Alberta Transmission and Distribution Systems

Issues, Principles and Key Considerations for an Efficient and Sustainable Design

Multi-Client Study

Final Draft Report

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Table of Contents

Section 1: Introduction and Executive Summary

This paper has been prepared by Power Advisory to examine price signals, planning practices and system design in the transmission and distribution sectors of the Alberta electricity market. The paper provides an overview of real-time and investment price signals, as well as quasi-price signals created by practices and policies. The intent of the paper is to examine the existing package of tariff structures and rates and identify options for changes that are consistent with principles driving efficient decision making. Recommendations are not provided, but options are evaluated against criteria to identify pros and cons with various approaches.

The timing of the paper is driven by various issues being raised in ongoing regulatory proceedings as well as fundamental issues in the regulated sectors of the Alberta market. The distribution system inquiry is a process to evaluate the impact of new technologies on the distribution system and identify potential areas for regulatory change. The 2018 tariff made a number of determinations on the treatment of distribution connected generation. The AESO is consulting on its 2021 tariff with major questions around appropriate incentives to send to transmission customers through the billing determinants as well as the possibility of new rate classes.

The intent of the paper is to identify options to improve the investment decisions in the transmission and distribution systems as well as improve signals for generation and load investment where possible. The primary objective is identifying opportunities to reduce future system costs and improve the efficiency of tariffs in allocating the existing fixed costs. Maintaining transmission and distribution rates at a flat nominal level, for example, was raised by several stakeholders as the type of goal that could be pursued.

A range of stakeholders were consulted in the development of this paper, and their concerns with the current situation and views of opportunities are documented as part of this report. The views in the paper, other than where noted explicitly as stakeholder views, are Power Advisory's views. Not all stakeholders hold the same or similar views, and the concerns identified in this paper include concerns held broadly as well as those held by a minority of stakeholders. All principles identified, along with the examination of potential options, represent Power Advisory's opinions.

At a high level, many of the identified concerns with the current structure are related to rising costs and the sustainability of the current congestion free, postage stamp design, in general. High costs for transmission and distribution increase the pressure on the system as more customers look for alternatives to leave the centralized grid. New technology such as small-scale distributed generation, demand response options and storage were also identified as challenges and opportunities for the current transmission and distribution framework. Measures to address these concerns were explored with stakeholders, and there were a range of views put forward. It is important to note that stakeholders were generally aligned that the energy only market is working well, but sustainability concerns related to wires costs are creeping into the view of the market.

Themes for Efficiency

Several themes for driving efficiency emerged during discussions with stakeholders. These themes do not form recommendations but rather are the root driver behind the options identified in the final section for the paper.

1. The structure of the industry and design of processes can be used to deliver competitive alternatives to regulated investments.
2. Incentives through tariffs or other mechanisms can be used to drive behaviour that lowers future costs provided those incentives are aligned and tied to cost drivers.
3. The planning process is no longer sufficient to reflect the state of the industry.
    a) Real options have value[1] where there is uncertainty and deferring and reducing sunk costs has value as a result.
    b) There are now more options to resolve traditional transmission and distribution needs. Competitive solutions may be available where in the past regulated solutions were the only option.
    c) Transparent and probabilistic approaches to planning and investment may provide opportunities to improve investment efficiency.

A number of the issues raised and potential solutions tie back to the existing transmission policy and the Transmission Regulation. In particular, the objective of a congestion free transmission system with very limited locational price signals and an untested framework for non-wires alternatives were seen as an issue. The ISO's planning approach to meet the regulation was also a concern. On the distribution side, there are fewer direct hurdles to new approaches, but regulatory uncertainty was identified as a concern.

This final section of this paper examines alternatives that fit within the existing policy, as well as alternative policies that could be realistically adopted in Alberta. The key areas potential alternatives address include:

1. Develop more efficient signals in the transmission and distribution tariffs
    a) Improve locational signals for generation and load
    b) Increase the number of rate classes to optimize use of the system
2. Examine opportunities to 'bend the curve' and stop or reduce the escalation in wires costs
    a) Revise planning approaches and approaches to congestion to decrease the need for investment in wires infrastructure without increasing investment risk for generators and loads
    b) Introduce avenues for competition and flexibility in the regulated transmission and distribution systems

[1] A real option pertains to investment choices in tangible assets. In this case, the real option is the value created by the ability to alter, defer or stop a wires investment in response to changing conditions such as lower load growth, increased local generation, cancelled generation projects or other factors that reduce or delay the need for new wires investment.

- Use cost effective and competitively procured non-wires solutions where technically feasible

c) Attract new load with the use of innovative rates where new load lowers transmission or distribution costs (locational incentives for load)
d) Integrate new technology

The main goal of the options identified can be summarized as an attempt to reduce cost escalation in the transmission and distribution systems through reducing spending and increasing load. The options to do this include changing planning approaches, more efficient tariff signals through new and revised rates, and introducing competition in providing diverse solutions. Opportunities to drive load growth as a means to lower average costs are also examined.

The existing legislation and regulation does limit the ability to pursue some options, but there is flexibility to make a range of changes without new legislation. However, many of the changes will require new regulatory approaches to introduce competition and examine opportunities for solutions that are at odds with the current process. There are tradeoffs and challenges associated with the majority of options identified, but some options appear to have very strong economic rationale with administrative barriers and complexity the key challenges to overcome. In some instances, the barriers are minimal and could easily be pursued within the existing framework.

1.1 Principles for Evaluating Options

The principles for evaluating options are outlined in Section 2 of this report and further detail is provided in the Appendix. Since the options examined fall both within the categories of rate-making and general 'price signals', principles include Bonbright rate-making principles and overall economic efficiency principles. Alberta regulatory and legislative principles will also be considered.

Appendix A provides more details on the principles.

1.2 Current Alberta Approach

The current Alberta approach is outlined across a range of topics that impact operational and investment decisions. The broad areas outlined in the report include:

1. Review of the current legislative and regulatory framework: the review will provide an overview of the structure of the regulated portion of the industry to provide context for what is feasible in the current framework and where barriers to change exist;
2. Summarize the existing regulatory structure for transmission and distribution;
3. Connection price signals for load, generators and wires services providers: this area includes examining locational signals, treatment of non-wires solutions and other policies that impact investment decisions;

4. Operational price signals for load, generators and other market participants: this includes the relationship between wires and energy price signals, congestion management and ancillary services treatment; and
5. Planning and incentives in the industry: the approach used to drive investment decisions in transmission, distribution, generation and load.

Appendix B provides more detail on the current Alberta approach as well.

1.3 Concerns with Current Approach

This section of the report will outline a range of concerns with the current approach, particularly those identified by stakeholders participating in this study. Power Advisory will also identify issues where the price signals and incentives created by the current framework are at odds with the principles identified in the paper.

1.4 Options for Changes

The potential options for changes to the current approach will focus on identifying possible changes and assess the pros and cons of these changes relative to the principles identified in the report. The potential changes will also be considered in the context of the current legislative framework. As part of the assessment of options, the report will consider the impact of the change on incumbents relative to the current approach.

1.5 Appendix A – Principles for Evaluating Options – Details

Further details related to principles for evaluating options are provided in this Appendix. The key issues are summarized in Section 2 and this section is intended to provide greater depth rather than incremental information.

1.6 Appendix B – Current Alberta Approach - Details

Further details related to the current Alberta approach are provided in this Appendix. The key issues are summarized in Section 3 and this section is intended to provide greater depth rather than incremental information.

1.7 Appendix C – Stakeholder Comments

The Appendix will not be authored by Power Advisory. Rather, Power Advisory will include, unedited comments on the final report from stakeholders that participated in the project. As noted, this report represents Power Advisory's view rather than the view of any participant or participants. The intent of the Appendix is to ensure study participants are able to identify where they agree or disagree with Power Advisory's view.

Section 2: Principles

There are two layers of principles considered in this report. First, basic economic principles that drive efficiency are assessed relative to regulated transmission and distribution networks. These principles are based on sending clear price signals that reflect the costs of using the system, both in the short-term and long-term. The cost of using the system should reflect both the fixed cost of the existing system as well as the long-term marginal cost of expanding the system. The core principles also include maximizing competition within the regulated sectors and maintaining option value in the system. Planning concepts and the notion of examining costs and benefits in system expansions are also principles in an efficient system.

The core set of principles used to evaluate options in this paper relate to economic efficiency. With respect to transmission and distribution, efficiency can largely be summed up as ensuring price signals encourage efficient use of the existing system combined with efficient expansion of the system. Efficient expansion of the system involves deciding when expansion should take place as well as the size and type of the expansion. It also requires that future generation and loads with locational discretion are added to the system as beneficially as possible from a total cost perspective, i.e. the marginal cost of transmission expansion is ideally part of the consideration in locating system users. Structural issues, such as introducing competition to the transmission and distribution sector is also considered.

Second, rate-making principles are assessed as many of the pricing elements of the system will be subject to regulatory approval and these principles will potentially be binding on feasible options. These principles are largely intended to reflect competitive outcomes, i.e. they act as a replacement for competition in a natural monopoly. The rate-making, or so-called 'Bonbright principles', apply only to the subset of choices that relate to transmission tariffs or distribution tariffs, including terms and conditions. Planning concepts and incentives for the regulated entities in the overall market structure do not fall within the context of these principles.

2.1 Core Principles

Efficient pricing in economic terms generally means that price is equal to marginal cost. However, within the electricity market, transmission and distribution assets are generally seen as natural monopolies, with very low marginal costs and high fixed costs. The primary short-term marginal costs on the network are losses, which are locational, and congestion, which is also locational. Note that both losses and congestion are a function of the network, generation and load in combination.

Some markets recover a portion of the total wires costs through charging marginal losses or paying generators based on these marginal losses (which are generally higher than average losses in total) and capturing the rents associated with locational marginal prices (LMP). In Alberta's market context, with a single energy price, little to no congestion and revenue neutral loss factors[2], the

[2] This is the high level situation in the Alberta market for both the transmission and distribution systems.

entirety of the fixed transmission and distribution costs must be recovered from an incremental administrative charge such as a fixed charge on a per MW or per MWh basis. From an efficiency perspective, fixed charges where the underlying costs are fixed such as on the transmission and distribution system are generally preferred in order to avoid distortions to the real-time energy market.

It is also important to note that economic efficiency does not require that all consumers face the same price. In fact, efficiency can generally be improved when there is a natural monopoly by charging less to consumers with a higher price elasticity. In other words, if charging all consumers the same average price causes some portion of those consumers (*i.e.* customers with high price elasticity) to leave the market (either through locating in another jurisdiction, investing capital to self-supply, reducing consumption, or some other means), economic efficiency suggests differential pricing is beneficial to keep these price elastic customers on the system. This reality suggests that transmission and distribution pricing is limited by the cost of the alternative, i.e. exiting the market.

Another core concept to efficient planning for the transmission and distribution systems is that there is significant uncertainty in how the system will evolve. Generation and load patterns are uncertain, especially in light of the changing technological picture for renewable generation, general economic uncertainty, and the potential for growth in new load such as electric vehicles. In this context, real-options have value, where a real-option is defined as the ability to avoid sinking a cost and losing future flexibility. Since flexibility has value, options with lower sunk costs, shorter project lives and occurring in smaller increments should be favored over choices with higher sunk costs. The trade-offs between higher per unit costs or other 'costs' associated with alternatives that preserve future options by avoiding large-scale investments should be explicitly considered rather than simply choosing the lowest cost option, especially on a per unit basis.[3]

It is also not strictly required that prices or tariffs are the mechanism to send signals to the market. In some cases, such as system expansions, a planning framework utilizing economic principles could be used to drive towards optimizing the network. The core principles are listed below and outlined in more detail in Appendix A.

- Direct allocation of costs – costs that are clearly a direct function of participant choices and are used strictly by that participant should be allocated directly to that participant.
- Efficient real-time operation of the energy market - both marginal loss factors and real-time congestion should be considered in the dispatch of the system.
- Rational system expansion - the benefits of system expansion meet or exceed the cost of system expansion and options such as non-wires solutions are considered. The value of

[3] In Australia and the UK, this is explicitly considered as part of the planning process and is often termed 'the choice of least regret'. See the AEMO https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2019/2019-to-2020-Forecasting-and-Planning-Scenarios-Inputs-and-Assumptions-Report.pdf for example.

deferring or minimizing sunk costs and maintaining real-options are factored into decisions.
- Locational signals - the need for investment in transmission and distribution networks are not independent of load and generation choices and tariff design should consider the relative value of locating generation or load in one location versus another.
- Service differentiation - system access does not need to be a homogeneous product in terms of reliability or other terms of service.
- Clear and transparent - prices that are simple and transparent are much more effective at driving responses than complex or opaque price signals, with the caveat that the signal must be sufficiently complex to reflect underlying cost drivers.
- Consistent and aligned incentives that maximize competition - the structure of the regulated sectors of the industry, as well as the suite of tariff price signals, should provide consistent price signals that are aligned towards driving efficient outcomes. Wherever possible, regulated entities should have an incentive to drive efficient outcomes.

Overall, the core principles relate to making efficient decisions around when and how to expand the system, which at a high level requires a cost benefit approach. Locational signals for generation and load that mimic locational marginal price signals to some degree, managing real-time constraints and allowing differentiation of service levels also fit into this sending efficient tariff signals.

2.2 Rate Making Principles

A number of sources should be considered when determining the principles of tariff ratemaking. Bonbright's *Principles of Public Utility Rates* is often looked to as an important consideration in ratemaking. Professor James Bonbright's *Principles of Public Utility Rates* was first published in 1961. Bonbright approached ratemaking largely as an exercise in balancing the interests of capital attraction with those of ratepayers within a 'public interest' framework.

It is virtually impossible to satisfy all of Bonbright's rate design principles with any given rates structure (e.g. it may not be possible to have rates that are both simple and fair). Accordingly, trade-offs need to be made with an understanding of which principles should take precedence in any given situation. In its decisions, the Alberta Utilities Commission (Commission) places more weight on some of Bonbright's principles, relying on some to establish its findings while providing rationale for why some principles can be ignored in the specific situation.

Rate making principles are generally not at odds with the core economic concepts, but they add nuance to setting the administrative tariffs that should be reflected in regulated rates. For example, there are additional non-economic principles such as fairness, avoidance of intergenerational inequity, and avoidance of undue discrimination, which are not traits that necessarily exist in an efficient competitive market. The Bonbright principles introduce a number of other trade-offs. For example, locational signals might not be fair or simple, but they are efficient and could significantly reduce cost to consumers over time. The rate making principles highlighted below are reviewed in greater detail in Appendix A.

- Cost causation – the party causing costs should pay the full amount of those costs.
- Efficiency – the amount of infrastructure needed to deliver a given level of service should be minimized.
- Avoidance of Intergenerational Inequity - each generation of rate payer should pay for their own costs and not shift these costs into the future or pay a disproportionate share of current investments relative to future ratepayers.
- Avoidance of cross-subsidies - rates should be designed to fairly share the total costs among the different customers and different customer groups. This is typically tied to cost causation.
- Avoidance of undue discrimination - a logical goal is to attempt to avoid discrimination except when to do so would contradict another of the rate design principles.
- Simplicity - rates should be designed in a manner that allows them to be understood by and accepted by the public. Rate complexity can vary by customer type as more sophisticated customer classes may be able to understand and respond to more complex rates.
- Avoidance of rate shock - The Commission in Alberta has commonly considered that an increase in the total bill of a customer with typical usage in a given rate class by more than 10% from one billing period to the next could be indicative of rate shock.
- Rate stability - rate stability on a total billing basis from billing period to billing period is a desirable outcome.
- Yields total revenue requirements – the rates must be designed to collect the total needed revenue to ensure fair returns.

