ISSUE:
MARCH 2016
DECISIONS

ENERGY REGULATORY REPORT

Regulatory Law Chambers *is a Calgary-based boutique law firm dedicated to excellence in energy regulatory matters. We have expertise in oil and gas, electricity, including renewable energies and commercial matters, tolls and tariff, 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"), all levels of 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 Vincent Light at Vincent.Light@RLChambers.ca.

IN THIS ISSUE:

Supreme Court of Canada 3

Chippewas of the Thames First Nation v Enbridge Pipelines Inc. et al. (2016 CanLII 12151) 3

Hamlet of Clyde River Inc., et al. v. Petroleum Geo-Services Inc., et al. (2016 CanLII 12154) 3

Alberta Government 4

Government of Alberta Announces Coal Facilitator for Phase-Out of Coal Power Plants (March 16, 2016) 4

Alberta Energy Regulator 5

Bulletin 2016-02: Direction for Conservation and Reclamation Submissions Under an Environmental Protection and Enhancement Act Approval for Enhanced Recovery In Situ Oil Sands and Heavy Oil Processing Plants and Oil Production Sites 5

Bulletin 2016-03: Invitation for Feedback on Amendments to Directive 013: Suspension Requirements for Wells 5

Bulletin 2016-05: First 2016/17 Orphan Fund Levy 6

Root Cause and Regulatory Response Report: Canadian Natural Resources Ltd. Primrose Bitumen Emulsion Releases, 20136

Bulletin 2016-07: Updates to Directive 017: Measurement Requirements for Oil and Gas Operations 7

Alberta Utilities Commission 8

EDF EN Canada Development Inc. Blackspring Ridge Wind Power Plant Supplementary Post-Construction Comprehensive Noise Study for Receptor Location LM5 (Decision 21203-D01-2016) 8

ATCO Utilities Evergreen II Application – Compliance Filing to Decision 2014-169 (Errata) (Decision 3378-D01-2016) 8

ATCO Electric Ltd. 2014 PBR Capital Tracker True-Up and 2016-2017 PBR Capital Tracker Forecast (Decision 20555-D01-2016) 9

Proceeding 790 – AUC ruling on AESO Implementation Plan and Response to Clarification Requests (March 18, 2016) 14

Recommendation to Reject for Adoption of NERC Reliability Standards: New Versions of NERC Reliability Standards and INT-011 and INT-011-1, Intra-Balancing Authority Transaction Identification (Decision 21075-D02-2016) 16

Decision on Request for Review and Variance of Decision 20598-D10-2016 AltaLink Management Ltd. and TransAlta Corporation Time Extension Request for Transmission Lines 909L and 1043L (Decision 21291-D01-2016) 16

EPCOR Distribution & Transmission Inc. 2013-2014 AESO Deferral Account Reconciliation True-Up Rider (Decision 21290-D01-2016) 17

ATCO Gas and Pipelines Ltd. Z Factor Application for Recovery of 2013 Southern Alberta Flood Costs (Decision 2738-D01-2016) 17

Office of the Utilities Consumer Advocate Review of Decision 20271-D01-2015: FortisAlberta Inc. Disposition of Land in High River (Decision 20990-D01-2016) 20

Direct Energy Regulated Services 2012-2016 Default Rate Tariff and Regulated Rate Tariff Compliance Filing (Decision 20785-D01-2016) 21

ENMAX Generation Portfolio Inc. ENMAX Downtown District Energy Centre 3.3-Megawatt Natural Gas-Fired Power Plant (Decision 21247-D01-2016) 24

Livingstone Landowners Guild Decision on Preliminary Question Application for Review of Decision 2009-126 AESO Needs Identification Document Application Southern Alberta Transmission System Reinforcement (Decision 20846-D01-2016) 24

Alberta Electric System Operator 2016 ISO Tariff Update (Decision 21302-D01-2016) 25

Bulletin 2016-06: Notice of Consultation Process for Standardization of Confidential Undertaking 25

Bulletin 2016-07: Practice Advisory and Procedural Change – Expert Witness Qualification No Longer Required 26

Bulletin 2016-08: Amendments to Rule 009: Rules on Local Intervener Costs and Rule 022: Rules on Costs in Utility Rate Proceedings 26

Bulletin 2016-09: Amendment of AUC Rule 016 Review of Commission Decisions 27

Bulletin 2016-10: Practices regarding enforcement proceedings and amendments to AUC Rule 001: Rules of Practice 27

Bulletin 2016-11: Rule 030: Compliance with the Code of Conduct Regulation 28

National Energy Board 29

Energy East Pipeline - Supplemental Application To Participate Notice 29

SUPREME COURT OF CANADA

Chippewas of the Thames First Nation v Enbridge Pipelines Inc. et al. (2016 CanLII 12151)
Leave to Appeal – Duty to Consult – National Energy Board

The Supreme Court of Canada granted leave to appeal with costs to the Chippewas of the Thames First Nation in respect of the decision of the Federal Court of Appeal in *Chippewas of the Thames First Nation v Enbridge Pipelines Inc.*, (2015 FCA 222).

The Supreme Court of Canada, as is its normal practice, did not provide reasons for its decision to allow leave to appeal.

The decision under appeal concerned a request by the Chippewas of the Thames First Nation to quash the NEB's approval of the Line 9B Reversal and Line 9 Capacity Expansion Project, in Hearing Order OH-002-2013. The Chippewas of the Thames First Nation applied to the Federal Court of Appeal on the basis that the NEB had no jurisdiction to issue exemptions and authorizations to Enbridge Pipelines Inc. prior to the Crown's fulfilment of its duty to consult and accommodate the Chippewas of the Thames First Nation. The Federal Court of Appeal dismissed the appeal of the Chippewas of the Thames First Nation.

The Supreme Court noted that the appeal in this instance will be heard together with *Hamlet of Clyde River Inc., et al. v. Petroleum Geo-Services Inc., et al*.

Hamlet of Clyde River Inc., et al. v. Petroleum Geo-Services Inc., et al. (2016 CanLII 12154)
Leave to Appeal – Duty to Consult – National Energy Board

The Supreme Court of Canada granted leave to appeal without costs to the Hamlet of Clyde River, Nammautaq Hunters & Trappers Organization - Clyde River and Jerry Natanine (collectively, the "Applicants") in respect of the decision of the Federal Court of Appeal in *Hamlet of Clyde River v. TGS-NOPEC Geophysical Company ASA (TGS),* (2015 FCA 179).

The Supreme Court of Canada, as is its normal practice, did not provide reasons for its decision to allow leave to appeal.

The decision under appeal concerned a request by the Applicants for judicial review of the NEB's decision to grant a Geophysical Operations Authorization ("GOA") near Baffin Bay and the Davis Strait. The issues raised by the applicants in the Federal Court of Appeal concerned whether the Crown adequately fulfilled its duty to consult with the Applicants, whether the NEB erred in issuing the GOA, and whether the Crown was obliged to seek the advice of the Nunavut Wildlife Management Board prior to rendering a decision on the GOA.

The Supreme Court noted that the appeal in this instance will be heard together with *Chippewas of the Thames First Nation v Enbridge Pipelines Inc. et al*.

ALBERTA GOVERNMENT

Government of Alberta Announces Coal Facilitator for Phase-Out of Coal Power Plants (March 16, 2016)
Climate Leadership Plan – Coal Fired Generation

The Government of Alberta announced that it had appointed Mr. Terry Boston as the Coal Phase-Out Facilitator under the Climate Leadership Plan.

Mr. Boston is the former head of the PJM Interconnection, the second largest centrally dispatched power system in the world. During Mr. Boston's tenure at the PJM Interconnection, approximately 16,000 megawatts of coal-fired generation were retired, and an additional 7,000 megawatts are planned for retirement there prior to 2019.

The Government of Alberta announced that Mr. Boston with work with coal-fired electricity generators, the Alberta Electric System Operator, and the Government of Alberta to develop options in phasing out emissions from coal-fired generation in Alberta by 2030 under the Climate Leadership Plan.

The announcement notes that 12 of Alberta's 18 coal-fired generators are expected to shut down before 2030 under federal coal regulations. The announcement notes that the primary focus of the coal facilitator's work is to work with the remaining six coal-fired generating units that would otherwise be expected to operate past 2030.

More information regarding the scope of work of the coal facilitator can be found here.

ALBERTA ENERGY REGULATOR

Bulletin 2016-02: Direction for Conservation and Reclamation Submissions Under an Environmental Protection and Enhancement Act Approval for Enhanced Recovery In Situ Oil Sands and Heavy Oil Processing Plants and Oil Production Sites
Specified Enactment Direction – EPEA Approvals

The AER announced that it had issued *Specified Enactment Direction 001: Direction for Conservation and Reclamation Submissions Under an Environmental Protection and Enhancement Act Approval for Enhanced Recovery In Situ Oil Sands and Heavy Oil Processing Plants and Oil Production Sites* ("SED 001") under section 137 of the *Environmental Protection and Enhancement Act* ("*EPEA*"). The AER noted that SED 001 replaces *Manual 010: Guidelines for the Submission of Predisturbance Assessment and Conservation and Reclamation Plan*, and *Guidelines for Submission of an Annual Conservation and Reclamation Report*.

The AER noted that SED 001 includes a direction on completion of a project-level conservation, reclamation, and closure plan ("PLCRCP"). Although a PLCRCP was typically required by *EPEA* approval terms, guidance for developing a PLCRCP had not been documented previously.

SED 001, according to the AER, integrates the PLCRCP, site predisturbance assessment, and site specific conservation and construction plans, as well as annual conservation and reclamation reporting into a single document.

Current *EPEA* approval holders must fulfill the requirements in SED 001 to demonstrate compliance with their *EPEA* approvals.

A copy of SED 001 can be found here.

Bulletin 2016-03: Invitation for Feedback on Amendments to Directive 013: Suspension Requirements for Wells
Directive 013 – Well Suspension – Well Integrity

The AER announced that it was inviting stakeholder feedback on changes to *Directive 013: Suspension Requirements for Wells* ("Directive 13"), which ensures the long-term integrity of a well, and mitigates risks to public safety and the environment. The AER noted that it expected the proposed changes to Directive 13 would improve resource recovery and promote regulatory compliance without compromising effective regulation of inactive well integrity.

The proposed changes to Directive 13 are limited to the following items:

- The method by which compliance deadlines are calculated in section 2.1 would be changed to provide more efficient and integrated regional approaches to managing inactive wells:
  - The suspension deadline date is 12 months after the inactive status date.
  - Deadlines for inspections will be calculated based on the inspection due date in the AER's Digital Data Submission System ("DDS"). All inspection deadlines will be moved from a specific date to the end of that calendar year. For example, the AER noted that an inspection deadline date of July 13, 2016, would be moved to December 31, 2016.
- The requirements for changing a high-risk well to medium or low risk will be included in section 2.2.
- For inactive cavern wells under section 3.2, the licensee would submit a non-routine application to the AER for a suspension.
- Suspension requirements would be amended to provide consistency between well risk types and to align with AER Directive 020: Well Abandonment requirements:
  - Nonsaline water or inhibited (noncorrosive) fluid is to be used in the wellbore, and the top two metres of the wellbore must be filled with a nonfreezing fluid (sections 3.1.1, 3.2.1, and 3.3.1).
  - Pressure testing of low-risk type 1 wells is not required for the purpose of initial suspension nor at the time of ongoing inspections (section 3.1.1).
- Changes in reactivation criteria are provided in section 4 to align with operational practices for low productivity producing wells and for intermittently used injection wells.
  - For a well to be reactivated on DDS, a well will need to report volumetric activity for at least one hour per month for three consecutive months.

    - Pressure testing of casing and tubing for the reactivation of a well are not required if the initial well suspension was completed less than 12 months ago.

