotiated settlement agreement ("NSA"), and presented so as to be either accepted or rejected in its entirety, the AUC assessed the filing in accordance with AUC Rule 018: *Rules on Negotiated Settlements* ("*Rule 018*"). Section 8 of Rule 018 provides that a unanimous or unopposed NSA be assessed on the following two elements:

(a) Whether the NSA will result in rates, and terms and conditions that are just and reasonable; and

(b) Whether the NSA is patently against the public interest or contrary to law.

ENMAX submitted that the NSA process was open and fair, and was sufficiently flexible to accommodate unique circumstances and requirements. The NSA was signed by ENMAX, the Utilities Consumer Advocate ("UCA") and the Consumers' Coalition of Alberta ("CCA").

The AUC held that the filing provided adequate information, and further that the UCA and CCA had sufficient information at the outset of negotiations to understand and participate in the negotiation as informed parties. The AUC therefore found that adequate notice was provided by ENMAX to all parties.

ENMAX submitted that the NSA was unanimously supported, and that such support was evidence of a just and reasonable outcome. ENMAX also submitted that the impact of the settlement amounts is not material on a customer basis, and that the amounts similarly would not affect the AESO, as the settlement amounts to 0.67 percent of the AESO's 2014 revenue requirement.

In assessing the public interest, the AUC held that the adjustments, if approved, would not materially impact costs to customers, and would not constitute a rate shock or cause rate instability. The NSA was unanimously accepted, and did not require any changes to the terms and conditions of service. The AUC also found that the unanimous support for the NSA supported a finding that it was in the public interest, as it would result in greater regulatory efficiency and cost savings by avoiding a contested process. As a result of the above, the AUC determined that the NSA was in the public interest.

Accordingly, the AUC approved ENMAX's compliance filing as filed. In approving the NSA, the AUC relieved ENMAX from the requirement to comply with the directions given in Decision 2014-100.

Various AUC NID and Facility Applications
Needs Identification Document - Facility Application

The AUC approved the following need applications and related facility applications upon finding that:

- The public consultation complies with *AUC Rule 007*;
- The noise impact assessment summary complies with *AUC Rule 012*;
- There was no evidence that the AESO need assessment is technically deficient;
- The facility proposed satisfies the need identified;
- Technical, siting and environmental aspects of the facilities comply with *AUC Rule 007*;
- Considering the social, economic and environmental impacts, the project is in the public interest; and
- The project is in accordance with any applicable regional plan.

Decision	Party	Application
2014-343	AESO	Southern Alberta Transmission Reinforcement Approval NID
	AltaLink Management Ltd.	138-kV Transmission Line 161/876L Facility Application
2014-353	AESO	Deerland Peaking Station Energy Connection NID
	AltaLink Management Ltd.	Deerland Peaking Station Facility Application
2014-355	AESO	Lambton E803S Substation Upgrade NID
	EPCOR Distribution & Transmission Inc.	Lambton E803S Substation Upgrade Facility Application

The AUC approved the following facility applications upon finding that:

- The public consultation complies with *AUC Rule 007*;
- The noise impact assessment summary will comply with *AUC Rule 012*;
- Technical, siting and environmental aspects of the facilities comply with *AUC Rule 007*; and
- Considering the social, economic and environmental impacts, the project is in the public interest.

Decision	Party	Application
2014-341	TransCanada Energy Ltd.	MacKay River 874S Substation Alteration Facility Application
2014-349	City of Medicine Hat	Electric Utility Transmission Line MH-20L Upgrade Project Facility Application
2014-350	Northstone Power Corp.	Application to add 9.3MW turbine to existing power plant
2014-358	AltaLink Management Ltd.	Medicine Hat Area 138-kV Transmission Development Amendment to Access Trails, Workspaces and Right-of-Way Facility Amendment Application
2014-374	Genalta Construction GP Ltd.	Muskwa Gas to Power Project Facility Application
2014-376	Enbridge Inc.	Whitetail Peaking Station Power Plant Facility Application

NATIONAL ENERGY BOARD

Guidance Notes for the Decommissioning Provisions under the Onshore Pipeline Regulations (OPR)
Updated Guidance Material

The NEB updated guidance material under its *Filing Manual* Guide K Decommissioning to clarify existing processes related to decommissioning provisions governed by section 43.1 and 45.1 of the *Onshore Pipeline Regulations.*

An explanation of the changes can be found on the NEB's website, or by clicking on this link.

Government of Canada Introduces Pipeline Safety Act in Parliament
Pipeline Safety Act – Bill C-46

The Minister of Natural Resources introduced Bill C-46*, An Act to Amend the National Energy Board Act* as well as the *Canada Oil and Gas Operations Act*, entitled as the *Pipeline Safety Act,* for first reading in the House of Commons. The bill is currently awaiting second reading in the House of Commons.