Overall, the Bonbright principles generally relate to the fair and efficient allocation of the fixed costs of the existing system.

Section 3: Current Alberta Approach and Situation

This section of the report outlines the existing system in Alberta, starting from the high level legislation and regulation that guides the market and stepping down to a relatively detailed overview of the various tariffs, business practices and other price signals. There are several purposes to the section:

- Provide a summary of the legislation and regulation to provide context for the options analysis section of the report
- Outline the regulatory structure and overall organization of the industry
- Summarize the key elements of the transmission system that impact efficiency, including the tariff, the planning approach and business practices
- Summarize the key elements of the distribution system in a similar manner to the transmission system
- Evaluate the existing approach at a high level relative to the principles outlined in the principles section of the report

Greater detail on several of the areas is provided in Appendix B.

3.1 Alberta Legislation and Policy

At a high level, Alberta legislation establishes that both transmission and distribution are regulated sectors, with the Alberta Utilities Commission having oversight. The legislation and related regulations also establish a number of obligations and restrictions on how transmission is planned and priced. A large portion of the obligations apply to the ISO in its role as system planner, provider of system access and real-time market operator.

3.1.1 Electric Utilities Act

The key legislation providing the structure of the Alberta electricity market is the *Electric Utilities Act* (EUA). The EUA outlines the following:

- Establishes the Independent System Operator (ISO).
- The ISO is the sole provider of system access service, and the ISO must provide a reasonable opportunity for all participants to exchange electricity.
- The ISO must establish the tariff for system access, along with the associated terms and conditions. Rates must recover the costs that are reasonably attributable to each class of customer service.
- Rates must not be different due to location on the transmission system, *i.e.* the same rate class must have the same rate regardless of location.
- Proposals <u>other than transmission infrastructure</u> to alleviate congestion are contemplated in the Act (Section 36).

- Section 37 – Transmission Facility Owners (TFOs) must submit to the ISO a tariff to be paid for using the transmission facilities. In practice, this means TFOs submit revenue requirements and the ISO designs a tariff to collect the total required TFO revenues.
- TFOs must apply to build transmission facilities when directed by the ISO.
- Section 101 establishes exclusive territory based approach to distribution, with the exception that parties can apply directly to the ISO for transmission system access.
- Distribution Facility Owners (DFOs) must provide access that is not unduly discriminatory.
- DFOs are responsible to plan and build the distribution system in their territory.

The EUA also gives the Commission guidance on tariff considerations. In particular, Section 121 provides that the tariff must not be unduly preferential, or arbitrarily or unjustly discriminatory. However, Section 121 (3) states that a tariff that provides incentives for efficiency is not unjust or unreasonable simply because it provides those incentives. Section 122(3) of the EUA also creates the ability for the ISO to have elements of the tariff reflect real-time costs and have these costs flow through directly to end users.

3.1.2 Hydro and Electric Energy Act

The *Hydro and Electric Energy Act* (HEEA) outlines the process for developing infrastructure, including generation, transmission and distribution facilities. Projects must be approved by the Alberta Utilities Commission. Incentives, including those proposed by the project proponent, may be approved by the Commission if they are intended to result in cost savings or other benefits.

It also outlines the concept of an industrial system designation, where an industrial system allows an integrated facility to build transmission and distribution infrastructure within its boundaries. Generally, an industrial system is comprised of generation integrated with industrial processes. The industrial system designation requires that internal supply of generation must be the most economical source of supply, and that the designation must not facilitate the development of independent systems intended to avoid costs associated with the interconnected system and/or inefficient bypass.

3.1.3 Transmission Regulation

The *Transmission Regulation* (T-Reg) establishes many of the main principles of planning, transmission development and tariff design in the Alberta market. This Regulation largely applies to the ISO, but it also outlines the AUC's responsibilities.

The ISO is obligated to plan the system prospectively, taking into account factors such as load growth, generation type and location, as well as access to other markets. Of note, the ISO may consider transmission improvements for the purposes of improving reliability, facilitating competition, increasing system efficiency and flexibility, and maintaining future options for the development of the system.[4]

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[4] T-Reg, Section 8(d)(i-v)

There is a general mandate for the system to be planned to be free of congestion. In particular, Section 15(1)(e)(i) mandates that the system "is sufficiently robust that 100% of the time, transmission of all anticipated in-merit energy referred to in section 17(c) of the Act can occur when all transmission facilities are in service". This clause has generally been used to suggest the ISO must maintain a congestion free system, but the Regulation does contemplate an exemption to the requirement.

Section 15(2) provides for the exemption to the congestion free system and states "In planning and arranging for enhancements or upgrades to the transmission system, the ISO may make or provide for specific and limited exceptions to the matters described in subsection (1)(e) and (f) and in section 16(1), or any of them, and if it does so, must (a) file the exceptions with the Commission for approval, and (b) specify the periods of time the exceptions apply."

Non-wires solutions are also explicitly contemplated in the T-Reg in 15(3). "In considering the design and planning of the transmission system, the ISO may make or provide for specific and limited exceptions to the requirements of subsection (1) and propose a non-wires solution (a) in areas where there is limited potential for growth of load, and the cost of the non-wires solution is materially less than the life-cycle cost of the transmission wires solution, compared over an equivalent study period, or (b) if the non-wires solution is required to ensure reliable service due to the shorter lead time of the non-wires solution, for a specified limited period of time."

The T-Reg establishes the framework for competitive procurement of transmission infrastructure. This framework generally relates to large well defined transmission projects, and does not contemplate general competitive procurement of transmission, nor does it consider non-wires alternatives.

The T-Reg establishes that local interconnection costs are paid for by the owner of a generating unit connecting to the system. A generator does not have exclusive access to the infrastructure it paid for, but in the event another user accesses the facility, the original cost must be refunded to the person who paid it. In addition to direct interconnection costs, the T-Reg also establishes that generators must pay the Generating Unit Owners Contribution (GUOC) as part of the interconnection process. The GUOC is a refundable charge that is intended as a locational signal. It ranges from $10,000 per MW to $50,000 per MW and is refunded over the first 10 years of generation operations.

System losses are charged to generators in a specific manner outlined in the T-Reg. In particular, generators collectively pay for the average losses on the system on an annual basis. Each generator receives a single loss factor that applies for at least one year, and that loss factor must range from a 12% credit to a 12% charge at a maximum.

3.1.4 Key Legislative Requirements and Alignment with Principles

The legislative requirements set a number of limitations for the ISO in planning the system and in setting tariffs for accessing the system, but there appears to be material discretion. The following issues outline Power Advisory's interpretation of where there is and is not discretion but notes that some of these areas have not been tested by the AUC in terms of an ISO or DFO application.

- The postage stamp requirement for load transmission rates creates challenges in that many costs of using the transmission system are location dependent.
- There are no limits on rate classes to the extent they impose differential impacts on the transmission system, and the ISO's current policy to use one primary rate class for load (Demand Transmission Service or DTS) is a discretionary choice.
- The limitations on GUOC and losses further reduce locational signals and may not allow material locational signals to be sent to generators in the current framework.
- There is no absolute requirement to plan the system to be congestion free, but congestion is a limited exception to the policy rather than the norm. The ISO appears to have discretion to allow congestion with AUC approval.
- Constrained down payments to generators or loads are not prohibited as a means of managing congestion but have not been used to date in Alberta.[5]
- Non-wires solutions are allowed where they provide distinct advantages and in certain situations.

The T-Reg contemplates at least some weight can be applied to maintaining future flexibility. This aligns with the principle that real-options have value, but the T-Reg does not mandate this as a requirement.

3.2 Market Structure – Current Approach and Incentives

The market structure sets incentives for each stakeholder involved in the planning and operation of the transmission and distribution systems. This section outlines the current incentives for the ISO, TFOs and DFOs. It identifies where there is a potential for incentives that do not drive efficient outcomes, as well as areas where the overlap amongst stakeholders has the potential to create misaligned incentives.

3.2.1 Independent System Operator

The ISO is regulated by the Alberta Utilities Commission, in that its proposals to upgrade the transmission system and its rules to reliably and economically operate the market are approved by the AUC. The ISO does not face any explicit incentives around the financial cost of the system from the governing legislation and regulation.

The ISO provides transparency and a plan for future system needs, and this is done in coordination with the TFOs. DFOs provide input such as expected load growth and possible expansion requirements into the ISO transmission plan. However, the ISO planning process is largely internal

[5] The AESO does procure Dispatch Down Service (DDS) to offset the price impact of Transmission Must Run (TMR) generation. However, this is intended as a price offset and does not compensate generators actually constrained down due to congestion.

and is not subject to a standardized approach, nor is there a requirement to perform options analysis or a cost benefit analysis to support investments. As noted, congestion and non-wires solutions are primarily exceptions to the existing Regulation. The long-term transmission plan is a high level document, and is the first step in the transmission planning process. The ISO must also apply on a case by case basis to the AUC to develop infrastructure, and this is done through a Needs Identification Document.

Needs Identification Process

All new electric transmission facilities (except for projects classified as critical transmission infrastructure) require two approvals from the Commission: (i) an approval of the need for new facilities as set out in a needs identification document (NID) developed by the AESO; and (ii) an approval of a facility application for the specific siting or routing of the new facilities, made by a TFO. In NID applications, the AESO must demonstrate the need for new transmission, and propose a transmission solution to meet that need.

The specific planning approach, as articulated in ISO system studies, is on a deterministic basis and tests for congestion in 'tail' events. For example, when assessing the need for transmission to accommodate wind generation, the ISO assumes near full output from wind and solar combined with high output from local thermal resources. The resulting congestion event, especially when considered in the context of relatively low local load, highlights congestion that is feasible and drives the need for a transmission upgrade. The recent PENV NID application provides an example that assumed local wind and solar generation were operating at 90% output concurrently with full output from Sheerness and Battle River stations.[6][7]

Alignment with Principles

The key concern with ISO incentives is that efficient decision making with respect to new investments and maintaining future options is not mandated. Financial costs of the system are not an explicit consideration – rather, reliability and ability to accommodate supply and demand in a congestion free manner is mandated but the cost effectiveness of meeting this mandate is secondary and only considered within a narrow construct. Cost-benefit analysis of infrastructure expenditures are not contemplated, nor is there a mandate to evaluate alternative solutions. The majority of other jurisdictions have a framework for network expansion that includes some notion of economic efficiency, however broadly or narrowly defined.

As noted, the ISO mandate also lacks a directive to evaluate all options in planning the system. Rather, the legislation and the resulting approach have a deference to large-scale infrastructure

[6] This set of circumstances is unlikely as wind and solar are concurrently at 90% output less than 1% of the time based on Power Advisory's analysis of Alberta data, and during these rare hours thermal generation is likely to be very low from high cost resources like Sheerness and Battle River due to low prices attributable to the high output of wind and solar.

[7] See AUC 23249-X0006.1 Table 3.1 and 23249-X0064 page 105

investments. The ISO has adopted an approach of staging transmission projects and triggering stages based on actual milestones, but this remains a limited means of maintaining system optionality and the milestones have not historically been related to actual congestion. Options such as storage, demand response, targeted energy efficiency and locational incentives to generators are not transparently considered as specific options in the planning process.

The planning approach fails to incent efficient decision making because the approach for congestion does not consider the market operations in evaluating transmission needs. For example, peaking generation located in the same location (electrically) as renewable generation would result in higher average utilization of the transmission system, and congestion would be minimal because the market would seldom, if ever, result in near maximum renewable generation concurrent with high peaking generation. In principle, the planning approach should encourage co-location of negatively correlated generators in or to maximize the use of fixed capacity transmission assets.

3.2.2 Transmission Facility Owners

TFOs are regulated by the AUC on a cost of service basis, though as noted previously, the ISO plans and designs the tariff to fund the system, as well as controls access to the system both in the connection and the operational timeframes. TFOs own the transmission assets, operate the transmission assets and build new assets where directed by the ISO.

Cost of Service Regulation

TFO regulation in Alberta is done under a traditional cost of service approach, with full cost recovery of all prudent expenditures. Return on capital is based on a return determined by the AUC through a cost of capital process that sets rates for a fixed period of time, and operating costs are recovered from rate-payers with no associated return.

Competitive Processes

TFOs are largely territory based in Alberta, and the large majority of transmission development is directly assigned to the TFO in that area. There is a framework for competitive procurement, and the Fort McMurray West 500 kV project was developed under the competitive framework, with the project awarded in 2014 and recently brought into service.[8]

Market participants can also choose to build their own facilities in some cases through a process known as Market Participant Choice (MPC). Under MPC, the TFO will submit a Facility Application, Service Proposal and other deliverables for their part of the build and the market participant will submit similar documents for their portion of the build. Upon completion of the build and commissioning, the facilities transfer to the incumbent TFO for ownership and operation.[9]

[8] https://www.aeso.ca/grid/competitive-process/
[9] https://www.aeso.ca/grid/connecting-to-the-grid/market-participant-choice/

Stranded Assets and Utility Asset Disposition

As noted, TFOs are regulated on a cost of service basis, but if specific transmission assets are no longer needed due to changes in the load and generation patterns, utilities face a risk that the assets will be stranded. Generally, this is framed as a 'used and useful' test, *i.e.* are the transmission elements still required. In the event that the assets are removed from rate base, treatment of undepreciated amounts would be assessed based on the Commission's Utility Asset Disposition (UAD) decision.[10] There the Commission found that the courts have clarified that all proceeds and losses on all utility assets are for the account of the shareholders, as the sole owners of the utility assets.

The implication of the UAD Decision is that TFOs and DFOs face the risk of stranded assets, with one key difference that transmission development and rate design is developed under ISO direction, whereas distribution development and rate design is planned by the DFO.

Alignment with Principles

The key concern with respect to TFOs is that the current regulatory structure provides very few incentives to minimize costs and drive efficient outcomes. Under a cost of service model, all prudent costs are recovered and a higher rate base yields greater total return for the TFO. In the Alberta process, the TFO is not incented to propose more efficient options than those put forth by the ISO, nor are there explicit incentives to minimize O&M costs or sustaining capital expenditures.

Of note, AltaLink has recently announced a pilot project to use battery storage to defer or potentially eliminate the need to build a line in Whitecourt. AltaLink has stated the project will reduce expected transmission costs relative to a new transmission line, and has received Emissions Reduction Alberta (ERA) funding.[11] This is a pilot project and has not yet gone through the normal NID process. The regulatory structure for storage acting as transmission has not yet been laid out, but in principle competitive approaches should be favored over cost of service approaches where feasible.