- The inactive well licence list will be available to all stakeholders on the Directive 013 page of the AER website.
- Unclear or conflicting definitions to be clarified:
    - The critical sour well definition from Directive 056: Energy Development Applications and Schedules is used (section 1.2).
    - The H2S level discrepancy between low and medium risk well definitions (section 3.1) will be eliminated.
    - “noncritical sour cased wells” will mean “cased-hole wells that are not critical sour” for low-risk wells (section 3.1).
    - Low-risk wells inactive for more than 10 years will be moved to the medium-risk well category (section 3.2).

The AER noted that the proposed revisions of Directive 013 do not include any other changes, and the AER requested that stakeholder comments be limited to the above topics.

The AER noted that feedback will be accepted until March 31, 2016. A full copy of the proposed changes can be viewed here.

Bulletin 2016-05: First 2016/17 Orphan Fund Levy
Orphan Fund Levy

The AER announced that, in accordance with Part 11 of the *Oil and Gas Conservation Act*, the AER will prescribe an orphan fund levy in the amount of $15 million.

The Bulletin notes that the Orphan Well Association, along with the Canadian Association of Petroleum Producers and the Explorers and Producers Association of Canada have approved a $30 million orphan fund levy to fund the Orphan Well Association’s budget for the 2016/17 fiscal year.

The first instalment of the orphan fund levy will be $15 million in March 2016, and the second instalment will also be $15 million in August or September 2016.

Allocation of the orphan fund levy among licensees will be as follows:

Levy = A / B x $15,000,00

Where A is the licencee’s deemed liabilities on February 6, 2016 included within the Licensee Liability Rating and Oilfield Waste Liability programs, and where B is the sum of the industry’s deemed liabilities on February 6, 2016 under the same programs.

An orphan fund levy invoice will be sent to each licensee’s chief financial officer via e-mail by March 23, 2016. Licensee’s who do not receive a copy of their orphan fund levy by March 28, 2016 must request a copy from the AER.

All orphan fund levy invoices must be paid by April 25, 2016. All appeals of orphan fund levy amounts must also be received by the AER by April 25, 2016.

Root Cause and Regulatory Response Report: Canadian Natural Resources Ltd. Primrose Bitumen Emulsion Releases, 2013
Flow-to-Surface – Investigation Report

The AER announced the results of its investigation into the four flow-to-surface (“FTS”) events which released bitumen emulsion at Canadian Natural Resources Limited’s (“CNRL”) Primrose and Wolf Lake (“PAW”) high pressure cyclic steam stimulation (“HPCSS”) project.

The AER noted that the report focused on the root cause and regulatory response to the FTS events, and did not address the environmental impacts or the cleanup and remediation of the FTS sites.

In response to the initial releases of bitumen emulsion, the AER had ordered CNRL to:

- Submit detailed containment, clean up, and remediation plans for each of the four FTS sites;
- Submit a plan to confirm that CNRL had identified all of the FTS sites in the PAW project;
- Suspend steaming operations within 1000 meters of specific FTS sites;
- Modify steaming operations, including:
    - Reducing overall cycle volumes;
    - Capping volume above fill-up; and
    - Tapering steam volumes at the edges of steam waves;

- Implement more stringent operation monitoring protocols; and
- Conduct a risk assessment of and develop a mitigation plan for existing wellbores in the vicinity of pads prior to steaming.

CNRL identified four separate conditions that contributed to or caused the FTS events to occur from the Clearwater reservoir to surface:

- an excessive release of bitumen emulsion from the Clearwater reservoir into the next overlying permeable formation, the Grand Rapids formation;
- a hydraulically induced vertical fracture that propagated up to the top of the Grand Rapids formation;
- vertical pathways that facilitated fluid transfer through highly impermeable shales that have in situ stress states that usually favour horizontal hydraulic fracturing; and
- an uplift of the overburden above the Clearwater reservoir that changed the stress in the overlying shale such that the minimum horizontal and vertical principal in situ stresses approached each other.

CNRL noted that not all of the conditions were necessary to create an FTS event.

The AER agreed with CNRL's assessment of the conditions, and found that HPCSS operations will cause a significant increase to reservoir pore pressure, resulting in a decrease to effective stress, causing either tensile fractures, or shear failure in the reservoir sands. The resulting high shear stress can lead to failure of the capping shale, and casing failures in wells that penetrate the interface where shear stresses occur.

The AER however noted that three aspects of the enabling conditions identified by CNRL were controllable:

1) the existence of a cased well or open-hole wellbore with a poor seal along at least a portion of its path;

2) excessive uplift generated by operational steaming in the Clearwater reservoir; and

3) excessive fluid volume released from the Clearwater reservoir into the Grand Rapids formation.

Since the minimum in situ stress was vertically oriented in some formations, increases to vertical stresses caused the minimum horizontal and vertical stresses to approach each other, making vertical fractures more likely. The AER noted that this mechanism increased the probability of bitumen emulsion flowing upward.

Accordingly, the AER determined that bitumen emulsion was released through the Clearwater capping shale due to failure of the caprock from HPCSS operations. The AER noted that HPCSS operations at PAW have either activated existing fracture networks and faulting of the Clearwater shale, or altered the in situ stress state sufficiently to enable release of bitumen into the Grand Rapids formation.

The AER determined that CNRL did not contravene any rules in their use of the specific steaming strategy at PAW. However, the AER noted that it has since imposed regulatory requirements to prevent any further such FTS incidents.

Bulletin 2016-07: Updates to Directive 017: Measurement Requirements for Oil and Gas Operations
Bulletin – Directive 017

The AER announced that it had released a revised edition of Directive 017: *Measurement Requirements for Oil and Gas Operations* ("Directive 17"), replacing the current edition effective March 31, 2016. The AER noted that the updated Directive 17 revises aspects of measurements systems for production operations in the Duvernay and Montney formations, pad-level measurement at thermal operations, smart transmitter calibration, and proving and sampling frequencies. The AER stated its view that these changes would provide greater flexibility and reduce operating costs without compromising the accuracy of measuring and reporting.

A table of the changes to Directive 17 can be found here, and the full text of the updated edition of Directive 17 can be found here.

ALBERTA UTILITIES COMMISSION

EDF EN Canada Development Inc. Blackspring Ridge Wind Power Plant Supplementary Post-Construction Comprehensive Noise Study for Receptor Location LM5 (Decision 21203-D01-2016)
Wind – Noise Study

EDF EN Canada Development Inc. ("ECDI") asked the AUC to consider whether its post-construction comprehensive noise study complied with AUC Rule 012: *Noise Control* ("Rule 12").

ECDI received approval from the AUC to modify the Blackspring Ridge wind power plant ("Blackspring") in Decision 2013-004 and Decision 2013-238. In Decision 3537-D01-2015, the AUC determined that while Blackspring was compliant with Rule 12 for daytime and nighttime sound levels at four receptor locations, the AUC held that ECDI had not complied at a fifth receptor location for nighttime sound levels after isolation. The AUC accordingly ordered ECDI to conduct a post-construction comprehensive noise study within two years of the decision.

ECDI submitted a post-construction noise study which analyzed two, nine hour nighttime periods, of which it submitted 4.2 hours could be considered as "representative conditions". ECDI submitted that the measured and adjusted average sound levels during representative conditions were 36.8 dBA L_{eq}, and that low frequency noise was not a concern for the project.

The AUC determined that the measurements collected by ECDI for the purposes of the post-construction noise assessment, and the conclusions of the noise assessment were compliant with the requirements of Rule 12. Accordingly, the AUC held that ECDI's noise assessment was within the 40 dBA L_{eq} nighttime permissible sound limit under Rule 12, and therefore ECDI had satisfied the AUC's order in Decision 3537-D01-2015.

ATCO Utilities Evergreen II Application – Compliance Filing to Decision 2014-169 (Errata) (Decision 3378-D01-2016)
Compliance Filing – Rates

ATCO Gas, ATCO Pipelines and ATCO Electric Ltd. (collectively, "ATCO") submitted a compliance filing based on the direction in Decision 2014-169 respecting ATCO's 2010 Evergreen application.

ATCO's Evergreen application was originally a benchmarking report to establish a fair market value pricing for information technology ("IT") and customer care and billing ("CC&B") services for ATCO by non-regulated ATCO affiliates. ATCO's Evergreen strategy was aimed at ensuring that pricing for IT and CC&B services remained aligned to the market in future years without the necessity to periodically benchmark the costs of such services. The AUC originally considered ATCO's 2010 Evergreen application in Decision 2014-169, ordering a compliance filing.

<u>IT Costs and Customer Care Costs</u>

ATCO submitted that it applied the approved glide paths approved by the AUC in Decision 2014-169 (which were redacted) to its 2010 prices, in order to establish the 2011 and 2012 IT prices and CC&B prices. ATCO submitted that the 2012 IT and CC&B prices were reflected in the 2012 base rates for its distribution companies operating under performance based regulation ("PBR").

The City of Calgary submitted that it had no concerns with the pricing updates made by ATCO, and stated that the updated filings were satisfactory to demonstrate compliance with base year adjustments for IT costs. However, the City of Calgary submitted that ATCO had incorrectly calculated CC&B costs for central processing unit ("CPU") minutes, and labour rates.

The AUC held that after review, it was satisfied that any potential misstatement of CPU minutes did not have a material effect on the relevant CC&B amounts or resulting refund amounts. The AUC also held that ATCO correctly applied a blended rate of consultants, project managers and other staff in calculating labour rates.

The AUC held that ATCO had complied with the AUC's direction in 2014-169 to adjust the IT costs as directed.

<u>Placeholders</u>

The AUC directed ATCO to filed its actual IT and CC&B costs collected in revenues from customers in 2010 for consideration in a true-up as part of any ATCO companies' next annual PBR rates adjustment, or as part of annual filing adjustments for cost-of-service. However, the AUC noted that ATCO should not be using actuals for placeholders, noting that placeholders should be based on forecast values.

<u>Present value approach</u>

ATCO further submitted that the rates approved in Decision 2014-169 impacted capital items and associated property, plant and equipment balances. ATCO proposed using a present-value ("PV") approach to deal with any resulting balance adjustments as a one-time adjustment. ATCO submitted that this approach would allow ATCO to keep existing direct capital and other capital amounts included in rate bases of each of the ATCO companies, allowing customer rates to remain unchanged.

ATCO also submitted that the use of the PV method would align with its audited financial statement and income tax filings, thereby avoiding further administrative effort and complexity associated with making further adjustments.

For PBR utilities, ATCO proposed to calculate the impacts for 2013 and 2014 using the I-X mechanism (revenue requirement, multiplied by an inflation factor less a productivity factor). For cost-of-service utilities, ATCO proposed to calculate impacts by applying approved rates to actual volumes, and comparing that to actual costs to arrive at the adjustment amount.

ATCO calculated the refund amounts using the PV methodology as follows:

- ATCO Electric Distribution - $13,791,000;
- ATCO Gas South - $12,845,000;
- ATCO Gas North - $12,853,000;
- ATCO Electric Transmission - $7,883,000; and
- ATCO Pipelines - $3,225,000.

The Utilities Consumer Advocate ("UCA") submitted that international financial reporting standards ("IFRS") asset impairment would eliminate the need for the use of the PV methodology. The UCA argued that it would have the same benefits in avoid duplication of work, while also avoiding intergenerational equity concerns and risk problems from future economic conditions assumed in the PV method.

The City of Calgary submitted that the information provided by ATCO for the PV method was inconsistent past 2014, because ATCO had not provided all the data required to quantify the amounts for the purpose of redetermining rate base overstatement for the IT and CC&B costs. The inconsistency from ATCO resulted in an overstatement of revenue requirement beyond 2015 of approximately $27,643,000. The City of Calgary submitted that ATCO's PV proposal should be denied, since it would otherwise lead to intergenerational inequity, and would deny the benefit of reduced prices to consumers.

