Competitive Process for Critical Transmission Infrastructure

Recommendation Paper
June 1, 2011

2500, 330-5th Avenue SW, Calgary, Alberta T2P 0L4 Phone: 403-539-2450 Fax: 403-539-2949
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1. Executive Summary

In December 2008, the Government of Alberta (Government) introduced the Provincial Energy Strategy, a comprehensive plan for Alberta's energy future. The Government's vision for electricity includes substantial upgrades to the transmission system. An important first step in achieving this vision was to approve the need for critical transmission infrastructure (CTI). The *Electric Statutes Amendment Act* (ESA Act), enacted in November 2009, provided legislation to ensure this much-needed CTI is built. Under the ESA Act, the Government is responsible for approving the need for CTI.

Since 2009, the Government has passed additional legislation to implement this policy. Amendments to the *Transmission Regulation* (T-Reg) in 2010 mandated the Alberta Electric System Operator (AESO) to develop and implement a competitive process (Process) for CTI. All future CTI, including the Fort McMurray project, which is comprised of two single-circuit 500 kV alternating current transmission facilities from the Edmonton region to the Fort McMurray region, will utilize the Process. The Process must be approved by the Alberta Utilities Commission (AUC or Commission).

This Recommendation Paper (Paper), along with any stakeholder comments received by June 24, 2011, will conclude a comprehensive series of consultations, analysis and prudent development of the Process by the AESO and will lead to a formal application to the Alberta Utilities Commission.

The imperative has been to move expeditiously to develop the Process to ensure CTIs subject to the Process can be in service when required. The AESO recognizes that there are many legislative and policy constraints that must be respected in the development of the Process. Therefore, this Process has been designed to be open, transparent and to recognize the unique nature of the Alberta transmission industry and CTI projects.

The recommendations contained in Section 2 below, highlight the key aspects of the Process to encourage low-cost, reliable electrical transmission for the citizens of Alberta well into the future.

2. Recommendations

Based on its benchmarking studies as described in Section 4.3 of the Paper, the AESO recognizes that the design of the transmission framework and the level of competitive pressures introduced into the framework are industry and jurisdiction specific.

Issues unique to Alberta CTI are (1) the magnitude of the spend on any particular CTI project, (2) the size and nature of the CTI facilities – CTI facilities in Alberta comprise the backbone of the Alberta interconnected electric system (AIES), (3) route uncertainty at time of bid, and (4) the time period between submission of Proponents' bids and financial close. Route uncertainty and the aforementioned time period have implications for preparing a high quality bid.

Recognizing the above, the AESO recommends:

- The Own alternative (AESO Own model) where a successful bidder designs, builds, finances, owns, operates and maintains CTI facilities.

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- Utilization of a risk sharing model, as summarized in Table 1.0, to allocate risk between ratepayers and Proponents; this model differs from a traditional cost-of-service model.
- Key commercial terms as reflected in the Draft Contract Term Sheet contained in Appendix G.
- Process procedures as described in Section 9.1 of the Paper.
- Utilizing a Process that contains three stages:
  - Issuance of an Expression of Interest (EOI) as identified in Appendix I
  - Issuance of a Request for Qualifications (RFQ) as identified in Appendix D
  - Issuance of a Request for Proposal (RFP) as identified in Appendix F
- A selection process as identified in Appendix D and Appendix E.

3. Background

3.1. Alberta Government Strategy

In December 2008, the Government introduced the Provincial Energy Strategy, a comprehensive plan for Alberta's energy future. The strategy noted the importance of electricity as a "facilitator of prosperity" and a key contributor to economic development in Alberta. Industrial and commercial customers account for 80% of all electricity consumption; economic growth and job creation is dependent on reliable, efficient power.

"Advancing new transmission investment will ensure that reliable service for Albertans, help drive our clean energy agenda by growing new renewable energy potential, and enhance our ability to serve electricity export markets."[1]

The Government, in its Provincial Energy Strategy, noted that new transmission investment would be needed to reliably serve current and forecast demand, reduce congestion, enable and support the development of new generation facilities, reduce line losses stemming from overload, introduce newer sources of power, increase Alberta's intertie capacity, increase efficiency and maintain a robust transmission infrastructure.

The Government established a policy goal of increasing competition in the electricity transmission sector and attracting investment in CTI. It emphasized growth of renewable energy, low emission energy and cleaner electricity production from fossil fuels, further increasing the need to expand and upgrade transmission facilities.

Through changes in legislation, and as described in more detail below, the AESO has been mandated with developing and implementing a competitive process for certain CTI facilities in Alberta. The AESO is an independent not-for-profit corporation governed by the *Electric Utilities Act* (EUA) for facilitating a fair, efficient and openly competitive market for electricity. The AESO is responsible for forecasting future electricity requirements for Alberta and for planning and developing Alberta's electricity transmission. It also manages the safe, reliable and economic operation of the Alberta Interconnected Electric System (AIES). Since 2003 (and prior to that for predecessor entities), the AESO has also been responsible for operating more than 26,000 kilometres of transmission lines in the AIES.

[1] Launching Alberta's Energy Future, Provincial Energy Strategy, p. 44.

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3.2. Legislative Amendments

The EUA is an important component of the legislative scheme that governs the electricity industry in Alberta. It also outlines the duties, responsibilities and authority of the AESO.

The enactment of the ESA Act, which amended the EUA after November 2009, provided additional legislation to ensure much-needed CTI is built. Under the ESA Act, the Government is responsible for approving the need for CTI.

With the passage of the ESA Act, several specific projects set out in the schedule to the EUA are designated as CTI, as follows:

a) Two new high voltage direct current lines between Edmonton and Calgary
b) One new alternating current line between Edmonton and the Industrial Heartland area
c) Two new alternating current lines between Edmonton and the Fort McMurray area
d) One substation in the Calgary area

The EUA also provides that the Lieutenant Governor in Council (LGIC) may also designate a transmission facility as CTI subject to that facility meeting certain conditions. Importantly, under the EUA, the need for CTI has effectively already been approved, meaning further Alberta Utilities Commission (AUC) approval of need is not required.

As provided in Subsection 41.1(1) of the EUA, the Government may designate certain transmission facilities as CTI if such facilities are contained in the plan prepared by the AESO and meet certain other conditions. Additionally, the AESO may recommend transmission facilities which in the AESO's opinion merit designation as CTI under the EUA to the Minister. When the AESO makes such a recommendation to the Minister, the AESO must complete the requirements of Section 11(3)(a) to (h) of the T-Reg in respect of those transmission facilities but is not required to submit a needs identification document (NID) to the AUC.

On September 30, 2010, the Government amended the T-Reg; the amendments require the AESO to develop a Process for certain transmission facilities, including CTI.

Specifically, Section 24.2 of the T-Reg titled "competitive process to develop certain transmission facilities" provides:

24.2(1) For the purposes of this section, "competitive process" means a fair and open process that allows any qualified person, as determined by the ISO, to submit a proposal in respect of a transmission facility, including a financial bid, as the method to determine the person referred to in subsection (2).[2]

(2) The ISO must develop a competitive process to determine the person who is eligible to apply for the construction or operation, or both, of the transmission facilities referred to in section 24(3)(a), (c)[3] and (d).

[2] The ISO is the Independent System Operator. This term is synonymous with the AESO.

[3] Which refers to two single-circuit 500 kV alternating current transmission facilities from the Edmonton region to the Fort McMurray region as described in Section 4 of the Schedule to the EUA (the Fort McMurray project).

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(3) Before the ISO implements a competitive process developed under subsection (2), the ISO must obtain the Commission's approval of the competitive process.

(4) Where the Commission approves a competitive process developed under subsection (2), the Commission must consider any resulting arrangements as prudent.

(5) The competitive process developed under subsection (2) must not exclude

(a) a TFO, whether or not the TFO has undertaken any work or provided any services to the ISO in respect of a proposed transmission facility, or

(b) any other person that has undertaken any work or provided any services to the ISO in respect of a proposed transmission facility unless the TFO or other person does not have the necessary qualifications to participate in the competitive process.[4]

(6) Subject to subsection (7), the ISO may request, and a TFO or other person must provide, any records to the ISO that are necessary to develop and implement a competitive process.

(7) If there is a dispute between the ISO and a TFO or other person regarding whether a record is necessary for the purposes of the ISO as referred to in subsection (6), the matter must be determined by the Commission.

(8) A competitive process that is approved by the Commission may be used by the ISO for more than one transmission facility project.

The Fort McMurray project consists of two 500 kV AC lines to Fort McMurray, including one from the Wabamun Lake area and one from the Industrial Heartland area, and will be the first CTI project to utilize the Process developed by the AESO.

4. The Consultation Process

The AESO recognizes the development of the Process is a complex undertaking. Developing a robust Process requires participation, input and support from various stakeholders. With this in mind, the AESO has undertaken the following consultation process.

4.1. AESO Discussion Paper

On September 17, 2010, the AESO issued Terms of Reference and a Discussion Paper (Discussion Paper) on a Process for CTI. Following the publication of the Discussion Paper, the AESO held a general stakeholder session on October 13, 2010 to provide an overview of the Discussion Paper and to respond to stakeholder questions. The AESO also requested that written comments on the Discussion Paper be provided by November 4, 2010.

Based on stakeholder comments received, the AESO, on February 3, 2011, published a more detailed schedule for the development, approval and implementation of the Process. In a February 3, 2011 letter to

[4] A TFO is a Transmission Facility Owner.

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stakeholders, the AESO indicated its desire to meet one-on-one with stakeholders who had provided comments on its Discussion Paper. The AESO also extended an invitation to meet with any other stakeholders who were interested in discussing the development of the Process.

The Discussion Paper set out two alternatives intended to form the "bookends" of competitive models that would allow for the injection of competitive pressures in developing CTI. In the Own alternative (AESO Own model), a successful bidder designs, builds, finances, owns, operates and maintains CTI facilities. In the EPC alternative (AESO EPC model)[5], a successful bidder designs and builds the CTI facilities. Once construction is complete, the CTI facilities are transferred to an incumbent transmission facility owner (TFO) to own, operate and maintain.

The Discussion Paper also set out an implementation schedule, objectives and principles of the Process, a proposed structure for Request for Qualifications (RFQ) and suggested possible changes to relevant legislation that may be necessary to allow for implementation of the Process.

A review of stakeholder comments on the Discussion Paper, received on November 4, 2010, provided insight and input as the AESO prepared its Draft Recommendation Paper.

4.2. Draft Recommendation Paper

On March 31, 2011, the AESO issued a Draft Recommendation Paper to further advance the consultation process and to provide greater detail on the AESO's plans for meeting its legislative mandate regarding the Process. Following the publication of the Draft Recommendation Paper, the AESO held a general stakeholder session on April 14, 2011 to provide an overview of the Draft Recommendation Paper and to respond to stakeholder questions. The AESO also requested that written comments on the Draft Recommendation Paper be provided by April 28, 2011.

The Draft Recommendation Paper provided a response to stakeholder comments on the Discussion Paper, discussed the competitive models considered and provided the AESO's conclusion and detailed rationale for the competitive model recommended – the AESO Own model. In addition, the Draft Recommendation Paper provided an initial framework for the allocation of risk and the associated cost recovery/pricing scheme for the AESO Own model and asked for stakeholder feedback on the framework.

The Draft Recommendation Paper provided an initial framework for the development of terms and conditions for a selection process and contractual arrangements arising from the Process and further advanced the development of the RFQ and RFP documents. Finally, the Draft Recommendation Paper sought comment on whether or not project stages should be bid separately, using the Fort McMurray project as an example.

Stakeholders' comments on the Draft Recommendation Paper generally revolved around the following four issues:

- There were varying views on the risk allocation model proposed by the AESO. Some stakeholders were of the view that the risk allocation model transferred too much risk to the Proponents and would result in significant risk premiums. Other stakeholders believed the proposed risk allocation was appropriate.

[5] EPC refers to engineering, procurement and construction.

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- Stakeholders desired a contract term that was more in line with the life of the asset.
- Stakeholders had varying views regarding whether or not the Fort McMurray project should be split into phases or kept whole for purposes of tendering.
- Stakeholders suggested Proponents participating in the RFP process be compensated for their proposal costs.

A more thorough discussion of stakeholders' comments on the Draft Recommendation Paper can be found in Appendix A – Draft Recommendation Paper – Summary of Stakeholder Comments and Appendix B – Draft Recommendation Paper – Stakeholder Comment Matrix..

An updated schedule provided on February 3, 2011 regarding the development, approval and implementation of the Process remained unchanged.

4.3. Broad Expert and External Consultation

Stakeholders suggested the AESO seek broad advice and consult with experts from other jurisdictions and under similar circumstances to ensure the AESO's development of the Process could take advantage of a full range of acquired knowledge and experience. There is an emerging trend in the introduction of competitive pressures into the transmission infrastructure marketplace through the redesign of market structures driven, particularly where significant investment is required, by the expectation of positive results for ratepayers. The AESO has consulted widely to design a Process that captures these positive results.

4.3.1. Alberta Transportation

In its Draft Recommendation Paper, the AESO noted that it had undertaken discussions wtih Alberta Transportation with respect to its recent experiences using Public Private Partnerships (P3). Alberta Transportation is responsible for the long-term planning of the province's highway network and oversees the network's design, construction and maintenance. It currently uses a P3 model and a competitive tendering process to award major projects. The AESO has drawn applicable learnings from that experience and applied them to the development of its Process.

4.3.2. The AUC

The AUC has also looked to other organizations to understand the introduction of competitive pressures into existing market designs. In 2010, the AUC announced its intention to move to performance-based rate making (PBR) for, amongst others, transmission and distribution companies. This addresses the AUC's "assumption that rate-based, rate of return regulation offers few incentives to improve efficiency, and produces incentives for regulated companies to maximize costs and inefficiently allocate resources."[6] The AUC is adjusting the regulatory regime to encourage economic behaviours that more closely mimic the incentives in a competitive market.

[6] AUC Letter dated February 26, 2010 regarding Rate Regulation Initiative Round Table. http://www.auc.ab.ca/items-of-interest/Rate-Regulation-Initiative/Documents/2010-02-26_Rate_Regulation_Initiative_RoundTable.pdf

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4.3.3. Power Advisory LLC.

The AESO retained Power Advisory LLC to perform a comprehensive benchmarking study on the competitive procurement activities in the transmission industry in other jurisdictions. A copy of the Power Advisory report is provided in Appendix C, Review of Competitive Procurement for CTI Facilities, Power Advisory, LLC, December 2010. The review of competitive procurement of CTI facilities included Texas, Ontario, Brazil and the U.K.

