Transmission Cost Recovery Subcommittee Report

From The Transmission Facilities
Cost Monitoring Committee

June 8, 2012 Report

EXECUTIVE SUMMARY

The mandate of the Transmission Cost Recovery Subcommittee (TCRS) was to examine the potential cost impact of the proposed transmission build in Alberta, and to develop alternative cost-recovery mechanisms that would minimize near-term rate shock and would ensure that transmission costs are allocated fairly between current and future ratepayers.

On February 23, 2012, the Alberta Government released its response to the Critical Transmission Review Committee Report (CTRC). The Government's action plan included the following:

> *2. Pursue options to reduce the impact to consumers of the cost of transmission projects. This work will include:*
>
> - *Developing preliminary transmission cost recovery options by the existing Transmission Cost Recovery Subcommittee.*
> - *Directing the AUC to conduct a public transmission cost recovery inquiry into approaches that could mitigate the rate impact of new transmission on consumers.*
> - *Implementing changes to transmission cost recovery approaches as appropriate prior to the completion of the Western and Eastern Alberta Transmission Lines.*

The development of preliminary transmission cost recovery options noted in the Government's action plan is consistent with the mandate of the TCRS (see Appendix A).

The TCRS developed a detailed model to forecast the cost impact of the proposed transmission build, and to analyze the impact on transmission wires rates of various cost-recovery options. The first 10 years of the model are based on the Alberta Electric System Operator's (AESO) draft 2011 Long Term Plan, with less detailed forecasts used thereafter. Under the baseline case (status quo), the wires portion of the transmission rate is forecast to increase from $14/MWh in 2011 to approximately $32/MWh in 2018. These costs represent only a portion of the total transmission costs, and the total transmission costs, in turn, represent only a portion of the total delivered costs of electricity (see Appendix F).

Seven alternative cost recovery mechanisms were explored to assess their effectiveness in mitigating the cost impacts of the proposed transmission build:

1. A government loan or debt guarantee;
2. Individual transmission project financing for large projects with long-term fixed-price contracts;
3. A fixed cap (in real terms and nominal terms) on the wires portion of the transmission rate, combined with a deferral account mechanism;
4. A percentage cap on the annual increases in the total revenue requirements of all of the transmission facility owners (TFOs), combined with a deferral account mechanism;
5. A fixed annual transfer amount based on levelized forecast transmission wire rates (in nominal terms) combined with a fixed term deferral account mechanism;
6. A non-ratepayer source of funding to offset some of the costs associated with transmission for renewable generation; and

7. The use of load retention rates to retain existing load that would otherwise leave the system as a result of increases in the wires portion of the transmission rate.

The TCRS's assessments with respect to the alternative cost recovery mechanisms are as follows:

1. Government debt financing would only result in a small reduction in the wires portion of the transmission rate.
2. Individual transmission project financing with long-term fixed-price contracts would not have a material impact on the wires portion of the transmission rate, since this approach would only be practicable for a limited number of large projects.
3. A cap on the wires portion of the transmission rate combined with a deferral account mechanism would be an effective method of shifting costs from current to future customers. The balance in the deferral account would be very sensitive to actual load growth and actual transmission costs, and a process would need to be established to adjust the price cap periodically to ensure that the deferral account balance is contained within acceptable limits.
4. A percentage cap on the annual increases in the total revenue requirements of all of the TFOs combined with a deferral account mechanism would be an effective method of shifting costs from current to future customers. The balance in the deferral account would be very sensitive to actual transmission costs, and a process would need to be established to adjust the revenue requirement cap periodically to ensure that the deferral account balance is contained within acceptable limits. A revenue requirement cap is not equivalent to a price cap, since a revenue requirement cap is not linked to load growth.
5. A fixed annual transfer amount based on levelized forecast transmission wire rates (in nominal terms) combined with a fixed term deferral account would shift costs from current to future customers. Under this approach, the deferral account balances and the end date for the deferral account would be known in advance, but the actual wires portion of the transmission rate could vary from forecast depending on actual load growth and actual transmission costs.
6. Non-ratepayer funding could result in a material reduction in the wires portion of the transmission rate, depending on the magnitude and duration of the funding. Whether individual ratepayers would benefit from non-ratepayer funding depends on the source of the non-ratepayer funding. For example, if the non-ratepayer funding were provided by Alberta taxpayers, then this approach would shift costs from industrial customers to residential customers.
7. Load retention rates could be an effective mechanism for retaining load that would otherwise leave the system due to increases in the wires portion of the transmission rate, but would not shift any costs from current to future customers.

The TCRS concludes that Option 3 (wires price cap), Option 5 (fixed annual transfer amount) and Option 6 (non-ratepayer funding) warrant further consideration as potential mechanisms to address the cost impact of the proposed transmission build in Alberta. The TCRS notes that some of these options are not all mutually exclusive, and that some of the options could be combined.

I. BACKGROUND AND OBJECTIVES

The TCRS was set up as a cross-industry committee (see Appendix B) to examine the potential cost impact of the proposed transmission build in Alberta.

The TCRS's analysis addresses the impact on current ratepayers arising from the combined effect of the "lumpy" nature of the transmission expansion (numerous projects being developed at about the same time) and the current cost of service approach, where the tariff is greatest in the earlier years. Issues that might arise from higher transmission wire costs include the following:

1) Higher transmission wire costs may result in load customers reducing their dependence on the transmission grid with behind-the-fence (BTF) generation or by relocating outside of Alberta. If this were to occur, it would result in an increased cost burden on the remaining ratepayers; and
2) Higher transmission wire costs are unavoidable for most customers and difficult for some customers to absorb.

In developing and assessing alternative mechanisms, the TCRS followed six guiding principles as follows:

Principle 1: *The new transmission cost recover mechanism must allow the TFOs to recover their prudently incurred costs and provide a reasonable opportunity to earn a fair rate of return that is commensurate with the risks associated with the new transmission cost recover mechanism, subject to the approval of the Alberta Utilities Commission.*

Principle 2: *It must be a sustainable process for all stakeholders and provide measurable benefits to ratepayers of electricity in the Province.*

Principle 3: *It must respect the principle of fairness to all classes of rate payers.*

Principle 4: *It must be reasonably easy to understand, able to be implemented and administered.*

Principle 5: *It should not transfer current problems to future generations.*

Principle 6: *Any new cost recovery mechanisms should be tested against existing legislation, regulations, AESO rules and AUC rules.*

II. METHODOLOGY

As set out in the scope of work (see Appendix C), the TCRS analysis initially focused on three alternative cost recovering mechanisms:

1. TFO use of government loan or debt guarantees to reduce financing costs;
2. Using long-term fixed-price contracts for selected projects to levelize annual costs; and
3. A fixed rate cap (in real terms and nominal terms) on the wires portion of the transmission rate, combined with a deferral account mechanism.

Subsequently, four additional cost recovery mechanisms were identified:

4. A percentage cap on the annual increases in the total revenue requirements of all of the TFOs, combined with a deferral account mechanism;

5. A fixed levelized rate (in nominal terms) for the forecast total revenue requirements of all of the TFOs, combined with a deferral account mechanism;
6. A non-ratepayer source of funding to offset some of the costs associated with transmission for renewable generation; and
7. The use of load retention rates to retain existing load that would otherwise leave the system as a result of increases in the wires portion of the transmission rate.

The methodology employed consisted of the following steps:

1) Determine a baseline projection (status quo) of the rate impacts of the transmission projects based on total forecast TFO revenue requirements using current tariff methodology;
2) Determine the annual revenue requirement and $/MWh rate based on alternative cost recovery mechanisms;
3) Determine the annual rate difference between the baseline and each of the alternative mechanisms and assess their relative effectiveness in addressing customer cost issues; and
4) Determine the magnitude and impact of the alternatives on rates.

The TCRS developed a detailed model to forecast the cost impact of the proposed transmission build, and to analyze the impact on transmission wires rates of various cost-recovery options. The first 10 years of the model are based on the AESO's draft 2011 Long Term Plan, with less detailed forecasts used thereafter. Inputs to the model include cost of existing systems, planned new projects and maintenance capital for existing and new transmission facilities. Non wire ancillary transmission costs and other components of total delivered costs of electricity have not been included in the analysis. Appendix F provides details on other portions of transmission costs and the total delivered costs of electricity.

The analysis also included sensitivity testing of each of the alternatives against exogenous factors that are beyond the control of the TFOs or customers, including key factors such as capped rates and load growth (see Appendix D).

III. BASELINE (STATUS QUO) DEVELOPMENT

This section describes the baseline, which was established to illustrate the transmission wires impact under the status quo and provide a basis for comparison of alternative mechanisms.