The *Pipeline Safety Act*, as summarized by the Library of Parliament, proposes the following changes:

(a) Reinforces the "polluter pays" principle;

(b) Confirms that the liability of companies that operate pipelines is unlimited if an unintended or uncontrolled release of oil, gas or any other commodity from a pipeline that they operate is the result of their fault or negligence;

(c) Establishes the limit of liability without proof of fault or negligence at no less than one billion dollars for companies that operate pipelines that have the capacity to transport at least 250,000 barrels of oil per day and at an amount prescribed by regulation for companies that operate any other pipelines;

(d) Requires that companies that operate pipelines maintain the financial resources necessary to pay the amount of the limit of liability that applies to them;

(e) Authorizes the NEB to order any company that operates a pipeline from which an unintended or uncontrolled release of oil, gas or any other commodity occurs to reimburse any government institution the costs it incurred in taking any action or measure in relation to that release;

(f) Requires that companies that operate pipelines remain responsible for their abandoned pipelines;

(g) Authorizes the NEB to order companies that operate pipelines to maintain funds to pay for the abandonment of their pipelines or for their abandoned pipelines;

(h) Allows the Governor in Council to authorize the NEB to take, in certain circumstances, any action or measure that the NEB considers necessary in relation to an unintended or uncontrolled release of oil, gas or any other commodity from a pipeline;

(i) Allows the Governor in Council to establish, in certain circumstances, a pipeline claims tribunal whose purpose is to examine and adjudicate the claims for compensation for compensable damage caused by an unintended or uncontrolled release of oil, gas or any other commodity from a pipeline;

(j) Authorizes, in certain circumstances, that funds may be paid out of the Consolidated Revenue Fund to pay the costs of taking the actions or measures that the NEB considers necessary in relation to an unintended or uncontrolled release of oil, gas or any other commodity from a pipeline, to pay the costs related to establishing a pipeline claims tribunal and to pay any amount of compensation that such a tribunal awards; and

(k) Authorizes the NEB, subject to Treasury Board approval, to impose fees, levies or charges from the company that operates the pipeline from which the release occurred and from companies that operate pipelines that transport a commodity of the same class as the one that was released.

ALBERTA COURT OF APPEAL

ATCO Gas and Pipelines Ltd. v Alberta (Utilities Commission), 2014 ABCA 397
Appeal – Costs Awards

The Alberta Court of Appeal (the "ABCA") heard appeals from costs awards related to participation in AUC Decision 2013-051, otherwise known as the Performance-Based Reform Proceeding (the "PBR Proceeding") and AUC Decision 2013-417, otherwise known as the Utility Asset Disposition Proceeding (the "UAD Proceeding").

The UAD Proceeding was initiated by the AUC on April 2, 2008, in order to consider the implications of the Supreme Court of Canada's decision in *Atco Gas and Pipelines Ltd. v Alberta (Energy and Utilities Board)*, 2006 SCC 4. This proceeding was later suspended on November 28, 2008, at the request of ATCO Gas and Pipelines Ltd. and ATCO Electric Ltd. (collectively, the "ATCO Utilities"). The UAD Proceeding resumed on October 17, 2012.

The PBR Proceeding was also initiated by the AUC to examine the merits of performance-based regulation as part of a broader initiative to reform utility regulation in Alberta.

Each of the appeals related to legal and consulting costs claimed by the ATCO Utilities, on the following issue:

> Did the Commission err in law or jurisdiction by denying or limiting recovery of the Appellants' claimed regulatory costs and by treating the costs of or incidental to any hearing or other proceeding of the Commission differently than other costs?

Fraser C.J.A. noted that whether the actual amounts of the costs awards were reasonable was not put in issue by any party, but simply whether the AUC had a separate legal authority to award legal costs. The method that the AUC uses to award costs to be recovered are within the discretion of the AUC.

In both the PBR Proceeding and the UAD Proceeding, the ATCO Utilities were entitled, but were not compelled, to participate. The notice for the UAD Proceeding expressly stated that "Each party shall be responsible for its own costs".

In both proceedings, the AUC held that it had the authority to manage and assess the legal costs of all regulated utilities in Alberta in proceedings before it, including the establishment of guidelines for such costs recovery.

The AUC declined to award the ATCO Utilities all of their legal costs in the UAD Proceeding, limiting cost recovery to the period following the suspension requested by the ATCO Utilities. The AUC had previously denied all legal costs in the UAD Proceeding. However, due to the expansion of the scope of the UAD Proceeding to include issues related to stranded assets and production abandonment, the AUC allowed a partial recovery of costs after October 17, 2012, the date these issues were added.

The AUC also declined to award the ATCO Utilities all of their legal costs in the PBR Proceeding, limiting cost recovery in accordance with Rule 022, plus a premium of 20% over and above the scale of costs provided for in that rule.

The ATCO Utilities asserted that as regulated public utilities, they enjoyed a right to recover from their ratepayers all of their prudently incurred costs for utility operations, and that the AUC did not have the statutory authority to limit or deny an award of legal costs on the basis that it did. The ATCO Utilities took the position that its entitlement included legal costs for proceedings before the AUC, with the only limitation being that the costs must meet the "prudently incurred standard". Accordingly, the ATCO Utilities argued that the decisions below should be reviewed on a standard of correctness.