Key findings of the study relevant to the Process for CTI in Alberta include:

- Other jurisdictions have put legislation in place to enable a competitive tendering process to proceed.
- Significant investment was/is required in each jurisdiction to expand its transmission system.
- A competitive approach, through the use of a competitive tendering process, is believed to create value for both investors and consumers.
- Innovation and new sources of technical and financial expertise were identified as key benefits of competition.
- All jurisdictions studied allowed for new entrants to develop, construct, own, operate and maintain CTI facilities. Entry was not restricted to one component of a project.
- The design of the transmission infrastructure market and the level of competitive pressures introduced into the market were specific to each jurisdiction. Some jurisdictions chose to move risk from customers to shareholders through the use of predetermined and agreed-upon pricing while others continued to employ traditional cost-of-service rate making principles.
- Tendering rules were jurisdiction specific.

4.3.4. PricewaterhouseCoopers LLC.

The AESO has retained PricewaterhouseCoopers LLC (PwC) to provide advice on the development of the Process with regards to risk allocation, key commercial terms and the tendering process. PwC is the world's largest integrated professional services organization, operating in 151 countries. It has developed a specialized financial and procurement advisory practice with more than 300 Infrastructure and P3 practitioners, 30 of whom are based in Canada. It is recognized as a world leader for advice on successful competitive procurements and P3 projects.

4.3.5. Additional Consultations

As the AESO continues to develop the Process, it will continue to and welcomes additional consultation with all interested parties.

5. Terminology

For ease of reading and as the AESO continues to develop the Process the following terminology will be used:

- Interested Parties: Parties who respond to the AESO's Expression of Interest
- Respondents: Parties who respond to the AESO's Request for Qualification (RFQ)
- Proponents: Parties who are invited by the AESO to submit a proposal as part of the Request for Proposal (RFP) stage
- Proponent's Bid Submission: a Proponent's bid submission as defined in the RFP document
- Preferred Proponent: the Proponent who is ultimately selected during the RFP stage to implement the project.

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- AUC Facilities Application Process: the regulatory process whereby the AUC makes a determination on the final route and grants a permit to construct and a license to operate a transmission facility.

6. Summary of Previously Discussed Items

6.1. Objectives and Principles

In its Discussion Paper, the AESO suggested a set of objectives and principles for the Process. The Draft Recommendation Paper integrated stakeholder comments into a revised set of objectives and principles for the Process.

These objectives and principles are designed to meet the goal of the Process for CTI to create a fair, transparent and openly competitive opportunity for incumbent and new entities to develop, own and operate CTI. The objectives and principles remain unchanged for this Paper. To reiterate:

- the competitive model must result in the minimization of life-cycle costs through the use of competitive pricing,
- the competitive model must create opportunity for maximum innovation throughout the life cycle of the CTI facility,
- the competitive model must create opportunity for new market entry,
- the competitive model must allocate risk to most efficiently and effectively reduce costs and mitigate risk,
- the competitive model must foster efficient investment, operation and maintenance of assets across the life cycle of the CTI facility,
- the Process must foster regulatory predictability,
- the Process must be straightforward and efficient,
- the Process must clearly state the accountabilities of each party involved,
- the Process must achieve a reasonable level of transparency and consistency over time,
- the Process must ensure CTI facilities are designed to meet standards for performance and reliability and do not jeopardize the Alberta interconnected electric system,
- the Process must be fair, open and consultative
- the Process must consider obligations typically assumed by the incumbent TFO,
- the Process must provide transparent selection criteria to address the principles outlined above.

6.2. Process Schedule

An updated schedule was presented in the Draft Recommendation Paper. The schedule reflected a commitment to the consultation process and a commitment that the Process advance in a timely manner. This updated schedule remains unchanged.

ACTIVITY	DATE
AESO issues Discussion Paper	September 17, 2010
Stakeholders provide comments	November 4, 2010
AESO undertakes further stakeholder consultation	Prior to March 31, 2011
AESO issues Draft Recommendation Paper	March 31, 2011
Stakeholders provide comments	April 28, 2011
AESO undertakes further stakeholder consultation as appropriate	Prior to May 27, 2011

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ACTIVITY	DATE
AESO issues Recommendation Paper	May 27, 2011
Stakeholders provide comment	June 24, 2011
AESO files application with AUC for approval of Process	September 15, 2011
Expected AUC Decision*	June 2012
AESO issues RFQ	July 2012
Bidders respond to RFQ	September 2012
AESO evaluates RFQ responses and prepares short list of bidders	November 2012
AESO issues RFP	November 2012
Bidders respond to RFP	May 2013
AESO evaluates bids and awards project to successful bidder	August 2013

* Indicative only—the AUC will determine the timelines of the approval process.

6.3. The AESO Own Model

After extensive stakeholder consultation and analysis, the AESO concluded the AESO Own model best fits with the goals and objectives for the Process. In the AESO Own model, a Preferred Proponent completes upfront development work (preliminary design, landowner consultation, siting and facility preparation), builds, finances, owns, operates and maintains the CTI facility. The Preferred Proponent is responsible for the CTI facility from inception to decommissioning. The Preferred Proponent will become the "owner of a transmission facility" as defined in the EUA and will be subject to its statutory obligations.

The advantages of a single owner under the Own model are:

Broader Market Participation – lower entry barriers increase competitive pressures in the marketplace.

Life Cycle Efficiencies – a single entity develops, operates and maintains the CTI facility, allowing it to optimize costs across the project's life cycle.

Innovation – a single entity allows for maximum innovation across the project's life cycle, including financial innovation.

Landowner Relationships – one owner minimizes the risk of establishing and managing relationships with landowners because it takes responsibility for landowner relationships from project inception to decommissioning.

Performance and Reliability Standards – standards are specified as a requirement of an incumbent TFO or new entrant who will become a TFO subject to all TFO accountabilities and responsibilities with regard to performance and reliability standards.

Simple Administration – a single owner does not require transfers between entities and removes the AESO's involvement in transfer-related issues. Additionally, TFO responsibilities and accountabilities are well understood and well managed under the current regulatory regime.

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Risk Considerations – predictable pricing in the Process comes from well-defined projects. Project uncertainty increases risk premiums. Upfront development work and its impact on bids is not well defined, increasing uncertainty and adding to risk premiums. The AESO Own model most adequately manages risk over the life of the project.

A full discussion of the various models contemplated can be found in the Discussion Paper and the Draft Recommendation Paper. The AESO continues to support the AESO Own model as the model that will be enabled by the Process.

6.4. Further Legislative Changes

It is the AESO's view that no further legislative changes will be needed to implement the Process. However, if additional legislative changes are identified during the consultation period, those changes will be in place prior to the implementation of the Process.

6.5. Role of the AUC and the Regulatory Process for CTI

As summarized in Section 2.2, changes to the EUA and recent amendments to the T-Reg define the roles of the AESO and the AUC with regards to developing the Process.

Upon completion of the development of the Process, the AESO must submit the Process to the AUC for approval. The AESO recommendations, as contained in this Paper, and subsequent stakeholder responses provided to the AESO by June 24, 2011, will form the basis of the AESO's Process application to the AUC. The AESO currently expects to file its Process application with the AUC in September 2011. As indicated in Subsection 24.2(4) of the T-Reg, once the Process is approved by the AUC, currently expected in June 2012, the AUC must consider any resulting arrangements as prudent.

Upon AUC approval of the Process, the AESO will then initiate and implement the Process (Section 9 of the Paper provides a detailed description of the Process). The Preferred Proponent is expected to be chosen by August 2013. Upon completing the provisions of the Project Development Agreement – see Appendix F for a description of the Project Development Agreement contained within the RFP – the AESO will direct the Preferred Proponent to move to the AUC Facilities Application Process.

Consistent with the current regulatory regime, the AUC will hold public hearings on the facilities application (FA) of the Preferred Proponent. Through its Facilities Application Process, the AUC may approve the FA subject to such terms and conditions as it may prescribe, which may include requiring changes in the applied-for location of the facilities, or, prescribing their location and route. The AUC's oversight of public consultation, route selection, environmental and economic assessment and the ultimate decision on whether to issue a permit to construct and a license to operate remains a part of the AUC Facilities Application Process.

6.6. Role of the AUC Over the Life of the Contract

The respective roles for the AESO and the AUC over the future of any CTI projects after all approvals have been awarded is continuing to be developed. Further detail can be found in the Draft Contract Term Sheet found in Appendix G.

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6.7. Affiliate Rules

The AESO will use its best efforts to develop a Process that is fair and equitable for all market participants including new entrants. As the AESO develops the Process and the RFQ/RFP documents, it will consider the inherent competitive circumstances held by Proponents including circumstances related to cost recovery methods, taxes, subsidies or financing and whether any necessary provisions are required in the Process or the RFQ/RFP documents to address such circumstances.

Codes of conduct currently exist between Alberta-regulated entities and their non-regulated affiliates. They provide the framework for how the entities must interact with respect to transactions, information sharing services and resources. Codes of conduct are approved by the AUC. In the event that a regulated entity is of the view that it is at a competitive disadvantage due to the provisions of its code of conduct, such regulated entity should address its concerns with the AUC including obtaining any necessary exemptions that the regulated entity may consider to be necessary.

6.8. Tariff Issues

The AESO intends to include costs paid for arrangements arising from the approved Process in the AESO tariff, similar to the inclusion of other approved costs. The costs will be recovered, in conjunction with other wires costs, through system access service charges to market participants.

7. Recommended Risk Allocation Model

7.1. General

Stakeholders have noted that the risks and costs of upfront development work in a competitive bidding process are considered high when bidders are expected to bid without certainty on specific information necessary for a high quality bid, e.g., route certainty. In addition, firm bids must be filed years in advance of the AUC approval of the FA. The time lag between bid submission and AUC approval of the FA – where a determination of route is made and a permit to construct and a license to operate is granted – is shown in Graph 1.0, Timing Considerations.

The information gap and the time delays both increase risk and create uncertainties in all phases of the project, including operating and maintaining the project over its life cycle. Stakeholders strongly suggested the AESO rework the assignment of risk to achieve the goal of the Process, namely, to allocate risk to most efficiently and effectively reduce costs and mitigate risk.

The AESO has reworked the risk allocation options based on the stakeholder comments and its consultation with PwC. As stated in Section 4.3.4 of the Paper, PwC brings a wealth of experience from other jurisdictions both in Canada and abroad specifically relating to the development of competitive processes for infrastructure, e.g., Alberta’s public private partnerships.

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Prior to describing the risk allocation model the AESO has subsequently developed, it is important to identify externally imposed constraints the AESO faces in developing the Process.[7] These constraints assist with understanding the boundaries the AESO faces in developing the Process.

7.2. The Constraints

There are many externally imposed constraints that impact the development of the Process. These constraints impact the AESO's ability to develop a Process that takes advantage of the full spectrum of competitive pressures. There was never an expectation that a perfectly competitive transmission infrastructure market design could be achieved. Current constraints will remain and will have a significant impact on the ultimate design of the Process, the allocation of risk and on potential risk premiums which Proponents may seek to include in their respective bids. The constraints are as follows:

- The AESO must develop a Process to determine the person who is eligible to apply for the construction or operation, or both, of transmission facilities. A competitive process means a fair and open process that allows any qualified person, as determined by the AESO, to submit a proposal in respect of a transmission facility, including a financial bid.
- Once the Process is approved by the AUC, it will be applicable to projects designated as CTI.
- The Fort McMurray is a project designated as CTI and will be the first project to utilize the Process.
- In keeping with its current mandate, the AESO will provide point-to-point project coordinates only at the RFQ and RFP stages of the Process. The AUC will determine a specific project route at the FA stage and the Preferred Proponent will only have route certainty when the AUC makes its decision on the FA.
- The AESO assumes that unlike the P3 projects, there will be no public funding, i.e., government funding of CTI projects. If applicable, any honoraria associated with the RFP process and/or lump sum incentive payments will form part of the contractual terms.
- The AESO recognizes that final approval of the FA is not within its mandate. Its role is to develop a Process to encourage competition and to determine the person who is eligible to apply to the AUC for the construction or operation, or both, of the transmission facilities. The AUC will be asked to approve the Preferred Proponent's FA.
- The current Alberta regulatory regime, from Proponent bids to Preferred Proponent award by the AESO to breaking ground, is estimated to be in excess of three years, which creates timing issues for development of the Process.

The AESO seeks stakeholder comments on other constraints that may be thought to impact the development of the Process.

7.3. The Risk Allocation Model

The AESO recognizes that there are many aspects to the challenge of moving from a traditional cost-of-service model to a new model that seeks to allocate costs and risks between ratepayers and the Preferred Proponent differently.

In its work with PwC, the AESO has evaluated other methods of distributing risk not offered in the Draft Recommendation Paper. After reconsidering the appropriate allocation of risk, the AESO is of the view that

[7] A constraint is an externally imposed "limitation" as it pertains to the accomplishment of the desired outcome of the Process and specifically with regards to the AESO's ability to inject competitive pressures into the market for transmission infrastructure.

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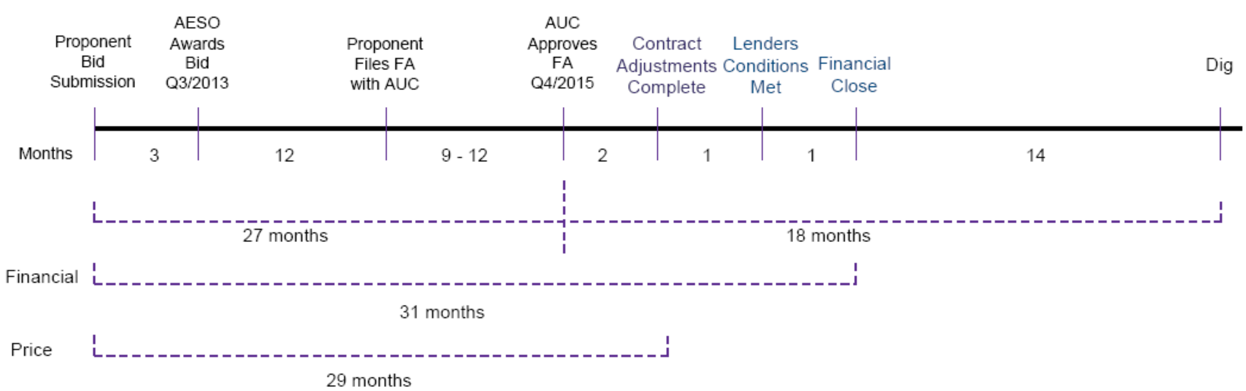
the AESO Own model continues to allow for the flexible distribution of risk across the life cycle of the facilities.