The model and baseline scenario (Figure 1 below) were established based on the following inputs and assumptions:

- The baseline includes all transmission projects included in the AESO's 2011 Long Term Plan (draft version released in June 2011);
- The model adds each new project into the respective TFO rate base using the approach currently approved within their respective tariffs (e.g. construction work in progress (CWIP) in ratebase);
- The model segments each of the projects into four categories as follows:
    - Regional projects to upgrade existing facilities and connect load and generation projects;

- Bulk-system projects for capacity expansion and reliability, including designated CTI projects;
- Renewable projects principally required to connect to new renewable energy sources (primarily wind); and
- Other capital predominantly to maintain the system into the future.

- The resultant revenue requirements are projected for 30 years; and
- The revenue requirement in each year is divided by the total expected energy (load), which is set out in the AESO load forecast inclusive to 2030 and is assumed to increase at a rate of 2.3% per year thereafter.

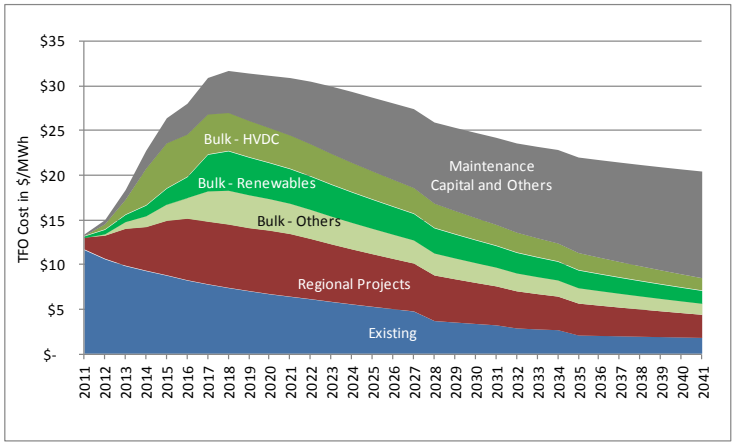


Figure 1 - Baseline of TFO Wires Rates in $/MWh

As illustrated in Figure 1 above, under the baseline scenario, the TFO or "Wires" cost to ratepayers is projected to increase from approximately $14/MWh in 2011 to a maximum level of $32/MWh in 2018, and decline thereafter. Following are several observations on the baseline scenario:

- The rapid increase of TFO costs over the next 5 to 10 years is due to the "lumpy" nature of transmission expansion and the use of cost of service methodology to determine revenue requirements;
- Over the next 5 to 10 years, these transmission costs rise to a level that might be high enough to trigger additional behind the fence generation, which would expose the remaining customers to even higher costs; and
- The rapid increase in transmission wires costs over a short period may negatively affect large consumers who cannot avoid these costs and whose bottom line would be impacted by their inability to absorb such costs.

Figure 2 below shows the annual revenue requirement for new build and the existing projects already in rate base as well as the capital maintenance requirements.

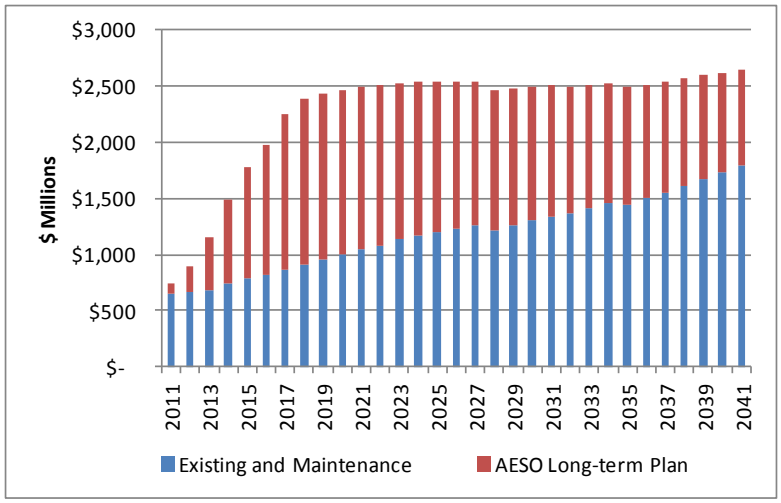


Figure 2 - Annual Revenue Requirements for Wires Only

IV. ALTERNATIVE COST RECOVERY MECHANISMS

The following sections explain the alternative cost recovery mechanisms and assess their effectiveness in mitigating the impacts of increases in transmission wire costs. Section VI below, provides a quantitative comparison of the alternatives.

1 Government Loan/Debt Guarantee

Description:

- Government provides direct debt or government guarantees for 50% of the debt requirements of the following projects:
    a. Southern Alberta Transmission Reinforcement (SATR)
    b. Two HVDC lines: WATL and EATL
    c. Heartland
    d. Fort McMurray
- Government debt (or debt guarantee) is assumed to lower TFO debt financing costs by approximately 70 bps relative to market based debt;

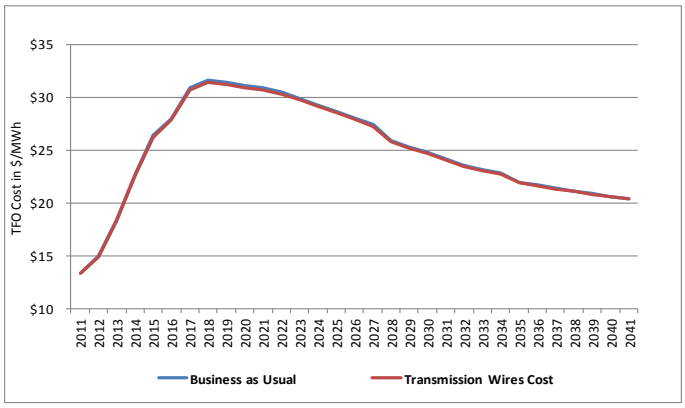


Figure 3 - Impact of Government Loan/Debt Guarantee

Observations:

- As illustrated in Figure 3 above, this alternative results in a decrease of less than 1% from the baseline wires costs.
- This alternative would provide no substantive shift of costs from current to future customers.

2 Long Term Fixed-Price Contracts For Selected Projects

Description:

- The TFO would enter into a long-term contract with a government agency, such as the AESO, with a fixed price for the life of the asset;
- The price would be fixed in nominal terms, which would yield a lower rate in the earlier years and higher in the later years, compared to the cost of service tariff;
- The long-term contract would allow the TFO to use structured project financing rather than conventional term debt; and
- Since project financing could only be economically used for the large projects identified above, it is assumed that this would only apply to the two HVDC and Fort McMurray projects.

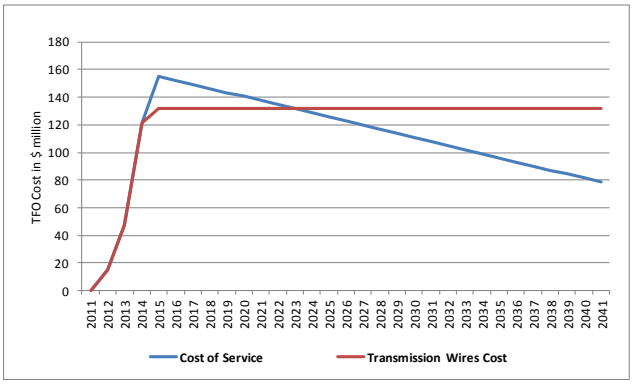
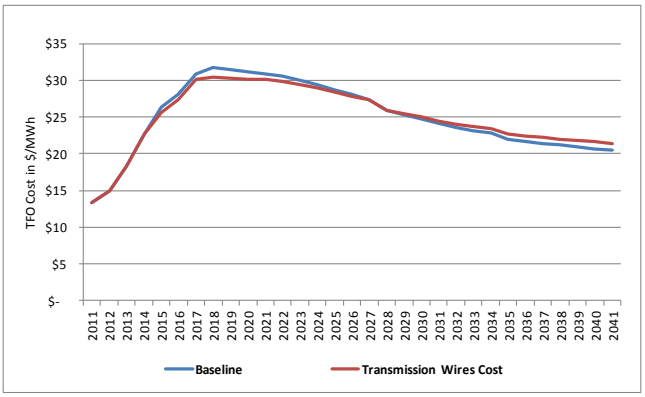


Figure 4 – Levelized Tariff for WATL



- Figure 5 - Levelized Wires Cost for the Two HVDC lines and Fort McMurray

Observations:

- As shown in Figure 4 above, the levelized tariff is lower in the early years and greater in the latter years, compared to the cost of service tariff for the proposed WATL project.
- As shown in Figure 5 above, if this mechanism were applied to the three large projects, the impact of shifting costs from current to future customers is minimal.