In theory, the UAD framework provides some incentive for a TFO to minimize expenditures on sustaining capital, especially on existing lines that are minimally used, although it could be argued there is a concurrent incentive to increase depreciation rates to reduce this risk.[12] In addition, the risk of stranded assets is typically relatively far in the future and is uncertain. As such, there is little incentive, or even ability, for a TFO to minimize expenditures on new lines where those lines are driven by new connections (either load or generation). These lines will presumably be used, even if the value is limited to preventing congestion in a small number of hours.

[10] Decision 2013-417.
[11] http://www.altalink.ca/news/news-releases.cfm?releasePage=05062019134813
[12] In Power Advisory's view, the UAD framework provides a weak form of incentive to minimize sustaining capital expenditures on lines that risk becoming unnecessary, such as a radial line to a single industrial customer or generator approaching end of life.

There is also a potential misalignment of incentives and risk in the future to the extent the ISO plans and directs transmission investments, yet TFOs bear the risk of stranded assets. In theory, this should provide an incentive for TFOs to oppose or propose alternatives to ISO Need Identification Document Applications, but this is not directly contemplated in the T-Reg and in practice does not occur.

3.2.3 Distribution Facility Owners

Distribution Facility Owners (DFOs) are regulated by the AUC on a performance based regulation (PBR) basis. DFOs own the distribution assets, operate the assets and plan and build new assets as required to maintain reliability standards. However, revenue requirements are set based on a formula, and DFOs have some risk around recovering sufficient revenue to meet their costs.

Revenue Requirement

The key point under PBR for DFOs is that revenues are set formulaically to an extent, as year-over-year revenue growth is tied primarily to inflation and customer growth, net of an efficiency term that is intended to capture efficiency gains over time. However, the Alberta experience with PBR has added an additional cost recovery element that allows for capital investment in growth and system replacement that is in excess of inflationary cost. In this sense, Alberta has operated under a PBR plus type system.

At the introduction of PBR, the utilities successfully argued that they were entering an asset replacement cycle and needed capital investment to grow at a rate in excess of inflation and growth,[13] in effect adding to the invested capital at a rate greater than inflation and load growth. In order to deal with this, K factors (capital trackers) were added to the framework. A capital tracker is an incremental funding mechanism to allow capital investments to be added to rate base at a higher rate than implied by the steady state formula. Capital trackers from the 2013-2017 PBR plans have been replaced by an alternative incremental capital account known as K-Bar in the 2018-2022 PBR plans. The incentive structure of K-bar is different than that of capital trackers, but the fundamental impact is similar with capital addition funding growing faster than inflation.

Another typical feature of PBR is that revenue requirements are rebased to reflect cost of service periodically, and in Alberta this is scheduled to occur every five years, occurring first entering into the 2013-2017 PBR term and occurring again at the outset of the 2018-2022 PBR term. The 2018 rebasing did not follow the traditional alignment of rates with the current cost of service, so the Alberta PBR rates have not been truly aligned with actual costs since 2012 (or 2014 for ENMAX). Based on the pure PBR framework, retail rates would have increased at about 1% from 2013 through 2018 because X was set at 1.16%.[14] However, with the addition of capital trackers and

[13] The formula for the PBR framework is (I-X)*Q where I is the inflationary term, X is the productivity factor or industry average efficiency improvement, and Q is the change in customer demand (growth).
[14] X was set at 0.96% plus a 0.20% stretch factor was added in consideration of the fact that this was the first PBR term for these utilities. Decision 2012-237, paragraph 514-515.

other offramps from the traditional PBR framework, electric distribution rates have grown at average closer to 4% annually.

Rates

Distribution rates have multiple components. In addition to collecting the DFO revenue requirement through PBR rates, DFO rates contain a number of flow-through items. DFOs pass on transmission rates, among other flow through items, to end use distribution customers. However, DFOs do not mirror the billing determinants set by AESO Phase II applications when passing through transmission rates. Instead, features like the 12CP charge and the bill capacity charges are lost and end use customers are typically faced with high proportions of fixed and energy charges, with only larger rate classes employing more complex rate design. It should be noted that many distribution customers are relatively small and arguably have limited ability to respond to complex rates.

Incentives

The design of the 2018-2022 PBR term creates a single revenue requirement for each year in the five-year period that can be used by the DFO as it sees fit. This means the DFO is not bound by pre-allocations of capital funding and O&M funding, nor is the DFO bound to maintain historical capital programs. The DFO is able to invest in capital projects, without the need to have prudency assessed by the Commission. The DFO is further able to employ non-capital solutions, where these are cost effective.

These incentives exist for the length of the PBR term, however, every five years the DFO must go through a rebasing process. Under a traditional cost of service rebasing the Commission would assess prudence of O&M and capital costs separately. It is important to note that capital costs earn a rate of return, whereas O&M expenditures are flow through. The utilities will be faced with additional regulatory burden and regulatory risk associated with defending prudence on new capital programs, whereas previously approved capital programs tend to draw less scrutiny. Accordingly, the rebasing process may dampen some of the signals that PBR is intended to establish.

There is also a concern that DFO planning practices lack transparency. On December 12, 2019, AltaLink filed a letter with the Commission requesting a distribution planning criteria inquiry.[15] The Commission responded by allowing parties to register for the proceeding and then requesting they submit preliminary submissions addressing the need for an inquiry, the timing of such and inquiry, and other aspects of the application. Following this stage, AltaLink was given a chance to reply. It is expected that the Commission will issue a ruling in the near future either denying AltaLink's request or setting out the timing and scope of a distribution planning criteria inquiry.

[15] Proceeding 25188.

Alignment with Principles

The PBR approach used to set revenue requirements for DFOs theoretically provides strong incentives to minimize costs. However, the addition of capital trackers in the initial term have muddied the incentives and as a result the Alberta PBR framework is not a pure PBR system.

The incentive and ability for DFOs to use non-wires solutions and price signals to reduce investment is also unclear. These questions are being addressed in the Distribution System Inquiry, but at the moment the PBR framework is not driving investment in non-wires solutions to defer or eliminate distribution system upgrades. Of note, solutions that prioritize invested capital over O&M costs may be favored within the framework because there is no rate of return associated with O&M expenditures at the time of rebasing. Some PBR frameworks, such as in the UK, use a total expenditures approach that attempts to align incentives. The regulatory framework for a DFO to invest in or contract with a generator, demand response or storage device is also not well defined, and as a result there is regulatory risk associated with solutions outside the traditional wires infrastructure approach.

Of note, Fortis has recently been awarded Emissions Reduction Alberta (ERA) funding to provide a non-wires solution in Waterton. The project is paired with a solar project and is intended to improve reliability.[16] The project is a pilot project, but marks a potential non-wires solution in Alberta if it proceeds. The inclusion of a solar generation project as part of a regulated solution (absent a competitive process) does not fit within the principles outlined in this report because it puts a regulated entity in competition with the unregulated generation sector.

While DFOs do not appear to have the regulatory restrictions that limit ISO tariff design, DFO rates have not been designed to provide incentives to minimize investment requirements. Regulatory uncertainty is an issue, as it is not clear whether the Commission would approve novel rates if some customers would be able to respond to a price signal while others would not. The legislation explicitly allows for this, but it has not been a feature of rate design historically. Finally, DFOs may actually face increased risk with incentive rates because DFOs bear volume risk for billing determinants, and rates with less certain volumes are therefore riskier. The lack of deferral accounts and volume true-ups may be a barrier to innovative rates.

Lack of transparency in DFO planning and the lack of a standardized set of planning criteria in Alberta is a potential concern. There is no mandate for within the distribution sector to consider non-wires solutions, maintain options or perform a cost benefit analysis in general for the distribution grid. Under a pure PBR system this would not necessarily be required as utilizes would be incented to minimize expenditures, but the Alberta approach with elevated capital expenditures through incremental capital funding, a unique and complex form of rebasing, and rebasing that does not allow a rate of return on rebased O&M does not necessarily create the same incentives.

The rigidity of the regulatory framework is also a concern. As an example, EPCOR proposed an advanced metering initiative that suggested a net benefit to consumers, but could not proceed due

[16] https://www.eralberta.ca/projects/details/fortisalberta-waterton-energy-storage-project/

to the UAD rule. In this example, an investment that would have resulted in lower rates was not approved because the cost of undepreciated meters were required to be borne by EPCOR, despite the fact consumers would be better off even if they bore the cost.[17]

3.3 Transmission System Access

This section examines the signals and practices associated with accessing the transmission system for generators and loads, both at the time of interconnection and during the operational timeframe. Interconnection signals and process can influence where and how a generator or load connects to the system, and operational signals influence production and consumption decisions for existing participants. The combination of these signals determine the attractiveness of a market, drive siting decisions and ultimately influence network costs over time.

3.3.1 Transmission Connected Generation

Transmission connected generation pays for system access through the Supply Transmission Service (STS) tariff. This tariff outlines costs for generators both at the time of interconnection and during operations. There are also a number of other market rules and business practices that impact transmission connected generators.

3.3.1.1. Interconnection

Interconnection signals comprise the charges to generators initiating access to the system. The magnitude of the charges, as well as the timing of the charges is important in creating efficient price signals.

System Access

The AESO is the sole provider of system access service, which in practice means that a generator that wants to access the transmission system in Alberta must apply to the AESO for access. In terms of costs, generators in Alberta pay the full 'direct' costs. The AESO classifies costs of a connection project as either participant-related or system-related. Participant-related costs include the connection substation, radial lines, and a share of transmission facilities that were constructed to connect another market participant within the last 20 years.[18]

System-related costs include looped transmission facilities, radial transmission facilities that are planned to become looped within five years, and transmission facilities in excess of the minimum size required to serve the market participant. Generally, this approach is consistent with a 'shallow' interconnection charge, in contrast to a 'deep' connection charge which is applied in some

[17] Note that EPCOR chose to proceed with the installation despite the capital tracker not being approved but this may not occur in all cases.
[18] The full list of all items classified as participant-related costs can be found in Section 8, Subsection 3(2) of the ISO tariff.

jurisdictions such as PJM.[19] However, Alberta does have an element of deep charges as the participant is also required to pay a charge based on the net present value of earlier expenditures if the project advances a regional or critical transmission enhancement that is scheduled to occur more than five years in the future.

In situations where a market participant builds infrastructure such as a radial line or substation, unused capacity may be used by other participants connecting at a later date. The original participant is compensated at the depreciated book value of the 'shared' infrastructure.

The only type of transmission right in Alberta is based on timing – if a connection is allowed in an area that experiences congestion (generally under contingency situations), a remedial action scheme (RAS) is put in place on the last generator into the area. The cost of the RAS is also borne by the participant on last in, first out type basis, but the timing is defined by the application for service rather than the online date. Real-time congestion is borne first based on the energy market merit order, i.e. price, and second on a pro-rata basis across all generators in the congested zone.

There is arguably a limited consideration of deep system costs in Alberta. The AESO charges an access fee that is locational in nature. A generating unit owner's contribution (GUOC) is a charge per MW that is calculated based on the region to which it connects. GUOC is designed as a locational signal in that the charge is higher in areas where generation exceeds load, and lower in areas where load exceeds generation. However, it should be noted the signal is very broad, as it is defined at a regional level rather than at a node or sub-regional level. Cost differentials for new generation connections might vary at a more granular level. The GUOC is also refundable over a 10-year timeframe with acceptable performance, and performance is defined on a technology level. The refund term generally reduces the magnitude of the GUOC by 50%, i.e. the effective cost GUOC to generators ranges from about $5,000/MW to $25,000/MW on an NPV basis. In this sense, the differential in GUOC is relatively minor as a locational signal as it accounts for less than 10% of the capital cost of a generator.

Previously, the AESO required the GUOC to be paid 30 days before the SAS would become effective and required the SAS to be executed and effective on the first of the month which contains the in-service date. The AESO has now moved the GUOC payment requirement and the SAS execution date to a point much earlier in the connection process. The new proposal requires the SAS to be executed and effective 60 days after the functional specifications are determined and prior to a project entering Gate 3/4. The GUOC is then required to be paid 30 days after the SAS becomes effective.

[19] A deep interconnection charge would assess all costs, including system upgrades that benefit other participants, and assess them to the interconnection project. However, in PJM congestion does not preclude the ability to connect.

Alignment with Principles – Generation Interconnection

The interconnection price signals generally align with the principles. Direct costs are attributable to the generator and are paid in full by the generator. Assets are transferred to the TFO and are operated by the TFO.

The timing of the GUOC payment should be carefully considered. The intent of the GUOC, and its move to being charged earlier in the process, appears to be two-fold. First, it is a weak locational signal, but the timing of this signal is likely not the determining factor in when GUOC should be paid. In other words, the AESO's move to advance the GUOC payment is not driven by the desire for a stronger locational signal. Second and more importantly with respect to the timing of the payment, GUOC appears to be used as a signal of intent that a project is serious. By advancing the costs associated with interconnection, the intent appears to be to rationalize the connection queue and provide clearer signals around likely generation additions.

There is a risk that earlier payment of GUOC will form a barrier to entry. An earlier GUOC, particularly if it is not refundable, poses a risk that projects must bear prior to project approval. It is reasonable to have developers pay all the direct costs associated with having them in the queue, but it may not be an efficient price signal to force a payment when risks to project execution still exist in the absence of costs accruing to the system. In other words, efficient timing for GUOC payments is a function of the timing of ISO expenditures (i.e. once costs are sunk) rather than the desire to signal the likelihood of a project proceeding.

GUOC has now been proposed to be charged based on maximum capability as well, rather than as a function of an STS agreement. This is an impact to behind the fence generation projects and it is unclear what the charge is intended to represent. If GUOC is based on maximum capability, it is effectively a tax on generation capacity rather than a signal about the cost of using the transmission system as a market access point because a generator without an STS contract is not using the transmission system in the sense currently defined by the AESO, i.e. it is not exporting to the market.

The lack of granularity in the GUOC regions is also inconsistent with economic principles. It is unlikely that a locational signal defined at such as high level that there are only five regions in Alberta will accurately reflect the cost of a given location.

3.3.1.2. Operations

In the operational timeframe, the key price signals to generators from the transmission system relate to losses, congestion and ancillary services costs. Congestion must be managed regardless of the approach taken, as it is a real-time limitation on the ability of generators to access the market and a requirement for other generators to operate instead. Congestion can also result in un-served load if there is an absolute inability for the market to meet demand in a given location, but this is exceptionally rare in Alberta and most other markets.

Losses do not specifically need to be integrated into real-time operations, but most markets reflect to some degree the concept that 1 MW of energy added to the system in one location results in higher losses than 1 MW of energy added in a different location. All else equal, it is more efficient to dispatch the unit with the lowest loss factor at the given time. As such, incorporating locational loss factors into dispatch decisions is efficient by effectively including the losses as an element of marginal costs.

Alberta's current approach charges generators a locational loss factor as a percentage of the pool price. Generators can embed their particular loss factor into their offers. As such, locational loss factors do influence dispatch decisions. Unlike markets with real-time loss factors, the Alberta approach results in a single estimate of locational loss factors that is applied for each generator for a year, which may result in inefficiencies in hours where the system operating differently than 'average' conditions. The range in system conditions, particularly as the system evolves with more variable generation, is such that the concept of an average hour lacks meaning and is unlikely to result in efficient dispatch. In addition, the range of loss factors allowed in the T-Reg is constrained within a narrower range than actual real-time loss factors. In addition, as noted in the review of the T-Reg, loss charges to generators are shifted such that the loss charges to individual generators recover average annual losses.