As discussed earlier, the final route cannot be ascertained until the FA is approved by the AUC. As illustrated in Graph 1.0, Timing Considerations, the AESO selection process requires firm bids well in advance of the AUC FA approval. This creates three risks for bidders: (1) routing, (2) timing, and (3) pricing risk.

Graph 1.0

Timing Considerations



* AESO award will be conditional on receipt of a permit to construct and license to operate (P&L) from the AUC

7.3.1. Routing Risk

The AESO is constrained to providing end point coordinates for a transmission line during the RFQ and RFP stages. The actual route will not be determined until AUC approval of the FA, approximately two-plus years subsequent to the selection of the Preferred Proponent. This presents uncertainty for Proponents in costing certain elements of their bids.

7.3.2. Timing Risk

Proponents must deliver firm commitments approximately three-plus years before construction commences. It is clear that risk premiums will be included in a Proponent's price if no allowance is made for timing-related risk adjustments associated with the regulatory process. For example, over a three-year period, Proponents can legitimately expect changes in interest rates and Alberta labour costs. The AESO believes Proponents have the ability to manage commodity price risk.

7.3.3. Pricing Risk

Because of uncertainty in timing, routing and the new Process, Proponents may attach significant risk premiums to all phases of the project and may choose not to bid if they perceive there is excessive risk. Proponents may not be fully acquainted with other risk models beyond the current cost-of-service model

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and can be expected to add a further risk premium to accommodate this learning curve (similar to the P3 experience).

The challenge for the AESO in developing the Process is to recognize these constraints and develop a risk sharing model that encourages competition and delivers an efficient and beneficial cost and risk sharing result for ratepayers.

As shown in Table 1.0, Allocation of Risk – High Level Summary, the AESO has developed a high level risk sharing matrix. Appendix G provides a Draft Contract Term Sheet and details on how the allocation of risk has been translated into commercial terms for inclusion in the Project Agreement that will result from the Process.

Table 1.0.

Allocation of Risk - High Level Summary

Risks Allocation Decisions	Ratepayer Retain	Transfer to Preferred Proponent	Share	Comments
Development of Project to Energization				
Route Uncertainty • Route length • Geotechnical • Structures • Land Acquisition			 X X X X	Up to FA Transferred to Proponent thereafter
Timing and Impact on Pricing Uncertainty • Commodity Price Risk • Alberta Labour Rates • Interest Rates • Long leads • Inflation		 X	 X X X X	Up to FA Transferred to Proponent thereafter For public sector delays only
Land Acquisition Costs • Aboriginal Peoples / Federal Government • Provincial Lands • Private Landowners		 X X X		
Land Acquisition Timing • Aboriginal Peoples • Provincial Lands • Private Landowners		 X X X		
Project Scope • AUC initiated • AESO initiated • TFO initiated	 X X	 X		
New Process Risk			X	Shared to extent we have had stakeholder consultation
Change in Law	X			

Risks Allocation Decisions	Ratepayer Retain	Transfer to Preferred Proponent	Share	Comments
(i.e., changes in reliability standards)				
Project Operation and Maintenance				
Project Operation and Maintenance ● Change in Law ● Inflation ● Reopen at 20-Year Mark	 X		 X X	
Route Uncertainty on O&M			X	
End of Contract Term		X		
Post Contract Period[8]			X	
Commercial Terms (as per Draft Contract Term Sheet)[9]	X	X	X	

7.3.4. Ratepayer Retained Risk

In general terms, ratepayers will be responsible for those risks over which Proponents have no control. For example, if project scope changes post-award as a result of either an AESO or AUC decision on project scope, ratepayers will be required to hold this risk. Ratepayers will also be required to carry the risk and associated cost of changes in law. It is the AESO's view that a transfer of these risks to Proponents may result in unacceptable risk premiums in a Proponent's bid.

7.3.5. Risk Transferred to Proponents

Certain risks are best managed by Proponents. For example, stakeholders have highlighted the need for Proponents to have excellent relationships with landowners and affected parties.[10] It is the AESO's view that relationship development and management is best managed by Proponents and consequently, risks associated with land acquisition activities will be held by this group.

7.3.6. Risk Shared Between Ratepayer and Proponents

There are several risks that will be shared between ratepayers and Proponents. It is the AESO's view that some of these risks have an expiration date, e.g., upon AUC FA approval, risks associated with an uncertain route will be resolved. In this instance, a Preferred Proponent's bid price would be adjusted post-AUC FA approval to reflect any AUC-directed changes in route. Subsequent to this point, all future route-related risk would transfer to the Preferred Proponent.

7.3.7. Routing Risk

In the Draft Recommendation Paper, the AESO noted that it was studying information to make available to Proponents based on existing expertise within the AESO, other information available to the AESO and the

[8] Post contract term refers to the period following the end of the 40-year contract term.
[9] The Draft Contract Term Sheet can be found in Appendix G of the Paper
[10] The AUC, through its Facilities Application Process, provides consultation requirements for applicants.

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time available for the Process to provide better information on possible route considerations. The AESO will do the following:

First, the AESO will provide Proponents with a high level description of the project study area including maps through a Land Research Study (Study). The Study will be provided for information only; the AESO will not warrant its content or accuracy.

The objective of providing the Study is to make the playing field as level as possible for all participants whether they are incumbent TFOs who may already have first-hand knowledge of land and environmental factors within the study area, or new market entrants who are unfamiliar with the study area. Providing this information will help mitigate some uncertainty for all Proponents as they develop the scheduling and cost components of their respective proposals.

The AESO will develop the study area for the Study utilizing start and end coordinates for the specific transmission facility and will allow for a reasonable geographic area recognizing that routing transmission lines is a sensitive undertaking and may require a wider field in which to find the best routes. The study area developed by the AESO will not restrict Proponents who may ultimately propose routes that fall outside of such study area.

It is important to note that the AESO will not provide this information in order to illustrate or suggest specific routes for transmission. Detailed routing will be developed as part of a Preferred Proponent's FA. Rather, the AESO is providing information regarding land, environment, infrastructure and social aspects of the study area to assist Proponents in refining their risk assessments in support of their proposals to the AESO. The AESO understands that how and where transmission lines are built are major components of the cost and timing of a project.

Proponents will assess risks and balance various constraints with respect to land, environment, cost and constructability. See Appendix H for a draft Study table of contents.

Second, the AESO will require Proponents, in preparing bid submissions, to rely only on table top assessments for all land assessments and route selection.

Third, the AESO will play a leading role in educating and informing the public regarding the Process prior to and during Process implementation.

The AESO seeks stakeholder comments on the risk allocation model.

The AESO seeks stakeholder comments on the proposed contents of the Study.

The AESO seeks stakeholder comments on the proposed land assessment methodology.

7.3.8. Incentive Mechanisms

The AESO Own model lends itself to enabling successful project implementation, particularly if reinforced by incentive mechanisms. The current payment mechanism, as illustrated in the Draft Contract Term Sheet,

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contemplates a penalty in the form of lost monthly revenue if the in-service date (ISD) for the project is delayed. It also provides an incentive – if the project is completed ahead of schedule, for example, or if the Preferred Proponent minimizes interest costs during construction and realizes its monthly revenue stream earlier.

Loss of monthly revenue due to a late ISD is undesirable from both the Preferred Proponent's perspective and importantly, from the AESO's perspective, acting in the public interest. Therefore, the AESO and the Preferred Proponents have a common interest in achieving milestone certainty including:

- AUC FA Approval – consultation, technical and a complete filing
- Construction milestones associated with traditional construction stages
- ISD to the benefit of all Albertans

The AESO believes that a collaborative approach with the Preferred Proponent, particularly during the development of the project and at key milestones, will ensure schedule integrity and result in a benefit to ratepayers.

The AESO is considering various means to incent milestone certainty.

An incentive payment at the AUC FA milestone will motivate the Preferred Proponent to develop robust long-term relationships with landowners and affected parties, will ensure the technical aspects of their project satisfies the AESO's requirements and will ensure a robust and complete FA to the AUC.

The AESO seeks stakeholder comments on the incentives initiative.

8. Linking Risk Allocation to Commercial Terms

Based on the allocation of risk and as illustrated in Table 1.0, Allocation of Risk – High Level Summary above, the AESO has identified key commercial terms. Appendix G, the Draft Contract Term Sheet to the Paper provides further details on these commercial terms. Terms associated with pricing mechanisms will also be contained in the RFP document and will form part of the selection process. A copy of the structure of the RFP document can be found in Appendix F.

The AESO seeks stakeholder comments on the key commercial terms identified in the Draft Contract Term Sheet contained in Appendix G to the Paper.

9. The Process

9.1. General Process Procedures

The Process Procedures (Procedures) will provide the framework and the duties and responsibilities of the AESO when administering the Process for the transmission facilities referred to in Subsection 24(3)(a), (c) or (d) of the T-Reg. The Procedures will contain a general overview of the Process requirements for the

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AESO and the obligations of both the AESO and potential Interested Parties/Respondents/Proponents/ Preferred Proponents at each stage of the Process, including, but not limited to:

1. timing for the commencement of the Process for a specific project;
2. EOI/RFQ/RFQ requirements; and
3. withdrawal and/or disqualification of Interested Parties/Respondents/Proponents/Preferred Proponents; and
4. cancellation of the Process for a specific project.

The AESO is proposing the Process contain three stages: an EOI stage, an RFQ stage and an RFP stage. In addition, the AESO is proposing a selection process including criteria and a weighted and pass/fail system for the RFQ and RFP stages of the Process. The AESO proposes a selection panel, including the mechanism to appoint panel members, to oversee the selection process and arrive at a Preferred Proponent. A fairness advisor will oversee the implementation of the Process.

The AESO seeks stakeholder comments on the Procedures.

9.2. Process Documentation

The following documents comprise the draft Procedures.

9.2.1. Expression of Interest

The first stage of the Process will invite expressions of interest by announcing the Process in the media. The EOI phase will be designed to cast the net as broadly as possible, to attract as much interest as possible and will allow the AESO to gauge the level of interest from interested parties including potential new entrants.

The EOI will be sent to reputable domestic and international transmission developers and other interested parties. The purpose of the EOI is to obtain feedback from candidates likely to participate in the Process in order to ensure the transaction is structured to maximize participation and competition during the later stages of the RFQ and the RFP.

This stage will include a public information session to explain the bidding process and ensure incumbents and new entrants alike have as much information as possible to decide whether to engage further in the Process.

Appendix I to the Paper contains the indicative structure of the EOI.

The AESO seeks stakeholder comments on the indicative structure of the EOI.

9.2.2. Request for Qualifications

The second stage of the Process will be an RFQ stage. The RFQ will be sent to those responding to the EOI and to reputable domestic and international transmission developers. To ensure broad participation, the RFQ tender notice will also be published in professional journals and websites. A public information session will assist potential Respondents in thoroughly understanding the Process and the CTI project

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which is subject to the Process. Adequate time will be provided to Respondents to thoroughly prepare their submissions.

The RFQ has been designed to reflect the unique features of Alberta's transmission industry. The AESO has chosen a scored test. A pass/fail test during the RFQ stage is not predictable and may result in too many or too few Respondents advancing to the RFP stage. A scored test will provide predictability of the number of Respondents who advance to the RFP stage but must not be overly subjective or too complex.

Appendix D provides a high level summary of the contents of the RFQ.

Appendix E provides an indicative description of the RFQ selection process.

The AESO seeks stakeholder comments on the high level summary of the RFQ.

The AESO seeks stakeholder comments on the indicative description of the RFQ selection process.

9.2.3. Request for Proposals

RFQ Respondents who qualify and are asked to submit a proposal as part of the RFP process will be limited to those Respondents who successfully advance through the RFQ stage. The AESO is currently considering limiting the number of Respondents to advance to the RFP stage to three (3). The RFP has been designed to reflect the unique features of Alberta's transmission industry.

Appendix F provides a high level summary of the contents of the RFP document and the indicative RFP selection criteria.

The AESO seeks stakeholder comments on the high level summary of the RFP.

The AESO seeks stakeholder comments on the indicative RFP selection criteria.

9.3. The Selection Panel

The AESO is considering three panels: financial, technical and other (environmental and consultation). Each panel will consist of three members, with expertise in those fora. Members of the selection panels, utilizing the predefined selection process, will evaluate and adjudicate the process related to their specific areas of expertise. Upon completion of the area specific evaluation, all selection panel members will convene to determine the top-ranking Respondents (RFQ) and Proponents (RFP). This group will determine and make its recommendations to the AESO management and the AESO Board as to the Proponents and ultimately, the Preferred Proponent. The AESO will inform the AUC and the Minister of its decision at each stage of the selection process.

The selection of panel members for the RFQ and RFP will be pan-Canadian or internationally recognized experts, preferably with specific expertise in the areas identified and with an awareness of Alberta-specific issues. Panel members will be recruited by external contracts. The AESO Board, upon recommendation by the AESO CEO, will approve panel members.

The AESO will consider seeking nominees for the selection panel members from ratepayer representatives and landowner representatives and those with relevant technical, financial, major construction and electrical

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transmission experience. Individuals from these groups will be chosen based upon the recruitment requirements for panel members.

The AESO seeks stakeholder comments on the selection panel approach.

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10. Next Steps

As indicated in the schedule contained in Section 6.2 of the Paper, the AESO seeks stakeholder comments on the Paper by June 24, 2011. The AESO anticipates filing its Process application with the AUC in September 2011.

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Appendix A

Draft Recommendation Paper – Summary of Stakeholder Comments

The AESO received comments from nine stakeholders on its Draft Recommendation Paper. Responding stakeholders represented incumbent TFOs, transmission developers from within and outside of Alberta and others. The AESO responses to stakeholders can be found in the Draft Recommendation Paper Stakeholder Comment Matrix contained in Appendix B. Stakeholder comments have been categorized into the following five groups and are summarized below; Risk allocation, contract provision considerations, bidding of project components, RFQ selection criteria and other stakeholder comments.

1. Risk Allocation

The AESO sought stakeholder comments on two proposed risk allocation models (Options 1 and 2) that resulted in varying distributions of risk between ratepayers and participants. As a general principle, the AESO seeks to allocate risk to those who can most efficiently and effectively manage risks and therefore minimize costs.

1.1. Stakeholder Comments

Generally, stakeholders were supportive of the goal of more appropriately allocating risk between ratepayers and Proponents within the AESO Own model.

