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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.

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ALBERTA ENERGY REGULATOR

2014B AER Administration Fees (Industry Levy) (AER Bulletin 2014-34)
AER Bulletin – Administration Fees

The AER issued Bulletin 2014-34 (the "Bulletin") to provide notice of a second industry levy for operating fees for 2014. The Bulletin states that the first levy, approved on April 15, 2014 was made in the amount of $207.3 million (the "2014A Levy"). The second levy, approved on October 16, 2014, was made in the amount of $35.9 million (the "2014B Levy").

Fees for the 2014B Levy were calculated according to the same methodology as the 2014A Levy, and will be shared between the following energy sectors:

(a)	Oil and Gas	-	$26,054,000
(b)	Oil Sands	-	$9,310,000
(c)	Coal	-	$536,000

Invoices to operators will be mailed on November 3, 2014 detailing fee calculations, and will be payable by December 3, 2014. The Bulletin notes that fees are payable, irrespective of whether an operator has filed an appeal.

Changes to the Hydraulic Fracturing Notification Submission Procedure (AER Bulletin 2014-36)
AER Bulletin – Notification Procedures

The AER has updated its fracturing notification procedure under Directive 083 *Hydraulic Fracturing – Subsurface Integrity*, including the hydraulic fracturing notification form. The notification form must be submitted at least five days before the pressure test of surface equipment for hydraulic fracturing operations. These changes will become effective December 3, 2014.

Prosper Petroleum Ltd. Regulatory Appeal of 24 Well Licences and a Letter of Authority Undefined Field (Decision 2014 ABAER 013)
Regulatory Appeal – Well Licence – Letter of Authority

In early 2013 Prosper Petroleum Ltd. ("Prosper") applied for and received 24 oil sands evaluation well licences and a Letter of Authority ("LOA") issued under the *Public Lands Act* ("*PLA*").

On August 2, 2013 the Fort McKay First Nation and the Fort McKay Métis Community Association ("Fort McKay") applied to the AER for a regulatory appeal of the wells and LOA under division 3 of the *Responsible Energy Development Act* (the "*REDA*") and the *Alberta Energy Rules of Practice*. Fort McKay also requested a regulatory appeal of the extensions of the well licences and LOA granted by the AER.

In the winter of 2013, Prosper drilled eight wells, of which seven were abandoned. After receipt of the regulatory appeal request, Prosper voluntarily suspended its work in the area and did not drill the remaining 16 wells.

On November 14, 2014 the AER granted the request for regulatory appeal and issued a notice of hearing.

<u>Issues</u>

Fort McKay submitted that Prosper's well development would prejudice Fort McKay's work with the Government of Alberta ("GOA") in implementing the Moose Lake Protection Plan (the "MLPP") to guide development near the Fort McKay Reserves 174a and 174b, and would impair the plan's ability to protect ecological and culturally significant functions in Fort McKay's traditional territory. Fort McKay also raised concerns with the adequacy of the Lower Athabasca Regional Plan ("LARP") for protecting treaty and aboriginal rights, as it submitted the LARP had yet to assess the management of cumulative effects such as biodiversity and landscape management. Fort McKay also submitted that Prosper had failed to meet the requirements of Ministerial Order 141/2013.

The AER considered the issues to be:

(a) The applicability of the Ministerial Order 141/2013;

(b) The need for the project;

(c) Land use planning;

(d) Environmental Effects; and

(e) Traditional Land Use.

<u>Applicability of Ministerial Orders 141/2013</u>

Ministerial Order 141/2014 ("Ministerial Order") was an Aboriginal Consultation Direction made on November 26, 2013 under section 67 of the *REDA*. The Ministerial Order operates to ensure that the AER makes decisions in respect of energy applications that are consistent with the work of the GOA:

(a) In meeting its consultation obligations associated with the existing rights of aboriginal peoples as recognized under Part II of the *Constitution Act*, 1982; and

(b) In undertaking its consultation obligations pursuant to *The Government of Alberta's First Nations Consultation Policy on Land Management and Resource Development* (2005).

The AER held that the effect of this direction establishes that Alberta is responsible for assessing the adequacy of Crown consultation related to energy applications. The AER has to ask the Aboriginal Consultation Office whether the Government has found the consultation to have been adequate, pending the outcome of the AER's processes. Functionally this requires that project proponents provide a detailed assessment of potential impacts of energy resource activities on aboriginal communities so that the AER can meet its obligations.

In interpreting the Ministerial Order, the AER held that the Ministerial Order clearly states that it applies only to "energy applications" which are ultimately for "energy resource activity approvals" under "specified enactments." The *REDA* distinguishes between "specified enactments", which includes the *PLA*, and "energy resource enactments", which includes the *Oil and Gas Conservation Act*. Therefore, the AER concluded that the Ministerial Order did not apply to the 24 well licences, but that it did apply to the LOA.

The AER held that the LOA extension did not affect the scope of Prosper's proposed work, and thus did not require any new Crown consultation. The AER further saw no useful purpose to restarting the Crown's consultation process, especially since the consultation adequacy decision for the LOA was reviewed and confirmed by the Alberta Court of Queen's Bench as adequate.

<u>Need for the Project</u>

The AER held that there was a need for the oil sands exploration program, as the delineation of the oil sands leases was needed for Prosper to continue development of its Rigel project. The delineation therefore also established the need for the proposed 24 core-hole evaluation wells and the extension of the LOA.

<u>Land Use Planning</u>

The AER noted its requirement under section 20 of *REDA* to act in accordance with regional plans under the *Alberta Land Stewardship Act.* The Prosper OSE program is within an area subject to LARP.

The AER accepted that broad-scale land use decisions are directed by LARP. The AER understood that various subregional plans and frameworks are currently being developed, such as The Moose Lake Protection Plan. However, until they are implemented by the GOA, the AER cannot speculate on what these plans and frameworks will contain.