Congestion in the Alberta market is currently dealt with through re-dispatch as generators upstream of a constraint are dispatched to lower production levels, and generators downstream are dispatched to higher level. Where possible, the merit order is used to manage the constraint. The highest priced operating generator upstream of the constraint is dispatched down, and the lowest cost generator downstream with uncommitted output is dispatched up. The market price continues to be set as though the constraint was absent. The generator dispatched up is paid its offer price via an uplift payment, and the generator dispatched down is not compensated. The cost of this congestion has totaled about $470,000 over the last four plus years, or a slightly more than $100,000 per year.

Another element of generation operations is operating reserves, which are procured day-ahead in Alberta, and these reserves comprise the large majority of ancillary services costs. The AESO provides real-time visibility of assets providing operating reserves, but there is no transparent merit order for directing reserve providers to actually provide the service.[20] Further, there is no real-time price signal for the value of ancillary services from a load perspective, i.e. load does not have the ability to incorporate ancillary services costs into decision making.

Alignment with Principles – Generation Operations

The operational signals to generators align with the principles at a high level, though the process of setting an annual loss rate and charging generators the same loss rate throughout the year may

[20] For example, all providers of spinning reserve have equal apparent risk of being directed to provide energy as there is no visibility of how the ISO selects which provider to direct in response to an event.

result in some level of inefficient dispatch. However, any benefit of real-time loss factors should be weighed against increased complexity.

Charging generators the real-time marginal loss rate rather than the shifted average rate would result in lower transmission costs but higher energy costs as generators would embed the higher loss factors into their offers. This again is a potential improvement to real-time decision making because more costs would be transparent and calculated in real-time rather than embedded in the transmission tariff.

Day-ahead operating reserve procurement does not allow alignment of real-time market conditions and system dispatch. Again, the complexity of moving to a real-time operating reserve market, whether co-optimized or not, must be weighed against the expected benefit. For context, operating reserves in Alberta cost $81 million in 2017 and $236 million in 2018, representing about $1.20/MWh to $4/MWh in transmission costs. Operating reserve costs are flowed through to load based on hourly consumption, though the hourly cost is not transparent until well after the fact.[21]

The re-dispatch approach for congestion uses generator offers in the initial choice to dispatch generators down, however where congestion persists for two hours or more, it is managed on a pro-rata basis. This has the potential to result in inefficient dispatch for prolonged congestion events, but given the minimal amounts of congestion it is unlikely to be material. An LMP approach is generally seen as the most efficient approach to managing congestion because it provides a transparent price signal rather than administrative curtailment, but the complexity and market power concerns it raises could be an issue in Alberta. Further, the increased investment uncertainty for generation developers associated with basis risk[22] may not be a desirable design feature in a small market to the extent it increases the cost of investment.[23]

3.3.2 Transmission Connected Load

Transmission connected load pays for system access through the Demand Transmission Service (STS) tariff, as well as the Demand Opportunity Service (DOS) tariff in limited situations.

3.3.2.1. Interconnection

As outlined in Section 2.4.1.1 for transmission connected generation, the AESO begins by classifying costs of a connection project as either participant-related or system-related. Participant-related costs are then allocated to market participants receiving system access service at a single substation, including both load and generation. These costs are allocated between DTS and STS using the substation fractioning methodology. The key difference between DTS and STS is that DTS system service is supported via the tariff through local investment allocations. In effect, a

[21] Hourly AS costs are generally very strongly correlated with the hourly energy price.
[22] Basis risk is defined as the difference between LMP and the overall system price in this example.
[23] It is arguable whether bearing basis risk improves investment decisions sufficiently to offset increased risks but many markets have used this solution to send locational incentives.

portion of the participant costs are covered by all customers, and in return the new customer has long-term DTS obligations.

The load on the substation pays for participant-related costs allocated to DTS less the local investment amount. In effect, the participant related costs are reduced by the local investment amounts.

If the DTS customer connection is a DFO, the process is very similar although the customer contribution costs are currently put into the DFOs rate base. In effect, the cost of connections for DFO customers are in the rate base of the DFO for the amount of the customer contribution, and the remaining amount is in the TFO rate base. However, the 2018 ISO Tariff Decision directed that substations in the Fortis territory (DFO) go into AltaLink rate base (TFO) and future customer contributions go directly into AltaLink rate base. This Decision has been appealed and the outcome of this appeal is uncertain.

It should also be noted that 'deep' system costs can be charged to load interconnections to the extent they advance a system cost that was not scheduled to occur for more than five years.

DOS does not apply at interconnection, as it is only available to assets with existing DTS service. A market participant must pre-qualify on an annual basis for demand opportunity service to receive system access service under Rate DOS, and it is limited to circumstances where there is a temporary need for increased capacity. A DOS applicant must demonstrate to the ISO that in the absence of DOS it would not be economic to increase its DTS contract volume. The key benefit of DOS is that it is lower cost and does not have the long-term commitment associated with DTS.[24]

Alignment with Principles – Load Interconnection

As noted, the key difference for a load interconnection is that the market participant has a long-term obligation under the DTS contract, and in return the cost of interconnection is reduced by the local investment amount. The approach does not charge the full cost of interconnection to a new load, it is intended to manage inter-generational inequity issues and ease the up-front cost of connecting to the system for new customers. These issues can be especially important in situations where the economic size of a new substation is much larger than the individual customer need. It is also important to recognize that a DTS customer takes on a long-term obligation for service that provides value to other customers by funding the overall system costs.

The DOS approach is consistent with the principles in that it is a different level of service and its lower price better reflects the cost of provision. However, there are limitations on the applicability of DOS, i.e., it is temporary and restricted to circumstances where the system has excess capability and the participant would not choose to pay for DTS. It is not broadly available as a means to purchase a differentiated product in general, which is in contrast to the principle that service can be differentiated to improve efficiency of the system.

[24] DOS Term is actually more expensive than DTS but DOS 7 Minutes and DOS 1 Hour is lower cost.

3.3.2.2. Operational Signals

Operational signals to load are primarily DTS (Demand Transmission Service) charges. DTS charges apply to all large customers connected directly to the transmission system, as well as all DFOs that purchase DTS on behalf of customers connected to the distribution system. Of note, customers on the distribution system do not see DTS charges directly as they are embedded in the DFO rates.

Other than transmission losses, all transmission costs are charged through the DTS tariff. There are three high elements to the DTS tariff: (1) Bulk (2) Regional and (3) Point of Delivery.

Coincident Peak Charge – Bulk System

Each month, the 15-minute peak system load is determined based on actual load and calculated after the fact. This 15-minute window is the billing period for that month's coincident peak charge (commonly referred to as the "12CP charge"). In 2019, the monthly coincident peak charge was $10,524/MW.

This charge incents loads to reduce consumption or self-supply during any time periods that may become the monthly 15-minute system peak. For loads that respond to this price signal, the response is observed approximately 20 hours per month. This relatively frequent response is required because the interval that sets the monthly 15-minute system peak cannot be known until the month is complete.

Charge for Total Energy Use – Bulk System and Regional System

A small portion of the ISO tariff is billed based on total metered energy at a site. In 2019, the bulk system metered energy charge was $1.26/MWh and the regional system metered energy charge was $0.87/MWh.

Billing Capacity Charge - Regional System and Point of Delivery

The billing capacity charge is calculated as the highest of three calculations: (1) 90% of the DTS contract capacity; (2) the non-coincident peak demand or highest metered demand in the billing period; and (3) 90% of the highest metered demand in the previous 24 months.

The billing capacity charge is used to calculate the majority of the costs associated with both the regional system and the point of delivery charge.

This charge sends the incentive to right size a load's DTS contract capacity and to avoid triggering a new record site non-coincident peak demand, as the site will pay costs associated with that new peak demand for the following 24 months.

The tariff has evolved over time, and is currently undergoing review. The key issues have revolved around billing determinants and how efficient signals can be sent to load. The Appendix (section 6.2.2.2) outlines some issues that have evolved over time.

Alignment with Principles – Load Operations

The price signal to load is strongly weighted to the monthly coincident peak charge, with is a demand metric un-related to energy market conditions and loading on the transmission system. To the extent that coincident peak demands influence the system expansion this is a reasonable proxy for real-time conditions, but the AESO has indicated varying positions on whether this is or is not the case. However, even in this case, the current 12 CP price signal is unlikely to be optimal.

In principle, the tariff should facilitate efficient real-time decision making. The 12 CP charge incents loads to reduce consumption during high load periods in all months, regardless of market and/or transmission loading. This results in many hours where load could and should consume because the marginal cost on the system is well below the marginal value to the load, but the price signal incents load curtailment. A similar argument exists for the use of dispatchable on-site generation – the market price for energy may be below the variable cost of the generation but the transmission price signal creates an incentive to run the generator.

One area the existing price signal is consistent with the principles, albeit indirectly, is that it effectively allows loads with a high price elasticity to avoid a portion of the rate through selective curtailment. As noted in the principles section, efficiency gains occur when differential rates are charged to loads with high elasticity, particularly if those loads would otherwise leave the system through either onsite generation or closing operations.

The restriction of tariff options that attempt to tie costs more directly to individual participants, such as locational charges[25], are not optimal but are restricted by legislation.

3.3.3 Self-Supply

Self-supply is a large element in the Alberta industry, is generally a combination of transmission connected generation and transmission connected load. It is usually combined at a single interconnection point, i.e. a single substation, although this is not strictly the case. The majority of capacity deemed as self-supply is large-scale industrial sites with cogeneration, although self-supply with peaking natural gas and at a smaller scale solar and batteries are possible.

The key point with self-supply in the Alberta market design is that sites are billed for transmission based on the net flows at the substation. In effect, if a 100 MW load has 95 MW of generation onsite, it will be billed for 5 MW of DTS as though it was a 5 MW load. This site will not pay losses as it does not export to the grid. In most cases, the site would maintain a DTS contract in excess of 5 MW in order to provide reliable service in the event the generator is offline and the

[25] For example, the 2014 DUC proposal of a demand-distance charge is used in other jurisdictions to reflect locational charges but is contrary to legislation in Alberta.

load is still online, although the DTS contract may not be for 100 MW depending on site characteristics.[26]

Self-supply is currently being debated in the industry[27] because as transmission costs have increased, the incentive to self-supply has risen to the level that investments in onsite generation are very attractive. Second, the number of options for self-supply has increased due to changing technology, and a number of these options are viable with the current combination of energy prices and avoided transmission costs. Onsite storage and solar generation have not yet been seen in a material way in Alberta at the transmission connected level, but these technologies are employed in other markets and solar is in Alberta at the distribution level. For example, a significant number of sites in Ontario have invested in onsite storage as a means of mitigating market costs through changing consumption profile for similar reasons as onsite generation is attractive in Alberta.

Industrial System Designations

Sites with an Industrial System Designation (ISD) are exempted from the *Electric Utilities Act*. In order for a site to attain an ISD, some level of integration within the site is required. Sites with an ISD have revenue class meters at the substation to track the amount of electricity exported by the site or consumed by the site. These sites are metered and settled on a net basis.

Transmission-level Self-supply without an Industrial System Designation

Transmission connected load may also install on-site generation to supply its own load without an ISD or without any system integration. Historically, many self-supply sites would over-size their generator and sell excess electricity to the transmission system. These sites would be net-metered, *i.e.* billed for DTS when the site consumed electricity from the grid and required to hold an STS contract for net electricity expected to be sold to the grid.

In 2019, the Commission has made three decisions that depart from this historical practice. These are the EPCOR Water decision,[28] the Advantage decision,[29,30] and the International Paper decision.[31]

In these decisions, the Commission found that under Alberta legislation there are limited circumstances in which the owner of a generating unit is allowed to consume electricity produced from that generating unit on their own property and also export electricity to the grid. Exemptions

[26] For example, if the load is entirely dependent on the onsite generation to operate, it is possible only 5 MW of DTS are needed. However, if the load is entirely independent, 100 MW of DTS would be required. Each site is unique and will carry DTS that fits with its characteristics.
[27] The AUC has recently reduced the scope of self-supply options to ISDs and micro-generation through the E L Smith decision.
[28] Decision 23418-D01-2019, EPCOR Water Services Inc., E.L. Smith Solar Power Plant, February 20, 2019.
[29] Decision 23756-D01-2019, Advantage Oil and Gas Ltd., Glacier Power Plant Alteration, April 26, 2019.
[30] Advantage applied to R&V Decision 23756-D01-2019, but the review application was denied in Decision 24674-D01-2019 on October 17, 2019.
[31] Decision 24393-D01-2019, International Paper Canada Pulp Holdings ULC, Request for Permanent Connection for 48-Megawatt Power Plant, June 6, 2019.

are made for Industrial System Designations under the *Hydro and Electric Energy Act* and for small generators under the *Micro-generation Regulation.* Outside of these exemptions, generators must be either for self-supply or export, but not for both. Accordingly, if more electricity is generated at the substation than what is consumed by the load, the site must operate on a gross basis, *i.e.* the load would receive a DTS bill as if the generator were not there to offset any power and the generator would require an STS contract for its full generation potential as if all of its power was supplied to the grid.

On September 13, 2019, the Commission issued Bulletin 2019-16[32] which initiated a consultation on the issue of self-supply and export at transmission connected sites. The bulletin noted that the Commission recognized that its findings on the self-supply and export issue in these decisions represented a departure from earlier decisions and could have implications for previously-approved projects. The bulletin asked parties to comment on if changes should be made to the statutory scheme to allow limited or unlimited self-supply and export, in contrast to the recent Commission decisions which did not allow self-supply and export to occur simultaneously at one site unless the market participant had one of the two exemptions.

Unless a legislative change comes from the Commission consultation, future self-supply will largely be limited to ISDs and micro-generation. Projects with previous approvals have been notionally given an exception for the time being but their ultimate status is uncertain.

Alignment with Principles – Self Supply

At a high level, a competitive market should allow participants the maximum flexibility possible as this will drive efficiency and incent creative responses from the market. The recent changes to the net-supply rule create arbitrary restrictions on self-supply that do not mesh with fundamental differences between sites. For example, a site with 50 MW of load can put a 45 MW generator on site and self-supply without an ISD, but a 40 MW load would be restricted to a smaller generator, despite the fact that the economically efficient technology choice at both sites could be identical.

Both efficiency and fairness mandate that the market treat all participants with similar characteristics similarly. It is unclear that a reduction in hourly load achieved through self-supply, energy efficiency, onsite storage or other means should be treated differently depending on how it is achieved.

Since self-supply and a direct reduction in load are unlikely to actually be identical in practice, the challenging aspect of self-supply treatment relates to the choice of billing determinants. A perfectly efficient tariff would accurately differentiate amongst participants that never import from the grid to meet their needs, those that seldom import but can generally control the timing of imports, those that frequently import, etc. It is highly unlikely that each participant type imposes the same cost on the grid, but it is challenging to design an efficient and fair tariff.