Stakeholders expressed concern that the move from a cost-of-service model to a risk sharing model may result in higher costs to ratepayers over the life of the project since a risk premium would be required. Proponents would face significant timing risks (scheduling, regulatory approvals, and landowner issues), inflation risk, risk associated with an unknown route and therefore unknown geotechnical conditions, operating and maintenance cost change risks and finally, changing financial market conditions risks.

Uncertainty over route at the time of a Proponents bid submission was specifically noted as adding a significant amount of risk and uncertainty to the Process. Stakeholders noted that the AESO does not have authority to select routes but only end points; it is the AUC which determines route selection after the Preferred Proponent has been selected. Route approval occurs during the AUC Facilities Application Process. It was thought that route uncertainty and timing risk may dissuade bidders from participating or may result in a risk premium.

Several stakeholders suggested the Process should allow Proponents the flexibility to determine and propose their own risk sharing alternatives in their RFP submission.

1.2. AESO Response

The AESO recognizes that risk should be allocated between ratepayers and Proponents based on their respective ability to best manage that risk. Based on stakeholder comments, the AESO recognizes that the two options put forward in the Draft Recommendation Paper may not adequately reflect the timing and routing risks associated with the competitive and regulatory processes.

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In the Paper, the AESO has put forward a more balanced risk sharing model that recognizes the bidding process and regulatory constraints and mitigates timing issues and route uncertainty. Section 6. of the Paper describes a more balanced risk sharing model.

The AESO recognizes that compensation for RFP-related costs is appropriate.

2. Contract Provision Considerations

The AESO sought stakeholder comments on the length of contract term and performance specifications.

2.1. Stakeholder Comments

Most stakeholders recommended the contract term align with asset life. Stakeholders also suggested that the Preferred Proponent have a right to renew the contract at the end of its term.

Stakeholders recommended that RFP selection criteria include a consideration of project functional specifications.

2.2. AESO Response

The AESO agrees with a contract term in alignment with the life of the transmission assets. Additionally, contract renewal rights have been considered. A summary of key contract terms can be found in Appendix G.

As indicated in Appendix F, the RFP selection criteria will include an evaluation of a Proponent's ability to meet the project's functional specifications.

3. Bidding of Project Components

The AESO sought stakeholder comments on whether the three stages of the Fort McMurray project should be bid out as one project or whether each stage should be bid out separately.

3.1. Stakeholder Comments

Most stakeholders recommended the Fort McMurray project be separated into two or three stages bid separately. Stakeholders cited more bidder participation, more options, less overall risk and more competition. Several stakeholders recommended that all stages of the project be bid as a single unit. These stakeholders were of the view that a single unit bid would result in economies of scale, process streamlining and regulatory and administrative simplicity.

3.2. AESO Response

The AESO acknowledges the recommendations and further consider splitting the project into an east/west orientation.

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4. RFQ Selection Criteria

4.1. *Stakeholder Comments*

Stakeholders recommended selection criteria include experience in successful landowner relationship development and management, and experience in integrating new projects into existing systems. They also suggested selection criteria not be specific to Fort McMurray. One stakeholder suggested that, since the RFQ was crucial to the overall Process, the selection criteria and selection process must ensure the best evaluation and selection process possible.

Stakeholders suggested that Proponents be reimbursed for costs associated with preparing a proposal as part of the RFP process. They also suggested sanctions be imposed on successful bidders who fail to file an FA with the AUC.

Stakeholders suggested that bidders, once qualified in the RFQ process, should remain qualified for further CTIs.

4.2. *AESO Response*

The AESO has integrated stakeholder suggestions into the RFQ selection criteria as appropriate. A summary of RFQ selection criteria can be found in Appendix E.

Given the potential for an extended time period between the tendering of specific projects, bidders who qualify during a project specific tendering process will not remain qualified for subsequent projects.

5. 5.0 Other Stakeholder Comments

The AESO sought stakeholder comments on any other aspects of the Draft Recommendation Paper.

5.1. *Stakeholder Comments*

The Office of the Utilities Consumer Advocate (UCA) was strongly supportive of the Process and the principle of moving risk to bidders. They suggested benchmarking an incumbent TFO's cost-of-service project against a new CTI project's costs to demonstrate benefits to ratepayers.

One stakeholder recommended a default provider be identified to ensure the successful completion of a project if the Process failed.

One stakeholder suggested that the AESO play a leading role in educating and informing landowners and affected stakeholders about implications for them of the multiple bidder process at the upfront development stage.

5.2. *AESO Response*

The AESO recognizes the interest of ratepayers in the development of the Process for CTI. One of the AESO's goals is to introduce competitive pressures for the benefits of Alberta ratepayers. The AESO, in developing the allocation of risk between ratepayers and bidders, must ensure it does not transfer so much risk to bidders that the resulting risk premiums outweigh the benefits of competition. Likewise, the AESO must also transfer sufficient risk, and risk that is best managed by bidders, to achieve the outcome of optimal cost to ratepayers.

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As shown in Appendix E to this Paper, the AESO has identified and given significant weight to consultation and relationship development and management in the RFQ process.

The AESO also agrees that it should play a leading role in advance of implementing the Process in educating and informing landowners and affected stakeholders regarding the Process, including setting expectations that multiple bidders may be on the ground during the tendering process.

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Appendix B

Stakeholder Comments – Draft Recommendation Paper

1. Risk Sharing Options – Cost Recovery / Pricing Arrangements

The AESO seeks stakeholder comments on other risk sharing options the AESO may consider for the AESO Own model.

Stakeholder	Stakeholder Comment[11]	AESO Replies
AltaLink Management Ltd., in its capacity as general partner of AltaLink, L.P. (AltaLink)	The proposal for a route length adjustment mechanism does little to recognize timing risks associated with initial planning and the regulatory process prior to Permit & Licence. During the stakeholder meeting, the AESO indicated that it would seek commitment of the AUC regarding the duration of the P & L process. Other timing risks are associated with potential legal challenges and delays through the land acquisition process and dealing before the Surface Rights Board, both of which are beyond the control of the AUC. Consideration should be given to some sort of price reopener mechanism in the event of unforeseen delays during the front end process. Consideration should also be given to an alternative mechanism for dealing with O & M risks, particularly the need for maintenance capital and dealing with catastrophic failures due to weather, etc.	The AESO recognizes timing issues arising between submission of a Preferred Proponent's bid, approval of the facilities application by the AUC and contract execution. See Section 7.3 of the Recommendation Paper for refinements to the risk allocation model.
ATCO Electric Ltd. (ATCO)	ATCO Electric does not favor any specific risk sharing option as all options have advantages and disadvantages to both customers and owners. The potential impact of any risk will vary with the project and market conditions at the time of the project. Consequently, bidders should be allowed to propose how the risks should be allocated as part of their offer. This might include alternate pricing if the owner is prepared to accept some or all of the risks. The AESO would then select the offer which provides the lowest cost on a risk adjusted basis.	The AESO recognizes that Proponents may be best able to analyze and allocate risk in developing their proposals. See Section 7.3 of the Recommendation Paper for refinements to the risk allocation model. The AESO will consider a proposal that

[11] Stakeholder comments are verbatim of comments submitted on or before April 28, 2011.

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Stakeholder	Stakeholder Comment[11]	AESO Replies
		deviates from the risk allocation model contained in Section 7.3 of the Recommendation Paper,(i.e., proposals that require risk adjustments to determine value.)
Brookfield Asset Management Inc. (Brookfield)	• As we understand the proposed AESO-Own model, transmitters are effectively being asked to bid a fixed price and guaranteed schedule for an incompletely specified transmission facility to be built at an unknown time in the future. Once it is built, the transmitter will be required to operate it in accordance with future international operating standards for ten to twenty years. It is not yet known what happens at the end of this operating period. • We are not aware of any reasons why the AESO-Own model would not work. In principle, it is no different from merchant transmission with a single long-term customer. • However the 'price tag' seen by consumers, driven by the investment returns required to support the implied level of risk, may result in ratepayer 'sticker shock'. There is a risk the cost may be perceived to be unacceptable compared to what would be payable under cost-of-service rate making. • We would therefore like to explore opportunities to refine the AESO-Own model and to temper 'sticker shock' by: - Reallocating certain risks between transmitters and ratepayers - Reducing overall risk by giving transmitters more opportunity to better define the project prior to completing the competitive RFP	See Section 7.3 of the Recommendation Paper for refinements to the risk allocation model. See Appendix G of the Recommendation Paper for key commercial terms associated with the proposed risk allocation model.
EPCOR	EPCOR continues to support the AESO recommended "Own" model as being most likely to generate bidding interest for these lines. EPCOR remains concerned that there are certain elements of the proposed framework that could increase the overall level of risk associated with delivery of a transmission facility, and so reduce or eliminate the potential benefits of the competitive process. In its initial comments, EPCOR expressed an overriding concern that, structured poorly, any of the proposed models could result in higher costs compared to what we have today. EPCOR's initial concern was that higher contingencies would of necessity be included in all	See Section 7.3 of the Recommendation Paper for refinements to the risk allocation model. See Section 7.2 of the Recommendation Paper for the constraints that impact the Process.

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Stakeholder	Stakeholder Comment[11]	AESO Replies
	bids without first conducting sufficient design and siting work. The AESO proposal has now made it clear that it expects RFP participants to each conduct such work in development of their bids. This approach has its own problems. From a societal perspective, multiple parties carrying out the same work is inefficient. The AESO suggests there would be three to five RFP participants. If development work constitutes 5% of total costs, this represents an additional 10-20% of costs incurred that would not be under the regulated model. If these costs are to be borne by project proponents, the high costs combined with the risk of not being the successful bidder will likely deter proponents from being interested in this project. EPCOR's previous submission suggested that the proposed process be divided in two, and the upfront design and siting component be developed by either the incumbent TFO or a third party under competitive contract. This would serve to both reduce the risk to potential bidders, and minimize the societal costs to do that work. The entity who would be responsible to prepare and have carriage of the Facility Application would have to be resolved along with how the final bid process would factor into the P&L approval.	
LS Power	The risk taken by ratepayers and the risk taken by the developer must be balanced so that the ultimate result for ratepayers is a risk adjusted low cost project. Cost-of-service based pricing, (which inherently carries a risk of disallowance for costs not prudently incurred) places a significant amount of the project risk on the ratepayer and provides less incentive for innovation or cost minimization. On the other hand, fixed price bids from the transmission developer place most of the risk on the developer and require the developer to price this risk into its bid. LS Power believes that fixed price bids will result in higher costs for ratepayers and that competitive pressures may not be enough to overcome the cost of risk premiums. Generally, LS Power believes that the best solution is to allow developers the flexibility to propose their own risk sharing approach when bidding. However, it is understood that varying risk sharing concepts and prices can become difficult to evaluate and bring a certain level of subjectivity into the selection process. LS Power suggests that the AESO consider these additional approaches for sharing risk. As mentioned below, it is difficult to fully comprehend risk sharing options without understanding other contract terms. For example, are major changes that are out of the developers' control considered events of force majeure and handled differently? In all of these risk sharing approaches, LS Power believes that it makes sense to have special provisions for significant events that are beyond the developer's	See Section 7.3 of the Recommendation Paper for refinements to the risk allocation model. See Appendix G of the Recommendation Paper for key commercial terms associated with the proposed risk allocation model. The AESO will consider a proposal that deviates from the risk allocation model contained in Section 7.3 of the Recommendation Paper, i.e., proposals that require risk adjustments to determine value.

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	control. • Price collars The general idea is to ensure developers are incented to perform based on the bid in which they were selected without causing high risk premiums, which would be borne by ratepayers. This approach also incents the developer to outperform its bid and share the upside with the ratepayers. The points below describes one way to approach this concept];. 1. Risk is shared at discrete levels based on developer performance in comparison to its bid. 2. At least three tiers of risk sharing would likely be required (See below for an example.) 3. The AESO establishes the number of tiers, the sharing of risk for each, and the price range in comparison to bid prices for each tier 4. Bidders provide a bid price 5. The AESO would select the lowest risk adjusted price. 6. This approach likely requires the separation of operations and maintenance (O&M) costs from development and construction costs. O&M could be handled in similar manner to project capital costs in this option. For example the AESO could mandate that if actual costs are +/- 10% from the bid that the impact of the change is passed through to ratepayers on a 100% basis (tier 1); if actual costs are +/- 25% from the bid then only 80% of the amount above tier 1 is passed through (tier 2); if actual costs are +/- 40% from the bid then only 60% of the amount above tier 2 would be passed to ratepayers (tier 3); and if actual costs differences are greater than 40% then the only 30% of the amount above tier 3 is passed to ratepayers. • Indexed bids The AESO could expand on the adjustment proposed for route length and allow a bidder to index additional elements of risk. These may include steel prices, aluminum prices, labor rates, diesel prices, schedule, geotechnical findings (i.e. amount of rock), interest rates, and concrete prices. This approach would allow the developer to propose an adjustment factor for	

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	each risk in accordance with those that it can best manage. The AESO would select the lowest risk adjusted bid. One downside to this approach is that it may be more difficult to evaluate. • ROE Adjusters The AESO could propose risk sharing through the use cost of service rates with an adjustment mechanism for the return on equity (ROE), based on the developer's performance in comparison to its bid subject to a ROE floor and ceiling. This approach would significantly reduce risk premiums while incenting bidders to outperform their bids. • Fixed price bid with risk sharing options If the AESO chooses to pursue the fixed price bid option, then it may make sense to allow bidders to provide additional prices for sharing of certain risks. The AESO could then choose what, in its opinion, is the best approach. For example, a bidder may propose a fixed price of X and provide the option for a price of Y if steel prices are indexed, or Z if geotechnical risk is shared.	
NextEra Energy Canada, ULC	NextEra Energy Canada submits that a competitive bid, cost of service model would be effective for Alberta transmission development. NextEra Energy Canada understands that AESO is looking for alternatives to the cost of service model; however unless the risk is appropriately balanced in the cost recovery/pricing arrangements, the ratepayer will ultimately pay for the risk premium that proponents will build into their bids. Even with the cost of development work being recoverable, the ability to provide a fixed-price bid (with or without a unit rate adder for route length) would inevitably lead to a significant risk premium from all bidders. NextEra Energy Canada believes that a competitive process is viable using traditional cost-of-service or performance-based regulation (PBR). AESO could consider using PBR where there are fixed price estimates for all components of the project but profits would depend on the extent to which the actual costs are less than the estimate. This is a flexible model that could be used to incent proponents to control their costs under a cost of service model. This	See Section 7.3 of the Recommendation Paper for refinements to the risk allocation model. See Appendix G of the Recommendation Paper for key commercial terms associated with the proposed risk allocation model.