The AER must also act in accordance with LARP as it exists today. It is unnecessary and would be inappropriate to defer AER decisions on regulatory appeals until the various LARP subregional plans and frameworks have been developed and implemented.

The AER found that the 24 evaluation well licences and the LOA were in compliance with and satisfied the current requirements of LARP.

<u>Environmental Effects</u>

The Panel accepted Prosper's submissions regarding disturbance required to accommodate any size of rig, but urged it to fully explore the availability of smaller rigs to minimize the footprint of disturbances. The Panel noted that Prosper's coarse woody debris management contravenes condition 22 of its LOA, and required that any access control be done in consultation with the AER.

The AER held that the Fort McKay submissions on cumulative regional impacts of the oil sands exploration program were of limited assistance in assessing the potential effects. The AER believed that regional planning under LARP was the appropriate mechanism for addressing regional cumulative effects of resource development. The AER accepted that with Prosper's minimal disturbance techniques and seasonal access, the project specific effects would be negligible.

<u>Technical Land Use</u>

The AER held that since limited evidence was submitted with respect to environmental effects of the oil sands exploration program and the general nature of the evidence on traditional use and cultural activities on or near the lease area, it was unable to conclude that the oil sands exploration program was likely to directly affect the traditional land use and cultural activities of Fort McKay.

<u>Disposition</u>

Accordingly, the AER confirmed the AER decisions to issue the 24 well licences and to extend the LOA.

ALBERTA UTILITIES COMMISSION

Stakeholder consultation on AUC Rule 002: Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors (AUC Bulletin 2014-14)
AUC Bulletin – Rule 002

The AUC sought comments from stakeholders on proposed changes to AUC Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors* ("*Rule 002*"). The AUC will review stakeholder submissions and proceed to finalize revisions to *Rule 002* prior to January 1, 2015. Information respecting the current draft of *Rule 002* can be found on the AUC's website, or by clicking this link.

Stakeholder consultation on the Participant Involvement Program of AUC Rule 007: Application for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments (AUC Bulletin 2014-15)
AUC Bulletin – Participant Involvement Program under AUC Rule 007

The AUC sought comments from stakeholders on proposed changes to Appendix A (Participant Involvement Program Requirements) and Appendix B (Cost Breakdown Formats) to AUC Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* ("*Rule 007*"). Information respecting the proposed changes to *Rule 007* can be found on the AUC's website, or by clicking this link.

EPCOR Energy Alberta GP Inc. 2014-2015 Non-Energy Regulated Rate Tariffs (Decision 2014-303)
Non-Energy Regulated Rate Tariffs

EPCOR Energy Alberta GP Inc. ("EPCOR"), in its capacity as general partner of EPCOR Energy Alberta Limited Partnership, applied to the AUC for approval of its non-energy regulated rate tariffs ("RRT"). The RRT provides service to eligible customers within EPCOR Distribution and Transmission Inc. ("EDTI") and Fortis Alberta Inc. ("FAI") service areas for regulated rate option ("RRO") service.

EPCOR requested approval of the following relief in its RRT application:

(a) A non-energy RRT revenue requirement of $46.32 million for 2014;

(b) A non-energy RRT revenue requirement of $45.01 million for 2015;

(c) A return margin of six percent on non-energy revenues;

(d) Continuation of the following deferral accounts:

  (i) bad debt expense; and

  (ii) hearing cost reserve;

(e) Forecast corporate services costs allocated to EPCOR;

(f) Price schedules; and

(g) Terms and Conditions of Services.

<u>Past Decision Compliance</u>

With respect to directions from prior decisions, the AUC held that EPCOR had complied with all directions from Decisions 2010-571, 2012-272, and 2013-110, with the exception of the use of headcounts as a labour component in the composite cost causation allocator, and the inclusion of EPCOR Utilities Inc. investments in Capital Power Corporation ("CPC").

On the matter of headcounts as a labour component, EPCOR explained that historical full-time equivalent ("FTE") data was not previously tracked, and that any reductions in the allocation of corporate services costs would not be material. The AUC accepted this explanation, noting that the change in methodology would reduce the allocations by approximately $0.14 million for each of 2014 and 2015.

With respect to investments and revenues from CPC, EPCOR submitted that it would treat the investment with CPC as a disallowance of regulated revenue requirements. EPCOR explained that this methodology more accurately reflects the AUC's prior findings in Decision 2012-272 and also achieves nearly identical results for the revenue requirement. The AUC accepted EPCOR's methodology, noting the nearly identical outcomes of both methodologies.

EPCOR proposed to forecast its site counts based on an expected announcement from the Minister of Energy to reduce RRO eligibility criteria from 250 MWh to 50 MWh of electric energy consumed.

Since there had been no change to the RRO eligibility criteria, the AUC held that there was insufficient information supporting the conclusion that any such change in the RRO eligibility criteria would occur during 2014 or 2015. Therefore, the AUC directed EPCOR to use the current RRO eligibility criteria of 250MWh of electric energy consumed in its compliance filing.

The Consumers' Coalition of Alberta ("CCA") requested that the AUC apply an increase to forecasted utility associates site counts by EPCOR, in noting that the previous four year average of variances showed an underestimation of approximately 1.22 percent. The AUC agreed with these submissions and directed EPCOR to increase its utility associates site count by 1.22 percent.

The AUC also held that EPCOR's proposed change in methodology, to use the 24 most recent months of site attrition rates to calculate attrition rate forecasts, was not warranted. Using the 12 most recent months of data continues to best reflect current changes in the RRO market. The AUC directed EPCOR to calculate forecast attrition rates using the 12 most recent months of data available.