3 Transmission Wires Rate Cap with a Deferral Account Mechanism

Description:

- This alternative utilizes a fixed rate cap on the wires portion of the transmission rate to provide a predictable maximum wires cost each year, and uses a deferral account to shift current costs to future years;

- The AESO would pay the TFOs' full revenue requirement, but only collect the rate capped amount from ratepayers;
- Differences, which would arise between the rate cap and the TFOs' revenue requirement in the early years, would be accrued in a deferral account and financed with government supported debt to minimize the carrying costs;
- In later years when the rate cap exceeds the TFO revenue requirement, the difference would be used to reduce the balances in the deferral account;
- The level of the cap on the wires portion of the transmission rate could be established by levelizing the forecast baseline transmission costs over the next 30 years, and
- A rate levelization expressed on a real term basis yields a $22/MWh cap in 2015 and escalates with inflation (see Figure 8).

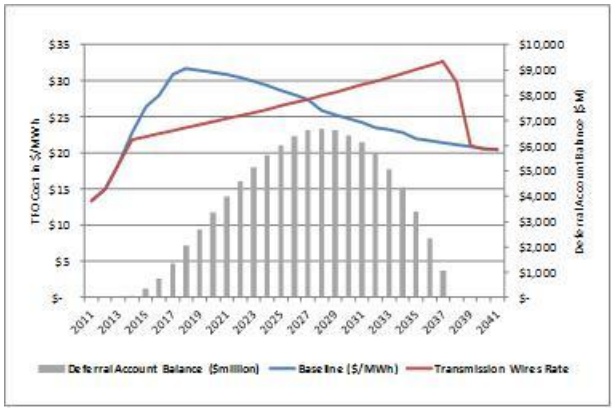


Figure 6 – Rate Cap Escalating at General Inflation and Deferral Account in Nominal Terms

- A rate levelization expressed in nominal terms yields a constant dollar cap of $26/MWh for future years (see Figure 7)

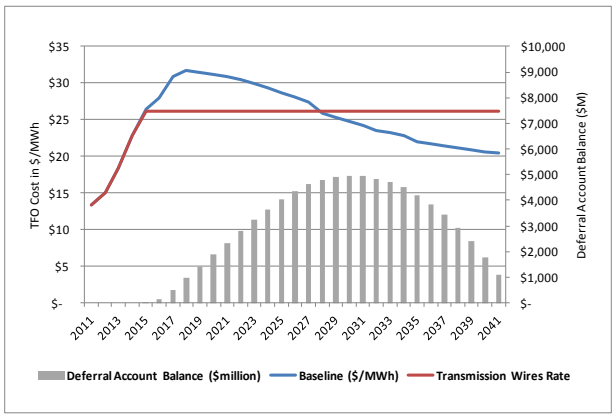


Figure 7 – Flat Rate Cap and Deferral Account Concept in Nominal Terms

Observations:

- These alternatives result in a material shift of costs from current to future customers compared to the status quo.

- Under the escalating real rate cap scenario (Figure 6), current customers pay the same amount for transmission in real terms as do future customers when the nominal price is adjusted for inflation.
- Under the flat nominal rate cap scenario (Figure 7), current customers pay more for transmission than would future customers when taking inflation into consideration.
- The forecast balance in the deferral account is very sensitive to the initial cap selected, and the actual balance in the deferral account is very sensitive to actual load growth and actual transmission wire costs (see Appendix D).
- Under this option, it would be necessary to establish a process by which appropriate adjustments to the price cap could be made periodically to ensure that the deferral account balance is contained within acceptable limits.

4 Total TFO Revenue Requirements Cap With a Deferral Account Mechanism

Description:

- This mechanism would be similar to the rate cap approach described above, except that a percentage cap would be applied to the total TFO revenue requirements to be collected from customers in a given year.
- The total TFO revenue requirements cap was based on the forecast total TFO revenue requirements in 2014, escalated thereafter by a maximum of 5% per year.

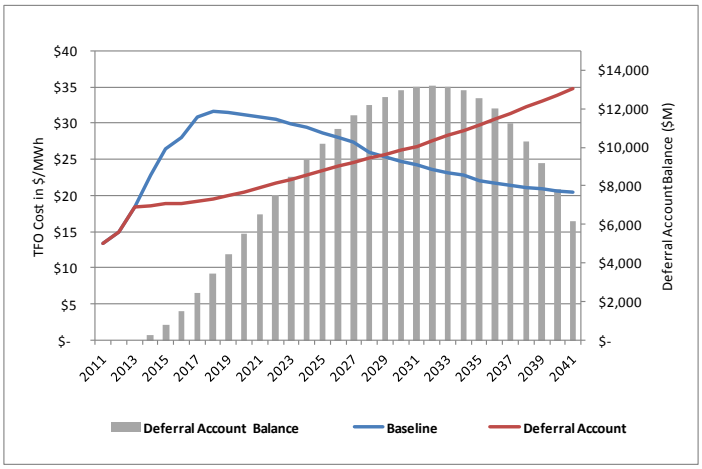


Figure 8 – Revenue Requirement Cap and Deferral Account

Observations:

- As shown in Figure 8 above, the deferral account begins to accumulate in 2014 and peaks in 2032 at about $13 billion based on the above assumptions. The deferral account is not eliminated by 2041 under this scenario.
- The deferral account balance is influenced by the year in which the revenue cap is activated and the percentage cap on the growth in the total annual TFO revenue requirements.
- Under this option, it would be necessary to establish a process by which appropriate adjustments to the price cap could be made periodically to ensure that the deferral account balance is contained within acceptable limits.

- A revenue requirement cap is not equivalent to a price cap, since a revenue requirement cap is not linked to load growth.

5 Fixed Annual Transfer Amount Based on a Levelized Rate With a Fixed-Term Deferral Account Mechanism

Description:

- Under this alternative, the forecast wires component of the transmission rate would be levelized over a selected term, and a deferral account mechanism would be used to achieve this levelized forecast wires rate. The level of annual transfers into or out of the deferral account required to achieve the desired levelized forecast wires rate would be determined and fixed in advance.
- The TFOs would continue to receive their approved annual revenue requirements from the AESO, but the AESO would adjust the total approved TFO revenue requirements by the deferral account transfers determined above.
- Using a levelization period of 20 years as an example, the following figure illustrates the alternative of a levelized nominal price with a deferral mechanism:

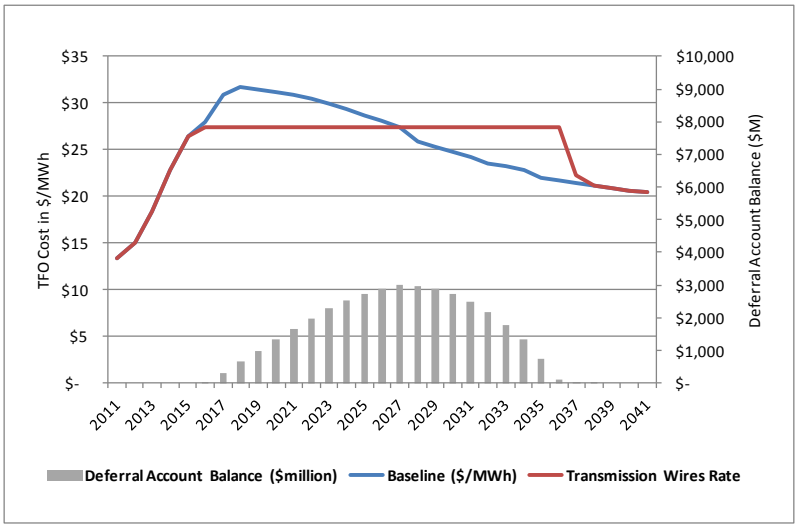


Figure 9 – Levelization of TFO Forecast Revenue Requirement in Nominal terms

Observations:

- Figure 9 above illustrates that levelizing the forecast TFO revenue requirement over a 20-year period produces a levelized forecast wires price of $27/MWh.
- Since the amount and timing of the deferral account transfers are fixed in advance, the timing, size and duration associated with the build-up and draw-down of the deferral account are known with certainty.
- The actual wires portion of the transmission rate could vary from forecast depending on actual load growth and actual transmission costs

6 Non-Ratepayer Funding

Description:

- Obtaining alternative funding from various CEF sources (such as Climate Change and Emissions Management Fund or Carbon Capture and Storage Fund) to offset transmission cost to connect renewable generation.