The ABCA disagreed with the ATCO Utilities' position, holding that the AUC's decision on costs did not involve a question of true jurisdiction, insofar as those decisions did not require the AUC to determine whether it was statutorily permitted to decide a particular matter. It was common ground that section 21 of the *Alberta Utilities Commission Act* ("*AUCA*") empowered the AUC to make determinations on the recovery of costs. The question as such was not whether the AUC had the authority necessary to award legal costs, but whether it was required to make such decisions on a particular standard.

The ABCA therefore reviewed the AUC's decision on a standard of reasonableness, noting that the AUC was interpreting its home statute with which it is particularly familiar. The ABCA also noted the AUC's broad expertise in areas including utility regulatory reform competition policy, strategic planning and development, wholesale markets, service quality and compliance standards, performance-based and incentive regulation, capital structure of regulated utilities, debt and equity markets, utility assets dispositions, utility deregulation, rate-related regulation, and associated policy questions.

Fraser C.J.A offered six reasons to support a finding that the AUC's interpretation of its authority was reasonable:

(a) Section 21 of the *AUCA* and its associated historical provisions, expressly grant the AUC the power to determine whether to award costs, and,

if so, to whom and in what amount. The scheme of the *AUCA* also allowed the AUC to make its own rules with respect to awarding costs from proceedings;

(b) The *AUCA* does not contain any provisions which entitle a utility to full recovery of its legal costs in a proceeding. Any entitlements to cost recovery found in the legislative scheme were held to be associated with the provision of services to ratepayers. Fraser C.J.A held that these services do not include legal costs for regulatory proceedings, much less for generic proceedings before the AUC;

(c) For policy reasons, the AUC would be unduly restricted in its ability to govern its own proceedings were it required to award legal costs to utilities, as utilities would no longer have an incentive not to seek out review and variances of nearly every decision, or keep legal costs in check;

(d) The common law "regulatory compact", which provides that a utility has an opportunity to earn a reasonable return on its prudent investments, and to recover its prudently incurred expenses, could not trump the statutory scheme in place in Alberta. Fraser C.J.A went on to note that even if the regulatory compact guaranteed recovery of such expenses, it would still be subject to, and must give way to, the current statutory framework;

(e) Fraser C.J.A. held that the UAD Proceeding and PBR Proceeding did not involve actual rate-setting for a specific utility. While both proceedings directed their attention towards rates and rate-setting in a general sense, both were held to be fundamentally different than traditional rate-setting hearings, as neither considered whether any specific rate would be "just and reasonable". Therefore, none of the legal costs incurred in these proceedings fell within the scope of regulatory costs incurred in rate-setting hearings; and

(f) The AUC's decision not to award, or to limit the award, of legal costs does not improperly reduce the rate of return for the ATCO Utilities, as a "guaranteed" recovery of legal costs may well give rise to a lower rate of return due to a lower risk, a factor that the AUC takes into account when setting rates.

Côté J.A concurred in the result with Fraser C.J.A., agreeing with the Chief Justice's characterization of the proceedings as being fundamentally different from a traditional rate hearing, and that the AUC had the requisite authority to make rules respecting cost awards. However, Côté J.A. declined to engage with principles respecting how to handle a utility company's hearing expenses in traditional rate hearings, noting that the issue here was confined to how much the cost award should be. (The issue was the quantum of costs allowed, not whether the AUC had the requisite authority to award/deny costs.)

Côté J.A. dismissed arguments from the ATCO Utilities suggesting that the onus of proof lies with interveners to adduce evidence that the expenses incurred by a utility are not correct and reasonable, noting both the AUC's broad level of expertise and experience, and the AUC's ability to gather information on its own initiative.

Côté J.A. dismissed the appeals, noting that the AUC addressed and turned its mind to the proper topics, and found no grounds to interfere with the AUC's decisions.

Martin J.A. concurred in the result of the appeal of the PBR Proceeding, but dissented on the UAD Proceeding appeal, holding that parties could not reasonably be asked to incur costs in providing input, and then have the AUC arbitrarily decide that legal costs would not be recoverable. Therefore, Martin J.A. found that the prudently incurred standard was an effective standard and provided the necessary incentives to restrain expenses.

However, Martin J.A. rejected the arguments from the ATCO Utilities suggesting that the scale of costs unduly fettered the AUC's discretion in awarding legal costs. Martin J.A. held that the scale of costs was a flexible scale to be used as a reflection of what it considers to be reasonable legal tariffs, and did not impede the AUC's assessment of the prudence or reasonableness of the ATCO Utilities' legal costs.

In the result, the ABCA dismissed the appeals, finding that the AUC did not err in its findings denying in whole or in part, the legal costs of the ATCO Utilities. Fraser C.J.A also noted that "the appeals serve as a cautionary example of the complexity associated with the regulation of the utilities sector and why courts should be circumspect before interfering with decisions of expert tribunals."