The AUC held that the operating costs and corporate allocation cost forecasts as applied for were reasonable in comparison to 2013 preliminary actual amounts. However, as a compliance filing was necessary, the AUC directed EPCOR to update its forecasts in its compliance filing using actual 2013 year-end balances for: property, plant and equipment; accumulated depreciation, contributions and accumulated amortization; construction work-in-progress; and return on rate base amounts.

Labour Headcounts

EPCOR used a full time equivalent ("FTE") methodology for labour headcount, and submitted that forecast FTEs were expected to decline from 248 for 2014 to 239 for 2015.

The CCA opposed the proposed FTE amounts, as it submitted that EPCOR's previous approved FTEs compared with actual FTEs have been consistently over-estimated. EPCOR submitted that the largest variance, occurring in 2013, were temporary shortages, and should not reflect on future test years.

The AUC accepted EPCOR's explanation for past variances, and held that the application of a past variance, as suggested by the CCA, would presume that the same factors apply in future years, which the AUC noted was not supported on the record.

Labour Cost Escalation

EPCOR submitted that it did not modify its compensation structure from the 2012 and 2013 test years, and applied for escalators of 4.0 percent for 2014 and 4.5 percent for 2015 for non-unionized employees.

The AUC approved the escalation rates for non-unionized employees as filed, and would establish and approve escalators for unionized employees when deciding on EPCOR's compliance filing.

Operating Costs

EPCOR proposed a new methodology for forecasting bad debt, as the AUC had previously directed EPCOR to consider alternatives to the use of a deferral account. EPCOR proposed to use seasonality (with quarterly data) and trends for six of its nine rate classes in its methodology. EPCOR submitted that the bad debt percentages for the remaining rate classes percentages were not material, and were excluded on that basis. EPCOR submitted that in the absence of a deferral account it would request a risk compensation amount of approximately $0.90 million. EPCOR, however, proposed to continue using a deferral account for bad debt, but would reduce the true-up percentage to 50 percent of the outstanding amounts.

The UCA submitted that using quarterly data, combined with a deferral account would significantly reduce EPCOR's incentive to accurately forecast bad debt during the test years.

The AUC accepted EPCOR's submissions, holding that bad debt was affected by seasonality, and its inclusion would improve quarterly forecasts. However, the AUC continued to express concern over the lack of incentives provided by a deferral account used to manage bad debt expenses. Therefore the AUC accepted EPCOR's proposal for forecast bad debt, but denied EPCOR's request to update revenue forecast on a quarterly basis for the purposes of bad debt forecasting. Accordingly, the AUC directed EPCOR to re-file its bad debt forecast using the new methodology, subject to the finding that the revenue requirement will not be updated quarterly.

The AUC also approved EPCOR's late payment charges forecast, as filed. However, due to concerns respecting future applicability of the method, the AUC directed EPCOR to include an analysis of alternative methodologies in its next non-energy application.

Corporate Costs

EPCOR applied for allocation of corporate costs using the 50MWh RRO eligibility criteria in forecasting its costs, as opposed to the current 250MWh RRO eligibility criteria. Despite the AUC's determination that the amounts allocated under each methodology were substantially similar, the AUC directed EPCOR to apply the 250MWh RRO eligibility criteria for allocating corporate costs in its compliance filing.

The AUC accepted EPCOR's submission that its exclusion of a recent purchase of North Mohave Valley Corporation would have an immaterial impact on corporate cost allocations.

The AUC approved the remainder of the allocated corporate costs to EPCOR based on its occupied floor space within common facilities shared with its affiliates and parent companies.

Embedded Costs

EPCOR submitted that its embedded costs for 2015 had not been finalized prior to submission, opting instead to use 2014 forecast numbers with adjustments for inflation.

The AUC held that finalizing a 2015 forecast for embedded costs would not be particularly onerous, and therefore directed EPCOR to include it in its compliance filing.

Capital Assets and Rate Base

The AUC approved the capital additions and rate base forecasts as applied for, applying the 250MWh RRO eligibility criteria, consistent with other findings in this decision. Further, due to changes requested by EPCOR in the amount of $2.08 million for 2014 capital additions, the AUC directed a corresponding adjustment be made to the depreciation expense for 2014 and 2015 in EPCOR's compliance filing.

Return on Equity

EPCOR requested a continuation of its deemed capital structure of 100 percent debt for the test period. Therefore, without an equity component, EPCOR forecasted debt rates of 6.07 percent for 2014 and 6.20 percent for 2015, and a return on mid-year rate base of 4.8 percent for both 2014 and 2015.

The UCA took issue with ECPOR's 100 percent deemed debt ratio, and suggested a 61 percent debt ratio, as it argued that EPCOR's submissions on debt ratings and credit spreads were largely premised on EPCOR operating as a standalone entity, and not as a subsidiary of a parent company.

The AUC accepted the UCA's submissions, holding that, for the purposes of determining a return on equity, EPCOR is either a subsidiary of a parent, or a standalone entity, but not both. Given EPCOR's submissions on the record, the AUC held that EPCOR was a standalone entity. Standalone entities are distinct from subsidiaries in that the standalone entity employs debt and equity, whereas the subsidiary may be able to rely entirely on the parent company for debt financing, and benefit from stronger credit ratings and hence, lower debt costs.

The AUC held that EPCOR had simultaneously attempted to earn a debt associated with a standalone entity, while also attempting to employ a capital structure of a subsidiary of a parent company.

However, since the AUC was already in the process of reviewing return margins in a generic proceeding, including for RRO providers, the AUC was reluctant to change the deemed capital structure. Therefore, the AUC approved the capital structure as applied for, with a direction to address the issues identified by the AUC on capital structure in EPCOR's next non-energy application. The AUC also approved a six percent return margin for EPCOR, citing the same reasons.