The AUC held that the PV methodology was a reasonable methodology for the purposes of this decision and the PV methodology would be consistent with ATCO's audited financial statements and accordingly avoid duplication of administrative efforts. The AUC held that the PV methodology would not result in intergenerational inequity because the impacts on revenue requirements beyond 2014 were, in the AUC's determination, not material.

Carrying Charges

The City of Calgary noted that ATCO calculated carrying charges of $2.609 million in connection with the payment of refunds to customers. However the City of Calgary expressed concern with the difference of $2.75 million in carrying charges that arose in favour of customers in applying carrying costs using weighted average cost of capital.

The City of Calgary advocated for the calculation using weighted average cost of capital, noting that ATCO was able to invest its overcharged amounts at its weighted average cost of capital, but was only obligated to pay back at a lesser interest rate prescribed by Rule 023: *Payment of Interest* ("Rule 23").

ATCO did not make any submissions on the appropriate method of calculating carrying costs.

The AUC considered that while Rule 23 had been used extensively to determine carrying charges, the use of weighted average cost of capital was not precluded. The AUC held that final approved pricing was applied to both operating and capital projects. Accordingly, the use of weighted average cost of capital was not unreasonable, and directed ATCO to calculate its carrying costs using weighted average cost of capital.

Order

The AUC held that ATCO had complied with the directions made by the AUC in Decision 2014-169, and:

- Directed ATCO to provide evidence of a reconciliation of the true-up amounts as part of its next annual filings for PBR utilities, and as part of its next annual adjustment filings for cost-of-service utilities; and
- Directed ATCO to use weighted average cost of capital in determining carrying charges for any placeholder amounts determined in Decision 2014-169 and in this decision.

ATCO Electric Ltd. 2014 PBR Capital Tracker True-Up and 2016-2017 PBR Capital Tracker Forecast (Decision 20555-D01-2016)

Rates – True-up – Capital Tracker

ATCO Electric Ltd. ("ATCO") applied for approval of its 2014 capital tracker true-up and 2016-2017 capital tracker forecast under performance based regulation ("PBR"). ATCO applied for the revenue requirement associated with its capital trackers to be included in the K factor component of the PBR formula for the applicable year.

The PBR framework, as described by the AUC, provides a formula mechanism for the annual adjustment of rates over a five year term. In general, the companies' rates are adjusted annually by means of an indexing mechanism that tracks the rate of inflation ("I Factor") relevant to the prices of inputs less an offset ("X Factor") to reflect productivity improvements that the companies can be expected to achieve during the PBR plan period. The resultant I-X mechanism breaks the linkages of a utility's revenues and costs in a traditional cost-of-service model. The PBR framework allows a company to manage its business with the revenues provided for in the indexing mechanism and is intended to create efficiency incentives similar to those in competitive markets.

However, certain items may be adjusted for necessary capital expenditures ("K Factor"), flow through costs ("Y Factor"), or material exogenous events for which the company has no other reasonable cost control or recovery mechanism in its PBR plan ("Z Factor").

This supplemental funding mechanism was referred to in Decision 2012-237 as a "capital tracker" with the revenue requirement associated with approved amounts to be collected from ratepayers by way of a "K factor" adjustment to the annual PBR rate setting formula.

In order to receive capital tracker treatment under PBR, a capital project or program must meet the following three criteria established in Decision 2012-237:

- The project must be outside of the normal course of the company's ongoing operations ("Criterion 1");
- Ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party ("Criterion 2"); and
- The project must have a material effect on the company's finances ("Criterion 3").

ATCO applied for capital tracker treatment for the following amounts:

- A reduction of $9.5 million to its 2014 K factor revenue, taking into account actual capital additions and related costs, updated debt rates and weighted average cost of capital assumptions; and
- Forecast K factor revenue of $48.2 million for 2016 and $61.1 million for 2017.

ATCO used the following inflation factors in its 2016 and 2017 capital tracker forecast costs:

- A 3.75 per cent labour inflation rate was applied for union and non-union staff for both 2016 and 2017 to reflect the overall expected average increase for employees.
- An inflation rate of two per cent in 2016 and four per cent in 2017 contractor costs.
- An "other" inflation rate of 2.10 per cent for both 2016 and 2017.

The Consumers' Coalition of Alberta ("CCA") recommended that the AUC approve labour escalation rates of 2.71 for 2016, being a weighted average of the 3.75 percent negotiated rate for union employees, and the 2015 actual rate of 0.6 percent for non-union labour. For 2017, the CCA recommended a labour inflation rate of 1.0 percent. However, due to recent layoffs within the larger ATCO corporate group, the CCA updated its recommended labour escalation rates to 0.0 and 1.0 percent for 2016 and 2017 respectively.

The AUC held that the evidence before it suggested that economic growth forecasts are currently trending downward, but that economic growth is still expected. The AUC also rejected the CCA recommendation, pointing to a lack of evidence that recent layoffs would justify escalation rates of zero and one percent. However, the AUC determined that due to the lower forecast growth rates, ATCO's requested 3.75 percent escalation rate for non-union labour was not reasonable, and instead established an escalation rate of 3.0 percent for labour and contractor costs as more reasonable. The AUC directed ATCO to update its application using this value in its compliance filing for non-union labour and contractor costs.

ATCO's 2014 capital tracker true-up amounts that are the subject of this decision were applied for as follows:

($ million)	2014 Actual	2014 Forecast	Variance
Distribution to Transmission Contributions	0.7	0.8	(0.1)
Buildings, Structures & Leasehold Improvements	8.1	9.4	(1.3)
Information Technology Related	4.6	4.9	(0.3)
Tools and Instruments	1.7	2.1	(0.4)

Transportation Equipment	1.1	3.4	(2.3)
Third-Party Driven Relocations	0.9	1.4	(0.5)
New Extensions	2.9	6.3	(3.4)
Overhead Line Rebuilds, Replacements and Life Extension	2.8	2.7	0.1
Wood Pole Replacements and Life Extension	2.5	3.0	(0.5)
Reliability	0.4	0.9	(0.5)
Wildfire Risk Reduction	0.6	0.9	(0.3)
Total	**26.3**	**36.0**	**(9.5)**

ATCO's 2016 and 2017 capital tracker project forecast costs were applied for as follows:

($ million)	**2016 Forecast**	**2017 Forecast**
Distribution to Transmission Contributions	3.0	4.9
Buildings, Structures & Leasehold Improvements	10.6	12.0
Information Technology Related	4.4	4.5
Tools and Instruments	1.7	1.7
Transportation Equipment	2.6	3.5
Third-Party Driven Relocations	2.0	2.3
New Extensions	10.6	14.0
Overhead Line Rebuilds, Replacements and Life Extension	3.4	4.0
Wood Pole Replacements and Life Extension	5.7	7.4
Reliability	1.0	1.1
Wildfire Risk Reduction	2.7	3.8
Sub-Total	**47.7**	**59.0**
Distribution Automation (New)	0.5	0.9
Transmission Driven (New)	0.0	0.7
Underground Rebuilds, Replacements and Life Extension (New)	0.0	0.5
Total	**48.2**	**61.1**

<u>Project Groupings</u>

The AUC, in Decision 3218-D01-2015, approved a number of ATCO's project groupings. ATCO submitted that for all of its previously approved capital tracker programs, it had maintained the same project grouping as previously approved by the AUC.

ATCO proposed three new programs however, for 2016 and 2017: the Distribution Automation Program; the Transmission Driven Program; and the Underground Rebuilds, Replacements and Life Extension Program.

ATCO submitted that the Distribution Automation Program was required to maintain service reliability, quality and safe operation of its distribution systems, through the installation of field supervisory control and data acquisition ("SCADA") systems, and integrating control room technology and enterprise systems. ATCO submitted that its Distribution Automation Program was consistent with FortisAlberta's Distribution Control Centre/SCADA grouping, which the AUC approved in Decision 2013-435.

ATCO submitted that its Transmission Driven Program consisted of capital additions driven by transmission projects, such as relocating, extending or reconfiguring lines to reach relocated substations, or purchasing transmission line assets where distribution circuits are strung on transmission lines that are being decommissioned. ATCO noted that the Transmission Driven Program did not include transmission projects that address capacity, reliability or distribution deficiencies, as those are associated with other capital tracker programs.

ATCO submitted that the Underground Rebuilds, Replacements, and Life Extension Program was required to maximize the life of underground line components and replacement of damaged or defective equipment. ATCO submitted that this program was consistent with ATCO's Overhead Line Rebuilds, Replacement and Life Extension Program approved by the AUC in Decision 3218-D01-2015.

The Consumers' Coalition of Alberta ("CCA") submitted that ATCO did not provide details on capital expenditures for the Transmission Driven and Underground Rebuilds, Replacements, and Life Extension Programs for 2013-2016, which only surpassed the materiality threshold in 2017. The CCA also proposed that ATCO merge a large number of projects into two programs, being Capital Maintenance and Large System Improvements, which the CCA submitted were the only two programs maintained by ATCO prior to PBR.

The AUC dismissed the recommendation of the CCA, holding that the CCA had not satisfactorily explained any common driver or requirement for such programs.

The AUC determined that consistent with its prior capital tracker Decision 3558-D01-2015, to the extent that the groupings in the 2014 true-up and 2016-2017 capital tracker forecast were the same as those approved in Decision 3218-D01-2015, the AUC would not re-evaluate those groupings.

The AUC also held that the Distribution Automation program, the Transmission Driven Program; and the Underground Rebuilds, Replacements and Life Extension Program groupings were reasonable, and were approved as filed.

Criterion 1 Assessment

With the exception of Fort McMurray North Service Building Project, information technology projects for 2016-2017 and the Distribution Automation Program summarized below, the AUC approved all of the forecast business cases and engineering studies as applied for. The AUC found that the proposed scope, level, timing and forecast costs for the programs applied for continued to be reasonable. The AUC also held that the amounts included by ATCO were prudent, subject to certain adjustments made elsewhere in this decision.

ATCO proposed to have its Fort McMurray North Service Building included as part of its Buildings, Structures and Leasehold Improvements Program. ATCO submitted that rapid growth in the Fort McMurray service area increased the work force needed to operate and maintain it, growing from 39 staff to 103 staff from 2007 to 2014. ATCO noted that it temporarily leased facilities as a short term solution, but noted that its lease expires in 2019. Accordingly, ATCO proposed to include the construction of a North Service Building in 2016 and 2017, at a cost of $20.5 million and $0.61 million for each respective year.

The UCA submitted that this project did not satisfy the test for capital tracker treatment, because it did not satisfy Criterion 1, insofar as ATCO did not, in the UCA's view demonstrate the need, scope and timing of the project as being reasonable. The UCA submitted that ATCO had provided testimony that ATCO could continue to maintain service and safety in its current location. The UCA further took issue with the timing, noting that ATCO proposed to construct the building two years in advance of its lease expiration date.

The AUC accepted that the Fort McMurray service area experienced high levels of growth in the past decade, and noted the corresponding increase of ATCO staff in the region. The AUC also accepted that the construction of the facility would yield significant advantages by, for instance, improving response times for emergencies and customer service requests, and found that the need for the facility was driven by the significant levels of past growth. However, the AUC held that it was not satisfied that the timing of construction was reasonable, being more than two years prior to the expiration of ATCO's current lease. Accordingly, as the Fort McMurray North Service centre did not meet the requirements of Criterion 1, the AUC denied capital tracker treatment for this project in 2016 and 2017.

With respect to information technology projects, the AUC approved the scope, need and timing of ATCO's information technology programs as filed. However, ATCO had applied for a deferral of its measurement compliance project, due to recent changes to meter equipment testing requirements from Measurement Canada. The AUC determined that ATCO's deferral of the measurement compliance project resulted in some work being moved to 2015 from 2014. The AUC however, held that ATCO did not sufficiently explain the progress it made on this program, and did not explain why work was further moved into 2016, and why an additional $4.0 million was required in 2016 to complete the previously approved program for measurement compliance. As a result, the AUC held that it could not determine whether the measurement compliance program for 2016 met the requirements of Criterion 1. Accordingly, the AUC denied capital tracker treatment for the measurement compliance program.