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	would result in less risk to the ratepayer. Another model that AESO could consider is one proposed by the Ontario Energy Board (OEB). The OEB has proposed a two stage process that lends itself to giving both the regulator and the proponent greater certainty with respect to project costs. In the Ontario model, the process has effectively been divided into two parts; first the development of a given project, and second the construction, ownership and operation of the project. During the development phase, qualified bidders will prepare a bid to be submitted to the Regulator. Once the regulator selects a successful proponent or proponents, the developer can proceed with the certainty of being kept whole for development costs, which is a small part of the overall project cost. Upon the completion of the development stage, the proponent can	
TransAlta Corporation (TransAlta)	The options in most part cover the upfront portion of the costs. The other aspect is the term of the operating phase. We would suggest that transmission facilities have a very long life and even a term of 20 years is short. Perhaps a longer term of 25 or 30 years would also have some financing advantages allowing longer cost amortization and providing more investor certainty. Any contract should consider extensions at the end of term and the basis for such extensions through contractual language included for adjustment formulas and/or negotiations.	See Appendix G of the Recommendation Paper for key commercial terms associated with the proposed risk allocation model.
TransCanada Energy Ltd.	TransCanada is generally supportive of the AESO Own Model. The AESO EPC and TFO EPC model may not allow sufficient incentives for non incumbent transmission providers to participate in the process. TransCanada encourages the AESO to not be overly prescriptive in addressing risk issues. In keeping with the spirit and intent of this process, Qualified Bidders should be encouraged and rewarded for the creativity and innovation in their submissions on identifying and addressing areas of risk. The challenge for the AESO is to create a robust adjudication/review process with the capacity to evaluate bids on a number of relevant criteria including financial, technical,	See Section 7.3 of the Recommendation Paper for refinements to the risk allocation model. See Appendix G of the Recommendation Paper for key commercial terms associated with the proposed risk allocation model. The AESO will consider a proposal that deviates from the risk allocation model contained in Section 7.3 of the

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	environmental, social, and risk mitigation factors. In its earlier submission, TransCanada encouraged the AESO to bring in a qualified independent third party(s) to help develop the competitive procurement process and assess bids received under the RFP.	Recommendation Paper, i.e., proposals that require risk adjustments to determine value. See Section 9.3 of the Recommendation Paper for a discussion on the selection panel.
Utilities Consumer Advocate (UCA)	The UCA agrees with the principle of placing risk with the party most able to mitigate the risk. Consumers are not in a position to mitigate the risks associated with the EPC functions and the UCA agrees with AESO's objective of changing the paradigm of how risk is managed. The UCA also agrees with the AESO assessment that competition will result in bidders accepting risk at the same time as minimizing their bid price. In addition to the international examples provided in Appendix G, Alberta's experience with the PPA auction serves as a local example of entities willing to offer competitive prices while accepting significant risk. The process to develop the PPA contract relied on expert advice to assess the response of potential bidders to the risks which is different from this process where potential bidders are stakeholders with the opportunity to influence the contract terms and resulting risk allocation. In this process, potential bidders are providing the AESO with a sense of how they may respond to specific risk allocations and this is helpful but these stakeholders are also very capable of adapting to the economic environment as demonstrated by the strong responses experienced in the jurisdictions reviewed in Appendix G. The UCA recognizes the significance of this juncture in the development of Alberta's transmission system and encourages the AESO to trust the competitive market to manage risk with adaptability and creativity to produce efficiencies for consumers.	See Section 7.3 of the Recommendation Paper for refinements to the risk allocation model. See Appendix G of the Recommendation Paper for key commercial terms associated with the proposed risk allocation model. See Section 4.3 of the Recommendation Paper for further detail on the expertise retained by the AESO to assist in the development of the Process.

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2. Risk Sharing Options – Cost Recovery / Pricing Arrangements

The AESO also seeks stakeholder comments on all aspects of its cost recovery / pricing scheme including:

- The implied allocation of risk under Option 1 and Option 2
- O&M escalation provisions including proposed indices
- Information the AESO could provide to assist with route estimation in advance of bid submissions
- Performance specifications
- Contract term

Stakeholder	Stakeholder Comment[12]	AESO Replies
AltaLink Management Ltd., in its capacity as general partner of AltaLink, L.P. (AltaLink)	The proposal for a route length adjustment mechanism does little to recognize timing risks associated with initial planning and the regulatory process prior to Permit & Licence. During the stakeholder meeting, the AESO indicated that it would seek commitment of the AUC regarding the duration of the P & L process. Other timing risks are associated with potential legal challenges and delays through the land acquisition process and dealing before the Surface Rights Board, both of which are beyond the control of the AUC. Consideration should be given to some sort of price reopener mechanism in the event of unforeseen delays during the front end process. Consideration should also be given to an alternative mechanism for dealing with O & M risks, particularly the need for maintenance capital and dealing with catastrophic failures due to weather, etc.	The AESO recognizes timing issues arising between submission of a Preferred Proponent's bid, approval of the facilities application by the AUC and contract execution. See Section 7.3 of the Recommendation Paper for refinements to the risk allocation model.
ATCO	• The implied allocation of risk under Option 1 & 2 - Based on our understanding of the options, ATCO Electric has no preference between Option 1 and Option 2. - ATCO Electric favours 10-year periods for a variable O&M agreement. • O&M escalation provisions including proposed indices	See Section 7.3 of the Recommendation Paper for refinements to the risk allocation model. See Appendix G of the Recommendation Paper for key commercial terms associated with the proposed risk allocation model.

[12] Stakeholder comments are verbatim of comments submitted on or before April 28, 2011.

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	- Bidders should be allowed to submit an escalation provision of their choice for labour and materials over the O&M period • Information the AESO could provide to assist with route estimation in advance of bid submissions - ATCO Electric supports AESO providing only information about end points of the proposed route along with a functional spec – consistent with what is provided currently. • Performance Specifications - ATCO Electric supports the use of a functional specification rather than a detailed specification. A functional spec will allow bidders to be more innovative in their proposal - The functional spec should include reliability and availability requirements for the performance of the facilities during the O&M period which are consistent with current TFO standards. • Contract Term - ATCO Electric favours a 40-year contract term to match the lifetime of the assets involved. - The specific treatment of O&M after the initial period has not yet been finalized.	The AESO will include a functional specification for the CTI project in the tender documentation.
Brookfield	The proposed competitive procurement model exposes transmitters to significant risk by requiring them to provide a fixed price and schedule so far in advance of contract award and the completion of development, permitting and construction activities. There are three associated issues: • Not only is the RFP/development/permitting/construction activities time consuming, the time needed to complete them, in the absence of fixed regulatory service times, is uncertain. The overall bid-to-completion process could take as little as four years e.g. Texas, or more than a decade e.g. Wyoming-Jackson Ferry 765kV Project.	See Section 7.3 of the Recommendation Paper for refinements to the risk allocation model. See Appendix G of the Recommendation Paper for key commercial terms associated with the proposed risk allocation model. See Section 9. of the Recommendation Paper

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	• While completing these activities, the transmitter is fully exposed to inflation risk, equipment and labour cost changes, commodity/exchange rate volatility and regulatory changes. • The time taken to complete these activities is generally too long for the transmitter to readily and cheaply hedge these risks with using traditional tools such as fixed price construction contracts, commodity futures, call-off options for equipment etc. This is not to say that transmitters cannot manage these risks, just that the required risk premium may be significant compared to the capital cost of the facilities under traditional cost-of-service rate making. Risk re-allocation – inflation • According to Statistics Canada, annual price inflation measured by CPI has varied between 0.1% and 12.5% over the 40 years since 1971. • Based on this data, the CPI exposure between bid and completion (which could be anywhere between 4 and 10 years, or longer) could be anywhere between 4% and 151%. • It could be argued that ratepayers have a natural hedge against inflation over long periods of time – salaries and benefits tend to rise with inflation through annual pay increases, indexation etc. and asset values such as house prices, tend to track household incomes. • It may therefore be appropriate for inflation risk to be transferred from transmitters to ratepayers e.g. by indexing the transmitter's bid price. • Risk re-allocation – construction and equipment costs • Ratepayers may claim that transmitters are better able to manage construction and equipment cost risk than ratepayers. • The issue for transmitters its that it is difficult to manage these risks by passing them to contractors and suppliers through fixed price contracts because - The specification is incomplete at the time the RFP has to be finalized	for a discussion of the Process procedures.

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Stakeholder	Stakeholder Comment[12]	AESO Replies
	- Construction is so far into the future, an issue compounded by • the uncertain duration of the permitting process • the possibility that standards and regulations may change • obsolescence of selected equipment • the unavailability of futures and forwards with very long maturities ● Ratepayers have a partial natural hedge against construction and equipment costs because - construction is a significant part of the Alberta economy - commodities are a large part of the economy Risk re-allocation – construction and equipment costs (2) ● Three potential approaches to managing this risk include: - Allocating the risk to transmitters and allow them to price it into their bids • The premium may be unacceptable to ratepayers - Allocating the risk partly to ratepayers by indexing the transmitter's price against a suitable index e.g. Electric utility construction price indexes (Table 327-0011) published by Statistics Canada • How accurate is the index? • How relevant is it to conditions in Alberta? • Should prices also be indexed to an Alberta-specific index perhaps derived by AESO/AUC? - Allocating all the risk, other than prudency, to ratepayers by allowing for a pre-construction regulatory cost true-up e.g. Texas	

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	• Socializes cost escalation risk through an existing well understood, fair and transparent process Risk re-allocation – permitting duration • In the absence of prescribed service times, transmitters have little control over the duration of the permitting process provided their application is complete and accurate. In particular, the transmitter cannot prevent an intervener seeking judicial review of a tribunal's decision, and will suffer permitting delay even if the intervener's application is subsequently found to be frivolous and vexatious. • The risk of permitting delays is manifest in three ways: - cost over-runs caused by the project delay; - cost over-runs caused by inflation; and - loss of bonus or exposure to damages by missing project milestones. • Note that although development costs themselves are a risk for transmitters, they are perhaps not the most significant risk. Risk re-allocation – permitting duration (2) • The preferred long-term option would be for regulatory changes to bring time certainty to the permitting process e.g. prescribed timelines for official review etc. • In the short-term and in the absence of regulatory change, there are a number of possible options including: - Making transmitter's costs subject to regulatory cost true-up if the permitting process takes longer than a pre-agreed duration for reasons outside the transmitter's control - What delays are in the transmitter's control? - What prevents the transmitter's offer assuming an unrealistically quick permitting process?	

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	- Assuming ratepayers 'rent' the project from the transmitter for the duration of the permitting process at a pre-agreed $/month rate • Permitting risk is mainly transferred to ratepayers Risk re-allocation – line length • The line length cost risk is relatively small compared to inflation, cost and permitting duration risks. • The AESO-Own model's allocation of line length risk to ratepayers may give transmitters incentives e.g. - the transmitter bases its RFP response on a short route using cheap towers unsuitable for the route and, once selected, changes to a longer route than can be built using the cheap towers; - the transmitter selects an alternative route to get round an unforeseen obstacle where an alternative technology e.g. low height towers, would have given an overall lower cost to ratepayers. • Given that line length is just one factor in the overall cost of a new line, and given the relative size of this risk compared to other risks, it is not clear whether allocating this risk to ratepayers will lead to the best outcome. • Risk re-allocation – counterparty risk (for AESO) • The risk for AESO / ratepayers is that the winning transmitter sees the contract as an option rather than a commitment e.g. - if construction costs do not rise as quickly as the transmitter forecasted when preparing its RFP, it is profitable to go to construction and complete the project; - if construction costs rise faster than forecast, it is more profitable to pay the liquidated damages and abandon the project. • We suggest AESO considers appropriate commercial incentives e.g. bonding	

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	requirements, capitalization, bonuses/damages, transfer of ownership in administration, etc to ensure the project is completed on the terms originally agreed even if this results in the commercially failure of the originally selected transmitter. Risk re-allocation – counterparty risk (for transmitter) • There are two counterparty risks for transmitters: - Credit worthiness of AESO as a counterparty - Risk that project is delayed or abandoned by AESO • As a regulated not-for-profit statutory corporation, AESO's credibility as a counterparty can be readily evaluated. • The risk of project delay is difficult to evaluate. Although Bill 50 provides the need for new CTI, we are not aware of any prescribed in-service dates. The risk for transmitters is that the in-service date is delayed after contract award. • AESO should give some thought in designing the process as to what will happen if future studies determine that the optimal in-service date for a project has changed since contract award Risk re-allocation – O&M costs • Transmitters are required to provide a price, subject to indexation, for operating and maintaining the facilities for the duration of the concession period. The appropriate index has not yet been identified. • We think ratepayers are best able to manage cost inflation risk for the reasons discussed earlier. • AESO should in designing its process give consideration to some additional risks: - Future changes to regulations and standards e.g. elimination of SF6 as an insulator requiring switchgear replacement (many millions $), addition of new animals to the Species at Risk Act, more stringent North American transmission reliability	

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	standards, changes to corporation taxes. Given the very long duration of the concession: - Are these risks more cost effectively managed by the transmitter or ratepayers? - If by transmitters, should O&M costs be subject to routine regulatory review e.g. every fifth year, or should it be on an exception basis; and, if so, what constitutes an exceptional regulatory change? - What are the appropriate performance criteria for the transmitter to meet? - Guaranteed availability over a period sufficiently long to recognize the infrequency of overhaul outages; short-term guaranteed availability e.g. over winter peaks; emergency and force majeure restoration times; electrical losses; long-term, short-term and emergency transfer capacities; etc. Contract Term • Brookfield generally believes that longer contract terms provide better value for ratepayers subject to the term being commensurate with the life expectancy of the underlying asset: in the case of transmission is typically considered to be in the range 30 – 50 years although it is sometimes necessary or economic to replace certain components earlier. • Contract terms in other jurisdictions for similar infrastructure have typically been in range 25 – 30 years with the possibility of limited extensions. • AESO needs to decide whether the contract term includes development, permitting, and construction activities - Inclusion provides the transmitter an automatic bonus/penalty mechanism for schedule deviations; but - Inclusion further exacerbates the effect of permitting delays outside the transmitter's control, increases risks and thus cost to ratepayers • AESO should take care to structure the functional specifications so the facility life	