Cost of New Debt

EPCOR requested a cost of debt of approximately 4.80 percent, based on a credit spread of between 1.75 and 2.18 percent, and the 10 year government bond yield of 2.95 percent. The AUC approved a credit spread of 1.75 percent as reasonable, and held that EPCOR must re-file its cost of debt amounts, using an average of 2.70 percent for 10 year government bond yields as set out in consensus forecasts. In addition, the AUC directed EPCOR to submit a forward interest rate curve analysis in its application.

In the result, the AUC made the following findings and directions:

(a) The amounts requested in EPCOR's deferral accounts were approved;

(b) The changes requested by ECPOR for its terms and conditions of service were approved; and

(c) EPCOR must submit a compliance filing to reflect the findings in the decision on or before December 17, 2014.

City of Red Deer 2015 Interim Transmission Facility Owner Tariff (Decision 2014-305)
Interim Transmission Facility Owner Tariff

The City of Red Deer ("Red Deer") applied for an interim, refundable transmission facility owner tariff for 2015, for facilities operated by Red Deer Electric Light and Power Department. The current approved tariff for Red Deer is $323,715 per month. Red Deer requested a continuation of the current rates under its tariff on an interim basis.

Red Deer is expecting to submit its next general tariff application before the end of 2014, and is preparing for a test period beginning on January 1, 2015.

The AUC found that the continued application of the 2014 tariff, as applied for by Red Deer to be reasonable. The AUC therefore approved an interim refundable tariff in the amount of $323,715 per month for Red Deer, effective January 1, 2015.

AltaLink Management Ltd. Terms and Conditions of Service Progress Report and AESO Authoritative Documents Review (Decision 2014-307)
Extension and Relief of Condition – Transition of Authoritative Documents Initiative

AltaLink Management Ltd. ("AltaLink") applied on behalf of itself and other transmission facility owners ("TFO") to amend Direction 1 from Decision 2009-048, which required AltaLink to file an annual progress report on the Alberta Electric System Operator's ("AESO") authoritative documents review process. The purpose of these reports was to ensure that TFO terms and conditions were in alignment with the AESO's work to advance its Transition of Authoritative Documents initiative ("TOAD").

Both AltaLink and the AESO indicated that the TOAD process was largely completed and both parties requested an extension to ensure that all of the rule changes were accounted for and accurately reflected in the terms and conditions of each of the TFOs. Similarly, the AESO indicated that it planned to complete its review and transition relevant TFO terms and conditions into its authoritative documents over the course of the next year.

Therefore, AltaLink requested that it be relieved from the requirement to file an annual report on July 1st of each year, and that an extension be granted to reflect the time needed for the AESO to complete its review.

Based on the submissions received, the AUC directed AltaLink to file a progress report on or before October 1, 2015, and relieved AltaLink of its obligation to file a progress report as required under Direction 1 of Decision 2009-048.

City of Lethbridge 2015 Interim Transmission Facility Owner Tariff (Decision 2014-309)
Interim Transmission Facility Owner Tariff

The City of Lethbridge ("Lethbridge") applied for an interim, refundable transmission facility owner ("TFO") tariff for 2015, for facilities operated by Lethbridge Electric Utility Department. The current approved tariff for Lethbridge is $507,652 per month. Lethbridge requested a continuation of the current rates under its tariff on an interim basis.

Lethbridge is expecting to submit its next general tariff application before the end of 2014, and is preparing for a test period beginning on January 1, 2015. Lethbridge also advised that it would be adopting the generic TFO terms as approved by the AUC in Decision 2010-116, and that it would not be necessary to adjudicate on the general tariff application's terms and conditions.

The AUC found that the continued application of the 2014 tariff, as applied for by Lethbridge, to be reasonable. The AUC therefore approved an interim refundable tariff in the amount of $507,652 per month for Lethbridge, effective January 1, 2015. The AUC also found that it would not be necessary to re-approve the generic TFO terms in this decision.

Alberta Electric System Operator Amendment to the WECC-AESO Membership and Operating Agreement (Decision 2014-310)
Membership and Operating Agreement – Amendment

The Alberta Electric System Operator ("AESO") applied for consent to amend the Western Electricity Coordinating Council ("WECC") AESO Membership and Operating Agreement pursuant to section 21(1)(b) of *the Transmission Regulation* (the "*T-Reg*"). The AESO submitted that it may enter into arrangements or agreements with responsible authorities in other jurisdictions, pursuant to section 9(5)(b) of the *Electric Utilities Act*, though not without the approval of the AUC.

The AESO submitted that the amendments as requested are primarily to reflect changes in business relationships, and to reflect changes in WECC's governance structure. Examples of such changes as noted by the AESO include:

(a) Updates to the mandate of WECC;

(b) Changes as a result of changes to WECC bylaws;

(c) Deleting sections that no longer have any application in Alberta, such a Article 5, Article 8.4, and several definitions in Schedule A to the agreement; and

(d) Miscellaneous housekeeping items.

The AESO submitted that all of the requested changes were compliant with section 22 of the *T-Reg*.

Upon review of the proposed changes and submissions of the AESO, the AUC determined that the changes:

(a) Would continue to provide adequate and predictable frequency of reporting between the AESO and WECC;

(b) Did not offend section 22 of the *T-Reg;* and

(c) Did not delegate any of the AESO's powers, duties or responsibilities to persons outside of Alberta.

As a result, the AUC approved the requested changes to the WECC-AESO Membership and Operating Agreement as applied for.

ENMAX Power Corporation 2015 Interim Distribution and Transmission Tariff Application (Decision 2014-311)
Interim Distribution & Transmission Tariff

ENMAX Power Corporation ("EPC") applied to the AUC for approval to implement 2015 transmission and distribution rates on an interim refundable basis, effective January 1, 2015. EPC had previously filed its 2014 Phase I Distribution Tariff Application and 2014-2015 Transmission General Tariff Application on July 24, 2014. EPC explained that given the timing of a compliance filing, 2014 final rates would not likely be approved before the end of 2014, necessitating an interim tariff for 2015.