[32] AUC Bulletin 2019-16: Consultation on power plant self-supply and export

It is also important to consider whether or not a change in tariff will create new inefficiencies in an attempt to address current perceived problems or uneconomic incentives. For example, non-coincident peak demand at a self-supply site is almost certainly un-related to system conditions, but self-supply sites will have a very strong incentive to manage non-coincident peaks if contract demand is the largest billing determinant. Solutions such as back-up onsite generation, storage and the ability to curtail load will be incented to manage costs created by the new tariff signal, with no connection to real-time system conditions.

3.4 Distribution System Access

Distribution system access is controlled by individual DFOs, and each DFO has a geographically based territory. There is a requirement for each DFO to provide load access, but there is no mandated requirement to provide system access for generators in an unconstrained manner as exists on the transmission system.

3.4.1 Distribution Connected Generation

3.4.1.1. DCG Interconnection

As outlined in Section 3.3.1 regarding the interconnection process for transmission connected generation, the AESO begins by classifying costs of a connection project as either participant-related or system-related. Participant-related costs are then allocated to market participants receiving system access service at a single substation, including both load and generation. These costs are allocated between DTS and STS using the substation fractioning methodology.

In the event there is a single generator at a substation, the AESO would assess a construction contribution for that generation equal to all participant-related costs allocated to STS. In addition, a generator is responsible for paying the Generating Unit Owner's Contribution (GUOC), which is now to be calculated based on the capacity of the generator. Previously, GUOC was only assessed to a Distribution Connected Generator (DCG) on the basis of its STS contract, which was sized net of minimum load at that substation.

The load on the substation is responsible for participant-related costs allocated to DTS less the local investment amount, which are noted earlier in this report.

In the case of a distribution connected substation, the DFO holds both the DTS and STS contracts. Accordingly, any costs allocated to DTS after the local investment amounts are collected from the load customer through DFO rates. Whether the DFO is also able to pass along STS costs to DCGs is currently under dispute based on the language in DFO tariff terms and conditions.[33]

[33] See Proceeding 25058 (BluEarth complaint against FortisAlberta) and Proceeding 25102 (FortisAlberta request for review and variance of 2018 ISO tariff decision).

Substation Fractioning Methodology

The AESO determines the substation fraction of each market participant as that market participant's share of the total contract capacity on that substation. For example, if there is a 40 MW DTS contract and a 10 MW STS contract on a substation from a single generator, then the generator's substation fraction is 0.2.

This substation fraction is then used to allocate costs of transmission system upgrades where the costs are determined to be participant-related. The allocation is time weighted over the 20 years following the substation upgrade, which will take into account changes in DTS and STS contract capacities during that 20-year period.

Adjustments to Construction Contributions

The AESO will review the construction contribution and make adjustments when contract capacity at the substation changes, additional market participant(s) use facilities originally installed for an existing market participant, facilities classified as system-related are reclassified as participant-related or vice versa, an error in the original construction contribution is identified, or the actual cost of the connection project materially varies from the original estimate.

Alignment with Principles – DCG Interconnection

The key issue for DCG interconnection relates to the substation fractioning methodology. This methodology impacts the interconnection cost initially, as well as imposes an indefinite and somewhat unbounded risk of future costs. During interconnection, the DCG participant is charged for its share of direct costs based on the relative size of load and generation. This is inconsistent with a purely economic approach that would only charge the incremental costs associated with adding generation to an existing substation. The methodology also does not fit with a cost causation principle as the substation has typically been built to serve load and is sized for that purpose. However, the methodology does address fairness issues, i.e. without paying a share of the costs the DCG would effectively be a free-rider.

The substation fractioning methodology creates a long-term risk for DCG participants that is entirely un-related to their own operations. If load growth causes the need for a substation to be upgraded, a DCG participant will be charged a portion of the upgrade cost despite having no impact on the need for the upgrade. While the Commission decision currently suggests that DFOs do not have to flow through the costs to the DFG, the PBR framework incents DFOs to charge DCG participants for the upgrade to the extent the AESO allocates costs to the DCG. Likely for this reason, Fortis has appealed the commission decision regarding flow through of STS allocated costs to DCGs.

As a further issue, the interconnection charge is also completely un-related to any benefits that might accrue to the distribution system in terms of reducing the need for future upgrades. Although the planning approaches used in Alberta do not appear to value local generation, in general adding generation behind a substation that serves load could defer the need to upgrade that station for load growth provided the generation reliably operates during peak load periods. There is no obvious barrier to such a locational value to be paid by DFOs, though the regulatory framework does not contemplate such a payment and it would raise level playing field questions with transmission connected generators.

3.4.1.2. DCG Operating

Net-Metering vs Net-Billing

Most behind-the-fence generation projects are net-metered, which allows them to offset transmission and distribution charges, in addition to energy charges, for all electricity produced.

Distribution Connected Generation (DCG) acts like a behind-the-fence self-supply site due to the existence of DCG credits.[34] DCG credits are calculated as the difference between the monthly DTS bill from the AESO and the monthly DTS bill that would have been received in the absence of the DCG on that substation. This is a form of net metering. Based on the approval of the AESO's adjusted metering practice in Decision 22942-D02-2019, this netting will occur on each feeder rather than at the substation level beginning when the 2018 ISO Tariff becomes effective. The move to feeder level 'netting' reduces the amount of load notionally offset by DCG to a fraction of the total load at the substation.

Micro-generators are the exception to the net-metering rule. These generators are net-billed. This means that they are only able to avoid transmission and distribution charges for electricity that is consumed behind-the-fence. Any energy sold to the grid is only paid the electricity price. This sends an incentive to invest in a generation source that is able to match the needs of the load as electricity consumed onsite is more valuable than electricity exported to the grid due to the difference in wires charges. This incentive, however, only exists for micro-generators and not all behind-the-fence generators given the use of net-metering for other generators. There are currently 61 MW of micro-generation in Alberta.[35]

Distribution-level Self-supply: Small Micro-Generation

Small consumers connected to the distribution system are also able to self-supply their electricity needs under the *Micro-Generation Regulation*. The regulation considers generators less than 150 kW to be small micro-generation. Small micro-generators are not net-metered, but rather net-billed. Small micro-generators receive a bill credit for the value of the electricity supplied to the grid, but the credit does not extend to the costs of distribution, transmission, or other miscellaneous charges. In this way, a small micro-generator is able to save more in self-supply than it is able to earn for excess production. The bill credit for exported electricity is equal to the price per kWh that the energy service provider charges the customer for the cumulative energy the customer has drawn from the grid.

[34] FortisAlberta's Option M credits, ATCO Electric's Rate D32, and ENMAX Power Corporation's Rate D600.
[35] See https://www.aeso.ca/market/market-and-system-reporting/micro-generation-reporting/

Distribution-level Self-supply: Large Micro-Generation

Under the *Micro-Generation Regulation*, large micro-generation includes generation of at least 150 kW but less than 5 MW. These generators are net-billed, similar to small micro-generators, except that they receive the hourly pool price for electricity exported to the grid, rather than the price they pay for electricity during the month.

DCG Credits

DCG credits are offered through FortisAlberta's Option M credits, ATCO Electric's Rate D32, and ENMAX Power Corporation's Rate D600. These rate classes compensate DCGs for the difference between what the substation would have been charged under the ISO tariff without the DCG connected and what ISO tariff costs were actually charged to the substation.

Decision 22942-D02-2019 approved the AESO's adjusted metering proposal which sums load's tariff costs at the feeder rather than the substation. Accordingly, going forward DCG credits will only be able to offset costs of load on the same feeder, rather that load on the entire substation. There may be a transitional period where DCG credits remain higher until DFOs are able to install revenue class meters on each feeder of substations that have DCG connected.

DCG credits will signal preferable locations to be feeders on the distribution system where the generator can offset large DTS costs (such as the coincident peak charge). However, DCG credits are not a true locational signal because they do not differentiate based on expected 'value' to the system from the locational choice.

Transmission Line Losses

DCG pays for line losses only on the amounts exported to the grid. Prior to the change to substation totalization, losses were calculated only on volumes in excess of the substation load in a given settlement period. With the change to feeder level totalization, losses will be calculated on volumes in excess of load at the individual feeder. This has the impact of increasing the loss charges to DCG units in the same manner the DCG credits are reduced with the change.

Alignment with Principles – DCG Operations

The primary difference between the treatment of transmission connected generation and DCG is the DCG credits embedded in the DFO rates.[36] The existence of DCG credits is not in and of itself contrary to the principles identified in this paper, but the implementation of these credits may not align with the principles. A key factor in assessing whether DCG credits are appropriate in a given circumstance is whether the DCG reduced the need for investment due to its location, which is likely to be a function of the type of generation, its reliability and its location. In effect, DCG credits are appropriate when acting as a non-wires solution.

The first concern is that the current locational signal embedded in DCG credits is broad and tied only to connection voltage, i.e. the signal is that a lower voltage connection is more valuable than

[36] Fortis, ATCO, and ENMAX only. EPCOR does not offer DCG credits.

a higher voltage connection. This broad-based voltage signal is unlikely to be valuable to the system as a whole given it is independent of location.

The second concern with the DCG credits is that they are not tied to real-time conditions on either the transmission or distribution system. Given that the DCG credits are basically the inverse of the DTS charges to a DFO, the primary signal is the 12 CP charge. Any concerns with the existing tariff therefore apply to the DCG credits.

Third, some of benefits of DCG is likely to accrue to the distribution system to the extent DCG reduces peak loads on the distribution system. At present, the locational value of reducing investment needs on the distribution system are not captured, nor or any costs triggered by integrating DCG on the distribution system.

Overall, locational signals are valuable, but the design of locational incentives or disincentives should be carefully considered. It is reasonable to pay for benefits created by DCG, but the benefits must be real.

3.4.2 Distribution Connected Load

3.4.2.1. Interconnection

As outlined in Section 2.4.1.1 regarding the interconnection process for transmission connected generation, the AESO begins by classifying costs of a connection project as either participant-related or system-related. Participant-related costs are then allocated to market participants receiving system access service at a single substation, including both load and generation. These costs are allocated between DTS and STS using the substation fractioning methodology.

The load on the substation is responsible for participant-related costs allocated to DTS less the local investment amount. The current local investment amounts from the 2019 ISO tariff are listed in the Appendix (Section 6.4.1.2) regarding the interconnection process for transmission connected load.

The major difference between distribution connected load and transmission connected load is that the total amount assessed as the participant-related costs allocated to DTS less the local investment amount is not paid immediately and up front. As noted in Section 3.5.1.1, regarding distribution connected generation, the DFO holds both the DTS and STS contracts at a distribution connected substation. As a result, the DFO pays those costs and adds the relevant amount into its rate base. The up-front interconnection payment is then paid for over time by distribution connected loads through payment of their distribution rates. In addition to paying their distribution rates, the load will also pay for its share of system-related costs through its payment of DTS rates, which are flowed through its DFO.

Alignment with Principles – Distribution Load Connection

As with transmission connected load, there is an investment policy for distribution connected load that is intended to level inter-generational issues and reduce the upfront cost of connection.

This is consistent with the overall principles as it manages the potential free-rider concerns that a pure direct cost allocation could create.

3.4.2.2. Operations

Distribution connected load pays the DFO tariff specific to its rate class within its DFO territory. Unlike transmission costs, the is variation from one DFO territory to another. Within a DFO territory, rates are postage stamp in nature. However, DFOs have a broad range of rates, unlike the transmission system with effectively a single DTS tariff.

Although DFO customers are indirectly transmission customers as well, the DTS tariff is not directly flow through to end users. Rather, the DTS charges are bundled up with other DFO costs, and the resulting rate reflects the total costs. The billing determinants used by the ISO in the DTS tariff are not necessarily the same determinants used by DFOs.

In general, DFOs rely on two billing determinants for most customers, and three charges for larger customers. First, there is generally a fixed charge that applies to a customer regardless of how much energy is consumed. Second, there is an energy charge on a per kWh basis. Third, for larger customers, there is a demand charge related to peak demand during a period. The specifics of the demand charge vary by customer class and across the DFOs, but in general it employs the concept of a ratchet that charges the greater of contract capacity and peak demand over the last several years. In addition, the demand charge can be on either peak kW (or MW) or on kVA to reflect power factor. Some DFOs also require customers to correct their power factor if it is found to be below 90%.

Alignment with Principles – Distribution Load Operations

There are a wide range of distribution tariffs for each of the DFOs that vary primarily across customer size. In general, larger customers are given incentives to reduce peak consumption, whereas smaller customers are charged only a fixed fee plus an energy charge.

The lack of any real-time price signals or differentiation in the tariffs by service quality does not line up with the principles. These price signals could be used to reduce the need for new investment – for example, a non-firm tariff could be offered that could be curtailable to delay or eliminate the need for a system upgrade.

Locational signals appear to be possible for DFOs based on the tariff example, but it is unclear whether this could be used in the context of locational signals for DCG, as an example. It is also unclear whether incentives to locate large load additions in areas with excess capability are feasible. For example, if a large charging station for EVs is contemplated as a future load addition, particularly for fleet vehicles, it will likely be optimal to locate it in an area with excess charging capability. It will also be important to recognize that this type of load may be more flexible than typical load on the system.

Section 4: Concerns with the Current Approach

This section outlines concerns identified by stakeholders, as well as provides a brief summary of concerns the AESO has publicly identified. All concerns from Section 4.2 onwards were raised by one or more stakeholders, but not all stakeholders necessarily agree with the concerns noted.

4.1 AESO Concerns

The AESO has identified its concerns at a high level, and the key points are outlined here. Power Advisory has not discussed these concerns with the AESO as part of this project, but they are taken near verbatim from AESO public materials.[37]

- Transmission costs are sunk and high and there is little efficiency to be gained in reducing incremental build
- Future build is driven by factors other than load and limited efficiency can be incorporated given our rigid regulatory construct
- The regulatory construct is postage stamp and load only tariff but the Commission suggests the AESO has more legislative discretion than currently using
- New technologies are stretching the fit within the regulatory construct
- Customers have made investments and fairness is critical
- Current pricing signals do not align with planning signals and therefore the customer response to the price signal has not impacted transmission build

Given these concerns, the AESO has identified a number of guiding objectives for redesigning the transmission tariff. The AESO objectives include:

- Design a tariff that results in efficient long-term price signals to optimize current and future incremental transmission costs
- Allow participants to innovate and provide economic value to all of Alberta
- Reflect accurate costs and value of grid connection and services
- Explore options within legislation and regulation
- Provide a path for change that is effective and minimally disruptive

4.2 Sustainability

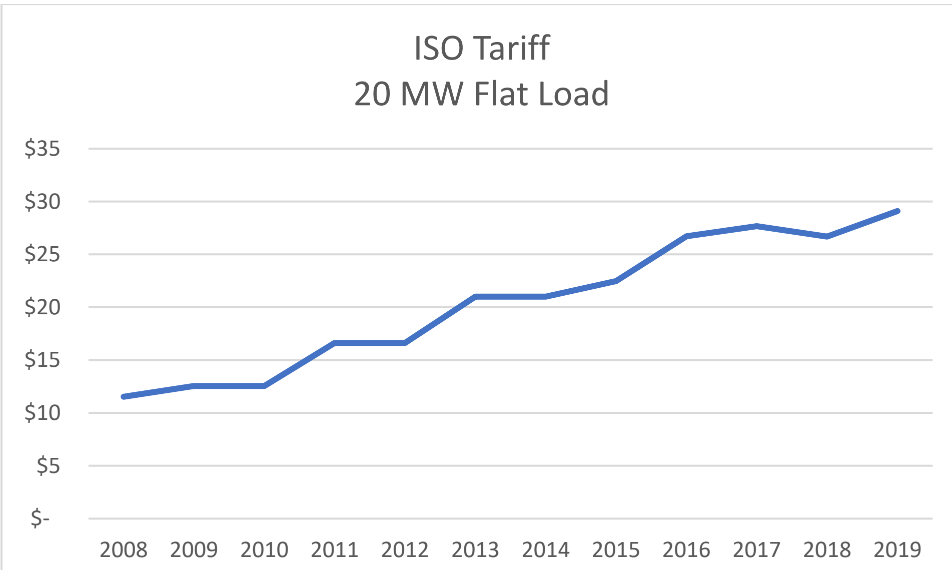
The most common concern raised by stakeholders is that the increase in wires costs puts the long-term sustainability of the market in question. In particular, the concern is that as wires costs increase and the cost to exit or reduce reliance on the grid falls, the size of the competitive market will be reduced. In effect, the AESO administered market will potentially shrink in size as more consumers exit. Generally, most of the study participants suggested that the ability to exit the

[37] Insert link to public version of TDAG presentation

market was an element of competition, but the price signals should not create a 'false' signal for exit.