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	expectancy and contract term are consistent with the long term need After the contract term • At the end of the contract term, there are a number of options: - Transfer the transmission facilities to ratepayers • Who would be responsible for their continued operation and maintenance? - Require the transmitter to continue to operate the facilities under AUC cost-of-service regulation until no longer required • What is the transfer value, if any? • May have tax implications - Invite transmitters to bid on a new 'concession' to refurbish and operate the facilities - Extend the existing contract with/without amendment • For the transmitter, each alternative has its costs and benefits e.g. committing today to operate under an unknown future regulatory regime v. option to reinvest in the future - The competitive process should be designed to capture the net benefit for ratepayers - The NPV of the net benefits is likely to be very small compared to the overall cost - The process should be sufficiently robust to protect future ratepayers' interests while remaining attractive to potential transmitters and preserving the value of the relationship between the transmitter and land owners - The balance would seem to lie towards the transmitter continuing to operate the facilities, assuming they are still required, either under AUC regulation or by contract extension Risk reduction	

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	• The previous pages spoke to opportunities to better allocate risks between ratepayers and transmitters. In addition or instead, there may also be opportunities to reduce project risk. • The main risks inherent in AESO-Own model as we understand it include: - The incomplete project specification used to price the RFP response - The time between submitting a binding RFP response and completing construction • Both these risks could be reduced by allowing transmitters time to substantially complete development work – perhaps up to but not including applying for major permits - prior to submitting their RFP response. • This would allow transmitters to have: - Confirmed the route, taken options on key parcels of land, and determined the need for expropriation (if any) - Completed sufficient technical, survey and geotechnical work to prepare a detailed and comprehensive technical specification - Gained a good understanding of the level of public support and thus the likely duration of the permitting process (or indeed whether permits will even be realistically obtainable) - Entered into fixed price options with equipment vendors and construction contractors - Demonstrated their capacity to complete the project Risk reduction (2) • The cost to transmitters of completing pre-RFP development work will be substantial e.g. $20m - $50m, and this raises some other issues: - Competing transmitters will need to be financially strong (a good thing) - The number of RFP competitors will need to be limited (perhaps limited to 2 or 3) for	

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	the competition to be attractive - Their needs to be a high degree of certainty that AESO will not arbitrarily decide to not award a contract - The RFP process needs to be able to eliminate unrealistically low cost proposals - There will need to be clear public messaging to prevent confusion as multiple transmitters meet with landowners and the public - Transmitters may require substantial honorarium to participate • However, the financial benefits of competition to ratepayers may justify the cost of honorarium • The honorarium could be refunded by liquidated damages payable if the winning transmitter defaults	
EPCOR	In its Recommendation Paper, the AESO proposes two options for allocation of risk. Option one requires bidders to incur all development costs, and include recovery of such costs as much as they believe they are able through their total bid price. Option two separates the development costs from the overall project costs, and suggests the potential for all bidders to recover at least some of their development costs on a cost recovery basis. EPCOR is of the view that the risk perceived by bidders, without some element of cost recovery, will significantly reduce the pool of interested bidders. The risk associated with not doing a good job on the development work is unacceptable, and with the odds of being successful between only one in three and one in five, EPCOR believes that under option one many potential bidders will be unwilling to spend the required funds and so will not participate at all. EPCOR therefore supports some development cost recovery as necessary to attract the largest pool of potential participants. EPCOR advocates cost recovery by bidders up to a cap. EPCOR suggests the cap be set at between two and three percent of the total bid. In making its bid, each bidder also sets the cap for itself for recoverable development costs. This mechanism has two positive attributes. First, the competitive pressures to keep the bid as low as possible will also serve to put	See Section 7.3 of the Recommendation Paper for refinements to the risk allocation model. See Appendix G of the Recommendation Paper for key commercial terms associated with the proposed risk allocation model.

Stakeholder	Stakeholder Comment[12]	AESO Replies
	pressure on the development costs, even though they are outside the scope of the bid. Second, rather than have a fixed recovery amount, the recoverable development costs are adjusted automatically with the size of the project. The matter of the size of the pool of bidders is similar in nature and should also be addressed. The objective should not be to have the largest pool of bidders as possible. The effect of that is to reduce the probability of winning, and so discourage some of them from participating, particularly at the RFP stage where significant resources are committed. The objective should be to have a very highly qualified pool, with a sufficient number of participants to force each bidder to make the best bid possible. More participants than required will incur more costs to rate payers under a development cost recovery model, while the AESO's option one will reduce the quality of the pool of bidders. Three or four bidders is likely sufficient to produce the best or near-best outcome without incurring unnecessary costs to rate payers. Third, EPCOR is concerned that the per km adjustment mechanism is a blunt tool that does not mitigate risk, and therefore costs, as fully as it could. EPCOR suggests that the cost adjustment be determined in conjunction with determination of the route. If the AUC decides to change the route, they will also at the same time determine the associated change in costs. If the AESO is open to such an approach, EPCOR is happy to work with stakeholders to develop a simple mechanism to do so.	
LS Power	LS Power notes that it is difficult to fully comment on the two options without reviewing the full contract. Both options place the majority of the project risk on the developer with the exception of route length. While Option 2 helps to reduce some developer risk it does not address what we believe are the major project risks. From our perspective, the up front development work is one of the easier areas of the project on which to provide a fixed bid because the developer has some direct control over the costs. On the other hand, a developer has little control over things like worldwide commodity prices, labor prices, abnormal weather events, unforeseen subsurface conditions, interest rate trends, etc. Some of these risks can be managed once the project has been awarded and some cannot. For those periods of time when these risks cannot be managed in a cost effective manner and for risks that cannot be controlled, LS Power believes that the risks should be shared between	See Section 7.3 of the Recommendation Paper for refinements to the risk allocation model . See Appendix G of the Recommendation Paper for key commercial terms associated with the proposed risk allocation model. See Section 9. of the Recommendation Paper for a discussion of the Process procedures.

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	the developer and the ratepayer to achieve the best overall value for the ratepayer. LS Power notes that it is difficult to forecast exact maintenance needs especially without long-term historical maintenance information. If long-term predictable pricing is provided, a menu of unit prices for maintenance tasks coupled with an escalator that considers labor rates and general inflation would probably make the most sense. It is not perfectly clear how costs are recovered under the two options identified by the AESO. However, we are assuming that the owner would recover all project costs through the operating and maintenance agreement and over the applicable term. It is very difficult to identify an ideal contract term without understanding post contract conditions. If the intent is that the developer would recover all costs over the contract term with no further recovery other than ongoing operating and maintenance expenses, then LS Power believes that the AESO should consider a contract term longer than 20 years. Typical transmission infrastructure has a useful life well beyond 20 years and is often financed over terms that exceed 20 years. Contract terms of 20 years or shorter may narrow financing options and increase costs to ratepayers on a net present value basis. LS Power suggests a contract term of either 25 or 30 years. However, in our opinion, requiring a developer to provide fixed or predictable pricing for operation and maintenance expenses over such a long term will not be in the interests of ratepayers. An alternative method for handling operation and maintenance expenses is to request fixed pricing for an initial period (5 years for example) followed by cost based pricing or indexed unit price methodology for the remainder of the contract term.	
TransAlta	TransAlta assumes that as part of the long term planning and the CTI designation process that capital cost estimates are developed which in part are based on some review of possible routing options. If the AESO has in mind future area developments of facilities which may connect to the CTI project and which may influence routing then these should be indicated. Such considerations should be provided to the bidders.	See Section 7.3.7 of the Recommendation Paper for a discussion of the Land Research Study the AESO proposes to undertake to aid with route uncertainty.
TransCanada	The Draft Recommendation Paper as currently worded suggests that all bidders under Option 2 would have their development costs reimbursed. Please clarify if this is in fact the case or	See Section 7.3 of the Recommendation Paper for refinements to the risk allocation

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Stakeholder	Stakeholder Comment[12]	AESO Replies
	that only the Successful Bidder would have its development costs covered. Qualified Bidders should be the ultimate determiners of how project risk is incorporated in to their bids. A prescriptive approach from AESO in this regard stifles innovation and creativity that might otherwise deliver the economic efficiencies this process is ultimately trying to achieve. The Recommendation Paper needs to address the risk and impacts of multiple companies, having been deemed Qualified Bidders through the RFQ process, approaching landowners and consulting with stakeholders during the development phase. The AESO should play a leading role in educating and informing the affected stakeholders about the project, explaining the process, and setting some boundaries for the Qualified Bidders regarding consultation in the development phase. TransCanada would encourage consideration of an alternative process that may address this issue. Without prejudicing the ultimate route submitted for permitting, the AESO could contract an independent 3rd party to conduct pre-feasibility studies and propose a theoretical route that all Qualified Bidders would base their bids on. Bids would be comparable on a routing basis and Qualified Bidders would compete on their technology, financial, environmental, social, and risk mitigation decisions. In respect of Route Uncertainty Adjustments, it should be up to each Qualified Bidder to determine whether or not such adjustments would be necessary or to identify the adjustment factor(s) that would be used to address the difference in cost from the pre-bid theoretical route and the actual route which is ultimately permitted by the AUC. It is unclear in the Draft Recommendation Paper as to the Contract Term for capital cost recovery. For financing and capital recovery purposes, the contract term should match the Economic Life of the transmission facility, i.e. 40-50 years. It is also unclear what happens to the assets at the end of the contract term. It is unlikely that Qualified Bidders would support any other outcome other then continued ownership and control of the asset. The AESO should indicate its anticipated approach to dealing with Capital and O&M costs beyond the contract term.	model. See Appendix G of the Recommendation Paper for key commercial terms associated with the proposed risk allocation model. See Section 9. of the Recommendation Paper for a discussion of the Process procedures.

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Stakeholder	Stakeholder Comment[12]	AESO Replies
	It is also unclear as to the Contract Term for O&M cost recovery. The O&M contract should match the Contract Term for capital cost recovery and the AESO should be open to O&M escalation provisions. Qualified Bidders should be left with the decision on how best to incorporate O&M escalation costs in to their respective bids. TransCanada seeks AESO clarification regarding "performance specifications". In general, TransCanada supports the requirement that the Successful Bidder must meet existing reliability and functional design standards but does not support requirements higher than those of existing TFOs today.	
UCA	It appears that the AESO has generally captured the nature and timing of upfront costs incurred by bidders and the UCA expects that the AESO will be able to provide information to bidders that will to some extent mitigate some risk. Some information, such as geotechnical and environmental, will be required by all bidders and the AESO should consider commissioning studies from independent third parties to include in the bid package. The cost of these studies would represent a contribution by customers towards the procurement of transmission development. No warranties could be offered by the AESO but bidders would have a solid foundation of information from which they could make their own decisions to incur costs for additional studies or not. Bid packages provided to qualified bidders should include the most current information available to the AESO in respect of anticipated loading and future customer and system connections. The UCA supports Option 1 for cost recovery to reinforce the principle of predictable pricing and belief in the ability of bidders to manage risks over the life of the project. If the AESO determines that some portion of upfront costs for all bidders should be shared between bidders and customers, then each bid will have to clearly indentify the volume of upfront costs incurred. Upfront costs incurred by the successful bidder would be included in its fixed price bid for the life of the project but those of unsuccessful bidders would need to be quantifiable for cost sharing to occur. The UCA does not currently have a view to the reasonable portion of upfront costs to be shared but does recognize that the AESO tariff mechanism could facilitate such a cost recovery.	See Section 7.3.7 of the Recommendation Paper for a discussion of the Land Research Study the AESO proposes to undertake to aid with route uncertainty. See Section 7.3 of the Recommendation Paper for refinements to the risk allocation model. See Appendix G of the Recommendation Paper for key commercial terms associated with the proposed risk allocation model. See Section 9. of the Recommendation Paper for a discussion of the Process procedures.

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	AESO has proposed the use of indices to adjust operating and maintenance costs over the life of the contract with an initial period identified as 20 years for Option 1 and 10 years for Option 2. Annual escalation factors tied to labour and industrial material indices are common in long term contracts and are generally viewed as reasonable in cost of service regulatory reviews. Where a 10 year review period is suggested in Option 2 the question at the end of the initial term would be what the actual costs have been and whether the indices have been reflective of cost changes over the period. UCA would question whether reviews at 10 year increments would undermine the long term nature of the contract. The overall contract term remains in discussion. The UCA notes the Objectives and Principles listed in section 3.2 and in particular the Process Goals that seek to perpetuate the expected levels of reliability and service that are currently the obligations of TFO's in Alberta. The current obligation of TFO's to serve customers reliably and safely does not have an end date and the expectation is that assets will be replaced in perpetuity. These basic tenets are difficult to mirror in contractual relationships but it is reasonable to expect that the initial contract life would reflect in some fashion the expected physical life of the primary assets being constructed. If that is 35 or 40 years then the expectation is set for both parties to the contract and the expectation of customers will continue that this essential service will remain a utility type obligation even with the revised process for procurement. A long term contract of this nature would necessarily contain provisions for asset transfers through sale or default. Performance expectations are changing continually for the Alberta Interconnected Electric System as physical and market connections with adjacent jurisdictions create changing requirements. The UCA believes it is reasonable to expect that the Alberta Reliability Standards will continue to evolve and the owner/operator of the competitively procured facilities must remain in step with the AIES. The UCA does not currently have a view as to the contractual mechanisms necessary to ensure viability for the owner and quality service for customers.	

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3. Arrangements Arising out of Implementation of the Process

With regard to contractual arrangement arising from the Process, the AESO is seeking stakeholder identification of key project risks and commentary on ways of allocating or otherwise addressing these risks in a fair and equitable manner. With regard to contractual arrangement arising from the Process.

Stakeholder	Stakeholder Comment[13]	AESO Replies
AltaLink	Considerable attention needs to be paid to end of term issues, particularly how any residual value is to be handled. Another key issue will be change of law, which will have to deal with changing regulatory requirements or reliability standards. Emphasis throughout the recommendation paper appears to be on shifting as much risk as possible to the successful proponent. Care must be taken in drafting the contract to ensure risks are allocated to the parties best able to mitigate them. If potential risks cannot be reasonably mitigated by bidders the result could be the unintended consequence of significant risk premiums or a lack of bids. Some of these risks may become significant enough in the future to encourage the successful proponent to simply abandon the project. Separate bids for each stage would allow for adjustments to the process based on lessons learned during the first stage. It would also ensure the projects are a reasonably manageable size, thereby encouraging participation by more potential bidders.	See Section 7.3 of the Recommendation Paper for refinements to the risk allocation model. See Appendix G of the Recommendation Paper for key commercial terms associated with the proposed risk allocation model. See Section 9. of the Recommendation Paper for a discussion of the Process procedures. See Appendix A, Section 3 of the Recommendation Paper for a discussion on bidding project stages.
ATCO	There are many risks that an owner faces in developing and constructing a project. This response will only address material risks that should be discussed between the owner and AESO. Schedule risk is the risk of not completing the project by the planned in-service date. This may occur as a result of • Delay in obtaining landowner or regulatory approvals • Unforeseeable geotechnical or environmental problems are encountered	See Section 7.3 of the Recommendation Paper for refinements to the risk allocation model. See Appendix G of the Recommendation Paper for key commercial terms associated with the proposed risk allocation model. See Section 9. of the Recommendation Paper for a discussion of the Process procedures.