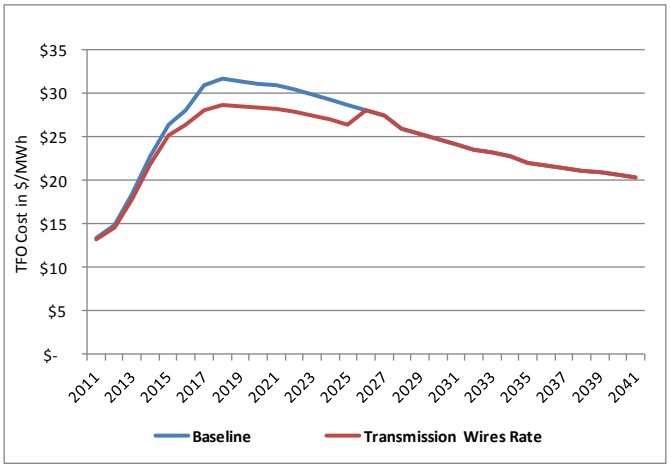


Figure10 – External Funding for Renewable Transmission

Observations:

- The alternate or external CEF funding option (assumed to average about $200 million per year) reduces the overall transmission rate impact amount by up to $3/MWh, as illustrated in Figure 10 above.
- Whether individual ratepayers would benefit from non-ratepayer funding depends on the source of the non-ratepayer funding. For example, if the non-ratepayer funding were provided by Alberta taxpayers, then this approach would shift costs from industrial customers to residential customers.

7 Load Retention Rate (LRR)

Description:

- A LRR is designed to retain load that would otherwise have an economic incentive to leave the system to the detriment of the remaining customers;
- Discounts from standard transmission rates would be provided as an economic incentive to specific large commercial or industrial customers to maintain a facility within the utility's service area; and
- A load retention rate typically applies to customers who can credibly demonstrate they are either considering relocation to another utility service territory, are contemplating plant closure or who can remove their load from the system through economically viable BTF generation.

Observations:

- A LRR would provide transmission rate relief to those industrial customers who would otherwise leave the system.

- This option can be enabled through the existing regulatory process, and is not materially exclusive from other options considered.
- Maintaining industrial load on the system benefits remaining customers through the defrayment of transmission costs across a larger load base.
- The transmission costs not covered by those customers will be spread among all other ratepayers.
- Load retention rates would not shift any costs from current to future customers.

V. QUANTITATIVE COMPARISON OF ALTERNATIVES

In order to make a quantitative comparison of the alternatives, each is compared to the baseline case using the following metrics:

1) Maximum rate reduction relative to the baseline.
2) Average rate reduction for the years 2015 to 2024.
3) Net present value (NPV) is calculated using two discount rates of 3.8% and 9.4% to determine the opportunity cost or benefits applied to cost reductions relative to the baseline. The discount rate of 3.8% is equal to the assumed rate at which the deferral account balances can be financed. The discount rate of 9.4% is based on the opportunity cost of capital for large industrial customers.

A summary of the results from the various alternatives examined, when compared to the Baseline or Status Quo case, is presented in Table 1 below.

	NPV Benefits ($ million) 3.8%	NPV Benefits ($ million) 9.4%	Max Price Reduction ($/MWh)	Average Price Reduction (2014-24)	Max Deferral Account Size ($ million)	Year of Elimination
Gov't Debt Financing	$ 197	$ 123	$ 0.22	$ 0.19	N/A	N/A
Project Financing for Large Projects	$ 163	$ 276	$ 1.23	$ 0.70	N/A	N/A
Deferral Account ($26.12/MWh Cap) - Nominal	$ -	$ 1,058	$ 5.58	$ 3.91	$ 4,900	> 2041
Deferral Account (2013 $21.53/MWh Cap) - Real	$ -	$ 1,503	$ 8.22	$ 5.90	$ 6,600	2039
Deferral Account (5% Revenue Req. Cap)	$ -	$ 3,054	$ 12.10	$ 9.56	$ 13,211	> 2041
Fixed Deferral Account ($27.43/MWh Cap)	$ -	$ 588	$ 4.27	$ 2.71	$ 3,007	2037
Non Ratepayer Funding	$ 1,681	$ 1,184	$ 3.08	$ 2.32	N/A	N/A
Non Ratepayer Funding & $22/MWh Cap - Real	$ 1,681	$ 1,955	$ 9.39	$ 6.95	$ 5,672	2039

Table 1 Summary Results

VI. CONCLUSIONS

The TCRS's observations with respect to the alternative cost recovery mechanisms are as follows:

1. Government debt financing would only result in a small reduction in the wires portion of the transmission rate.
2. Individual transmission project financing with long-term fixed-price contracts would not have a material impact on the wires portion of the transmission rate, since this approach would only be practicable for a limited number of large projects.
3. A cap on the wires portion of the transmission rate combined with a deferral account mechanism would be an effective method of shifting costs from current to future customers. The balance in the deferral account would be very sensitive to actual load growth and actual transmission costs, and a process would need to be established to adjust the price cap periodically to ensure that the deferral account balance is contained within acceptable limits.
4. A percentage cap on the annual increases in the total revenue requirements of all of the TFOs combined with a deferral account mechanism would be an effective method of shifting costs from current to future customers. The balance in the deferral account would be very sensitive to actual transmission costs, and a process would need to be established to adjust the revenue requirement cap periodically to ensure that the deferral account balance is contained within acceptable limits. A revenue requirement cap is not equivalent to a price cap, since a revenue requirement cap is not linked to load growth.
5. A fixed annual transfer amount based on levelized forecast transmission wire rates (in nominal terms) combined with a fixed term deferral account mechanism would shift costs from current to future customers. Under this approach, the deferral account balances and the end date of the deferral account would be known in advance, but the actual wires portion of the transmission rate could vary from forecast depending on actual load growth and actual transmission costs.
6. Non-ratepayer funding could result in a material reduction in the wires portion of the transmission rate, depending on the magnitude and duration of the funding. Whether individual ratepayers would benefit from non-ratepayer funding depends on the source of the non-ratepayer funding. For example, if the non-ratepayer funding were provided by Alberta taxpayers, then this approach would shift costs from industrial customers to residential customers.
7. Load retention rates could be an effective mechanism for retaining load that would otherwise leave the system due to increases in the wires portion of the transmission rate, but would not shift any costs from current to future customers. The transmission costs not covered under the load retention rates would be spread to all other ratepayers.

The TCRS concludes that Option 3 (wires price cap), Option 5 (fixed annual transfer amount) and Option 6 (non-ratepayer funding) warrant further consideration as potential mechanisms to address to cost impact of the proposed transmission build in Alberta:

- **Option 3** (wires price cap) could shelter current ratepayers from the rate impact and rate equity issues arising from the lumpy nature of the transmission build and provide substantive transmission rate relieve in early years.

- **Option 5** (fixed annual transfer amount) could shelter current ratepayers from the rate impact similar to Option 3. Since the amount and timing of the deferral account transfers are fixed in advance, the timing, size and duration associated with the build-up and draw-down of the deferral account are known with certainty. However, the actual transmission rate will vary depending on actual load growth and actual transmission investment.
- **Option 6** (non-ratepayer funding) could result in material reduction in the wires portion of the transmission rates. Clean Energy Funds could be used to offset costs of transmission projects that are primarily linked to new renewable generation.

The TCRS notes that some of these options are not all mutually exclusive, and that some of the options could be combined.

While the deferral account is considered to be the most effective cost mitigation mechanism, it is also recognized that several challenges concerning the deferral account design and implementation must be carefully considered and evaluated further. Specifically, factors such as future load growth, transmission projects (cost and timing), and threshold/trigger rate are difficult to predict, and the customer tariffs would have to be reviewed periodically and adjustments made if necessary.

However, it is TCRS's view that it would be prudent to put such a policy instrument in place ahead the time when it would be needed, to ensure that the instrument could be triggered to mitigate rate impact issues, when and if these issues become a significant concern to policy makers.

In order to make the deferral account mechanism acceptable, the design of such a mechanism must demonstrate two features. First, it must have the capability of mitigating the rate impact issues. Secondly, it must have built-in features that provide certainty such that both the size of the deferral account and the time required to eliminate it will stay within an acceptable ranges. The design should ensure that the proposed mechanism has sufficient flexibility to respond to future uncertainty and is robust under various potential scenarios. The TCRS has discussed a possible framework to address these concerns and they are provided in Appendix E, entitled Potential Framework for Deferral Account Implementation.

While the mandate of the TCRS was to examine options to mitigate the increasing cost of transmission only, an analysis was also done to illustrate the impact to customer's all-in delivered energy cost. The TCRS used less-detailed forecasts for distribution, commodity and retail costs in the determination of the total delivered costs of electricity to customers. The results of this analysis are set out in Appendix F.

APPENDIX A – ALBERTA MINISTER OF ENERGY MANDATE LETTER

ALBERTA
ENERGY

Office of the Minister
MLA, Calgary-West

AR7931

JUN 28 2011

Mr. Henry Yip
Chair
Transmission Facilities Cost Monitoring Committee
331 Wilkin Wynd
Edmonton, Alberta T6M 2H4

Dear Mr. Yip:

Thank you for your recent letters in which you requested my support for the Transmission Facilities Cost Monitoring Committee (the Committee) to explore and develop innovative approaches to cost recovery for new transmission facilities in Alberta.