Figure 2 illustrates the increase in transmission costs over the last 11 years, and this escalation is the key driver of the concern. The figure is based on the transmission cost for a flat 20 MW load with no variability and is not indicative of transmission costs for any particular customer. However, it is reasonably similar to a flat load profile where the customer does not respond to any existing price signals.

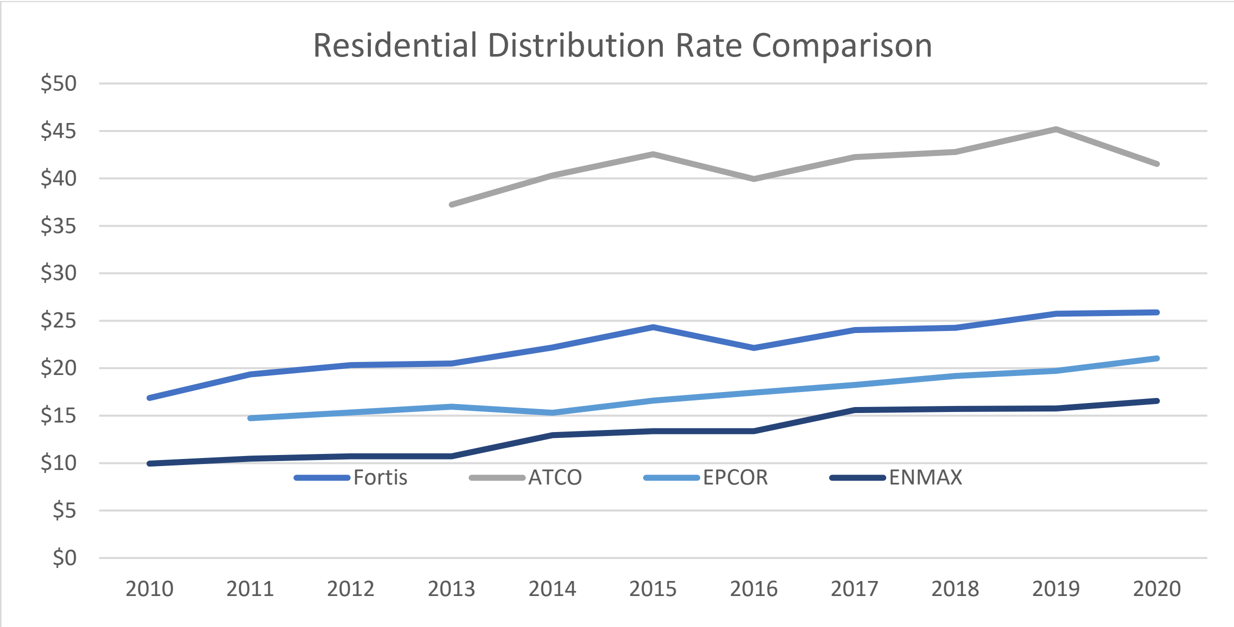
Figure 1 - Transmission Cost Escalation



At roughly $30/MWh average transmission cost, wires costs are now roughly equivalent to the fixed costs associated with generation. In effect, in the absence of the need to provide redundancy, the capital cost of new generation can largely be recovered in avoided transmission costs. The structure of the tariff design can impact this incentive, but the fundamental concern is that the sustainability of the market will be challenged by the cost of market access.

This concern extends to the distribution market, where average rates have escalated at about 4% annually for the last decade.

Figure 2 – Residential Distribution Rates in Alberta Based on 600 kWh Monthly Consumption



A related sustainability concern ties to the ability of the Alberta market to attract new load. The delivered cost of energy, even at a large-scale load that is transmission connected, will likely approach $100/MWh in most years. For distribution connected loads, the cost is generally $120/MWh or higher.

4.3 Level Playing Field

Several stakeholders were concerned that the incentive to avoid transmission and distribution costs results in an un-level playing field between generators on the grid and generators behind the fence. This concern is strongly related to the sustainability concern noted above, in that rising costs increase the incentive for generation to be located behind the fence for larger industrial customers. The incentive to locate behind the fence is a function of the tariff design and the overall magnitude of transmission and distribution costs.

Of note, participants generally did not support the notion that self-supply should be prohibited but some participants did support the concept that self-supply plus export should continue to be limited to micro-generation and ISDs.

4.4 Planning Approach

Stakeholders identified issues with the planning process at both the transmission and distribution levels.

4.4.1 Transmission Planning Concerns

This concern magnifies the sustainability concern in that it is expected to lead to ever increasing wires costs with very little benefit to the wholesale market.

The planning approach that does not account for typical market conditions raises concerns for participants. The AESO approach, based on review of a range of need applications, does not rely on a probabilistic or market based approach, but rather uses a deterministic approach that looks for the possibility of congestion. Some participants noted that the AESO approach appears to go further in planning for no congestion than even required in the Transmission Regulation, which does materially limit options.

4.4.1.1. Lack of Transparency

The lack of transparency in the planning process, along with a lack of a clear understanding of the current capability of the network were identified as issues. Project developers identified a desire to understand, at a node by node level, the capability of the system to absorb new generation capacity.

As an example, the AESO released a renewables integration paper in 2019 that identified the capability of the system. However, there was no consistent understanding of the assumptions underlying the projection (for example, the generation that was included in the projection).

A concern with the ability to intervene in needs applications was also identified. The AESO and transmission facility owners have the best ability to intervene but have quite similar incentives, i.e. build infrastructure. In the AESO's case, the incentive to build infrastructure is created by the combination of a reliability mandate, zero congestion and the lack of a requirement to perform cost benefit analysis.

4.4.1.2. Deterministic View of Congestion

The planning approach of using deterministic view of congestion, rather than an approach that accounts for reasonable system conditions, creates several concerns. First, it contributes to the cost escalation on the system because new transmission investments are triggered much earlier than necessary. Second, it understates the ability of the existing system to integrate new generation.

4.4.1.3. Zero Congestion Approach

Some stakeholders indicated that the zero congestion approach is unlikely to be sustainable due to the costs associated with it, but this was tempered by concerns about solutions such as LMP and large amounts of congestion. LMP and congestion were seen as a potential barrier to new investment due to the increase in risk associated with forecasting either an LMP or the volume of congestion.

Locational price signals created similar mixed views. Several participants supported locational signals as a means to reducing transmission requirements, but there were concerns with increased risk and complexity. It was also noted that the energy market itself creates locational price signals for renewable generation in particular, suggesting that locational signals in the tariff might be less valuable.

4.4.1.4. Intertie Restoration

Stakeholders did not view as the intertie restoration project to be a net benefit to the province. In particular, it raises transmission costs and enables purely opportunity service from a neighboring jurisdiction. Longer term, stakeholders had level playing field concerns associated with spending capital in Alberta to enable competition from regulated jurisdictions. The implementation of the carbon tax (wherein Alberta generators pay a carbon tax and competition from other markets may face a different tax or no tax) also raised level playing field concerns that are exacerbated by intertie expansion.

4.5 Lack of Flexibility, Competition and Opportunities for Innovation

A number of participants raised concerns that the existing approach limits the ability of the market to respond and that the evolution of the industry may further limit innovative solutions.

- Inability to connect and manage congestion at the participant level, i.e. it is not clear how the AESO would treat an integrated battery/renewable site in a congested area
- It is unclear how storage and other solutions can be integrated in a competitive way to provide non-wires solutions. The current approach does not lend itself to creative solutions and flexibility is limited.
- There are limited incentives on the transmission side – AESO planning incentives have no focus on cost minimization and intervenors have little ability to drive alternative outcomes.
- There is no process to examine non-wires solutions and creative options prior to the AESO submitting a NID.
- Solutions on the distribution grid are equally or more opaque
    - Participants indicated there is no visibility where congestion exists required to drive innovative responses such as storage or demand response
    - The DFO process does not create an opportunity to propose customer driven solutions, and if there is a customer solution the benefit accrues to the DFO

4.6 Inconsistent Approach

Recent decisions and changes by the AUC and AESO appear to indicate a concern with self-supply. The tariff redesign effort underway is focused on bulk system charges and the role of coincident demand charges. The possibility for new rate classes has also been raised. The result of changes has been to:

- Alter the value of DCG by changing the basis on which DCG credits are calculated
- Disallow exports from self-supply sites not covered by an industrial system designation or larger than allowed under the micro-generation act
- DCG credits are being challenged in general
- Costs are being allocated to DCG assets for substation upgrades
    - Arguably inappropriate risk for future costs
- Limited incentive to minimize transmission costs for load and generation siting decisions
- Price signals are not aligned across markets and the AESO does not appear to value the responses from portions of the market
    - For example, the AESO has indicated that load curtailment with respect to 12 CP does not alter transmission planning

The concern with a piecemeal approach is that it does not drive efficient outcomes and is likely to have unintended consequences. This section will outline the key risks, current and future issues associated with the path the market is currently on.

4.7 Technical Standards and Market Design for Ancillary Services

Participants noted that the ISO standards for ancillary services raise a number of concerns for non-traditional providers. This serves to reduce competition in this market. In particular, the standards for sites with storage (such as storage integrated with a renewable project) have not been considered. In addition, there was a concern that the lack of transparency of ancillary service directives. A merit order for directives could add value in that some suppliers have different cost structures for actually meeting the directive.[38]

The concept of an hourly or co-optimized ancillary services market had mixed views, with some participants supporting a market design more in-line with other markets and others supporting the current day-ahead Alberta approach.

4.8 Transition and Change Management

A number of participants noted that large changes in tariff design create a large risk of stranded assets. This was particularly the case for customers that had invested in either on-site generation or the ability to curtail load in response to price signals. If tariff design removes these price signals or changes them in a way that can no longer be managed, there is likely to be rate shock for some customers and some investments could be stranded.

The risk of stranded assets was also identified for distribution connected generation that is currently paid a credit. If the calculation of these credits is materially changed or eliminated, there is again risk that investments will be stranded due to regulatory change.

[38] An ancillary services directive directs a provider to produce the energy associated with its operating reserve block. Alternatively, it directs a demand response provider to curtail its consumption to meet its operating reserve obligation.

Section 5: Potential Options

The options in this paper are grouped into a range of broad areas that align with Section 3. The options relate to reducing future transmission and distribution costs through revised planning approaches, introducing incentives into more elements of the market, and altering the existing tariff signals. Some of the options presented can be combined with other options, while others are mutually exclusive. The intent of the options provided is to trigger further discussion rather than provide a detailed option for implementation.

At a high level, future rates can be reduced by reducing future capital expenditures, reducing sustaining capital expenditures, increasing load that contributes to the recovery of these costs, and/or reducing system O&M expenditures. The table below illustrates the AESO's view of transmission costs for the next 10 years and illustrates nominal costs (i.e., average transmission rate $/MWh) about 15% higher than current costs by 2023.

Figure 3 - AESO Transmission Cost Projection

	Near term projections (2019–2023)					Medium term projections (2024–2028)				
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Transmission system capital spend (2019 $ Million)	$1,430	$0	$252	$574	$980	$55	$55	$55	$55	$55
Transmission connection capital spend[1] (2019 $ Million)	$99	$99	$99	$99	$99	$99	$99	$99	$99	$99
Capital maintenance and replacement[2] (2019 $ Million)	$276	$276	$276	$276	$276	$276	$276	$276	$276	$276
Total revenue requirement[3] (nominal $ Millions)	$2,266	$2,330	$2,368	$2,493	$2,630	$2,722	$2,771	$2,814	$2,850	$2,896
DTS energy forecast[4] (GWh)	62,524	63,161	63,327	63,569	64,010	64,858	65,615	66,271	67,245	68,357
Average transmission rate (nominal $/MWh)	$36	$37	$37	$39	$41	$42	$42	$42	$42	$42
Average transmission portion (600kWh) of residential monthly bill (nominal $)	$22	$22	$22	$24	$25	$25	$25	$25	$25	$25

[1] Annual average from AESO's *2018 ISO tariff filing.*
[2] Information gathered from TFO *General Tariff Applications.*
[3] Revenue requirement is the total transmission charge that is to be recovered from all consumers in that year. For a more detailed breakdown of information, please refer to the AESO's *2019 ISO Tariff Update Application.*
[4] *AESO's 2017 Long-term Outlook.*

Within the cost projections, there are about $1.4 billion in new capital expenditures by 2023, about $100 million per year in new connection expenditures and $276 million per year in sustaining capital for the transmission system. Net load growth during the period is about 2% in total, suggesting continued growth of self-supply. The options outlined in the following sections generally tie to reducing the growth of one or more of the cost categories associated with transmission or distribution costs.

5.1 ISO Initiated Changes

5.1.1 Planning Approach

As noted, the AESO approach to planning is largely a deterministic assessment of the possibility of congestion. A probabilistic approach, particularly for transmission expansions driven by generation, could be adopted that would likely reduce or delay the need for new investment. As an example, in the recent Long-Term Transmission Plan,[39] the AESO indicated a one to one reduction in the ability to integrate renewables in the south for every MW of DCG solar capacity in the south. In Power Advisory's opinion, this is consistent with an approach that assumes wind and solar will be at peak output concurrently, and whatever underlying assumptions with respect to thermal resource dispatch levels are part of the analysis are unchanged (i.e., do not reflect the fact that these renewables will potentially displace these thermal resources) with the additional renewables.

Based on Power Advisory's analysis the relationship between wind and solar generation is not such that the transmission requirements would be perfectly additive. It appears as though the AESO planning approach does not assess the likelihood both wind and solar would be at full or high output concurrently. While this may occur in a very limited number of hours, our analysis indicates that it is very unlikely.

The planning approach could be adapted to focus on the probability of congestion across the year, rather than the technical possibility of congestion. As the supply mix evolves, and assets such as storage, solar, wind and flexible natural gas generation are added, congestion will likely become even less likely in practice. For example, if the AESO future planning scenarios do not assume storage is absorbing low-priced power and peaking gas generators are not offline during concurrent high wind and solar events, the process will dramatically over-state the likelihood of congestion. Locating resource types that are negatively correlated could be encouraged due to a minimal expectation of congestion.