[13] Stakeholder comments are verbatim of comments submitted on or before April 28, 2011.

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Stakeholder	Stakeholder Comment[13]	AESO Replies
	• Construction delays due to unusual weather conditions or labour shortages • Delay in delivery of equipment due to factors beyond the owner's control • An unrealistic schedule that fails to allow adequate float time Capital cost risk is the risk of not completing the project within the approved budget. This may occur as a result of • Lack of information prior to finalization of route and design concept. • Unforeseeable requirements that arise during the P&L approval process • Unforeseeable geotechnical or environmental problems are encountered • Construction cost increases due to unusual weather conditions or labour shortages • Increases in cost of materials due to unexpected changes in global markets Financing risk is the risk of being unable to raise sufficient debt to pay the capital cost or having to pay higher than expected interest on debt. This became a significant issue in the recent recession when long term debt was not always readily available and interest rates for short term debt increased. The current turmoil in global markets makes it extremely difficult to accurately predict interest rates. Project cancellation risk is the risk of AESO canceling the project after the owner has commenced work and prior to the in-service date. This risk can occur if transmission requirements change during the lengthy planning, approval and construction stages. The potential impact of any risk will vary with the project and market conditions at the time of the project. Consequently, bidders should be allowed to propose how the risks should be allocated as part of their offer. This might include alternate pricing if the owner is prepared to accept some or all of the risks. The AESO would then select the offer which provides the lowest cost on a risk adjusted basis.	The AESO will consider a proposal that deviates from the risk allocation model contained in Section 7.3, of the Recommendation Paper, i.e., proposals that require risk adjustments to determine value.
EPCOR	In its verbal comments at the April 14, 2011 stakeholder meeting the AESO suggested the existing legislative framework prevents the AESO expanding its scope of responsibility to	See Section 7.2 of the Recommendation Paper for the constraints that impact the

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Stakeholder	Stakeholder Comment[13]	AESO Replies
	include oversight of that development work. The AESO also expressed a strong preference to not be involved in the route recommendation as being outside of its scope of responsibility. It is EPCOR's view that if this process is intended to be applied on an ongoing basis, the AESO should be willing to explore what changes may be required to the legislative framework and their role in the process if those changes could produce a better result. EPCOR remains of the view that the process be divided in two as previously explained, and changes to the legislative framework or the AESO's responsibilities as required to support this approach be considered.	Process. See Section 7.3.7 of the Recommendation Paper for a discussion of the Land Research Study the AESO proposes to undertake to aid with route uncertainty.
LS Power	Other ways of addressing and allocating risk in a fair manner were suggested in previous comments. Transmission projects of this scope have numerous layers of risks. Some of these risks can be easily managed, but management of those risks comes at a cost. Risks generally fit into the following categories: 1. Development - Route length - Number of angle points (PI's) in route - Permitting - Community opposition - Litigation - Design changes - Changes in law 2. Commodity prices - Steel - Aluminum - Diesel - Concrete	See Section 7.3 of the Recommendation Paper for refinements to the risk allocation model. See Appendix G of the Recommendation Paper for key commercial terms associated with the proposed risk allocation model. See Section 9. of the Recommendation Paper for a discussion of the Process procedures.

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Stakeholder	Stakeholder Comment[13]	AESO Replies
	- Copper 3. Procurement and Construction - Labor rates - Weather - Manufacturing capacity - Design changes - Availability of labor 4. Subsurface Conditions - Rock - Artesian water pressure - Manmade buried debris - Hazardous waste - Non-drillable boulders - High water tables 5. O&M - Labor rates - Cost of transmission line components - Component failure rates - Vandalism and right-of-way dumping rates - System operating conditions - Changes in law - Weather and catastrophic events	

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Stakeholder	Stakeholder Comment[13]	AESO Replies
TransAlta	The cost-of-service regulatory process covers risks by pass through to the tariff process to the ratepayer. A contractual model is entirely different and risks must be foreseen, estimated and included in a proposed payment schedule over the facility life cycle. For example, if adverse weather was to result in catastrophic destruction of numerous kilometers of line then the capital costs of restoration would be the responsibility of the facility owner. Such an owner would need to insure against such risks with an acceptable deductible and recover the premium costs of this insurance through the contract payments. The deductible would remain a risk and require a rate of return to cover this risk increase. The potential future cash calls may also lead to owners funding a reserve for such events and this may be required by lenders. Standard TFO practice is to self-insure in a regulatory model given the risks are borne by the ratepayer. Notwithstanding the above comments, it should not be interpreted that the overall life cycle costs of a competitive project would be more than if the project had been under traditional regulation. Directionally competitive processes have incentives which should lower the initial capital cost and the operating costs of the facilities and as such provide room to cover assumed risks.	See Section 7.3 of the Recommendation Paper for refinements to the risk allocation model. See Appendix G of the Recommendation Paper for key commercial terms associated with the proposed risk allocation model. See Section 9. of the Recommendation Paper for a discussion of the Process procedures.
TransCanada	TransCanada suggests the AESO not be overly prescriptive in addressing risk issues in this process. In keeping with the spirit and intent of this process, Qualified Bidders should be encouraged and rewarded for the creativity and innovation in their submissions on identifying and addressing areas of risk. The challenge to the AESO is to create a robust adjudication/review process with the capacity to evaluate bids on a number of relevant criteria including financial, technical, environmental, social, and risk mitigation factors. Consistent with its earlier submission, TransCanada encourages the AESO to bring in a qualified independent third party(s) to help assess bids received under the RFP.	See Section 7.3 of the Recommendation Paper for refinements to the risk allocation model. See Appendix G of the Recommendation Paper for key commercial terms associated with the proposed risk allocation model. The AESO will consider a proposal that deviates from the risk allocation model contained in Section 7. of the Recommendation Paper,(i.e., proposals that require risk adjustments to determine value.) See Section 9.3 of the Recommendation

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Stakeholder	Stakeholder Comment[13]	AESO Replies
		Paper for a discussion on the selection panel.
UCA	No further comment	

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4. Fort McMurray Project Components Subject to Bid

The AESO seeks stakeholder comments, including advantages and disadvantages, on whether the stages of the project should be bid out as one project or whether each stage should be bid out separately.

Stakeholder	Stakeholder Comment[14]	AESO Replies
AltaLink	Separate bids for each stage would allow for adjustments to the process based on lessons learned during the first stage. It would also ensure the projects are a reasonably manageable size, thereby encouraging participation by more potential bidders.	See Appendix A, Section 3 of the Recommendation Paper for a discussion on bidding project stages.
ATCO	ATCO Electric believes there should be one tender package that would include all three stages of the project. This would allow proponents to bid on any or all of the three stages. One project would simplify contract administration and coordination between potential multiple owners as well as possibly streamline the approval process. One project could reduce costs through economies of scale. For example, common permitting and overhead costs will not be duplicated by several owners.	See Appendix A, Section 3 of the Recommendation Paper for a discussion on bidding project stages.
Brookfield	Options for staging Fort McMurray • The proposed Fort McMurray project as described in the draft functional specification comprises three separate lines and associated terminals at an approximate cost of $¼bn , $¾bn and $¾bn respectively with proposed in-service dates of 2017, 2019 and 2021. • In assessing whether Fort McMurray should be let as a single, phased contract or two/three separate contracts, AESO should consider: - The opportunities for capturing economies of scale if the three contracts are let as a single package - The risk of letting a project of this size as a single project using an untested process - The willingness of suitably qualified investor/constructors to take on a project of this	See Appendix A, Section 3 of the Recommendation Paper for a discussion on bidding project stages.

[14] Stakeholder comments are verbatim of comments submitted on or before April 28, 2011.

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Stakeholder	Stakeholder Comment[14]	AESO Replies
	size - The benefit to ratepayers from attracting additional resources and innovation by having to or three separate projects • Our initial view, in the absence of a detailed RFP contract specification, would be to subdivide the work into two projects (east and west). - This limits exposure if the process does not work properly; and - If there are true economies of scale, then the same transmitter should win both projects allowing ratepayers to benefit	
EPCOR	Finally, the AESO seeks stakeholder views on the packaging of the Fort McMurray projects. It is EPCOR's view that a balance of risk mitigation and size sufficient to attract international participants is appropriate. Accordingly, EPCOR suggests that the project be offered to bid in two segments – one for each line. EPCOR also suggests that a separate pool of bidders into the RFP process for each segment be considered in order to mitigate operational risk should a single successful bidder fail.	See Appendix A, Section 3 of the Recommendation Paper for a discussion on bidding project stages.
LS Power	There are a number of advantages to bidding the project stages separately. While the project stages are similar in geography and scope there may be some developers that bring specific advantages to one stage that they don't bring to the other. This may include landowner relationships or other specific knowledge that reduces the pricing and risk. Further, if the project size becomes too large, there is a possibility that competitive pressures will decrease because the number of entities willing to take this level of risk may be small. In addition, contracting with multiple developers may reduce counterparty risk. One possible disadvantage to contracting the phases separately is the loss of economies of scale. As the project becomes larger, the developer has more buying power and can transition staff from one phase to the next. However, because the phases are spread out over time and they are relatively large in scope, LS Power does not believe the economy of scale disadvantage outweighs the advantages of bidding the phases separate.	See Appendix A, Section 3 of the Recommendation Paper for a discussion on bidding project stages.

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Stakeholder	Stakeholder Comment[14]	AESO Replies
TransAlta	We would suggest that 1A and 1B be combined as a single project. We would suggest separate bids for each project. Given the stated in service dates of the various projects being 2017/2019 and 2021 we are concerned of the ability of proponents to bid prices on work with such distant future in service dates. The second project is ten years in the future. Any bid would need to have numerous escalators to cover equipment, materials and labour costs so as to cover such risks for the bidder.	See Appendix A, Section 3 of the Recommendation Paper for a discussion on bidding project stages.
TransCanada	TransCanada's view is that the project should be bid out as one project and awarded as a lump sum basis in order to retain cost efficiencies and ensure efficiency in meeting AESO technical and operational requirements. TransCanada supports the requirement that the bid estimates be broken out according to project phases. Evaluation should be done on each component of the bid, and not solely on total project cost basis..	See Appendix A, Section 3 of the Recommendation Paper for a discussion on bidding project stages.
UCA	The UCA does not have a position on this issue at this time.	

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5. Draft Recommendation Paper – Other Comments

Do stakeholders have any other comments regarding the Draft Recommendation Paper?

Stakeholder	Stakeholder Comment[15]	AESO Replies
Alberta First Nations	The 2009 *Long-Term Transmission System Plan* prepared by the Alberta Electric System Operator ("AESO") states that: The oilsands industry is expected to continue its growth and is the primary driver of the need for new electricity infrastructure development in the northeastern part of Alberta. Electrical demand is driven by facilities associated with the extraction, upgrading and refining of bitumen from the oilsands into synthetic crude. The specific facilities being recommended for this reinforcement are a 500 kV AC line from the Genesee generating station to a new 500 kV substation in the Fort McMurray area, and a 500 kV AC line from the new Heartland substation to the new Fort McMurray 500 kV substation. The total estimated capital cost of the project is $2,045 million (in 2008 dollars). Construction is planned to begin in 2010 with all facilities in service by 2016. According to the DRP, the AESO is seeking feedback from various stakeholders and intends to implement the new competitive process for the first Critical Transmission Infrastructure ("CTI") project which consists of two single circuit 500 KW transmission facilities from the Edmonton region to the Fort McMurray region. We currently represent a group of First Nations which are signatories to Treaty 6 and Treaty 8 and whose constitutionally protected *sui generis* rights and interests in land may potentially be adversely affected by the Alberta Government's expansion of CTI in northeastern Alberta. We will be working with all First Nations whose reserve lands and traditional territories are traversed by the proposed CTI projects with a view toward creating a consortium of First	See Appendix E, RFQ Selection Criteria, for a discussion of the various selection criteria and proposed weightings associated with selecting Proponents who will move to the RFP stage of the Process. See Appendix F, Proposed Structure of the RFP, for a discussion of proposed selection process to select the Preferred Proponent.

[15] Stakeholder comments are verbatim of comments submitted on or before April 28, 2011.
[16] Competitive Process for Critical Transmission Infrastructure – Draft Recommendation Paper. March 31, 2011. Prepared by E. Moore [Appendix E - Selection Criteria (h)].