EPC also submitted that, in the absence of updated interim tariffs, it forecasted a revenue shortfall of $10.229 million for its distribution function, and $14.260 million for its transmission function. EPC's calculated revenue shortfalls would require increases of 5.31 percent to its distribution rates, and 23.11 percent to its transmission rates. However, EPC proposed to collect revenue of $70.264 million for transmission, and $198.710 million for distribution, resulting in the collection of 60 percent of the revenue shortfalls.

Therefore, in order to reduce the impact of rate increases upon implementation of 2015 final rates, EPC requested interim rates for its distribution and transmission tariffs. EPC calculated its revenue shortfalls by applying the performance based regulation formula, which applies the previous year's base rates for each customer class, multiplied by a reduced inflation factor (a product of subtracting a "productivity factor" from the "inflation factor").

Upon review of the application, based on the quantum and need for interim tolls, and consideration of the public interest in granting interim tolls, the AUC held that the total revenue deficiency would be a material amount that could impose certain financial hardships on EPC. The AUC also held that the magnitude of the potential revenue shortfall could cause a rate shock to customers in the event of an interim rate adjustment for the full amount. The AUC held that granting interim rates would provide a gradual and stable transition to 2015 final rates.

The AUC held that the requested amount was reasonable, noting that no objections were received, and that the amount represented an intermediate position between current rates and proposed final rates. The AUC also held that the allocation methodology of applying the increase to all rate classes across the board was a reasonable method, in that it was cost effective to apply and preserved the current approved rate structure.

The AUC therefore approved an increase to EPC's interim distribution tariff of 3.19 percent on an interim basis, effective January 1, 2015. The AUC also approved an increase to EPC's interim transmission tariff of 13.87 percent on an interim basis, effective January 1, 2015.

Alberta Electric System Operator 2015 Balancing Pool Consumer Allocation Rider F (Decision 2014-317)
Rider F

The Alberta Electric System Operator ("AESO") applied to the AUC pursuant to section 82(6) of the *Electric Utilities Act* (the "*EUA*") for approval of:

(a) An annualized amount provided by the Balancing Pool to the AESO for 2015; and

(b) A refund of the annualized amount through a $5.50 per megawatt hour (MWh) credit to demand transmission service and demand opportunity service customers, with the exception of the City of Medicine Hat and BC Hydro at Fort Nelson, for all consumption between January 1, 2015 and December 31, 2015.

The Balancing Pool, pursuant to section 82(4) of the *EUA,* must prepare a forecast of revenues and expenses in an annualized amount, and provide notice to the AESO of the same. The AESO, under sections 30(2)(b) and 82(5) of the *EUA* must include that amount in its tariff. The Balancing Pool notified the AESO of a positive annualized amount of $319,891,000 for 2015.

The AESO proposed the inclusion of this annualized amount as Rider F to its tariff, and submitted that the substantive aspects of its filing remain unchanged from previous filings for Rider F amounts approved by the AUC.

The AUC approved:

(a) The AESO's Rider F without modification, pursuant to section 82(6) of the *EUA;* and

(b) Inclusion of the $5.50 per MWh credit to all DTS and DOS customers, with the exception of the City of Medicine Hat and BC Hydro at Fort Nelson, as requested.

AltaGas Utilities Inc., AltaGas Ltd., Gas Utilities Act Code of Conduct Regulation Approval of Auditor, Audit Plans and Waiver (Decision 2014-318)
Audit Approvals – Gas Utilities Act Code of Conduct Regulation Waiver

AltaGas Utilities Inc. ("AUI") and AltaGas Ltd. ("AltaGas") applied to the AUC, pursuant to directions in Decision 2014-176 and Decision 2014-198 respectively, seeking an order of the AUC:

(a) Approving the appointment of Ernst & Young LLP as auditors for AUI and AltaGas for their 2013 audits;

(b) Approving AUI and AltaGas' 2013 audit work plan; and

(c) Waiving the requirement under section 37 of the *Gas Utilities Act Code of Conduct Regulation* ("*GUACCR*") for each gas distributor or default service provider and its affiliated retailer to each appoint an independent auditor.

The AUC noted that the audit work plans submitted by AUI and AltaGas were substantially similar to those approved by the AUC in Decision 2013-344. While the AUC was generally satisfied with the modifications made, the AUC directed further amendments to the audit work plans with respect to cross subsidization of gas purchases and meetings with retailers, as follows:

(a) For cross subsidization of gas purchases, the AUC directed that the work plan must include steps to obtain a list of all intercompany transactions, and select transactions using the appropriate sampling methodology. Following this step, the work plan must include steps to compare the price/gigajoule charged to affiliated retailers versus non-affiliated retailers as a check to ensure that no cross subsidization occurs; and

(b) For meetings with retailers, the AUC noted that section 8 of the *GUACCR* directed that the work plan must include a procedure to determine whether a meeting with retailers occurred within 30 days of a request for a meeting. The work plan must also include a procedure to determine whether any delay beyond 30 days is reasonable.

Therefore, the AUC approved the applications, but directed AUI and AltaGas to:

(a) File their audit reports for approval no later than January 28, 2015; and

(b) File copies of the updated work plans along with the 2013 audit reports.