With respect to the Distribution Automation Program, ATCO submitted that it consisted of two main categories, field SCADA installation, and Control Room Technology Development Integration. ATCO noted that its current control centre project consists of acquiring a SCADA master that will collect and present data in a control centre and other operational support. ATCO identified two alternatives to its proposed Distribution Automation program:

- Continuing to use the shard SCADA master with ATCO's transmission function; and
- Changing the rate of field SCADA installations.

ATCO stated that it rejected the first alternative since the shared SCADA master is subject to physical and cyber security regulations that prohibit inter-system integration. ATCO submitted that it rejected the second alternative, pointing to a need for the project at this time to provide adequate levels of service and safety.

The CCA and Utilities Consumer Advocate characterized the Distribution Automation program as a "bucket of costs" rather than a specific plan, and both recommended that the program be denied capital tracker treatment, pointing to a lack of detailed support for costs, aside from the budget provided by ATCO.

The AUC held that the Distribution Automation forecast scope and costs were not adequately supported, and accordingly, the AUC determined that the scope, level, timing and costs for the Distribution Automation Program were not supported. The AUC held that the Distribution Automation Program did not satisfy the requirement of Criterion 1, and was accordingly denied capital tracker treatment at this time.

The AUC generally approved of all of ATCO's proposed capital tracker projects and programs, except where noted otherwise. However, the AUC held that because the adjustments to the I-X mechanism, return on equity, weighted average cost of capital, and billing determinants (Q Factor) affected the program costs for 2016 and 2017, it was unable to make a final determination as to whether ATCO's programs or projects met the assessment requirements for Criterion 1. The AUC therefore directed ATCO to update its accounting test parameters for its applied for projects and programs in its compliance filings to reflect the AUC's findings in this decision.

Criterion 2 Assessment

ATCO submitted that the drivers for each of its previously approved programs and projects had not changed, since they were previously approved in Decision 3218-D01-2015, and submitted that a re-examination of Criterion 2 compliance was not necessary. None of the parties took issue with ATCO's submissions regarding Criterion 2.

The AUC held that there was no need to undertake a reassessment of any of the projects or programs against the Criterion 2 requirements. The AUC also determined that the driver for each of the three new capital tracker programs fell into asset replacement or refurbishment, required by a third party or growth related, and accordingly complied with Criterion 2.

Criterion 3 Assessment

Criterion 3 is a two step materiality test which assesses the impact of capital tracker costs at four basis points of total revenue requirement for individual projects or programs, and 40 basis points of total revenue requirement for the total capital tracker costs not covered by the I-X mechanism for the applicable year.

For its 2014 capital tracker true-up, ATCO applied a four basis point threshold of $0.228 million and a 40 basis point threshold of $2.274 million, which it submitted were previously approved in Decision 3218-D01-2015. ATCO also submitted that each 2014 capital tracker project or program satisfied both materiality requirements of Criterion 3.

For 2016-2017, ATCO submitted that it calculated the materiality thresholds consistent with the methodology set out in Decision 2013-435. However, since ATCO did not have approved inflation factors for 2016 or 2017, it used the approved 2015 inflation factor of 1.49 percent for both 2016 and 2017. Accordingly, ATCO calculated its 2016 materiality thresholds as follows:

- Four basis point threshold: $0.234million; and
- 40 basis point threshold: $2.342 million.

ATCO calculated its 2017 materiality thresholds as follows:

- Four basis point threshold: $0.238 million; and
- 40 basis point threshold: $2.377million.

None of the interveners to the proceeding took issue with ATCO's calculations.

The AUC held that ATCO's calculations and forecasting methods were reasonable. The AUC accordingly approved ATCO's 2014 threshold values as filed, and confirmed that the 2014 true-up values met the materiality thresholds of Criterion 3 for capital tracker treatment. However, since the filing of ATCO's application, the AUC provided a final 2016 I-X value of 0.90 percent in Decision 20822-D01-2015. Therefore, the AUC directed ATCO, in its compliance filing, to apply materiality thresholds for Criterion 3 using the approved 2016 I-X factor as a forecast value for both 2016 and 2017.

Order

The AUC directed ATCO to update the 2016 and 2017 forecast amounts of $48.2 million and $61.1 million in the compliance filing to this decision, to give effect to:

- The 2017 I-X index and Q factor, per Decision 20822-D01-2015;
- The approved labour escalation rates in this decision; and
- The projects that were denied capital tracker treatment (Fort McMurray North Service Building Project, Information Technology Projects and the Distribution Automation Program).

The AUC accordingly directed ATCO to file a compliance filing to this decision on or before April 14, 2016.

Proceeding 790 – AUC ruling on AESO Implementation Plan and Response to Clarification Requests (March 18, 2016)
Line Loss Rule – Procedural Ruling

The AUC released a procedural decision in proceeding 790, which relates to a complaint filed on December 31, 2005 by Milner Power Inc. ("Milner") concerning the Alberta Electric System Operator's ("AESO") Transmission Loss Factor Rule and Loss Factor Methodology ("Line Loss Rule"). The AUC previously ruled in Decision 790-D03-2015 that the AESO must file by February 1, 2016, a plan to develop a revised Line Loss Rule implementing the AUC's findings in Decision 790-D03-2015 regarding developing a compliant Line Loss Rule.

Clarification Requests

The AESO requested clarification of certain findings made in Decision 790-D03-2015, and its compliance with Decision 790-D03-2015.

The AESO requested clarification on calculating raw loss factors, stating that since loss factors are ultimately multiplied by the metered energy supplied, the corresponding value it would use in the loss factor calculation would be the dispatch volume, rather than total system losses as the denominator in the equation to determine loss factors.

The AUC confirmed that the use of dispatch volume as the denominator was the correct approach.

The AESO requested clarification regarding circumstances in which the system access point may not correspond to the energy market supply point. The AESO requested clarification on when a generation unit is connected to a distribution system, and when one or more generating units are connected within an industrial system. The AUC addressed this point in clarifying certain points for aggregating and disaggregating generating units for the purposes of calculating loss factors.

The AESO requested clarification regarding the compilation of 8,760 merit orders for the purposes of calculating loss factors. The AESO stated that the merit order changes throughout an hour, and may therefore result in compiling more than 8,760 merit orders during a year. The AESO stated that it would base its implementation plan on the use of a single merit order for each hour, and requested confirmation that this was the correct approach to complying with the finding in Decision 790-D03-2015. The AUC confirmed that calculating a single merit order for each hour in the year was the correct approach.

The AESO submitted that the use of 8,760 raw loss factors obviated the need for weighting of base cases, but submitted that volume weighting was still necessary. The AUC confirmed that the use of volume-weighted average loss factors was compliant.

The AESO submitted that it would apply loss factor collars and any subsequent adjustments (i.e. clipping and shifting loss factors) at the end of a year, but noted that it would do so from mid-year to mid-year, and not coincident with the calendar year. The AESO sought confirmation that its approach was compliant with the AUC's finding in Decision 790-D03-2015. The AUC confirmed that a mid-year to mid-year approach was compliant.

AESO Implementation Plan

The AESO plans to submit a revised Line Loss Rule in the summer of 2016, with a view to having new loss factors becoming effective by January 2017. The AUC found that the AESO's proposed timeline was reasonable.

AESO Modelling

The AESO stated that for modelling purposes:

- where blocks of available capacity are offered as operating reserves, it would include those blocks at the top of the merit order;
- if a source asset does not submit operating blocks, then a single block is used; and
- available transfer capacity not scheduled over the interties will be added as an import block at the top of the merit order.

The AESO also stated that historical load data will be adjusted to incorporate system changes throughout the year, and that load volumes would be increased or decreased so that total load matches forecast system load for the forecast loss factor year.

New source assets, according to the AESO would be inserted into the merit order based on average price quantity blocks offered by similar assets.

The AUC found that the AESO's modelling approach was consistent with its operation of the system, and was reasonable.

Publication of Input Data

The AESO stated that hourly data for individual data points would be commercially sensitive information which might harm competitive markets by, for example, disclosing bidding patterns or trends. As such, the AESO stated that it would not make public the hourly input data. The AESO stated it would make public any other data it uses for the development of loss factors that is not considered commercially sensitive.

A number of parties objected to the AESO holding any information in confidence, arguing that it would deny access to information necessary to make business decisions based on the AESO's calculations.

The AESO stated in reply that it would provide a random distribution of representative hours to enable testing of loss factors.

The AUC held that the AESO's approach to retaining commercially sensitive information was reasonable.

Aggregation of Source Assets

The AESO proposed to allow generators the choice of aggregating facilities by March 31, 2016 for 2017 loss factors. Market participants would be responsible for any direct costs or impacts under the ISO tariff arising from any aggregation or disaggregation.

The AESO's criteria for aggregation for multiple generating units were as follows:

- at a single location;
- owned or controlled by the same entity; and
- part of a single economic enterprise and not a standalone business.

The AESO stated that the generating units must be aggregated through a single measurement point, and that each point would be associated with one energy market supply point and one set of price-quantity pairs.

The AUC noted that with respect to power purchase arrangements ("PPA"), units held by a single PPA buyer would be eligible for aggregation, whereas units held by multiple buyers would not be, even if they are subject to common offer controls.

The AUC held that the AESO's approach was reasonable.

Exclusion of Hours

The AESO stated that when large assets are disconnected for the purposes of loss factor calculations the system would rebalance through dispatching up the merit order. However, in some hours for large units, supply would be insufficient to balance load. In these instances, the AESO proposed to exclude such hours from its calculations. The AESO expected that the number of such hours would be low, and would not materially affect the total number of hours.

Several parties requested further information regarding the number of hours that were expected to be excluded. The AESO stated that it would not know the total number of hours until Q4 of 2016, once it has calculated 2017 loss factors. The AESO expected to provide a workbook with raw loss factors for each excluded hour, including an explanation for why it was excluded. The AUC found that the AESO's approach was reasonable.

Steps for loss factor calculation methodology

The AESO proposed to take the following steps when calculating final loss factors:

- calculate raw loss factors for each source asset in 8,760 hours at 59:59 of each hour;
- calculate the volume weighted average loss factor for each source asset;
- apply a single annual shift factor to all average loss factors;
- clip and shift the loss factors within the collars; and
- include provisions for adjusting final loss factors when the final loss factor for a source asset changes by 0.25 of more.

With respect to the timing of recalculating loss factors, when a facility's loss factor changes by 0.25 or more, or when errors are identified, such were errors would be corrected prospectively by the AESO.

The AUC found that the AESO's proposed steps to calculate loss factors were reasonable, subject to any determinations the AUC may make based on any further consultation between the AESO and stakeholders.

The AUC therefore approved the AESO's implementation plan subject to the qualifications noted in the decision. Accordingly, the AUC directed the AESO to submit its compliance filing for review and approval in accordance with the timeline set out in the AESO's own implementation plan, or earlier if possible.

Recommendation to Reject for Adoption of NERC Reliability Standards: New Versions of NERC Reliability Standards and INT-011 and INT-011-1, Intra-Balancing Authority Transaction Identification (Decision 21075-D02-2016)
Alberta Reliability Standards – AESO Process – Consultation

The Alberta Electric System Operator ("AESO") applied to the AUC to reject eight reliability standards pertaining to Modeling, Data, and Analysis ("MOD"), Protection and Control ("PRC") and Interchange Scheduling and Coordination ("INT"), as the AESO determined that the reliability standards it rejected did not apply.

The AESO also requested that, going forward, it would not formally consult or forward to the AUC any future versions of previously rejected reliability standards developed by the North American Electric Reliability Corporation ("NERC"), unless the AESO determined the NERC reliability standard should be adopted in Alberta. The AESO was of the view that this change would improve efficiency.