I support your request and ask the Committee to undertake this initiative on a priority basis. I believe that the Committee is well structured to undertake this work together with the transmission facility owners, the Alberta Electric Systems Operator and Alberta Energy.

As a first step, please develop a work plan and proposed budget to complete this work. Please submit the budget to Sandra Locke, Acting Assistant Deputy Minister, Electricity, Alternative Energy and Carbon Capture and Storage, for her consideration and approval.

On completion of the work, please forward your findings and recommendations to Ms. Locke by email at sandra.locke@gov.ab.ca or by mail at Sixth Floor, North Petroleum Plaza, 9945 – 108 St., Edmonton, Alberta, T5K 2G6.

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Alberta

323 Legislature Building 10800 - 97 Avenue, Edmonton, Alberta T5K 2B6 Canada Telephone 780-427-3740 Fax 780-422-0195
Constituency Office Suite 230, 30 Springborough Blvd SW, Calgary, Alberta T3H 0N9 Canada Telephone 403-216-5439 Fax 403-216-5441

Mr. Henry Yip
Page 2

Thank you for taking on this work.

Sincerely,

Ron Liepert
Minister of Energy

cc: David Erickson
President and CEO
Alberta Electric System Operator

Siegfried Kiefer
Managing Director, Utilities
Canadian Utilities Ltd.

Charles Ruigrok
Interim President and CEO
ENMAX Corporation

Don Lowry
President and CEO
EPCOR Utilities Inc.

Scott Thon
President and CEO
AltaLink Management Ltd.

Bob Heggie
Chief Executive
Alberta Utilities Commission

Sandra Locke
Acting Assistant Deputy Minister
Electricity, Alternative Energy and
Carbon Capture and Storage
Alberta Energy

APPENDIX B – TCRS ORGANIZATION STRUCTURE AND GOVERNANCE RULES

B.1 TCRS ORGANIZATION STRUCTURE

The TCRS was formed as a sub-committee of the Transmission Facilities Cost Monitoring Committee (TFCMC). Selected members of TFCMC are part of the sub-committee. There are also representatives from ATCO, AltaLink, AESO and Epcor as members of this subcommittee. The TCRS has its own governance model. It carried out its work independently but that the TFCMC would be made fully aware of its work and that the sub-committee would bring back its work to the TFCMC for ratification.

TCRS Membership

- Colette Chekerda (TFCMC)
- Sheldon Fulton (TFCMC)
- Azad Merani (TFCMC)
- Jerry Mossing (TFCMC)
- Al Snyder (TFCMC)
- Wayne Taylor (TFCMC)
- Henry Yip (TFCMC)
- John Elford (Epcor)
- Duane Lyons (AltaLink)
- John Martin (AESO)
- Diane Wilson(ATCO)

Henry Yip is the Chair of the TCRS. Bevan Laing sits as an observer and the representative from the Department of Energy

B.2 TCRS GOVERNANCE RULES

Governance for the Sub-committee

- The Transmission Cost Recovery Sub-Committee (TCRS) is a sub-committee of the Transmission Facilities Cost Monitoring Committee (TFCMC). Recommendations and reports from TCRS will be subjected to the review and approval of the TFCMC.

- Chair responsibilities
    - Chairs meetings of the sub-committee.
    - Sets meeting agenda with input from sub-committee members.
    - Ensures timely distribution of information, i.e., meeting minutes, meeting agendas and all relevant material.
    - With all sub-committee members, ensures the fulfillment of the Committee's mandate.
    - Acts as spokesperson for the TCRS subject to the following:
        - Can speak to process and procedural issues;
        - Cannot express an opinion unless it has been approved by the sub-committee;
        - The Chair can speak on behalf of the sub-committee providing reports are approved;
    - Acts as liaison with the TFCMC.

- Member Rights and Responsibilities
    - Prepare for, attend and participate in all meetings.
    - Contribute to the fulfillment of the sub-committee's mandate.
    - Select an Acting Chair in the absence of the Chair.
    - All TCRS discussions are held without prejudice to members' future regulatory positions as well as rights to intervene.

- Cost Responsibilities
    - Non-TFCMC member organizations will be responsible for costs incurred by their

representatives.

- The TFCMC will be responsible for costs for meeting facilities (unless donated by other member organizations) and other incidental costs.
- The TFCMC will be responsible for costs related to retaining external consultants should the sub-committee approve such a requirement.

- Operational Procedures
  - Calling of Meetings
    - The sub-committee shall determine the dates for upcoming meetings;
    - The agenda for each meeting will be set by the sub-committee at each preceding meeting. Additional items may be added at the discretion of the Chair.
  - Meeting Procedures
    - Meeting locations will be determined by the sub-committee. All sub-committee members are encouraged to attend in person; however, attendance may be via telephone or video conference facilities;
    - The Chair shall make best efforts to provide the agenda and related material to all sub-committee members at least one week in advance of the meeting;
    - The Chair shall make best efforts to provide the minutes of each meeting no later than one week after the meeting is held. Approval of minutes will take place at the meeting immediately following the meeting to which the minutes apply;
    - The agenda, minutes and related material shall be distributed to the sub-committee by electronic means. Members can ask for paper copies.
  - Conduct of Business at Meetings
    - The sub-committee shall conduct its affairs at all times in accordance with the Ministerial letter dated 2011 06 28;
    - A quorum consists of at least 50% of the sub-committee members;
    - The quorum formula would apply to all meetings of the sub-committee;
    - For those items where motions for approval are required (including, but not limited to minutes, agenda, reports and recommendations) a motion shall pass if more than 50% of those present are in favour of the motion. A tie vote shall result in defeat of the motion;
    - If a member has a dissenting opinion, this can be recorded in the meeting proceedings, if the member makes such a request. Otherwise motions will just state “carried” or “defeated”;
    - Alternates can vote in place of their designated Committee member but there is the expectation that the alternate will be up to speed on committee business.

  - Treatment of Confidential Information
    - Any Committee member and their alternate(s) shall execute a non-disclosure agreement prior to receipt of confidential information;
    - Not all Committee members, however, would need to sign a non-disclosure agreement. Members who don’t sign a non-disclosure agreement for specific material will not have access to the confidential information in question;
    - Information provided to the Committee that is deemed confidential and commercially sensitive by owners of the information, shall be subject to the terms and conditions of the non-disclosure agreement;
    - Material that is specified as confidential will remain confidential and will need to have a date attached to it that specifies when it is no longer confidential, upon which the material will be available for public consumption.

APPENDIX C – TCRS SCOPE OF WORK

- The following Scope of Work was set out as the work elements to be undertaken by the TCRS. Baseline rate impact assessment:
    - Estimate transmission cost for existing assets and future projects contemplated in the 2011 AESO Plan over a 20 year period;(subsequently increased to thirty years)
    - Use AESO model as a starting point and make necessary changes to reflect Working Committee's assumptions;
    - AESO model has simplifying assumptions on translation of project costs for TFOs to revenue requirements – need to model each TFO in more detail – particularly:
        - Debt/equity structure
        - Operating costs – by project type – i.e., bulk vs. regional
        - Income tax treatment
        - Depreciation rates and methodology
        - CWIP vs. AFUDC;
    - Need to model other DTS costs in addition to wires (TFO Rev Requirements);
        - Ancillary services
        - Industry costs (AESO, AUC, MSA)
    - Need to model the transmission rate model (Bill estimator);
        - Ideally by rate class (residential, commercial, industrial)
        - Need to measure annual change in rates (rate shock determination);
- Cost Mitigation Analysis
    - Classify projects and define benchmark for allocating their costs between existing and future loads:
        - Regional projects
        - N-S HVDC, Fort McMurray, Heartland
        - Southern System Development
    - Determine the rate increase gap to be mitigated;
- Identification of potential options
    - Levelizing/contract/structured financing
        - Determine the key terms of long-term contract to enable structured financing
        - Investigate options of structured/project financing
        - Assess risk/return to TFO resulting from deferring cash flows
    - Government debt and/or debt guarantees
    - AESO or Government supported deferral account
    - Others (combination of the above and/or others);
- Estimate impact of various options or combination on the transmission tariff to ratepayers;
- Evaluation of Options:
    - Define evaluation metrics
    - Evaluate each option against the metrics; and

Determine preferred option(s).

APPENDIX D – SENSITIVITY ANALYSIS

Chart D-1 below depicts the impact of an annual 2.0% load growth (reduction of approximately 1% per year relative to AESO forecast) while maintaining the rate cap at $22/MWh in real terms. Compared to the AESO load forecast case (Figure 6), the size of the deferral account balance increases to approximately $17 billion.