EPCOR Energy Alberta GP Inc. Regulated Rate Option Arrangement Agreement (Decision 2014-319)
Regulated Rate Option Agreement

EPCOR Energy Alberta GP Inc. ("EEA") applied pursuant to section 20 of the *Regulated Rate Option Regulation* ("*RROR*") for approval of a regulated rate option ("RRO") agreement with EPCOR Distribution & Transmission Inc. ("EDTI"), whereby EEA would continue to provide RRO service to eligible customers in EDTI's distribution service area for a 10-year term, to commence on January 1, 2015. RRO agreements are expressly permitted under section 104(1) of the *Electric Utilities Act* (the "*EUA*"). Under the agreement, EEA would carry out the duties and functions of EDTI as set out in section 105(1) of the *EUA*, however, EDTI would not be relieved of its responsibilities and liabilities to carry out its duties and functions as an owner of an electric distribution system.

EEA is the current provider of regulated rate tariff ("RRT") service in EDTI's service area, pursuant to an agreement reached in October of 2003 between the predecessor companies of both EEA and EDTI.

In decision 2014-045, the AUC determined that once the restructuring of the EPCOR group of companies had occurred, EEA would be approved to provide RRO service to eligible customers in EDTI and FortisAlberta Inc. ("FortisAlberta") distribution service areas. The AUC, in Decision 2014-303, set the effective date of the EPCOR group of companies' restructuring as March 1, 2014.

EEA submitted that the agreement contained no substantive changes to the essential terms of the previous agreement reached in 2003, but does update the following items:

(a) Current applicable statutes, regulations, and other requirements and references thereto;

(b) The names of the parties to reflect the EPCOR restructuring; and

(c) Drafting style to involve more plain language to make the agreement easier for parties to understand.

The Utilities Consumer Advocate ("UCA") submitted that a comparison of the two agreements indicated that a number of changes and deletions were made, and that the status quo should be preserved where possible.

The AUC applied a public interest test to the application, looking specifically to whether the application will adversely impact the rates that customers would otherwise pay and whether it will disrupt safe and reliable service to customers. The AUC noted that it had previously determined in Decision 2014-045 that the "no harm" standard had been met in the appointment of EEA as the RRO service provider for EDTI, and FortisAlberta.

The AUC found the agreement and the proposed revisions over a 10 year term, to be reasonable, with the exception of the following:

(a) Article 3.1, which addresses changes in applicable laws. The AUC held that the proposed wording was not sufficiently broad to address the requirements of section 20 of the *RROR*. The AUC therefore directed that the Article be changed, and provided specific wording for EEA to amend the agreement;

(b) Article 5.2, which addresses the occurrence of an event where EDTI must "step-in" to provide RRO service. The AUC held that alternative wording offered by EEA in argument stated more clearly that the responsibility for the provision of service remains with EDTI on the occurrence of a "step-in" event. The AUC therefore directed that the Article be changed to reflect the alternative wording provided by EEA;

(c) Article 5.4 of the former agreement must be included in the proposed revisions (with subsequent amendments to reflect names changes). The AUC held that EEA's reliance on the requirements of the *Inter-Affiliate Code of Conduct and the Code of Conduct Regulation* outside of the agreement to ensure the necessary steps are taken to protect customers from the improper release or disclosure of sensitive information was insufficient. The AUC therefore directed that EEA include an updated version of the former agreement Article 5.4 as provided in EEA's reply argument;

(d) A clause similar to Article 5.2(c) of the proposed agreement, which governs access to data, books and records, should be added to Article 8, which governs termination provisions, as it would ensure completeness and parity throughout. The AUC therefore directed this inclusion; and

(e) Amend the indemnity provisions in Article 6 of the proposed agreement to include officers, directors and employees of EEA within the scope of the indemnity provisions, and to remove references to agents and consultants from the scope of the indemnity provisions.

Owing to the revisions required, the AUC directed EEA to provide an updated agreement, to be filed with the AUC for acknowledgement, by December 12, 2014.

Alberta Electric System Operator, Approval of new reliability coordination Alberta reliability standards, removal of Alberta reliability standard IRO-006-WECC-AB-1 and Approval of Reliability Standards Definitions (Decision 2014-320 and Decision 2014-321)
Reliability Standards and Definitions

The Alberta Electric System Operator ("AESO") filed, for review by the AUC, several new reliability standards, pursuant to section 19(4)(b) of the *Transmission Regulation* (the "*T-Reg*"). The AESO recommended the approval of the new reliability standards.

The AESO submitted that the changes were necessary to either reflect updated reliability standards from the Western Electric Coordinating Council ("WECC"), or to update the AESO's duties as a reliability coordinator in ensuring the safe and reliable operation of the interconnected electric system, especially vis-à-vis operating conditions in neighbouring jurisdictions.

The AUC, pursuant to section 19(5) and 19(6) of the *T-Reg*, is obligated to follow the recommendation of the AESO unless the proposed change is demonstrated to be technically deficient, or not in the public interest.

The AUC accepted the AESO's determination that no market participants were likely to be directly affected by the new reliability standards. No objections were filed indicating that the approval of the new reliability standards, or the removal of a reliability standard (as filed by the AESO) was either technically deficient, or not in the public interest.

Therefore, the AUC approved the new reliability standards in accordance with the recommendation of the AESO. The AUC also approved the removal of reliability standard IRO-006-WECC-AB-1 in accordance with the recommendation of the AESO. All of the above changes will be made effective on April 1, 2015.

In addition, the AESO filed for review by the AUC, several new reliability standards definitions, pursuant to section 19(4)(b) of the *T-Reg*. The AESO recommended the approval of the new definitions.

The AESO applied to add the following new terms to its Consolidated Authoritative Document Glossary:

(a) Operational planning analysis;

(b) Real-time

(c) Reliability coordinator;

(d) Reliability coordinator area;

(e) Wide-area; and

(f) Operating reserves.

As no other party made submissions, the AUC approved the reliability standards definitions, pursuant to section 19(6) of the *T-Reg*, in accordance with the AESO's recommendation, to be effective April 1, 2015.

ENMAX Power Corporation 2015 Balancing Pool Allocation Refund Rider (Decision 2014-322)
Refund Rider

ENMAX Power Corporation ("EPC") applied to the AUC for approval of its 2015 Balancing Pool allocation refund rider, to be effective January 1, 2015.