The AUC previously reserved its decision on the AESO's proposal to not consult on future versions of rejected NERC standards in Decision 21075-D01-2016.

The AESO submitted that the legal authority for its proposal to not consult was based on its interpretation of section 19 and 21(3) of the *Transmission Regulation*, noting that the words "to the extent that those reliability standards are adopted by the AESO" delegated authority and discretion to the AESO to adopt Alberta reliability standards.

The AUC held that the *Transmission Regulation* requires that the AESO forward reliability standards along with a recommendation that the AUC either adopt or reject the reliability standard. The AUC held that implicit in the AESO's responsibilities is to tender a copy of the reliability standard itself. The AUC also noted that it had its own obligation of procedural fairness to offer affected parties an opportunity to comment on the recommendation. Furthermore, the AUC held that it must confirm the adoption or rejection. On this basis, the AUC held that it was not within its purview to alter the obligations of the AESO or the AUC as prescribed by the *Transmission Regulation*. Therefore, the AUC rejected the AESO's proposal, and directed the AESO to continue to bring forward new versions of previously rejected NERC reliability standards.

Decision on Request for Review and Variance of Decision 20598-D10-2016 AltaLink Management Ltd. and TransAlta Corporation Time Extension Request for Transmission Lines 909L and 1043L (Decision 21291-D01-2016)
Review and Variance – Time Extension – Transmission Line

The AUC previously approved an application by TransAlta Corporation ("TransAlta") to extend its existing approvals to construct the 909L and 1043L transmission lines (the "Rebuild Project") until July 31, 2016, subject to the condition that TransAlta reach a negotiated settlement with the Enoch Cree Nation ("Enoch"). That condition is also the subject of the review and variance request filed by TransAlta on January 26, 2016.

The deadline for the construction of the Rebuild Project was originally set for August 2012. However the Enoch requested that construction be halted on the Stony Plain Indian Reserve 135. TransAlta and Enoch have since been engaged in settlement discussions to allow construction to continue. TransAlta noted on January 26, 2016 that an agreement in principle was likely to be reached by noon on February 1, 2016, but that such an agreement in principle could not be formalized, as such agreements require a Band Council Resolution from the Enoch. TransAlta therefore requested that the AUC grant additional time to complete the rebuild project out to November 30, 2016, as one of the terms of the agreement was to create subcontracting opportunities for the Enoch members, which would require additional time.

The ground of review advanced by TransAlta was that new facts or changed circumstances arose since Decision 20598-D10-2016 was issued, that could lead the AUC to materially vary or rescind the decision.

The AUC held that the evidence on the record demonstrates that TransAlta and Enoch reached an agreement, and noted that such an agreement constituted a material change since the issuance of Decision 20598-D01-2015 that could lead the AUC to materially vary or rescind the decision.

Having found that TransAlta met the test required for review of Decision 20598-D01-2015, the AUC considered whether it would:

- Delete the condition requiring TransAlta to file by February 1, 2016 confirmation of having reached a negotiated settlement with Enoch; and/or

- Granting a further extension to complete the Rebuild Project to November 30 ,2016.

The AUC noted that the evidence on the record of this proceeding indicated that the agreement was finalized on March 3, 2016, and that the time requested for the extension was to allow time to provide opportunities to the Enoch for the Rebuild Project. The AUC therefore held that the requested variations were in keeping with the broader public interest considerations in Decision 20598-D10-2015, and granted the requested variances.

EPCOR Distribution & Transmission Inc. 2013-2014 AESO Deferral Account Reconciliation True-Up Rider (Decision 21290-D01-2016)
Rates – True-Up – Deferral Account

EPCOR Distribution & Transmission Inc ("EDTI") applied to the AUC requesting approval of its 2013-2014 Alberta Electric System Operator ("AESO") deferral account reconciliation ("DAR") true-up by way of Rider J.

The AUC approved the AESO's reconciliations for deferral accounts in Decision 3334-D01-2015 for amounts related to transmission access charges, which are in turn included in the annual transmission access charge deferral account ("TACDA") true-up applications for each distribution facility owner ("DFO").

EDTI submitted that it received a net refund of $8.99 million to be flowed through to customers in its service area, pursuant to Decision 20866-D01-2016. EDTI submitted that while it would normally include the 2013-2014 AESO DAR true-up amount in its 2015 TACDA true-up application. However, it would refund the amount earlier than originally planned, due to the large amount being refunded constituting more than 25 percent of its forecasted distribution net income for 2015. EDTI also cited financial timing constraints, noting that it would have to book the $8.99 million as revenue for 2016, but that due to the anticipated timing of the 2015 TACDA true-up application, it would not be able to account for the corresponding refund until 2017. EDTI submitted that this would misstate its revenues for both 2016 and 2017.

EDTI proposed to apply Rider J on a per kilowatt-hour (kWh) basis, per rate class. EDTI provided the AUC with calculations for applying Rider J beginning in Q3 2016 and Q4 2016. EDTI expressed a preference for Q3, citing the large size of the refund, and its aforementioned timing concerns.

The AUC noted that in Decision 3334-D01-2015, it had standardized each DFO's annual TACDA applications, with the purpose of ensuring that the AESO tariff charges paid by a DFO are recovered by the revenues collected by a DFO. Accordingly, as the AESO DAR true-up was one such amount, the AUC stated that it preferred that DFOs collect or refund AESO DAR amounts with their annual TACDA applications. However, considering the circumstances of the application and the timing concerns regarding the refund to customers, the AUC held that it would allow EDTI's proposal to settle the amounts with its customers in 2016.

In keeping with the principles set out in Decision 3334-D01-2015 however, the AUC directed EDTI to bring the $8.99 million refund amount to the attention of the parties in its 2015 TACDA application, to be filed in August 2016.

The AUC held that EDTI's proposal and methodology for allocating the refund to be reasonable, and consistent with EDTI's past practice. The AUC also agreed with EDTI's preference to institute the refund in Q3 2015, holding that the principles of rate stability favoured instituting the change over the summer months, when billing determinants were forecast to be at their peak. Accordingly, the AUC held that a refund over this period would naturally smooth out customer billings. The AUC therefore approved EDTI's proposed Rider J in the amount of a refund of $8.99 million, effective July 1, 2016 to September 30, 2016.

ATCO Gas and Pipelines Ltd. Z Factor Application for Recovery of 2013 Southern Alberta Flood Costs (Decision 2738-D01-2016)
Rates – Z Factor – Performance Based Regulation

ATCO Gas and Pipelines Ltd. ("ATCO") applied to the AUC to recover $5.662 million through a Z factor rate adjustment to compensate ATCO for costs incurred as a result of the 2013 Southern Alberta flood. ATCO stated that its proposed adjustments were comprised of the following:

- Revenue requirement amounts totalling $2.461 million for capital assets replaced over five years ($75,000 for 2013; $379,000 for 2014; $660,000 for 2015, $682,000 for 2016, and $665,000 for 2017);
- Operations and maintenance costs totalling $2.951 million, including lost revenues; and
- $250,000 in carrying costs.

ATCO also sought approval to true up its Z factor costs to actuals each year once the actual costs are known.

The Z Factor is a part of the performance based regulation ("PBR"). The PBR framework, as described in other decisions by the AUC, provides a formula mechanism for the annual adjustment of rates over a five year term. In general, the companies' rates are adjusted annually by means of an indexing mechanism that tracks the rate of inflation ("I Factor") relevant to the prices of inputs less an offset ("X Factor") to reflect productivity improvements that the companies can be expected to achieve during the PBR plan period. The resultant I-X mechanism breaks the linkages of a utility's revenues and costs in a traditional cost-of-service model. The PBR framework allows a company to manage its business with the revenues provided for in the indexing mechanism and is intended to create efficiency incentives similar to those in competitive markets.

However, certain items may be adjusted for necessary capital expenditures ("K Factor"), flow through costs ("Y Factor"), or material exogenous events for which the company has no other reasonable cost control or recovery mechanism in its PBR plan ("Z Factor").

The AUC in this decision, noted that the Z Factor can be used to deal with significant events outside the company's control, such as floods or ice storms, which are not reflected in the inflation factor.

The AUC noted that the criteria applied for a Z Factor are as follows:

- The impact must be attributable to some event outside management's control.
- The impact of the event must be material. It must have a significant influence on the operation of the company, otherwise the impact should be expensed or recognized as income, in the normal course of business.
- The impact of the event should not have a significant influence on the inflation factor in the PBR formulas.
- All costs claimed as an exogenous adjustment must be prudently incurred.
- The impact of the event was unforeseen.

  (Collectively, the "Z Factor Criteria".)

The AUC noted that all of the Z Factor Criteria must be met in order to qualify for a rate adjustment.

ATCO submitted that the flooding in 2013 damaged portions of ATCO's distribution system, and submitted that its flood response plan consisted of three phases: 1) initial emergency response; 2) damage assessment; and 3) repair and restoration.

ATCO stated that in phase one, it was required in a number of instances to shut off customer service, resulting in lost delivery revenue, totalling $292,617 during the June 20, 2013 to December 31, 2013 period.

ATCO submitted that the bulk of the costs were capital related, and occurred in phase three, including installing new mains which were washed out, and replacing meters, stations and other service lines.

The AUC determined that, of the Z Factor Criteria, the 2013 Southern Alberta Floods were an unforeseen event outside of ATCO's control, and that the impact of the event did not have a significant influence on the inflation factor in the PBR formula.

ATCO itemized its costs for the Z Factor application by category, not by phase, as follows:

Group	2013 total	2014 total	Grand total
Field Operations	1,364,802	94,383	1,459,185
Customer Service	1,136,731	18,047	1,154,778
Information Technology	62,071	-	62,071
Customer care and Billing	60,857	-	60,857
Lost revenue	214,282	-	214,282

The AUC held that ATCO incurred $1.46 million in field operations costs due to the vast area affected by the flood, and the wide range of services required to repair its assets. The AUC also held that ATCO incurred $1.15 million in customer service related costs, to ensure that gas was being safely delivered to customers' homes, which necessitated a large number of site visits. The AUC held that it was persuaded by the evidence that ATCO responded to the flood in a measured and staged approach, and that ATCO diligently returned service to its customers in a reasonable amount of time. The AUC considered that given the scope and timing of the activities to restore service to pre-flood levels, the expenditures for operations and maintenance costs incurred were prudent.

With respect to ATCO's capital costs incurred in response to the 2013 flood events, the AUC noted that ATCO completed nearly 90 percent of its infrastructure repair and replacement by the end of 2014, finding that the scope of work performed, the timing of the repair and replacement activities, and the quantum of such costs to be reasonable. The AUC accordingly held that the capital costs incurred by ATCO in response to the 2013 flood events were prudently incurred.

With respect to lost revenue, the Utilities Consumer Advocate ("UCA") argued that ATCO's claim for $214,282 in lost revenue was not appropriate, as it should have qualified under ATCO's terms and conditions as a *force majeure*. Accordingly, the UCA argued that ATCO would have been permitted the interruption or reduction in service during the event. The UCA also submitted that ATCO did not file any evidence that ratepayers were unable or unwilling to pay their bills during this period.

ATCO replied, stating that the PBR regime does not limit a company from recovering costs beyond operating and capital costs, but rather the total impact of an exogenous event may be recovered. ATCO also submitted that invoking the *force majeure* clause would not have resulted in savings to customers, nor would it have had an impact on its Z Factor claim, since any claim would be collected from customers in any event.

The AUC determined that ATCO was still performing its duties as a utility service provider at the time of the flooding event, and that invoking *force majeure* with its retailers would not have resulted in any savings to consumers. Accordingly, the AUC accepted ATCO's evidence that it lost $214,282 of revenue due to the flood event, and held that the lost revenue amount claimed by ATCO was eligible for inclusion in the calculation of the Z Factor materiality threshold.