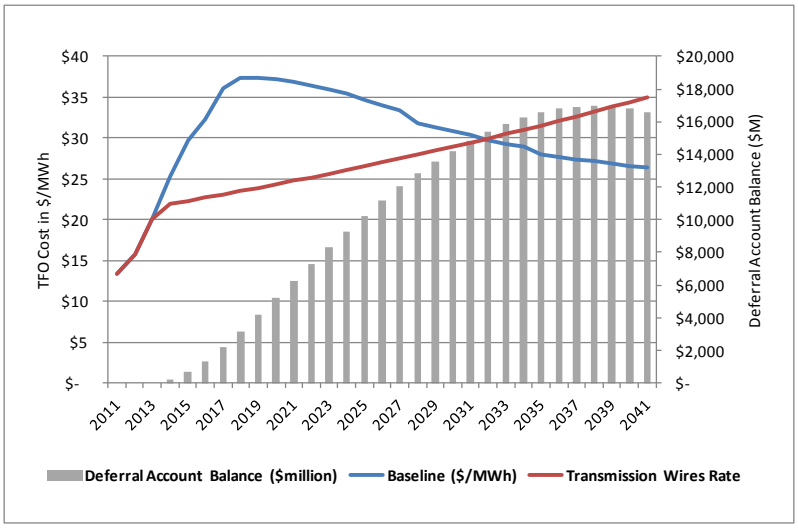


Figure D-1: $22/MWh Real Rate Cap With 1% Reduction in Load Growth

Chart D-2 below depicts the impact of reducing the real rate case by $1/MWh (from $22/MWh to $21/MWh). Compared to the $22/MWh case (Figure 6), the deferral account size increases from about $6.6 billion to $8.5 billion.

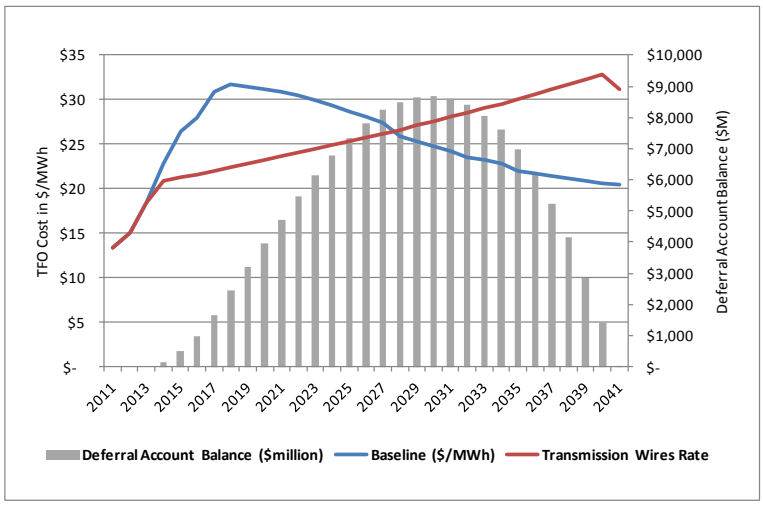


Figure D-2: $21/MWh Real Cap at AESO Load Forecast

Chart D-3 below depicts the impact of increasing the real rate case by $2/MWh (from $22/MWh to $24/MWh). Compared to the $22/MWh case (Figure 6), the deferral account size decreases from about $6.6 billion to approximately $3.8 billion.

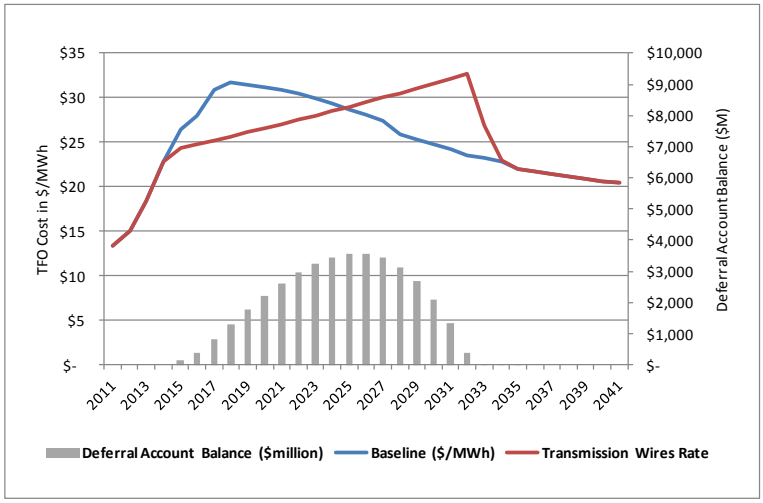


Figure D-3: $24/MWh Real Cap at AESO Load Forecast

APPENDIX E – POTENTIAL FRAMEWORK FOR TRANSMISSION RATE CAP AND DEFERRAL ACCOUNT IMPLEMENTATION

1. Context

It is recognized that several challenges concerning the deferral account design and implementation must be carefully considered and evaluated further. Specifically, factors such as future load growth, transmission projects (cost and timing), and threshold/trigger rate are difficult to predict, and the customer tariffs would have to be reviewed periodically and adjustments made if necessary.

In order to make the deferral account mechanism acceptable, the design of such a mechanism must demonstrate two features. First, it must have the capability of mitigating the rate impact issues. Secondly, it must have built-in features that provide certainty such that both the size of the deferral account and the time required to eliminate it will stay within an acceptable ranges. The design should ensure that the proposed mechanism has sufficient flexibility to respond to future uncertainty and is robust under various potential scenarios.

2. Concept

- The government announces the creation of a deferral account as a policy instrument, with necessary legal and regulatory changes for implementation, which will be triggered in the event that actual transmission rates exceeds certainty predefined threshold level;
- The deferral account is defined by the following parameters:
  a) Threshold rate level ($/MWh) – the rate at which the account will be triggered, and is defined as $XX/MWh. For instance, this could be a rate of $22/MWh.
  b) Escalation rate – a rate at which the initial threshold price will be escalated for the purpose of determining:
     (1) the cost to be recovered from existing customers; and
     (2) the remaining portion to be deferred to future. It is defined as xx% per year plus a band of +/-yy%;
  c) Maximum size of deferral account – a $ Billion figure (e.g. XX times of annual tariff revenue) which forms the cap of the account; and
  d) Forecast time of eliminating the deferral account - XX years.
- After the deferral account is triggered, the first two parameters (threshold rate and escalation rate) will be reviewed periodically in concert with the updates to the 20 year transmission plan and, if necessary, adjusted;
- The other two parameters, the maximum size of the deferral account and the time required to eliminate it, are expected to be held stable unless there is a material change of circumstances that justify a review of them;
- The government will appoint an entity such as the Balancing Pool to administer/manage the account.

3. Process

The deferral account administrator will manage the account in accordance with the process as outlined below:

- Triggering of Deferral Account
  a) Monitors the transmission rate and announces the activation of the deferral account if actual transmission rate exceeds the threshold price;
  b) Forecast/test the impact of different prices within the established range and escalation rates on the size of account and years required to eliminate such account based on the latest forecast of transmission costs (AESO plan, TFO maintenance capital, and customer projects) and DTS load; and
  c) Set the transmission tariff to customers within the established range, and escalation rate for the next 5 years.

- Ongoing Administration
  On an annual basis, the administrator will:
  a) Settle with the AESO with respect to revenue requirement gap to be met by the deferral account;
  b) Raise funding from capital markets and reimburse the AESO for the revenue requirement gap;
  c) Track the deferral account on an ongoing basis; and
  d) Provide regular reporting to stakeholders regarding the status of deferral account and process.

At the end of each 5-year term, the administrator will:

- Update the analysis on trigger rate ($/MWh);
- Forecast the maximum size of the deferral account and time required to eliminate it, based on the current threshold prices and escalation rate and updated forecast of transmission cost and DTS load;
- Determine if adjustments are required for the threshold price and escalation rate to maintain the maximum size and time of extinguish within acceptable ranges; and
- Reset the threshold price and escalation rate for next 5 years if required.