The planning approach could also explicitly adopt a cost benefit analysis, including the 'least regret' framework as is done in other jurisdictions. The current ISO approach does not perform a cost benefit analysis or risk evaluation from this perspective.

Legislative Requirements

As noted in Section 3.1, the legislative requirements for an unconstrained system are strong but not absolute. Alternative language in the T-Reg would facilitate this option, but it does not appear to be prohibited today, nor has the Commission ruled on this issue, to Power Advisory's knowledge. Nonetheless, a planning requirement that was framed in a similar context to the expected unserved energy (EUE) in the previously proposed capacity market regulation is an option for framing transmission needs. In general, unserved energy (or unserved in-merit generation) is probabilistic in nature.

Adopting an explicit cost benefit approach to transmission development would potentially require a change to the Transmission Regulation. The benefit of adopting such as change should be reduced transmission costs, but would require a more nimble planning and regulatory system to implement.

[39] https://www.aeso.ca/assets/downloads/AESO-2020-Long-termTransmissionPlan-Final.pdf, page 5.

5.1.2 Allow Congestion With or Without Constrained Down Payments

As noted in Section 3.1 of this paper, the current Transmission Regulation allows the ISO to apply to the AUC to allow congestion in limited circumstances. An option to reduce transmission requirements until congestion was actually experienced would be to allow a defined amount of congestion to occur prior to triggering the expansion. This is quite similar to the phased expansions used by the ISO currently when assessing expansions to integrate wind capacity. However, the expansions would go forward when congestion was actually observed. For reliability concerns where unserved load could occur this approach is not as feasible.

Constrained down payments are a secondary issue that arise when congestion is allowed on the system. Power Advisory sees two high level options that could be investigated within the current regulation.

The first option is to not make constrained down payments and allow minimal congestion for limited amounts of time. This option could be tied to triggering transmission upgrades once a threshold amount of congestion is reached. It would result in higher congestion risks to generators and likely modest deferrals in transmission requirements. Persistent long-term congestion would likely be challenged by generators on the basis that their in-merit generation was not accommodated by the market.

The second option is to allow congestion in specific areas and make constrained down payments available in those areas. As part of this process, generators would submit their specific opportunity costs (tied to variable cost and carbon credits for example) and the AESO would re-dispatch based on these costs. Transmission upgrades would be triggered when the costs of congestion exceeded the cost of transmission upgrades. This approach is a way of optimizing transmission expansions, and generators would be made whole relative to a transmission upgrade. Gaming concerns (reported variable cost and carbon credits) would need to be managed, but the key is that constrained down payments would be made based on verified costs and only in areas where congestion was explicitly allowed to occur due to deferred transmission. It should also be noted that constrained down payments effectively reduce the locational signal, suggesting that this approach could be paired with a stronger locational incentive such as a revised GUOC.

Both of these examples rely on the view that the AESO can apply to the AUC to allow congestion in limited circumstances. Allowing congestion without constrained down payments potentially reduces the attractiveness of investment in the Alberta market for generators by adding congestion risk. Constrained down payments maintain the current risk profile but add complexity to the settlement system. Care is also required to implement constrained down payments in a manner that does not distort investment or operational decisions, i.e. the incentive to avoid constrained areas must be maintained and real-time incentives to create congestion cannot be created. In addition, with a larger amount of congestion on the system, the AESO may need to upgrade dispatch software, though it should be noted that managing material amounts of congestion is a fundamental capability of the majority of ISOs and should not be a barrier to change.

5.1.3 Additional Rate Classes

At the transmission level, Alberta currently has basically two rate classes – STS for generators and DTS for suppliers. This creates a challenge in creating efficient price signals because it does not allow for material differentiation between different types of participants.[40]

5.1.3.1. Revised DTS Rate

As noted previously, the current DTS potentially creates an inefficient real-time price signal through the 12 CP approach. The intent of the 12 CP fits with the principle that the tariff should send incentives to reduce future investments and thereby reflect the long-run marginal cost of the system, but the specific use of 12 CP no longer aligns with planning criteria.[41]

One option to revise the DTS rate is to align the price signal with real-time conditions and provide sufficient transparency to participants to manage their response. As an example, the ISO could replace the 12 CP signal with a system notification provided at T-2. Consumption during the period would replace the 12 CP billing determinant. The signal should incent participants to reduce load and/or increase onsite generation only when the system is approaching tight conditions. The design of the charge should also ensure the ISO accounts for system response in its planning criteria.

The key principle is that the conditions under which the ISO would trigger the signal are transparent, tied to real-time conditions, and are accounted for in planning criteria. This has the advantage of allowing curtailments to reduce transmission needs and eliminating unnecessary curtailments. The downside is that the approach is arguably unfair because there will likely be very few curtailments in the near-term and any cost savings will likely be in return for minimal action.

5.1.3.2. Self Supply Rate

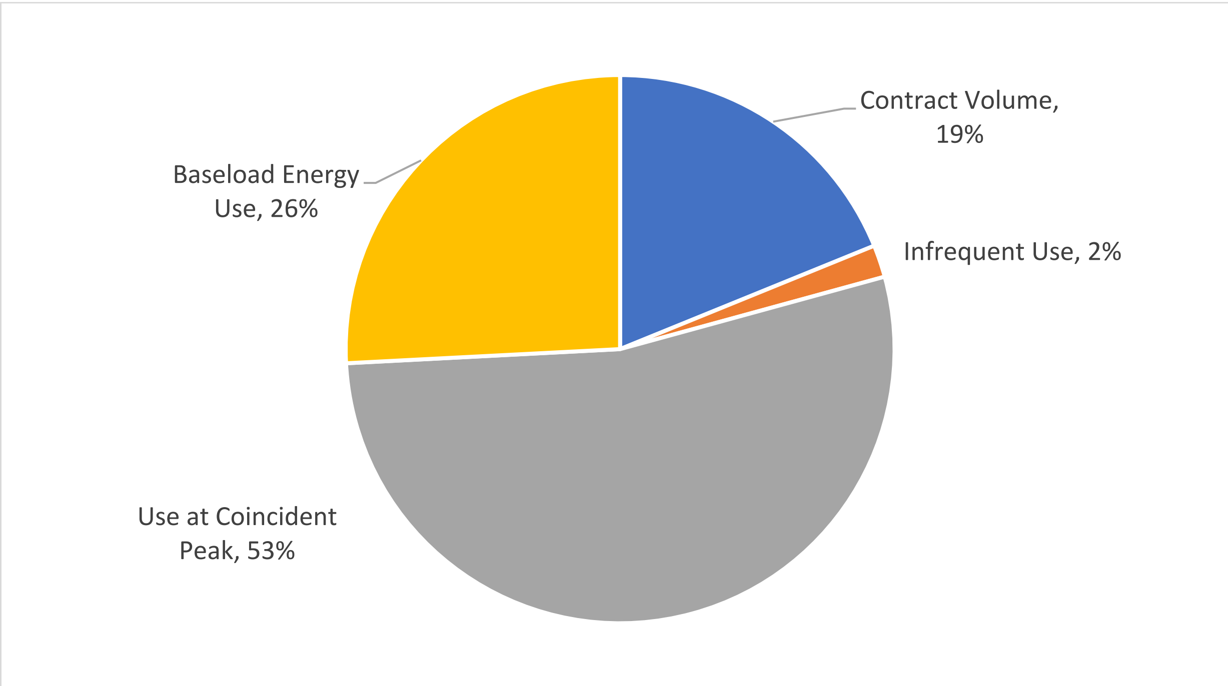
Self-supply is a response to rising transmission and distribution costs, changing technology and, to a degree, low natural gas costs because the value of higher efficiency generators is minimal. Although self-supply is generally seen as a large industrial choice, it can occur at smaller sites, and with changing technology it will move down to sites such as commercial operations with solar plus storage.

A self-supply rate should reflect the value of onsite generation and from a principles perspective should treat onsite generation identically to a reduction in load.[42] Based on the principles identified in this report, there should not be an 'incentive' to self-supply embedded in the design. Rather, onsite generation could be allowed to reduce tariff charges to exactly the same extent an equivalent reduction in load reduced charges. The challenge is that self-supply does not necessarily reduce

[40] Note that the several of the concepts for new rate classes could just as easily be adapted into a common rate class with billing determinants for firm service or passive service, as two examples.
[41] As stated by the AESO, though in previous tariff applications system peak demand has been identified as the key planning criteria.
[42] As long as the reduction is identical the tariff treatment should be identical. If the reduction is different in practice there can logically be a differential treatment.

load in all hours, and therefore the rates could reflect the frequency and timing of using the system to supply load. Figure 5 illustrates the current billing determinants for a self-supply site with a generator the same size as the load.

Figure 4 - Current Self-Supply Billing Impacts – Share of Total DTS Charge



As illustrated in the example for a site with 40 MW of load and 40 MW of generation, a self-supply site that never uses power from the grid would pay 19% of the tariff a 40 MW stand-alone load would pay.[43] This charge is effectively the rate for having access to back-up power, frequency stability and voltage support. Infrequent use of that back-up power (6% outage rate for the generator) adds only a small amount to the charge, but if the infrequent use occurs during a peak demand period (a 12 CP interval), the charge jumps to nearly 75% of the total charge for a stand-alone load. The final 25% of the charge is based on energy use.

If a self-supply rate is created, it is important to consider what it will be designed to incent relative to the current tariff. The current tariff sends a very strong signal to avoid consumption in the 12 CP hours, but does not have a large energy component in general. A high fixed charge tied to contract capacity has the potential to create inefficient investment incentives in back-up generation, strand existing assets and cause rate shock if it is set too high. A high energy charge potentially impacts the efficiency of the energy market by incenting on-site generators to run when they have higher variable costs than grid based supply. A high energy charge is also not reflective of the fixed cost nature of transmission costs.

[43] This graphic assumes a 40 MW flat load for the entire month with a 40 MW DTS contract and a 40 MW STS contract. It also assumes the load and generation operate when the other is not available.

5.1.3.3. Bypass Rate

A closely related option to the self-supply rate is the bypass rate. This concept is used in Australia, and it basically allows for efficient outcomes where transmission costs create an incentive to build onsite generation and avoid transmission costs. Large loads directly connected to the transmission network (such as smelters) may also approach the regional transmission company for a discount from the postage-stamped charge if they can demonstrate a credible risk of inefficient by-pass of the existing network. However, no discount is available of the charge intended to signal the long run marginal cost of using the network. In effect, loads must pay at least a minimum that reflects their direct costs of using the system, but can pay less than the full embedded cost of the system if that cost would result in bypass.

This is an efficiency improving policy because it keeps customers on the system that have elastic demand. It may be challenging to administer and each instance would likely need to be subject to AUC approval, i.e. does the site have a creditable option to bypass the system. A bypass rate interacts with the rate design. For example, if 100% of costs in the tariff are allocated on contract capacity rather than the current design, the ability to bypass the system is different. A bypass rate would determine if, based on a site's configuration, it would be able to install back-up generation or onsite storage, as example, and terminate its DTS contract. Since this investment would be inefficient from a social perspective, the intent of the bypass rate is to charge no more than it would cost to bypass the system, and thereby maintain the DTS contract and avoid inefficient investment. The downside of this type of rate is that it is difficult to implement without creating an incentive for all loads to access the bypass rate. As such, this rate would likely require a regulatory process to ensure it only applied where appropriate.

5.1.3.4. Opportunity or Interruptible Service

This rate class would be applicable to loads, or likely storage, that use the system only when real-time conditions allowed. For example, with local congestion or supply shortfall, this load would be curtailed if it had not already done so in response to price.

Note that this rate could be combined with another of the options such as the active rate. For example, a participant requesting interruptible service could be mandated to have an offer in the market to curtail consumption at a price up to $999.99. This is not a mandatory component of the option however, as the curtailment could occur after all generation in the merit order was dispatched, as is the case with the current DOS product. This rate provides the advantage of encouraging use of the transmission system that does not trigger investment, but as with the bypass rate, if opportunity service is widely available it will likely incent widespread usage given the current robust state of the system. As such, it would likely require some type of qualification process that ensured the potential to respond was real.

5.1.3.5. Active Versus Passive Service

The primary role of active loads in the market is to express their willingness to consume, and adjust their consumption in response to price (e.g., high prices or operating reserve activations). Active loads provide a value to the system as they add certainty for the system controller, they provide transparency as to load that can be curtailed in an emergency, and if used in planning they reduce the need for infrastructure.

A rate class could be designed for load that chose to be subject to must bid rules. This would allow the curtailable load to be accounted for in ISO planning, and would provide incremental capacity to support resource adequacy. A must bid requirement on opportunity service resolves some of the concerns around incentives for loads to use the opportunity service unless they are truly responsive because they could be dispatched offline in the energy market for a variety of reasons and would be subject to compliance obligations. It is important that the must bid requirement does not act as a barrier, i.e. the requirements to participate in this rate class should meet but not exceed what is necessary to drive the expected benefits.

5.1.3.6. Locational Service or Load Attraction

Another rate class option that is seen in some markets is a load attraction rate. It generally applies to regions with excess generation and can be considered a non-wires solution to reduce congestion associated with excess local generation.[44]

As an example of this rate applied to Alberta, the ISO could offer an inverse GUOC type payment to loads that meet performance standards. In this case, the load would receive a monthly or annual payment based on consuming during critical periods that eliminated or deferred the need for transmission investment. It could be a limited term such as 10 years or indefinite until system conditions change.

As a specific example in Alberta, this type of rate could be used to attract greenhouses or data-services load to areas of the grid where there is a negative marginal cost associated with incremental load. In other words, if adding load in that location delays or eliminates the need for transmission, it is eligible for the rate. Restrictions on eligibility would likely be required to incent new and large loads to an area where it would otherwise not locate. As with the bypass rate, this rate would create some administrative burden in return in order to ensure the rate accomplishes its intent. However given the situation in Alberta where generation additions are creating incremental transmission costs the opportunity to attract new load and offset system costs.

[44] Insert reference to NYISO rate.

5.1.4 Revised STS Rate

A number of potential changes to STS consistent with efficiency principles could be considered. The key element would be that charges to generators should not distort investment decisions by creating a barrier to entry nor should they drive real-time dispatch decisions away from the lowest marginal cost.

As noted previously, losses in other markets are generally calculated in real-time and are based on marginal losses rather than average losses. This approach results in revenue from losses charges being higher than average revenue required to pay for average losses, and improves real-time dispatch efficiency. It is not allowed by the current T-Reg, but with changes to the regulation, real-time efficiency could be improved and the revenue collected could lower the regulated revenue requirements for the transmission system.