The AUC noted that the Z Factor materiality threshold was established in Decision 2012-237 as the dollar value of a 40 basis point change in after tax return on equity, calculated using the company's equity for 2012 going-in rates, and adjusted annually by the I-X mechanism.

ATCO submitted that its 2013 materiality threshold was $1.187 million, which was approved in ATCO's 2013 capital tracker true-up application for the purposes of its K Factor.

The UCA opposed ATCO's approach to utilizing only 2013 as a Z Factor threshold.. The UCA noted that ATCO was in effect applying its Z Factor costs for up to 5 years against a single year for materiality purposes. The UCA submitted that in a similar manner to K Factor calculations for multi-year capital projects, the materiality threshold is applied annually to the incremental revenue requirement determined by the applicable accounting test. The UCA submitted that, in comparing the materiality amounts for 2013 through 2017 against the costs claimed by ATCO, that only costs for 2013 met the 40 basis point test.

The Consumers' Coalition of Alberta ("CCA") argued that a single year materiality value was inappropriate, and recommended that the AUC apply an arithmetic average of the annual materiality thresholds over the period in question, and assess the materiality of the entire Z Factor adjustment amount. The CCA submitted that this approach may help to assess costs of a one-time event having an impact over a multi-year period.

The AUC held that Z factor materiality threshold was to apply on an annual basis, since the I-X mechanism and return on equity values are similarly calculated and adjusted annually. Therefore, in applying the Z Factor threshold for 2013, the AUC held that ATCO's costs of $3.121 million for 2013 exceeded the materiality threshold of $1.187 million. The AUC determined that the $3.121 million was broken down as follows:

- $75,000 for revenue requirement and capital expenditures;
- $2.389 million for operations and maintenance costs and lost revenue; and
- $207,000 in carrying costs.

However, for the years, 2014 to 2017 the AUC determined that ATCO's costs did not satisfy the materiality threshold for Z Factor treatment, as shown in the table below:

($000)	**2013**	**2014**	**2015**	**2016**	**2017**
Z factor	3,121	517	677	682	665
Materiality threshold	1,187	1,206	1,224	1,242	1,261

Therefore, the AUC declined to award Z Factor treatment to costs incurred between 2014 and 2017. However, with respect to capital costs incurred over this period, the AUC noted that its determination did not preclude ATCO from bringing forward an application for these costs by way of a K Factor application, provided the costs satisfy the applicable criteria.

With respect to depreciation matters, the AUC held that the characteristics of the 2013 flood event were similar in nature to the 2005 Southern Alberta flood event, and that those effects were accounted for in ATCO's last depreciation study in 2009. Therefore the AUC concluded that the 2013 flood did not give rise to an extraordinary retirement of destroyed assets, and that accordingly, the undepreciated net book value of $496,747 would continue to be recovered from ratepayers.

The AUC therefore approved a Z Factor to ATCO in the amount of $3.121 million for the 2013 Southern Alberta Flood event.

Office of the Utilities Consumer Advocate Review of Decision 20271-D01-2015: FortisAlberta Inc. Disposition of Land in High River (Decision 20990-D01-2016)

Review and Variance –Disposition – Rates

The Office of the Utilities Consumer Advocate ("UCA") applied for a review of the AUC's Decision 20271-D01-2015, which granted approval for the disposition and removal of a parcel of land owned by FortisAlberta Inc. ("FAI") from FAI's rate base in its next revenue requirement application.

The UCA sought the review pursuant to section 6(2) of Rule 016: *Review and Variance of Commission Decision* ("Rule 16") based on the following alleged errors:

- The AUC erred by failing to consider whether the land that was the subject of FAI's application continued to be used for utility service after Q1 of 2011;
- The AUC erred by failing to apply the correct onus or standard of proof on FAI by accepting a level of evidence as sufficient in the decision, while stating that the same level of evidence would be insufficient in the future;
- The AUC erred by failing to determine the date when the parcel of land was no longer used or required to be used for utility service;
- The AUC erred by failing to give effect to the directions of the Supreme Court of Canada, requiring that assets that have no utility purpose be removed from rate base and customer rates; and
- The AUC erred by expressly or impliedly relying on Decision 2012-237 (the "PBR Decision") as a basis on which not to apply directions of the Supreme Court of Canada, requiring that assets that have no utility purpose be removed from rate base and customer rates.

FAI owned a parcel of land in High River, Alberta, adjacent to other buildings owned by FAI. The AUC had previously approved an FAI application to replace its existing service centre using a portion of the parcel of land which is the subject of this decision. Construction of the replacement facility by FAI was completed in Q1 of 2011. FAI later applied to dispose of the excess portion of the parcel of land.

As part of FAI's disposition application, FAI submitted that the parcel was not actively used in the provision of utility service, but had been held for potential future expansions for growth of service requirements in Southern Alberta. FAI submitted that it did not foresee any future need for the remaining portion of the parcel and requested permission to dispose of the property.

As FAI was under performance based regulation ("PBR") for a fixed five year term, it proposed to remove the net book value of the parcel from rate base at the time of FAI's next rate base determination, at the end of its PBR term. The next opportunity for FAI to remove its parcel of land from rate base was therefore on December 31, 2017.

The UCA submitted that the AUC hearing panel accepted that the evidence provided by FAI in its disposition application would not be sufficient to support the findings that the AUC hearing made nonetheless. The UCA submitted that this was an inconsistent and unfair position, noting that the standard and the onus of proof should not be "moving targets" in proceedings before the AUC.

FAI submitted in reply that it met both the onus and standard of proof, pointing to the fact that it presented evidence that warranted the approval on a balance of probabilities.

The AUC held that the UCA had not demonstrated that the hearing panel failed to consider the time at which the parcel of land was not used or required to be used for utility service. The AUC noted that the hearing panel turned its attention to this question, and expressed concern about the length of time that FAI took to determine that the parcel was no longer required in 2015.

The AUC held that there was no support for the allegation that the AUC hearing panel used a standard of proof or burden of proof different from the balance of probabilities, and further found that the AUC hearing panel correctly applied the standard.

With respect to the ground that the AUC hearing panel failed to give effect to directions from the Supreme Court of Canada regarding removal of non-utility assets from rate base, the UCA submitted that the direction to remove the assets at the time of FAI's next revenue requirement application was at odds with recent jurisprudence. The UCA submitted that assets no longer used or required to be used must be removed from rate base and customer rates immediately, and not at some future date. The UCA submitted that the principle underlying the regulatory treatment of this asset was material to the rates paid by consumers, and that such treatment amounts to a windfall for FAI contrary to the principles of PBR.

In response to the UCA, FAI submitted that there was no detriment to ratepayers arising from the original decision, and submitted that the effect of the UCA's request was to re-open the PBR going-in rates.

The AUC held that FAI remains under the PBR framework, and noted that under PBR, the company's revenue is largely decoupled from costs, and that adjustments to going-in rates are not to be made to reflect actual events throughout the PBR term of 2012 to 2017.

The AUC held that the PBR framework did not trump the directions from the Supreme Court of Canada, but rather that the directions by the AUC hearing panel were not inconsistent with such jurisprudence. The AUC found that the UCA's submissions did not accurately reflect the way that the AUC establishes just and reasonable rates under PBR, since rates are not actually tied to rate base until its next revenue requirement application in 2017. Therefore, the removal or addition of assets from rate base throughout the term has no impact on rates throughout the term, unless one of the specific flow-through mechanisms in the PBR framework applies. The AUC noted that the very essence of the PBR framework creates incentives for regulated companies to produce long-run efficiency gains through lower costs.

The AUC further dismissed the UCA's ground of review, noting that the hearing panel considered adjusting FAI's rate base, but declined to do so, holding that such adjustments were warranted only in exceptional circumstances. The AUC therefore concluded that the UCA had not demonstrated that the hearing panel committed an error of law or jurisdiction as it relates to the application of jurisprudence for removing non-utility assets from rate base.

The AUC accordingly concluded that the UCA had not raised a reasonable probability that the hearing panel's reasons disclosed an error which could lead the AUC to materially vary or rescind the decision in questions. The AUC therefore declined to review Decision 20271-D01-2015.

Direct Energy Regulated Services 2012-2016 Default Rate Tariff and Regulated Rate Tariff Compliance Filing (Decision 20785-D01-2016)
Regulated Rate Option – Rates – Compliance Filing

Direct Energy Regulated Services ("DERS") submitted its compliance filing pursuant to the AUC's directions made in Decision 2957-D01-2015, requesting approval of its 2012-2016 default rate tariff ("DRT") and regulated rate tariff ("RRT").

In Decision 2957-D01-2015, the AUC made a number of directions to DERS. Any directions not addressed in this summary were either complied with as filed, or are applicable to future applications. The AUC determined that DERS fully complied with all directions made in 2957-D01-2015, with the exception of direction 4, direction 12, direction 13, directions 16 and 17, and direction 32, which are summarized below.

Actual Costs

- Direction 4 – The Commission directed DERS to use the actual amounts for 2012, 2013 and 2014, with the exception of the amounts for the annual incentive program, the long-term incentive scheme and the share award scheme.

  (The "Actual Costs Direction")

With respect to the Actual Costs Direction, the AUC questioned DERS as to why it used bond rates of 4.95 percent in its compliance filing for 2012 values compared with rates of 5.56 in its original application. DERS did not provide an explanation for updating the bond rate. The AUC also questioned DERS as to why it used deemed tax rates of 25.00 percent in its compliance filing, compared with 26.50 percent respectively in its initial application. DERS stated that the updated tax rate was reflective of changes to the actual tax rate for 2012 and subsequent years.

Accordingly, the AUC found that DERS applied the correct tax rate, but that DERS had provided insufficient evidence for the bond rate of 4.95 percent. The AUC therefore approved the bond rate of 5.56 percent for 2012, and an actual tax rate of 25.00 percent for 2012 and subsequent years. The AUC held that DERS did not fully comply with the Actual Costs Direction, but that no further action was required by DERS.

Labour Costs

- Direction 12 – The Commission directed DERS to submit information similar in format to the attachment to the response to AUC-DERS-030, showing the components of the labour costs by department. The Commission also directed DERS to show the three-year average for the years from 2012 to 2014 for each component and department. The Commission directed DERS to inflate the resulting three-year average amounts for the years 2012-2014 by 1.92 per cent and show the results separately for the DRT and the RRT in columns entitled "2015 Forecast." The Commission directed DERS to inflate the figures in the columns entitled "2015 Forecast" by 2.95 per cent and show the results separately for the

DRT and the RRT in columns entitled "2016 Forecast." The Commission directed DERS to include the resulting total costs in the "2015 Forecast" and "2016 Forecast" columns as the forecast amounts for labour costs for each year, allocated appropriately between the "Labour (Gas Procurement)" and "Labour by Department" cost categories for the DRT and in the "Labour by Department" cost category for the RRT.

- Direction 13 – The Commission directed DERS, to submit a second attachment similar in format to the attachment to the response to AUC-DERS-030, showing the components of the labour costs by department for 2012, 2013 and 2014 for the DRT and the RRT separately. The Commission directed DERS to include the resulting total costs for 2012, 2013 and 2014, allocated appropriately between the "Labour (Gas Procurement)" and "Labour by Department" cost categories for the DRT and in the "Labour by Department" cost category for the RRT.

  (Collectively, the "Labour Costs Directions")

DERS submitted revised labour costs that, it submitted, reflected the AUC's Labour Costs Directions. DERS indicated that some of the labour amounts for DRT and RRT service did not correspond to amounts included in other schedules in the application. DERS noted that the reason for the differing amounts was due in part to the costs included for a new vendor manager (required to comply with Direction 31 given in Decision 2957-D01-2015), and the internal labour costs for its energy price setting plan ("EPSP") that were not included in the schedules.