Each year, the Balancing Pool, under *the Electric Utilities Act*, is obligated to advise the Alberta Electric System Operator ("AESO") of its annualized amount to be collected from or refunded to consumers based on its revenues and expenses. On October 16, 2014, the Balancing Pool advised that the consumer allocation refund would continue at $5.50 per MWh effective January 1, 2015 to December 31, 2015.

EPC submitted that it expected to receive approximately $55 million of this refund through the AESO's Rider F approved in Decision 2014-317, based on an energy forecast of 9,996 gigawatt hours (GWh). EPC submitted however, that since the credit is applied at the customer meter, it must also account for distribution losses, and therefore applied its expected line loss percentages provided in EPC's 2014 formula-based ratemaking annual rates and technical report. As a result of applying these losses against the credit, EPC calculated the forecast energy at the meter to be 9,744 GWh.

The AUC held that the methodology applied by EPC in calculating the Balancing Pool Allocation Refund Rider to be reasonable, and was consistent with prior approved Balancing Pool allocation refund rider applications. The AUC therefore approved EPC's 2015 Balancing Pool Allocation Refund Rider as applied for.

AltaLink Investment Management Ltd. and SNC Lavalin Transmission Ltd. et al, Proposed Sale of AltaLink, L.P. Transmission Assets and Business to MidAmerican (Alberta) Canada Holdings Corporation (Decision 2014-326)

Purchase and Sale of Transmission Assets – Share Issuance

The following companies filed applications with the AUC requesting approval for: (i) the issuance of shares; (ii) the transfer of shares; and (iii) the sale of multiple companies holding interests in AltaLink Management Ltd. ("AltaLink"), to MC Alberta (as defined below) pursuant to sections 101 and 102 of the *Public Utilities Act* (the "*PUA*") and the *Public Utilities Designation Regulation* (the "*PUDR*"):

(a) MidAmerican (Alberta) Canada Holdings Corporation ("MC Alberta"), an indirect, wholly-owned subsidiary of Berkshire Hathaway Energy Company ("Berkshire Hathaway");

(b) AltaLink; and

(c) SNC-Lavalin Transmission Ltd. ("T1"), SNC-Lavalin Transmission II Ltd. ("T2"), SNC-Lavalin Transmission III Ltd. ("T3") and SNC-Lavalin Energy Alberta Ltd. ("SNCEAL") (together "SNC").

The applicants described the restructuring and sale as a four step transaction:

(a) T1, T2 and T3 will each transfer the limited partnership units they hold in AltaLink Holdings, L.P. to a newly incorporated Alberta corporation ("NewCo") in consideration for NewCo issuing common shares of the capital of NewCo to each of T1, T2 and T3;

(b) 942064 Alberta Ltd. ("942064") will transfer all of the shares in the capital of SNCEAL to NewCo in consideration for NewCo issuing to 942064 common shares of the capital of NewCo;

(c) 942064 will transfer all of the common shares in NewCo's capital to T1 in consideration for T1 issuing shares of its capital to 942064; and

(d) T1, T2 and T3 will each transfer all of the shares they respectively hold in the capital of NewCo to MC Alberta.

Steps (a) through (c) are described as re-organization transactions prior to the sale, and step (d) is the sale itself.

Under the *PUDR*, each of the applicants requested that the AUC approve a recommendation to the lieutenant-governor in council to remove T1 and T2 as designated owners of a public utility, to be replaced by a yet to be incorporated company which will acquire the shares of all SNC entities that are designated owners of AltaLink. The applicants also requested a declaration that T3 is no longer required to conduct itself as an owner of a public utility.

The proposed sale was also reviewed separately by the Competition Bureau of Canada and Industry Canada, who found the proposed sale to be acceptable.

The AUC noted a large number of concerns expressed by the public generally covered three topics:

(a) Loss of control of Alberta infrastructure through a sale to a foreign entity;

(b) Concerns about power exports to the United States; and

(c) Quality of service and price increases as a result of the sale transaction.

The AUC declined to consider matters dealing with foreign investment, as it was outside of the scope of the AUC's mandate in this respect. The AUC also declined to consider concerns related to electricity exports, as it noted that AltaLink does not buy or sell the electricity moved over its infrastructure, and electricity imports and exports are regulated under the jurisdiction of the NEB.

The AUC applied the "no harm" test, consistent with previous purchase and sale decisions under sections 101 and 102 of the *PUA*. The AUC articulated the test as requiring AltaLink, MC Alberta and SNC to demonstrate that customers will be at least no worse off as a result of the transaction.

The AUC held that MC Alberta had satisfied the "no harm" test developed pursuant to its public interest mandate in sections 101 and 102 of the *PUA*, in that customers will be at least no worse off after the transaction is completed. In support of this determination, the AUC made the following findings related to the "no harm" test:

(a) The AUC noted that it will maintain its regulatory oversight of AltaLink;

(b) Berkshire Hathaway, the parent company of MC Alberta had made commitments to obtain all of the required approvals, with no additional costs being imposed on ratepayers;

(c) The credit rating analyses from Standard and Poor's and Dominion Bond Rating Services demonstrate either a neutral or beneficial effect on the cost of debt required to finance AltaLink transmission assets;

(d) The existing management expertise will not be changed, and AltaLink may benefit from sharing of best practices with MC Alberta;

(e) The change in ownership does not affect financial isolation and ring-fencing measures around AltaLink. The only amendments to these measures will reflect changes in ownership, but will not disturb the financial, legal and operational separation of AltaLink; and

(f) AltaLink will remain operationally independent.

Accordingly, the AUC approved the sale of AltaLink from SNC to MC Alberta. The AUC also approved the requested designation of MC Alberta as a designated owner of a public utility under the *PUDR*.