STS rates could also be revised in a more extensive manner to charge generators for system access. Typically, this type of approach would be paired with transmission rights, and would market a large and fundamental change to the market design in Alberta. Any changes in this regard would require material analysis to ensure the changes resulted in more efficient investment decisions and did not create a barrier to entry for new generation. It is also notable that the majority of jurisdictions collect the majority of transmission costs from load, though Alberta is currently at the boundary of this approach by collecting 100% of transmission costs from load via a postage stamp rate.[45]

5.1.5 NID Process and Competitive Forces including Non-Wires Solutions

The current process for identifying a reliability issue on the grid and solving that issue includes two steps (sometimes done concurrently as a single regulatory filing). The first step is for the AESO to establish need for a project, i.e. identify the issue and the required solution. This requires the AESO to file a NID application with the Commission for approval. The second step is for a TFO to develop a facilities application for approval of the specific solution.

An alternative option would be to structure the NID as a request for proposals rather than moving immediately to directing the TFO to adopt a traditional wires approach. Under this option, the NID would identify the issue and outline the characteristics of a solution. Local generation, interruptible load, and storage are all potential options for some transmission requirements. If excess generation is the issue, load attraction and storage are possible solutions. The traditional wires solution implemented by a TFO could be used as a backstop in the event no alternatives are discovered through a competitive process or the competitive options are more costly than the solution available to the regulated TFO.

If DFOs and TFOs always assess problems, develop solutions, and prepare business cases by only considering utility owned capital solutions, there are a number of missing options. There is also

[45] As noted in Section 5.1.6 making GUOC non-refundable would be a minor change that could be implemented with minimal change to the T-Reg and would have very little impact on interconnection costs for generators.

value in assessing options that are smaller scale. A new wire or new feeder to solve a forecast load growth problem is often significantly overbuilt relative to the current need. Other non-wires alternatives may be available to solve these issues at a smaller scale. Avoiding sunk costs and significant over-investment today provides a utility with option value in the event load growth does not materialize as forecast. It is possible that a non-wires solution, like storage or behind the fence generation, could have been designed as a five-year solution but end up as a 20-year solution when forecasts turn out to be wrong.

The Whitecourt storage project proposed by AltaLink provides an initial example of the potential process, though it was not competitively tendered. This project apparently provides a transmission alternative at much lower cost. It is notable that other options such as curtailable load and local generation could have conceivably performed a similar function if the process was altered to allow a competitive response to a system need.

This option may require legislative changes to fully embed in the overall transmission development process, but the ISO has some discretion that allows options to be investigated and the AltaLink pilot project illustrates that the the capability can potentially be exercised to a degree.[46]

5.1.6 Interconnection Charges

The primary interconnection charge is the GUOC, which ranges from $10,000/MW to $50,000/MWh as noted previously. The T-Reg defines the $10,000/MW as a minimum related to upgrades of existing facilities.[47] Since a generator pays the direct costs of its interconnection, this charge is presumably related to other system costs. The incremental GUOC, up to $40,000/MW, is to be charged where generation exceeds load in a given area.

The GUOC could presumably be set at a much more granular level as the Regulation does not limit the number of areas on the transmission grid. This would send more detailed locational signals, but could result in increased complexity for the ISO and participants. Nonetheless, to the extent the GUOC is intended as a locational signal, it should vary to the extent the cost or benefit of locating in different areas varies.

The timing of the GUOC is at the ISO's discretion with the exception that it is payable before construction of the local interconnection facilities for a project. GUOC could be considered from the perspective of making it payable when ISO or TFO costs are incurred. This is consistent with charging generators their direct interconnection costs.

Legislation could include expanding and altering the GUOC to improve locational incentives, as well as diversifying funding of the transmission system. GUOC could be changed to a non-refundable charge tied directly to the individual substation and priced based on the expected impact on the need for future transmission upgrades. In effect, the GUOC could be used both to partially fund transmission expansion and as a stronger locational price signal. Alternatively, the magnitude

[46] The AESO has not yet moved forward with this project.
[47] See Transmission Regulation, Section 29(2)

of the GUOC could be reduced by roughly 50% and made non-refundable. This results in a very similar cost structure relative to the refundable GUOC, yet makes funding available to the ISO for system expansion.

If GUOC was non-refundable, one potential approach would be to fund constrained down payments to generators. In this type of construct, GUOC is effectively the purchase of transmission rights. The purchase price of these transmission rights would vary based on location, i.e. in areas with a higher likelihood of congestion the purchase price would be higher. This would reduce or eliminate the risk of congestion for generators, while also providing the ISO with quantifiable measure for the need to expand transmission capability. It is quite similar to providing generators with financial transmission rights, which is done in some markets. This weakens the value of GUOC as a locational signal, but it could be incorporated within a larger package of reforms that create alternative locational signals.

Any changes to make GUOC non-refundable would increase the cost of generation investment in Alberta to some degree unless the magnitude of the payment is reduced by roughly 50%, but could be designed to provide a better locational signal and potentially as a funding mechanism for new transmission development. Legislative changes to the Transmission Regulation would be required to implement material changes to the GUOC.

5.1.7 Marginal Losses and Hourly Reserve Price

Employing marginal losses and hourly reserve prices would improve real-time price signals, but are unlikely to reduce transmission capital expenditures. However, they do potentially reduce the magnitude of the costs recovered by the transmission tariff as they fund some transmission expenses via a transparent hourly price.

As noted, losses are currently recovered based on an annual loss factor for each generator, and no net costs are recovered. Charging the marginal loss factor, whether hourly or on an annual basis, would provide revenue to offset transmission costs billed through DTS, and the benefit is that the revenue would be derived from real-time spot market prices. This change would require amendments to the Transmission Regulation.

Similarly, an hourly reserve price that is visible to loads along with the energy market price signal would enhance price transparency and allow loads to see the full spot market cost. Moving to an hourly operating reserve market could also provide potential benefits that should be investigated as Alberta has persistently high ancillary services costs relative to other markets. The day-ahead structure is one possible reason, although it should be noted that in the absence of a day-ahead energy market the ancillary services market is one of the few means for some generators to get some day-ahead certainty around their operations.

A move to a more real-time ancillary services market becomes more valuable if future ancillary services requirements are higher due to increased renewables penetration. Since ancillary services needs could become a function of real-time renewables production, procuring volumes closer to real-time will both reduce volume requirement and improve the accuracy of the price signal.

Volume requirements would fall both because the AESO currently over-procures relative to needs in some hours due to its block procurement approach, as well as the fact the reserves required to integrate wind generation could be tied to actual wind output rather than a day-ahead forecast that is likely to be highly conservative. However, as noted, there is value provided by the day-ahead price certainty from the existing ancillary services design that is otherwise hard to obtain in the absence of a day-ahead energy market. No changes to legislation would be required to enact these changes.

5.2 Improve TFO Incentives

As noted, TFOs are under cost of service regulation that provides limited incentives to minimize O&M and sustaining capital. New investments are driven by the ISO and as such are more difficult to place under a PBR framework. Specifically, consideration should be given to a hybrid approach wherein a TFO's O&M and sustainment capital costs are regulated under a PBR plan and a TFO's capital costs associated with new builds continue to be regulated under COS regulation. Based on Power Advisory's understanding of the process, there is little incentive for a TFO to pursue lower cost than like for like replacement sustainment options in the current structure. Creating an incentive to address this issue has the potential to lower sustainment capital expenses but would require fairly material changes to the current regulatory construct.

Another alternative is to minimize regulatory burden whenever costs are flat or declining. For example, if a TFO applies for costs that are flat in nominal terms and historical returns are in-line with target return on equity expectations, there is little apparent value in a cost of service process that comes with significant direct cost. In effect, the PBR framework could be designed to minimize regulatory burden as well as provide incentives to minimize growth in costs. Designing openers that protect consumers and allow TFOs to manage unavoidable cost escalation would be the key requirement of this type of approach, but it is one way to address the sustainment capital incentive noted above.

TFOs could also be incented to propose alternatives to ISO proposals in the NID process to increase the regulatory tension in the process. Currently, ISO and TFO incentives are largely aligned, and TFOs are best placed to test and vet ISO proposals for system expansions. If TFOs were incented to make alternative proposals via a profit sharing mechanism with consumers, for example, the regulatory process could drive more efficient results. Similarly, the process could also be open to third party proposals to allow greater competition.

5.3 Improve DFO Incentives and Clarify Alberta Framework

Incentives of Performance-Based Regulation

DFOs are already under a PBR framework in Alberta, which is a form of incentive-based regulation. However, there are issues with the implementation of PBR in Alberta. For example, in the 2013-2017 PBR term capital trackers created an incentive to over-invest in capital solutions. This was especially the case where DFOs could shift spending from O&M or non-capital tracker capital projects into capital tracker projects as it would allow the DFO to keep the profits on one hand while recovering costs and earning a return under capital trackers. The poor incentives of capital trackers appear to have been addressed with a transition to K-bar for the 2018-2022 PBR term.

DFO incentive issues also exist outside of PBR. The interplay between the transmission and distribution systems should be carefully examined to introduce appropriate incentives and transparency. For example, if a DFO has a choice between meeting growth at a substation with a substation expansion or a non-wires solution behind the substation, it will be incented to make the choice that maximizes returns subject to reliability requirements. If the costs associated with substation upgrades, inclusive of customer contributions,[48] flow into TFO ratebase, a DFO has no incentive to minimize costs via alternative solutions. In effect, the DFO has only a reliability incentive and basically free access to transmission capital. This creates a similar issue to the one that exists with the AESO's reliability mandate.

When faced with a reliability concern, a DFO should have a number of options, including a traditional wires and feeders solution, investing capital into an energy storage solution if this is cheaper than a competitive solution, or contracting for reliability services from the competitive market. The latter could include contracting for demand response, contracting for a behind-the-fence DCG solution, or contracting for an energy storage solution. During the PBR term, the incentives are to choose the solution that is least cost to the DFO (which as noted above may not be the least cost overall as there may be high TFO cost). However, the long-term incentive sent by rebasing is to engage in capital solutions as contracted services solutions will not earn a rate of return.

Ideally, DFOs should be solution agnostic and the process should include a competitive element wherever feasible. The regulatory framework could be designed with a process step to seek alternative solutions with the traditional wires solution used only as a backstop. DFOs should be incented within this framework to seek the lowest cost solution rather than to seek the status quo or long-term capital solution. This is especially important in instances where the status quo solution is the one with long-term fixed costs.

Regulatory Certainty

Another less obvious incentive created by the regulatory environment in Alberta is created by the risk of proposing new and novel solutions to problems. DFOs and TFOs have a high degree of certainty in getting costs approved as prudent when applying for traditional wires solutions. These utilities have an understanding of what the regulator requires and what aspects of a project could raise concerns.

When applying for a project that has never before been approved by the Commission in Alberta or even just never approved for that specific utility, there are a lot of additional unknowns. At the

[48] Based on the ruling in Decision 22942-D02-2019 that the Fortis rate base associated with customer contributions is to be transferred to AltaLink and future customer contributions are to be rate based by AltaLink.

very least, there is likely an increase in regulatory burden. At worst, the utility could have the project denied. This regulatory risk incents traditional solutions.

This risk could be mitigated by the Commission providing guidance on non-wires alternatives that it considers to be an option. These topics are currently being explored in the distribution system inquiry.[49] Guidance from the Commission at this stage has value with no apparent downside.

In addition to assessment of prudence of costs, DFOs also need to get their final rates approved. Aside from incentives surrounding the volumetric risks, as discussed in the next section, DFOs are incented to get through their Phase II applications with minimal regulatory burden. Accordingly, for similar reasons mentioned above, DFOs are not incented to introduce new and novel rate designs, such as incentive rates, regardless of potential benefits to customers. Again, the Commission could mitigate DFO risks by providing guidance on this topic in the form of principles for incentive rates.

Volumetric Risk

A second concern with the implementation of incentive rates is that incentive rates increase volumetric risk. DFOs with a desire to minimize risk will be averse to implementing incentive rates. This risk could be removed with the introduction of deferral accounts and the elimination of volumetric risk to DFOs on their rates.

DFOs currently flow through transmission rates and do not take volumetric risk on this flow through. Rather, they are made whole through the transmission access charge deferral account. This removes the disincentive for incentive rates when flowing through transmission costs and could be equally applied to DFO rates with a policy change removing volumetric risk.

Removing volumetric risk also allows for reduced regulatory burden. Currently billing determinants forecasts are used to set rates that are not trued up in the event of over or under collection. Accordingly, scrutiny must be applied to billing determinate forecasts and utilities prefer certain forecast methodologies that produce more favorable odds on the volumetric risk. This could be eliminated through the use of deferral accounts to true-up rates.

5.3.1 Planning Process

There is no explicit planning process in Alberta, and in Power Advisory's review of information on the public record there is limited transparency and consistency amongst DFOs. Further, the planning process could be clarified with the introduction of reliability targets common to similar DFOs, i.e. rural and urban DFOs may require different targets.

As with ISO NIDs, there is an option that all capital expenditure above a certain level are subject to a competitive process. This type of process is used in some jurisdictions[50] where the application to build new infrastructure kicks off a process to acquire competitive solutions and the DFO wires

[50] For example Australia uses an approach that evaluates if a non-wires approach is a technically feasible option and if so a mandatory competitive solicitation is used.

solution forms the backstop solution. Adding competition to the process is likely to result in lower cost, but adds some complexity that must be managed to avoid creating excess burden.

If non-wires solutions such as storage and DCG are to be used to minimize distribution expenses, it is also important to clarify how these arrangements can be structured and what control the DFO has over the asset if it is competitively procured.

5.4 DCG Options

Interconnection

A significant issue faced by DCGs today is the risk of an unbounded liability over the course of the project operation that is posed by the substation fractioning methodology. Regardless of whether the methodology properly allocates costs, the larger concern for DCGs is simply that past upgrade customer contribution determinations (CCDs) can be reassessed to allocate costs to a DCG and the substation can be upgraded in the future, which will result in costs to the DCG. The only way to avoid this today is to be small enough not to trigger an STS contract, as the substation fractioning methodology assesses costs based on the ratio of STS to DTS contracts at a substation. This unbounded liability may be enough to prevent a number of DCG projects that are otherwise economically viable.

An option to solve this issue is to finalize DCG costs before the DCG's ISD. These costs should, at a minimum, include the DCG's costs of connection. However, they could be expanded to include other costs the ISO deems should be allocated to that DCG.

Operations

DCG credits could be altered to act as a locational signal within the distribution network. DCG provide benefits to the system in cases where they are able to act like a non-wires solution, *i.e.* potentially able to defer DFO investment. Accordingly, adding a DCG to some substations may have limited benefits, while adding a DCG to other substations may have large benefits. DCG credits could be designed to reflect both the locational value and the temporal value to the DFO rather than a broad-based signal to locate on the distribution system generally.

A second alternative for DCG credits relates to the development of a self-supply tariff (section 5.1.3.1). If DCG is considered functionally equivalent to self-supply, it could be eligible for equivalent treatment to self-supply generation. The determination of whether DCG is equivalent to self-supply is key and hinges on whether self-supply should be restricted to participants with a DTS contract. The key difference is that DCG credits notionally provide a free option to benefit, but there is no cost to the DCG participant (in terms of paying DTS charges if the generator does not offset the load) if the generator performance does not match load characteristics. This does not raise an efficiency concern, but intervenors have raised fairness concerns with DCG credits.

DCG credits could be discontinued if there is no benefit to either the transmission system or distribution system from placing generation near load. This is unlikely to be the case in a broad sense, but may be true in specific locations.