The AUC held that the total amount of labour costs that were reclassified, resulting in the schedules not corresponding, amounted to 0.2 percent of 2013 revenue requirement and 0.5 percent of 2014 revenue requirement. As such the AUC did not consider either of the reclassifications to be significant, and would not materially affect non-energy rates for 2013 and 2014. Accordingly, the AUC approved these reclassifications as filed. However, the AUC directed DERS to file updated supplemental schedules detailing the labour components corresponding to labour amounts in the revenue requirement schedules as part of its next interim rate true-up application.

The AUC held that DERS did not fully comply with the Labour Costs Direction, but that no further action was required by DERS.

<u>Working Capital</u>

- Direction 16 and Direction 17 – The Commission directed DERS to update the working capital costs forecasts for 2015 and 2016 to incorporate the more recent information on the record, and also the revisions to the other applicable factors that are used in the forecast of working capital. This updated information included the forecast gas and electricity prices, and the rate of return and debt/equity figures as approved in Decision 2191-D01-2015. The Commission also directed DERS to incorporate all other applicable updated forecasts for 2015 and 2016. The Commission directed DERS to include supporting calculations for the weighted average cost of capital figure it uses for 2015 and 2016

  (Collectively, the "Working Capital Directions")

With respect to the Working Capital Directions, DERS submitted that it had updated its working capital forecasts as directed, noting that the changes reflected the updated weighted average cost of capital used in its compliance filing. DERS however noted that it did not update its working capital schedules for 2015 and 2016, noting that no specific direction was given by the AUC with respect to working capital schedules for those years.

The AUC held that, despite not having issued a specific direction to update the working capital amounts for 2015 and 2016, the AUC expected such items to be included as part of DERS' compliance filing. The AUC also noted that its other directions made in proceeding 2957 would clearly impact such working capital forecasts, including updates to site count forecasts and commodity curves, and that such updates for 2015 and 2016 would apply to the "other applicable factors that are used in the forecast of working capital" noted in Direction 16. The AUC however, incorporated the amounts for 2015 and 2016 as submitted by DERS in the DRT and RRT revenue requirement schedules.

The AUC held that DERS did not fully comply with the Working Capital Directions, but that no further action was required by DERS.

- Direction 32 – The Commission directed DERS to include the necessary supporting evidence and analysis to allow for full and thorough testing of its proposed internal EPSP costs.

  (The "Internal EPSP Costs Direction".)

DERS had originally included internal labour costs associated with the development, implementation and administration of its EPSP in the amount of $57,200 per month, which the AUC directed DERS to include as part of its non-energy RRT and DRT application. DERS indicated that it would cease collecting these costs once its final 2016 non-energy rates are in place. In its compliance filing, DERS requested monthly forecast costs of $50,016 for its EPSP, the majority of which ($48,862) was on account of labour.

DERS submitted that the 3.35 full time equivalent employee positions were required for its EPSP, since its EPSP requires tracking and reporting to manage the EPSP on an ongoing basis and to ensure the correct target price is set for procurement. DERS also explained that since the requirement for procurement occurs on every business day throughout the year, more than one position was required to address the need.

The AUC held that the full time equivalent positions and costs associated with DERS' EPSP were reasonable, and approved such costs as filed. However, the AUC determined that the costs for staff-related expenses and its forecasting system costs were not adequately supported, but the AUC approved them on the basis that DERS incurred costs in these categories in 2013 and 2014, and that the monthly forecasts for 2016 were much lower than actual costs in 2013 and 2014. Accordingly, the AUC approved the monthly internal EPSP costs of $50,016 as reasonable.

The AUC held that DERS did not fully comply with the Internal EPSP Costs Direction, but that no further action was required by DERS.

<u>True-up of Interim Rates</u>

DERS requested a true-up for its interim rates, noting that it has been collecting interim rates for DRT and RRT services with respect to return margin, DRT energy related "other" and "labour" charges, as well as non-energy charges for DRT and RRT rates. DERS proposed to collect or refund its resulting true-up amounts between May 1, 2016 and December 31, 2016.

The AUC held that it would not accept a true-up as proposed by DERS, pointing to a flaw in the methodology used by DERS to calculate its total true-up amount. The AUC determined that DERS is at risk for the volume of gas associated with DRT return margin and energy-related "other" costs. The AUC noted that if the actual volume of gas is greater than forecast, the result would be a higher return margin and revenue for DRT service. The AUC also noted that DERS was at risk for the number of sites associated with interim charges, and that if the number of sites is larger than forecast, it results in more non-energy revenue, as well as the inverse.

The AUC held that the methodology proposed by DERS for calculating the true-up did not account for these risks over the time period, since DERS used a mixture of actual and forecast information in its true-up.

The AUC determined that the DRT energy "labour" charges were reasonable, on the basis that these charges were unaffected by the problems identified by the AUC. However, for purposes of transparency and efficiency, the AUC directed DERS to include all of its true-ups in one application, and thereby declined to approve these costs as part of the decision.

The AUC ordered that DERS' RRT schedules, as well as the terms and conditions were approved on a final basis, effective April 1, 2016. The AUC approved DERS' DRT revenue requirement as follows:

($ million)	2012	2013	2014	2015	2016
Energy related revenue requirement	2.089	3.427	5.317	2.942	3.049
Non-energy related revenue requirement	49.948	49.204	51.396	52.483	51.963

The AUC approved DERS' RRT revenue requirement on a final basis as follows:

($ million)	2012	2013	2014	2015	2016
Energy related revenue requirement	0.542	0.605	1.034	0.525	0.577
Non-energy related revenue requirement	14.896	13.875	14.820	14.844	15.368

The AUC also approved the following costs for DERS:

- A default rate tariff return margin charge of $0.035 per gigajoule, effective April 1, 2016;
- A charge for energy costs of $0.023 per gigajoule effective April 1, 2016; and
- A monthly labour charge for gas procurement of $38,675, effective April 1, 2016.

The AUC directed DERS to file an application for its true-up figures for RRT, DRT, DRT return margin and DRT energy costs for the period of January 1, 2012 to March 31, 2016.

ENMAX Generation Portfolio Inc. ENMAX Downtown District Energy Centre 3.3-Megawatt Natural Gas-Fired Power Plant (Decision 21247-D01-2016)
Power Plant - Facilities

ENMAX Generation Portfolio Inc. ("EGPI") applied to the AUC for approval to construct and operate a power plant located at the existing ENMAX Downtown District Energy Centre, pursuant to section 18 of the *Hydro and Electric Energy Act* to connect the power plant to the 25-kilovolt distribution system.

EGPI submitted that the power plant would consist of one 3.3 megawatt natural gas-fired generator, equipped with a reciprocating engine and heat recovery equipment, using natural gas supplied from EGPI's existing facility.

EGPI noted that the ENMAX Downtown District Energy Centre was originally designed for a capacity of 3.5 megawatts, and that the proposed power plant would replace an existing 750-kilowatt diesel standby generator. The power plant would supply power to the ENMAX Downtown District Energy Centre, and export any surplus to the grid.

EGPI submitted that its noise impact assessment would be in compliance with Rule 012: *Noise Control*, provided certain mitigation measures are installed. EGPI also submitted that its air dispersion modelling for the power plant would meet the *Alberta Ambient Air Quality Objectives.*

EGPI also requested an independent assessment of the power plant pursuant to section 95 of the *Electric Utilities Act* to allow it to hold an interest in the proposed power plant, since EGPI, through the ENMAX corporate structure, is a subsidiary of a municipality (i.e. the City of Calgary).

The AUC held that EGPI met all the requirements required by AUC rules, and was satisfied that no significant environmental impacts were expected from the proposed project.

With respect to EGPI's compliance with section 95 of the *Electric Utilities Act*, the AUC held that because EGPI did not submit confirmation of its compliance with section 95 of the *Electric Utilities Act*, the project could only be approved on the condition that EGPI must file the independent assessment and authorization of the Minister of Energy with the AUC confirming compliance with Section 95 of the *Electric Utilities Act*.

Livingstone Landowners Guild Decision on Preliminary Question Application for Review of Decision 2009-126 AESO Needs Identification Document Application Southern Alberta Transmission System Reinforcement (Decision 20846-D01-2016)
Review Application – Needs Identification Document

The Livingstone Landowners Guild ("LLG"), a group of landowners located in southern Alberta in the Oldman River watershed, east of the Livingstone Range, applied to the AUC pursuant to Section 2 of AUC Rule 016: *Review of Commission Decisions* ("Rule 16") to request a review of Decision 2009-126, which granted approval for part of the Southern Alberta Transmission Reinforcement ("SATR") project. The LLG requested that the AUC review the decision on its own motion, given that the LLG was seeking relief more than 60 days after issuance of the decision in question.

Decision 2009-126 approved a Needs Identification Document ("NID") from the Alberta Electric System Operator ("AESO") seeking approval for the Castle Rock Ridge to Chapel Rock transmission line.

While the AUC declined to review the decision of its own motion, it held that it was prepared to treat the LLG's request as a review application based on new facts or changed circumstances under section 4(d)(ii) of Rule 16. In this decision, the AUC considered the preliminary question of whether it would review Decision 2009-126 based on the grounds advanced by the LLG.

The LLG sought a review of Decision 2009-126 by questioning the ongoing need for the Castle Rock Ridge to Chapel Rock transmission line portion of SATR. The LLG submitted that the AESO's original NID application stated that the NID was responding to the anticipated development of wind generation in Southern Alberta, enabling the connection of up to 2,700 MW of wind power over the next 10 year period. The LLG contended that development of wind farms in the Pincher Creek area had essentially stopped, submitting that only 620 MW of the predicted 2,700 MW in wind generation had been developed. The LLG further submitted that low power pool prices, coupled with low oil and gas prices would discourage any projects in the connection queue from proceeding.

The AUC determined that it had previously considered such changed circumstances in Decision 2010-343, where the AUC determined that the AESO's milestone assessment process for the SATR project were in the public interest. The AESO also applied for approval to amend the NID in question as part of Decision 2014-004, where it noted that "there is a large degree of uncertainty associated with future wind power development" acknowledging that some projects had been cancelled.

However, in that application, the AESO noted that current and future generation would total 992 MW reiterating the need for the project, which was again approved by the AUC.

The AUC noted that some of the concerns raised in the proceeding dealt with routing and environmental issues. The AUC held that facility applications are the appropriate forum for these concerns, and noted that the facility application for this particular line had not yet been filed.

With respect to the grounds advanced by the LLG however, the AUC held that the original hearing panel in Decisions 2009-126, 2010-343 and 2014-004 made explicit findings of fact that the Castle Rock Ridge to Chapel Rock transmission line was needed for a number of reasons, some of which were independent of simply connecting future wind developments, such as improving the reliability of the Alberta Interconnected Electric System.

The AUC therefore determined that the new facts or changed circumstances alleged in the review application were in fact future contingencies expressly contemplated in prior NID approvals applicable to the Castle Rock Ridge to Chapel Rock transmission line. The AUC also found that there was no reasonable possibility that the new facts or changed circumstances would lead the AUC to materially vary or rescind the original decision.

The AUC therefore declined to review Decision 2009-126 outside the 60 day period prescribed by Rule 16, and dismissed the application.

Alberta Electric System Operator 2016 ISO Tariff Update (Decision 21302-D01-2016)
Tariff – Rates

The Alberta Electric System Operator ("AESO") filed an application with the AUC to update its tariff ("ISO Tariff") for 2016. The AESO submitted its application was to reflect costs and billing determinants for the 2016 calendar year, and that the ISO Tariff update did not change the structure of rates or the provisions of the terms and conditions, aside from maximum investment levels. The AESO requested that the update to the ISO Tariff be approved effective April 1, 2016.

The AESO stated that the 2016 updated forecast costs represented an increase of $214.0 million or 11.5 percent over 2015 costs, primarily as a result of wires costs in transmission facility owner tariffs. The AESO also noted that ancillary services costs were forecast to increase by $19.6 million and line loss costs were forecast to increase by $35.5 million.