In the interim, the AUC directed MC Alberta to act as if it were a designated owner of a public utility pursuant to the *PUDR* until such time as the designation is complete.

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

The AUC approved the following need application and related facility application 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
2014-312	AESO	Pegasus Lake 659S Substation Upgrade NID Approval
	AltaLink Management Ltd.	Pegasus Lake 659S Substation Upgrade Facility Approval

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
2014-306	AltaLink Management Ltd.	Transmission Line 767L Relocation Facility approved
	AltaLink Management Ltd.	Transmission Line 767L Relocation Salvage Approval
2014-325	AltaLink Management Ltd.	Relocation and Construction of Transmission Line 880L Facility Application

Various AUC Franchise Agreements
Franchise Agreement

Pursuant to section 139 of the *Electric Utilities Act* the AUC approved the following franchise agreements upon having found that they were necessary and proper for the public convenience and properly serve the public interest. In each case the term of the agreement is 10 years with two five year options. The approved franchise fees are indicated below as are any applicable linear tax rates.

	Franchise Fee as % of Delivery Revenue	Linear Property Tax Rate
Town of Crossfield – FortisAlberta Inc. (Decision 2014-304)	0%	0.91%

NATIONAL ENERGY BOARD

TransCanada PipeLines Limited Application for Approval of 2015 to 2030 Tolls Decision with Reasons to Follow (RH-001-2014 Letter Decision)
Mainline Tolls and Tariff

TransCanada PipeLines Limited ("TransCanada") filed for approval of a settlement agreement on its Mainline System in December 2013, as a result of "off-ramps" included in the NEB's previous RH-003-2011 decision, setting tolls for TransCanada's mainline. TransCanada requested approval of:

(a) The negotiated settlement;

(b) Mainline tolls in accordance with the Second Amended Appendix D to the settlement for services from 2015 to 2020, with a toll-setting methodology applicable through 2030; and

(c) Revisions to the tariff.

The NEB approved the following service amendments proposed by TransCanada:

(a) 15-year minimum contract term requirements for expansion facilities;

(b) Introduction of an option and process for the conversion of long-haul firm transportation contracts to short-haul firm service;

(c) Amendments to diversion and alternate receipt point rights;

(d) New delivery locations, and modifications to distributor delivery areas;

(e) A new summer storage service; and

(f) A new enhanced market balancing service.

The NEB approved maintaining the current pricing discretion for interruptible service established in the RH-003-2011 decision. However, noting concerns raised during the hearing, the NEB directed TransCanada to undertake a comprehensive review of its trading desk's access to non-public information, and how this non-public information could influence TransCanada's setting of bid floors for interruptible service. The NEB also directed TransCanada to provide remedies on how it will prevent such access.

The NEB approved the following changes to TransCanada's rate base and revenue requirement components:

(a) Proposed revenue requirements for 2015 to 2020, including a deemed equity component of 40 percent, with a 10.1 percent return on equity;

(b) The recovery of the proposed Bridging Contribution attributable to Eastern Triangle tolls from January 1, 2015 to December 31, 2030;

(c) Incentive sharing mechanisms proposed by TransCanada;

(d) Capital expansions to the Eastern Triangle between 2015 and 2020, on a rolled-in basis;

(e) The creation of the Long-Term Adjustment Account;

(f) The allocation of the balance of the Toll Stabilization Account to the proposed Long-Term Adjustment Accounts; and

(g) The elimination of the Toll Stabilization account.

As a result of these findings, the NEB directed TransCanada to make the following filings:

(a) A compliance filing to RH-001-2014 before March 31, 2015. This compliance filing accounts for the tolls in this application being implemented on an interim basis from January 1, 2015, with any recorded differences through to the date of the compliance filing being recorded in the Long-Term Adjustment Account;

(b) A tolls application for 2018 to 2020, to be filed no later than December 31, 2017, which must include:

    (i) A review of revenue requirements and its components for the 2018 to 2020 period;

    (ii) A review of billing determinants;

    (iii) A review of discretionary miscellaneous revenue forecasts for 2018 to 2020; and

    (iv) Any other material changes that would impact the operation of the Mainline over the 2018 to 2020 period.

The NEB indicated that its reasons for decision would follow and be released on or before December 18, 2014.

Kinder Morgan Canada Inc. Trans Mountain Pipeline ULC Request to Lift Pressure Restriction Safety Order SO-T260-005-2013 NPS 24 Mainline Liquids Leak
Pressure Restriction – Safety Order

Kinder Morgan Canada Inc. ("Kinder Morgan") applied to the NEB to lift the pressure restriction imposed under condition 1 of Safety Order SO-T260-005-2013 for the segment of the Trans Mountain Pipeline running from Sumas, BC to the border with the United States of America (the "Sumas Segment").

Kinder Morgan had previously discovered and reported two leaks from cracks in the Sumas Segment as a result of inline inspections conducted in 2012.

Based on the engineering assessment provided by Kinder Morgan in support of its application, the NEB held that Kinder Morgan had complied with its commitments outlined in Kinder Morgan's Integrity Assurance Plan. The NEB therefore granted the application to lift the pressure restriction, and allowed Kinder Morgan to return the Sumas Segment to full service, as Kinder Morgan had complied with all of the conditions of Safety Order SO-T260-005-2013.

Updates to NEB Filing Manual
Filing Manual

The NEB released several minor amendments to the filing manual. Most changes are reflective of the repeal of the *Canadian Environmental Assessment Act*, SC 1992, c 37, the passage of the *Canadian Environmental Assessment Act, 2012*, and changes from *Regulations Amending the Regulations Designating Physical Activities* from Environment Canada with respect to wildlife and wildlife habitat.

The updated filing manual can be found on the NEB's website at this link.