4. Additional Analysis

Additional areas to be pursued and examined related to deferral account implementation:

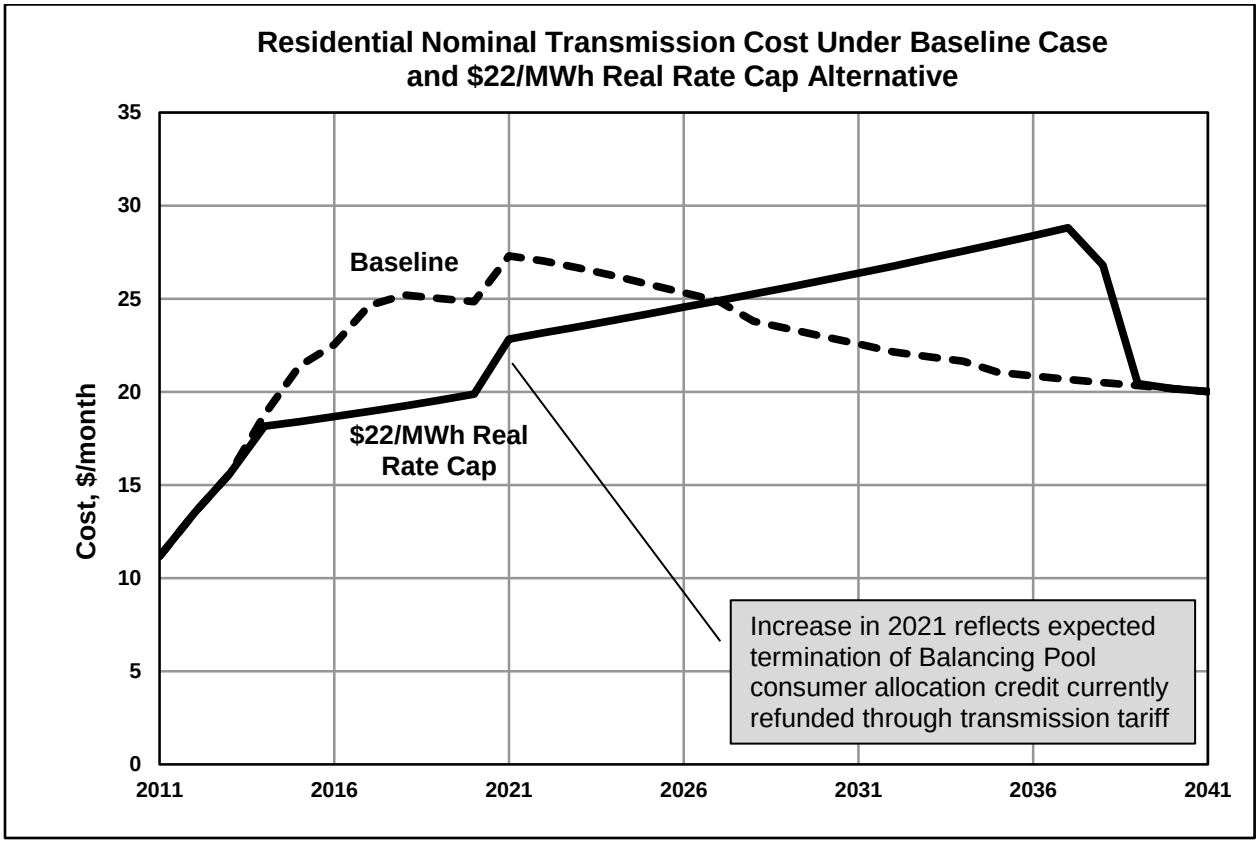
- Further explore financing options for both deferral account and support of revenue requirements associated with renewable resources; and
- Examine the issue of ratepayers leaving the system after the deferral account has been triggered, which could create stranded costs for remaining ratepayers.

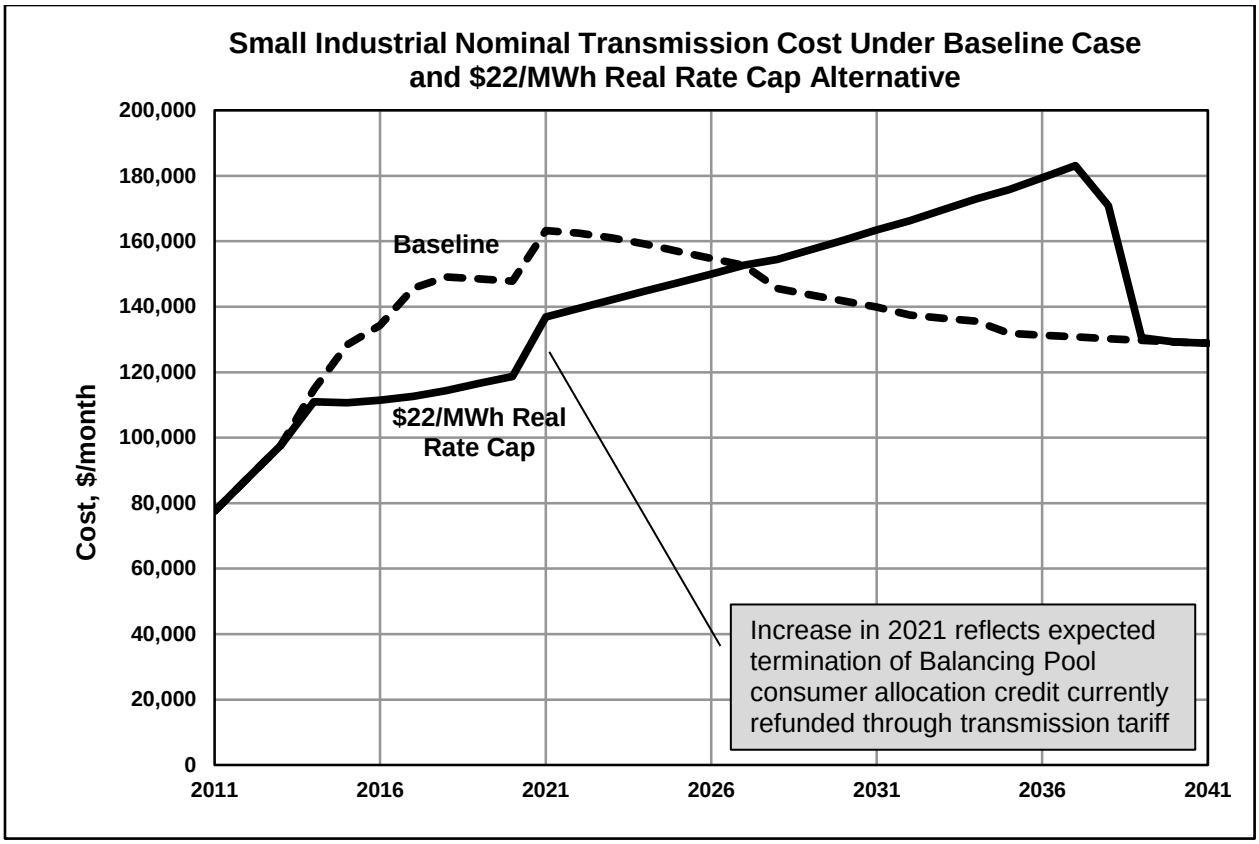
APPENDIX F – DELIVERED COST OF ELECTRICITY TO RATE PAYER

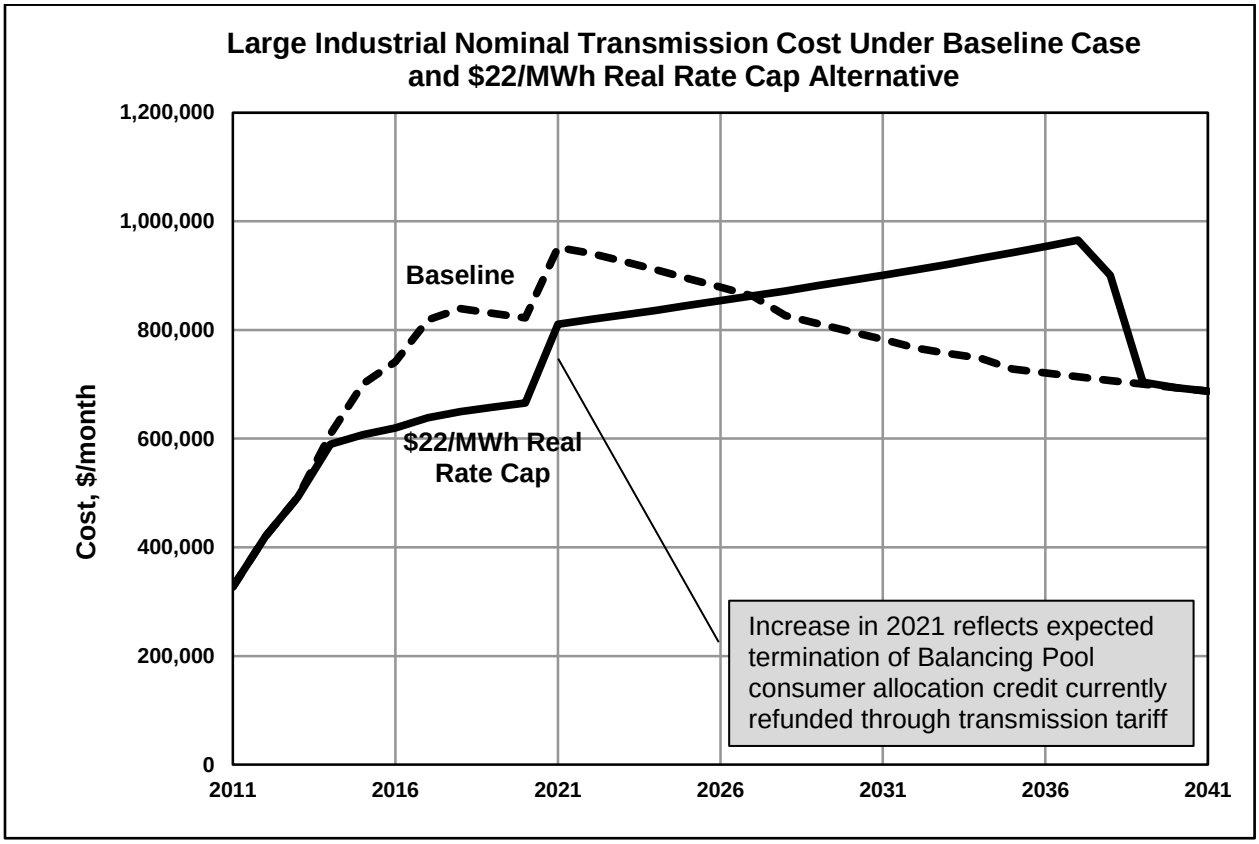
The TFO costs discussed in the body of this report are paid by the Alberta Electric System Operator. The AESO combines the TFO costs with other transmission-related costs (primarily the cost of ancillary services and its own general and administrative costs) in a transmission tariff, which is charged to all load consumers who access the transmission system.