The AESO submitted that it calculated its updated rates using the 2016 forecast revenue requirement, the functionalization of wires costs previously approved for 2016 in Decision 2013-421, and 2016 forecast billing determinants prepared for this application. The AESO also requested an update to its maximum investment level, consistent with the methodology approved in Decision 2010-606, using a composite inflation index applied to 2014 demand transmission service ("Rate DTS") maximum investment levels.

The AESO submitted that the 2016 ISO Tariff update was a formulaic update to the revenue requirement based on methodologies previously approved by the AUC in Decision 3473-D01-2015, and investment amounts approved in Decision 3473-D01-2015.

No parties objected to the application.

The AUC held that the annual revenue requirement and rate updates would benefit consumers by limiting misallocations and reducing cost imbalances. The AUC determined that the AESO's forecast costs were calculated in accordance with the methodology approved by the AUC in Decision 2010-606.

Accordingly, the AUC approved the AESO 2016 ISO Tariff update for Rate DTS, Fort Nelson demand transmission service (Rate FTS), demand opportunity service ("Rate DOS"), export opportunity service (Rate XOS), export opportunity merchant service (Rate XOM), primary service credit (Rate PSC), supply transmission service (Rate STS), Rider J and Section 8 costs for 2016, effective April 1, 2016.

Bulletin 2016-06: Notice of Consultation Process for Standardization of Confidential Undertaking
Bulletin – Confidentiality – Consultation

The AUC announced that it would make amendments to Section 13 of AUC Rule 001: *Rules of Practice* ("Rule 1") to simplify and improve the processing of motions requesting confidential treatment of documents in AUC proceedings.

Among the changes proposed is the adoption of a new form of undertaking to be used by external parties seeking access to information that is the subject of a confidential treatment ruling. The proposed form can be found here.

The AUC noted that it would be inviting stakeholder comment on the proposed form. Written submission are due to the AUC not later than April 15, 2016 at 2:00 p.m.

Other changes to Section 13 of Rule 1 include:

- Requiring the moving party to file on the public record either a redacted version of the document that is the subject of the request, or, where the request relates to the entire document, a description or summary of the document.
- Requiring the moving party to provide the Commission with an electronic un-redacted copy of the entire document that is the subject of the request.
- Requiring parties to submit all confidential document(s) in electronic format, such as a USB stick, by courier to the AUC's senior records officer rather than hard copy. Submissions by email are not permitted.
- Clarifying that the Commission will exercise its discretion on a case-by-case basis in determining who will have access to the documentation and indicating that the Commission may issue decisions in which confidential information is redacted.
- Requiring parties to file, with each undertaking, a document protocol outlining their internal processes and procedures for handling confidential information.
- Requiring a moving party who has been denied confidential treatment to file an un-redacted copy of the information on the record subject to an ability to withdraw the information rather than placing it on the public record, unless otherwise directed by the Commission.

A full copy of the proposed changes to Section 13 of Rule 1 can be found here.

Bulletin 2016-07: Practice Advisory and Procedural Change – Expert Witness Qualification No Longer Required
Bulletin – Expert Witnesses – Qualification – Practice Advisory

The AUC released a bulletin advising of a procedural change concerning expert witnesses.

The AUC noted that section 20 of the *Alberta Utilities Commission Act* provides that the AUC is not bound by the rules of evidence, and that section 76 also allows the AUC to set its rules of practice for hearings and procedures. A historical practice of parties in AUC proceedings has been to qualify witnesses as "experts" in a particular subject matter.

The AUC noted however that it has typically allowed opinion evidence from witnesses regardless of qualification, preferring to leave the value ascribed to such opinion evidence as a question of weight.

The AUC noted that it has recently altered its practice of qualifying witnesses as experts in several oral hearings in the past year as a test, in order to reduce the number of disputes arising over expert designation, while still providing parties the opportunity to address the weight to be given to "expert" testimony, through cross-examination and argument.

The AUC considered that the objectives of regulatory efficiency and protecting procedural fairness allowed this test practice to be extended to all facility, rate and market related oral hearings, with the exception of enforcement proceedings.

The AUC announced therefore that it was changing its practice such that parties no longer needed to qualify witnesses as experts in such proceedings. However, the AUC noted that despite there being no requirement to qualify a witness, the AUC reiterated that parties presenting witnesses should continue to provide curriculum vitae for each witness, and to orally review the qualifications of each witness.

The AUC also noted that the procedural change would not affect the costs claims for experts, as the scale of costs for both experts and consultants are the same, and do not depend on whether a witness is accepted as an expert or not.

Bulletin 2016-08: Amendments to Rule 009: Rules on Local Intervener Costs and Rule 022: Rules on Costs in Utility Rate Proceedings
Bulletin – Costs – Rule 009 – Rule 022

The AUC announced that it had completed a review of procedural requirements for Rule 009: *Rules on Local Intervener Costs* ("Rule 9") and Rule 022: *Rules on Costs in Utility Rate Proceedings* ("Rule 22"), as well as the associated forms used to file cost claims.

The AUC noted that Rule 9 has been amended to include costs claims associated with a review application for a facility decision, which were previously only addressed under Rule 22.

Parties are still required to file cost claims within 30 days of the close of the proceeding in which the costs were incurred.

The AUC announced that it had decided that it was no longer necessary for parties claiming costs under Rule 22 to circulate a summary of costs claimed, since all cost claims would be available to parties in the proceeding via the AUC's e-filing system.

The AUC further amended the time available for parties to file comments on costs claims, reducing the time for parties to file comments from 14 days to 7 days from the date a party files its cost claim (or 37 days from the close of proceedings). Similarly, the time frame for a party claiming costs to provide a reply to comments has been reduced from 14 days to 7 days from the date a party files its comments (or 44 days from the close of proceedings).

The AUC noted that the amended Rule 9 and Rule 22 will enter into force on May 2, 2016, and will apply to all costs applications filed on or after May 2, 2016.

A full copy of the amended Rule 9 will be posted on the AUC's website. The new cost form for Rule 9 can be found here.

A full copy of the amended Rule 22 will be posted on the AUC's website. The new cost form for Rule 22 can be found here.

Bulletin 2016-09: Amendment of AUC Rule 016 Review of Commission Decisions

Bulletin – Rule 016 – Review and Variance

The AUC announced that, effective March 24, 2016, it had amended certain provisions of AUC Rule 016: *Review of Commission Decisions* ("Rule 16"), including the following:

- Section 2 now clarifies the ability of the AUC to initiate a review of a decision on its own motion;
- Section 6 has been amended as follows:
    - Clarification has been added for the onus and standard of review required of an applicant in the initial review stage;
    - The two stage process involved in a review and variance proceeding has been clarified; and
    - A distinction has been added to distinguish between a review application based on an error of fact, law or jurisdiction, and a review application based on previously unavailable facts or changed circumstances.
- Section 7 has been amended to clarify the purpose of the second stage of a review and variance proceeding.

The amended Rule 16 will apply to all review applications filed after March 24, 2016. A full text copy of Rule 16 can be found here.

Bulletin 2016-10: Practices regarding enforcement proceedings and amendments to AUC Rule 001: Rules of Practice

Bulletin – Rules of Practice – Enforcement

The AUC announced several proposed changes to AUC Rule 001: *Rules of Practice* ("Rule 1"), and a further outline related to enforcement proceedings commenced by the Market Surveillance Administrator ("MSA").

<u>MSA Initiated Proceedings</u>

The AUC noted that the primary goals of enforcement are to promote compliance with Alberta's utility laws, and to prevent harm to persons, property and to the integrity of the regulatory process. Such compliance is generally addressed through a mixture of reporting, complaint investigations, inspections and audits.

With respect to investigations, the AUC noted that AUC staff will review circumstances and evaluate the identified conduct, including examining available sources of information and may contact the regulated entity in question for an explanation of the alleged conduct. The AUC noted that staff intends to provide the regulated entity in question an opportunity to respond to any allegations prior to the conclusion of the AUC's investigation.

With respect to enforcement proceedings, the AUC noted that it will have regard for the following principles in deciding whether to commence an enforcement action against a regulated utility:

- If, based on the information obtained through an investigation, the alleged contravention appears reasonably likely to be proven on a balance of probabilities; and
- If the enforcement action is in the public interest.

If an enforcement proceeding is initiated, the AUC stated that notice will be given to the alleged contravener with the particulars of the alleged contravention and the nature of the sanctions being sought. The AUC stated that staff assigned to the enforcement proceeding will have no contact with the AUC division conducting the proceeding, nor the staff assisting the AUC division that is conducting the proceeding, except through the public record.

<u>Rule 1</u>

The AUC also announced a number of proposed changes to Rule 1 as a result of several MSA enforcement matters and investigations. The AUC noted that Rule 1 was originally drafted broadly to apply to a large variety of proceedings. As a result, the AUC proposed a number of amendments to recognize the unique features of enforcement proceedings.

First, the AUC proposed to expand the definition of "party" to include a person named by the MSA or the AUC in a notice issued under sections 51 and 52 of the *Alberta Utilities Commission Act* ("*AUCA*").

Second, the AUC proposed new notice requirements setting out what information must be included in a notice from the AUC to initiate an enforcement proceeding, including the following information:

- The names of the alleged contraveners;
- Reasonable particulars of the alleged contravention of failure to comply to be considered by the AUC;
- A statement of the order or other relief requested; and
- Any other information ordered by the AUC.

The AUC noted that such information would effectively mirror the information requirements in an MSA-issued notice under section 51 of the *AUCA*.

Third, the AUC proposed to amend the information request ("IR") process in enforcement proceedings such that an IR process will only be available in the discretion of the AUC. The AUC stated that the proposed amendment shifts the onus on the person seeking an IR process to establish that the IR process is warranted.

The AUC noted that it did not intend to change Rule 1 to prescribe a level of disclosure required in enforcement proceedings, preferring to consider such determinations on a case-by-case basis.

The AUC stated that it did not intend to amend Rule 1 to address standing in enforcement proceedings. The AUC reiterated its stance set out in Bulletin 2010-17 that standing and participation in enforcement proceedings will remain limited to the MSA and the alleged contravener.

Next Steps

The AUC stated that it anticipated holding a stakeholder consultation in the Spring of 2016 regarding the proposed changes.

Bulletin 2016-11: Rule 030: Compliance with the Code of Conduct Regulation
Bulletin – Code of Conduct

The AUC noted that the *Code of Conduct Regulation* came into effect on January 1, 2016, and as a result the AUC undertook a consultation with industry to develop a new code of conduct rule.

Section 45(6) of the *Code of Conduct Regulation* requires the AUC to have new compliance plans approved before January 1, 2017. As a result, the AUC announced that it was directing each distributor, regulated rate provider and affiliated retailer to submit a new code of conduct plan on or before May 31, 2016.

Code of conduct templates are available for applicants to use as guidelines. One for distributors with a small number of customers is available here, and one for all others is available here.

The AUC announced that as a result of these consultations, the AUC approved the implementation of Rule 030: *Compliance with the Code of Conduct* ("Rule 30") effective April 1, 2016.

NATIONAL ENERGY BOARD

Energy East Pipeline - Supplemental Application To Participate Notice (March 23, 2016)
Application to Participate – Facilities

The NEB, by letter dated March 23, 2016, announced that it was opening a supplemental Application to Participate ("ATP") process for the Energy East Pipeline Ltd. ("EEPL") application to construct and operate the Energy East pipeline.

The NEB noted that the supplemental ATP is meant for those parties who may be directly affected by EEPL's amendment to the Energy East application filed on December 17, 2015, or who may have relevant information or expertise related to the amendments.

The NEB clarified that parties who have previously applied to participate need not do so again.

The supplemental ATP period has been open since on March 30, 2016 and will close on April 20, 2016.

A list of issues for Energy East can be found here, for those wishing to file an ATP.