Distribution utilities, as load consumers accessing the transmission system, pay the AESO's transmission tariff. They then recover the transmission costs they pay from individual distribution-connected consumers through the transmission component of their own distribution tariffs.

The model of TFO costs extends to include all transmission-related costs included in the AESO's tariff. The figures below illustrate the results of the analysis for transmission costs attributable to a typical distribution-connected residential consumer and to typical small and large transmission-connected industrial consumers. The figures include transmission costs under the baseline case as well as under an illustrative alternative cost recovery approach based on the rate cap at $22/MWh in real terms as discussed in Section V of the report.

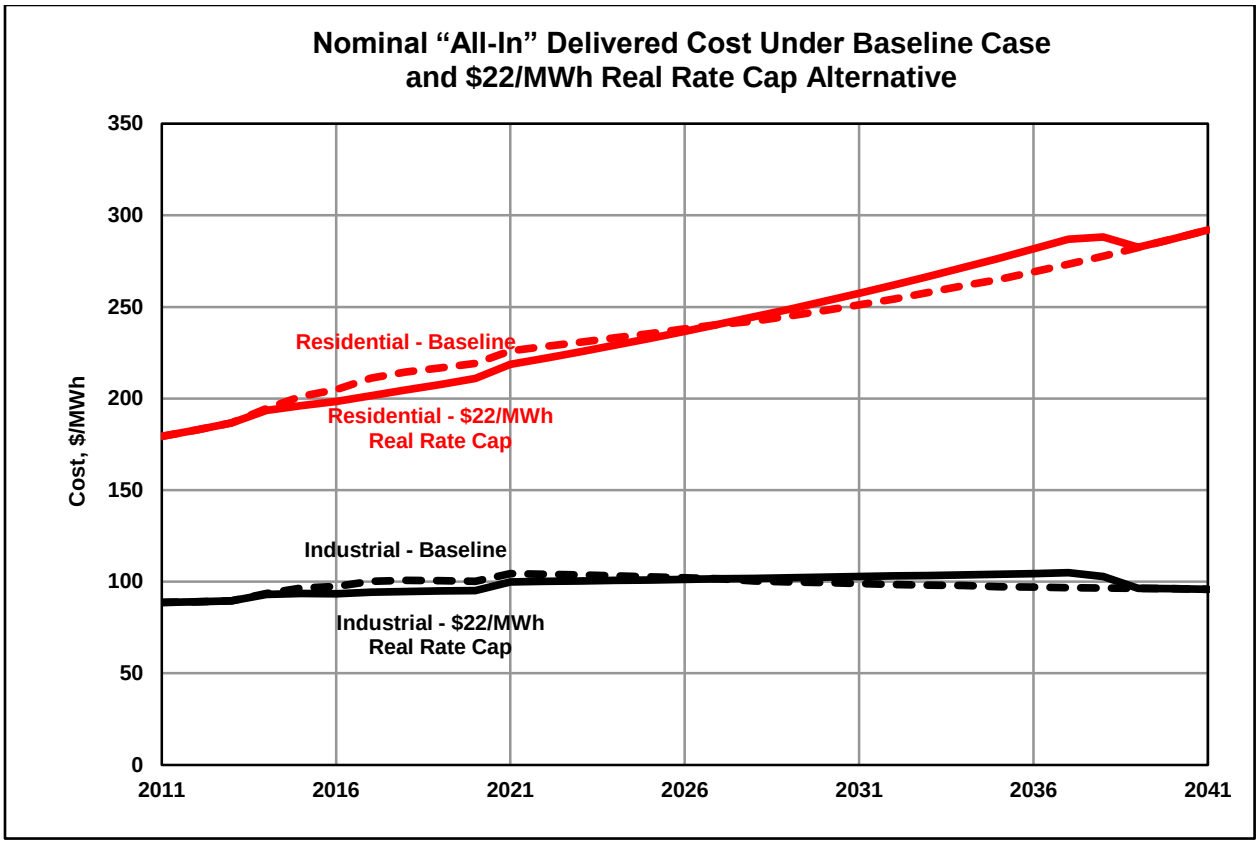



Small Industrial Nominal Transmission Cost Under Baseline Case and $22/MWh Real Rate Cap Alternative
Cost, $/month
200,000
180,000
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
2011
2016
2021
2026
2031
2036
2041
Baseline
$22/MWh Real Rate Cap
Increase in 2021 reflects expected termination of Balancing Pool consumer allocation credit currently refunded through transmission tariff


Large Industrial Nominal Transmission Cost Under Baseline Case and $22/MWh Real Rate Cap Alternative
Cost, $/month
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
2011
2016
2021
2026
2031
2036
2041
Baseline
$22/MWh Real Rate Cap
Increase in 2021 reflects expected termination of Balancing Pool consumer allocation credit currently refunded through transmission tariff

Transmission costs are only one component of the "all-in" delivered cost of electricity to end-use consumers. The delivered cost of electricity to a transmission-connected industrial user would typically include energy and transmission costs. The delivered cost of electricity to a distribution-connected small industrial, commercial, farm, or residential consumer would typically include energy, transmission, distribution, local access fee, and retail costs.

The model of TFO costs was further extended to include all costs included in the delivered cost of electricity. The results of the analysis, for both the baseline case and under an illustrative alternative cost recovery approach based on the rate cap at $22/MWh in real terms as discussed in Section V of the report, are illustrated in the figure below.



The "all-in" delivered cost includes assumptions about future costs of energy, distribution, retail, and other costs, which have not been as fully researched as the transmission-related assumptions.

From the perspective of the "all-in" delivered cost of electricity, the transmission build over the 2011-2020 period has a relatively small impact on total delivered electricity costs to consumers. The alternative cost recovery approaches discussed in this report will therefore have similarly limited impact on the delivered cost of electricity, as seen in the illustrative effect of the rate cap at $22/MWh in real terms in the figure above.

Although the transmission build will have a small relative impact, the dollar impact on large services may be appreciable. The table below provides the dollar increases attributable to the transmission component of monthly electricity bills under both the baseline and rate cap scenarios illustrated above.

Increase From 2011, $/month	2015	2020	2025	2030	2035	2040
Residential Increase (600 kWh/month: $11/month in 2011)						
Baseline Case	10	14	15	12	10	9
Rate Cap at $22/MWh Real	7	9	13	15	17	9
Difference, Rate Cap – Baseline	(3)	(5)	(2)	3	7	0
Small Industrial Increase (7.5 MW, 65% Load Factor, 85% Load at System Peak: $80,458/month in 2011)						
Baseline Case	50,914	70,359	79,462	64,228	54,413	51,786
Rate Cap at $22/MWh Real	33,193	41,240	69,871	82,880	98,310	51,800
Difference, Rate Cap – Baseline	(17,721)	(29,120)	(9,591)	18,652	43,897	14
Large Industrial Increase (50 MW, 85% Load Factor, 85% Load at System Peak: $339,210/month in 2011)						
Baseline Case	373,684	495,177	567,586	469,665	401,041	366,420
Rate Cap at $22/MWh Real	280,139	338,138	517,840	563,793	615,473	366,487
Difference, Rate Cap – Baseline	(93,545)	(157,039)	(49,745)	94,128	214,432	67

As illustrated in the table, the average household would pay as much as $5/month ($60/year) less under the rate cap approach; the small industrial as much as $29,000/month ($350,000/year) less, and the large industrial as much as $157,000/month ($1.9 million/year) less.