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Stakeholder	Stakeholder Comment[15]	AESO Replies
	Nations who share two key goals: (1) a desire to engage in appropriate consultations with the AESO on behalf of the Government of Alberta to avoid or minimize any adverse impacts on their Aboriginal and Treaty rights that could potentially be caused by the projects; and (2) to maximize economic benefits and opportunities in relation to training and employment, procurement and construction contracts, and the development of partnerships that will facilitate the First Nations' ability to build, own and operate CTI through their traditional territories to generate a long-term sustainable source of revenue for these historically disadvantaged communities. There can be no doubt that the exercise of First Nation's Treaty rights on lands along the proposed transmission corridors have remained important to their members since time immemorial, not only for the preservation and maintenance of their livelihood, but also their cultural identity. As the Supreme Court of Canada has clearly articulated in a number of decisions, any *prima facie* infringements of Treaty or Aboriginal rights must be accommodated so that they are impacted by government conduct and activities as little as possible, if at all. Further, the activities flowing from CTI development projects through the traditional territories of the First Nations inevitably engage the Crown's legal duty to participate in meaningful consultations with, and where appropriate, accommodate the interests of adversely affected First Nations. The expansion of transmission infrastructure into the traditional territories of First Nations has, and will have, potentially serious impacts on the continued exercise of constitutionally guaranteed Treaty or Aboriginal rights. Connection to the electrical system has played an integral role in the development of oilsands projects on both a small and massive scale. As the DRP states, oilsands development remains the key driver for the investment of an estimated $2.1 billion to expand "Critical Transmission Infrastructure". All of this development comes at a huge cost to the environment with cumulative impacts that threaten biodiversity and the health of wildlife, fowl, and fisheries habitat which First Nations necessarily depend upon for the exercise of their Treaty rights to hunt, fish and trap. We trust that all parties involved in CTI development and regulation are conscious of both the broad scope and potentially harmful nature of the immediate and/or cumulative effects faced by First Nations communities which are directly or indirectly caused by the establishment of	

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Stakeholder	Stakeholder Comment[15]	AESO Replies
	transmission facilities that foster oilsands development in Alberta. While some developers have engaged with First Nations located adjacent to their projects, it is regrettable that such consultations rarely generate tangible economic benefits for affected communities. More often than not, large scale industrial developments simply leave an environmental blight on the land and only serve to widen the economic gap between First Nations and other Albertans. In light of the scope and magnitude of the proposed upgrades to the transmission system in northeastern Alberta, it is essential that the AESO and industry proponents engage affected First Nations in a meaningful process of consultation and accommodation of their rights, interests and concerns. The status quo for consultations with First Nations is usually ad hoc and characterized by irregular and sporadic negotiations between industry proponents and individual First Nations who lack sufficient resources to adequately assess and articulate the potential impacts on their rights and interests or the expertise to capitalize on economic benefits and opportunities in such projects. This process has proven to be both unpredictable for proponents and regulators, and inherently unfair to First Nations, who in many cases are expected to engage and carry on such negotiations with little or no resources. Accordingly, and in the interest of infusing an element of certainty into what is currently a flawed strategy for reconciliation with First Nations, we are proposing to seek accommodation in the form of a process that will facilitate First Nation's ownership and substantive economic participation in the development and operation of future CTI projects in Alberta. Up until this point in time, the possibility of long-term facility ownership of CTI by First Nations communities has been foreclosed by the operation of what has remained a government-regulated oligopoly. We submit that this regime has not only been inefficient and costly to Albertans, but it has also operated in a manner contrary to public policy which dictates that First Nations who exercise treaty and Aboriginal rights upon their traditional lands should derive some substantive benefits from developments that traverse their territories and diminish the exercise of their rights. Notwithstanding this and the fact that discussions surrounding CTI expansion have generally occurred without real consideration of Treaty rights and Aboriginal interests, we are optimistic that the AESO's stated mandate to inject competitive pressures into the transmission marketplace through an open and fair bidding process for CTI expansion may afford an opportunity for First Nations to formulate	

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Stakeholder	Stakeholder Comment[15]	AESO Replies
	partnerships with established private sector developers to bid on and ultimately win the right to build, own and operate transmission facilities in Alberta. While we acknowledge that competitive procurement of transmission facilities is a complex undertaking with financial, regulatory and engineering implications, we are confident in our ability to partner with an experienced and qualified industry proponent that has the capacity and expertise to develop ("up-front"), build, finance, own and operate CTI in Alberta. We submit that any initiative undertaken by a First Nations-led consortium or transmission facility owner ("TFO") in the forthcoming CTI projects would offer advantages to the ratepayer in the form of Federal and Provincial programs that make funding available on a cost-effective basis, as well as potential tax advantages that decrease the cost of construction and ongoing operations. Further, we note that a significant amount of goodwill would be developed on behalf of the AESO and the electrical infrastructure sector at large if First Nations are invited to the table not as obstacles to the expansion of CTI, but rather as enthusiastic partners and proponents of these important infrastructure projects. As proponents, First Nations communities would be able to seize the opportunity to exercise their right of self-determination and generate reliable, long term sources of revenue to their communities in the form of AUC-regulated rate base payments, training and jobs during the construction phase of the projects, and the opportunity for careers in the operation and maintenance of CTI assets. Such revenue sources would invariably place significant capital in the hands of First Nations communities and promote economic spin-offs that would benefit and stimulate Alberta's economy well into the foreseeable future. While these advantages are remarkable, they remain modest relative to the unique benefit a First Nations consortium or TFO is capable of delivering with respect to securing timely access to large tracts of land that are crucial to CTI development. By directly involving First Nations with *sui generis* rights to the land, as equity owners, the current risk of protracted battles occurring between First Nations and CTI proponents over regulatory and environmental approvals would be either considerably mitigated or avoided altogether. In this regard, we would submit that First Nations' participation at the ownership level effectively fosters, and to some extent, even embodies a crucial aspect of the "regulatory predictability", which both the AESO and all commenting stakeholders have thus far identified as a	

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Stakeholder	Stakeholder Comment[15]	AESO Replies
	paramount "Process Goal". The advancement of regulatory predictability for CTI by First Nations communities in this context would be largely unprecedented but could provide a model for future developments of major infrastructure projects in Alberta and the rest of Canada. Moreover, when secured by the expertise of an experienced industry partner (which we are already seeking out), we are certain that an exceptionally efficient TFO could be created that would pose no threat to the integrity of Alberta's existing interconnected system; indeed, we feel confident that a First Nations' led proposal will also offer the AESO the opportunity to build these projects under budget and on-time, thus offering Albertans a reduction in their rates. As the possibility of equity ownership in CTI by First Nations communities brings with it an exceptional means to advance the competitive expansion of CTI in Alberta, we would comment on the structure of the bidding process that would ultimately support such an undertaking. At this time we understand that the AESO is currently developing the evaluation criteria associated with the selection criteria for each of the Request for Qualifications ("RFQ") and Request for Proposal ("RFP") documents to be used in the Process. We understand further that the AESO is currently comparing the advantages and disadvantages of utilizing a weighted scoring system against those of a gated pass-fail system and considering further, the use of a possible hybrid of these two schemes. Based on the all of the foregoing, we submit that at least some element of a weighted scoring system should be utilized. Further, we would recommend that considerable weight should be given and merit assigned to any proposal by a qualified TFO which supports substantive economic participation by First Nations communities. While we note that evidence of a TFO's plans to conduct consultation with a variety of stakeholders (including First Nations) in the proposed project area is currently within the RFQ selection criteria,[16] we feel that lumping First Nations in with "other relevant stakeholders" fails to appreciate or acknowledge the value that First Nations can add to the efficient and predictable development of new CTI in Alberta. For this reason, we would suggest that the existing criteria within the RFQ which identifies First Nations be amended. Accordingly we propose that First Nations be appropriately recognized as the holders of *sui generis* rights that are recognized and protected by the Constitution. This could be easily	

Stakeholder	Stakeholder Comment[15]	AESO Replies
	achieved by providing First Nations with an enumerated criteria that gives additional weight to any competitive process that provides for substantial participation by First Nations in the form of (1) training and employment opportunities; (2) procurement and contractual set asides during the design and construction phase of the projects; and (3) equity participation. Further, we would suggest that this selection criteria shift in focus from seeking evidence of a respondent's plans to conduct mere "consultation" with First Nations, to seeking evidence of a respondent's plans to facilitate substantive economic participation by First Nations. In ascending order, we would propose that graduated weight should be awarded based on compliance with the following sub-criteria, or similar forms thereof: ▪ Evidence of the respondent's plans to offer economic participation to First Nations communities by way of facilitating or providing substantive training and long-term employment opportunities; ▪ Evidence of the respondent's plans to offer economic participation to First Nations communities by way of providing First Nations with "set aside" opportunities within an Aboriginal procurement scheme; and, ▪ Evidence of the respondent's plans to offer economic participation to First Nations communities by way of equity ownership facilitated through a partnership, joint venture or similar arrangement. Further, the higher the percentage of ownership, the more weight should be attributed to this criterion.	
AltaLink	During the stakeholder meeting, the AESO indicated an intention of limiting the RFP to three participants following the RFQ process. There is merit in considering the AESO underwriting at least a portion of the substantial cost of participating in the RFP process.	See Appendix D and E of the Recommendation Paper for a discussion on honoraria.
ATCO	AESO is seeking comments on Appendix D With regard to Proponent Security, please clarify what is meant by a responsive bid in Clause	See Appendix G of the Recommendation

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Stakeholder	Stakeholder Comment[15]	AESO Replies
	7. A comprehensive bid (compliant or not) that is consistent with the intent of the RFP should be all that is required to receive reimbursement of the payment under Clause 7 (a). ATCO suggests that the second payment be returned upon confirmation the bidder is unsuccessful or when the bidder enters into a contract with the AESO. If the bidder fails to enter into a contract in accordance with its proposal, then the second payment should be forfeited. AESO is seeking comments on other selection criteria for the RFQ, see Appendix E Clarity is required on the RFQ process, including definition of what is required from interested parties to meet the expectation of the RFQ. Other criteria for the RFQ could include • Evidence of respondent's successful experience in obtaining landowners' consent and all regulatory approvals for similar projects Evidence of respondent's successful experience with integrating a similar project into an interconnected electrical system and successfully operating the project thereafter.	Paper for key commercial terms associated with the proposed risk allocation model. See Appendix D and E of the Recommendation Paper for a discussion on honoraria. See Section 9 of the Recommendation Paper for a discussion of the RFQ.
EPCOR	EPCOR has some additional general comments to make as well. First, the AESO has on occasion suggested that a bid for a life cycle project provides opportunities to mitigate risk because of the extended term. In EPCOR's view, this is incorrect. If the successful bidder makes a mistake in its bid, that effect will be realized and will not be mitigated, though it may occur over an extended period. Just as the bid will be determined on a discounted basis, so too will any loss resulting from a poor bid be immediately recognized on a discounted basis. Second, there are many competitive advantages that are appropriately brought to bear in preparing a bid, such as balance sheet, expertise, innovative ability, etc. However, there are others that should not be. For example, incumbents with similar facilities have an advantage in economies of scale for spares. EPCOR expects that some form of inventory sharing could and should be facilitated between the incumbent TFOs and the prospective project owner.	The AESO continues to maintain its view that the AESO Own model best meets the principles and objectives for the Process. The AESO will take into consideration EPCOR's suggestion regarding inventory sharing.
TransAlta	TransAlta generally reiterates in the left column the comments made in the comment matrix	See Section 7.3 of the Recommendation

Stakeholder	Stakeholder Comment[15]	AESO Replies
	submission of November 2010. We, in part, carry them forward given the generality of the provided responses. We believe that even with the OWN process there also needs to be included the concept of a default provider which would be the incumbent TFO(s) under the traditional cost-of-service regulated model. The benchmark for competitive procurement is the results expected from the regulated model and competitive procurement must provide a better life cycle result than the default or benchmark approach. TransAlta asserts the Policy, Legislation and the AESO, as implementer of the Policy and Legislation, must be clear as to the problems which are to be remedied by a competitive process rather than the traditional regulatory process and which problems could not be dealt with by either modifications to the traditional regulatory process or by adherence to the tools already provided by the regulatory process. We were pleased during the April 14th information session to find out that the AESO contemplates providing a draft contract as part of the process as this will add certainty to the bid process and shorten and/or eliminate any negotiation process during final selection. We would further ask that this draft contract be made part of these consultations such that market participants may comment on it. As well, during the information session it was indicated that consideration is being given as to how many proponents will be selected from the RFQ process to continue to the RFP process. We believe all qualified proponents should proceed to the RFP. The demonstrated capability and capacity of the proponent to obtain construction financing for non-regulated projects of the size and for the period required would appear to be an important selection criteria. Given an incumbent TFO is eligible in Step 2, how does the AESO plan on ensuring that the preparation of the RFQ is not a cost to be recovered through the regulatory process and that such costs are at the risk of the shareholders of the TFO? The analogous process was that for the Purchase Power Arrangements (PPA) except that the facilities in question already existed. We would suggest that the AESO study that process and inform themselves of the ongoing issues with substituting a long term contract in place of traditional regulation. It must be remembered that the PPA process was undertaken to	Paper for refinements to the risk allocation model. See Appendix G of the Recommendation Paper for key commercial terms associated with the proposed risk allocation model. See Section 3. of the Recommendation Paper on legislative amendments and the implications for the AESO. See Section 4.3 of the Recommendation Paper for benchmarking considerations. See Section 9. of the Recommendation Paper for a discussion of tendering procedures. See Section 6. of the Recommendation Paper for a discussion of affiliate rules.

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Stakeholder	Stakeholder Comment[15]	AESO Replies
	deregulate generation. TransAlta believes it is important that the AESO is clear on the intent and likely outcomes of competitive procurement. Competitive Procurement is being advanced as a solution or remedy to a perceived problem and implicitly that perception is that the traditional approaches to transmission are not working. Is deregulation of the bulk transmission system the intent of the Competitive Procurement process? It should be expected that if the Selected Entity is to take on increased risks than a traditional TFO then the rate of return requirements will increase. We wonder how a TFO who has both traditionally regulated transmission and an “Own Contract” will ensure separation of their regulated and unregulated businesses. Financial engineering is stated as a key driver for cost minimization. This assertion was provided without proof or evidence. Project financing is more expensive than balance sheet financing and requires higher interest rates given the non-recourse nature of such financing. The AESO should provide information on the relative merits of financial engineering to the traditional rate approach. The risk sharing has to be designed not only on the development and construction phase but for the operational and maintenance phase for the transmission facilities. The tradeoffs between capital costs and operational costs must be considered. The creation of a contract which will be viable and fair over the 30 to 50 year life of transmission assets is challenging and time consuming. To expedite any process involving such a contract a draft contract will have to be provided to qualified bidders prior to bidding to allow pricing consistent with the terms and conditions of the contract and the risks and uncertainties inherent in a long term contract. Implicit in structuring a “contract” outside of regulation which allows “financial engineering” is an underlying assessment that existing regulation and rates of return are deficient. Advocating such an approach is tantamount to deregulating transmission except for the	

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Stakeholder	Stakeholder Comment[15]	AESO Replies
	routing approvals. The AESO and the DOE need to consider if bifurcation of transmission into coexisting regulated and unregulated facilities is prudent. If regulation is not producing the required outcomes then regulation needs to be changed rather than having carved out processes which may be both disruptive and counterproductive. Section 26 of the Transmission Regulation already requires that transmission facilities be constructed by “a TFO or other person” using competitive tenders. Is it the assessment that Section 26 is ineffective in obtaining competitive costs for transmission facilities and that a new process is required? If it is ineffective in that it does produce the desired results, then what needs to done or changed so the process is effective? Prudency of capital expenditures must compare the initial forecast cost estimate and the actual as-built capital costs. Such prudency testing may result in such capital cost increases either being disallowed or allowed a lower rate of return on the increased portion.	
TransCanada	TransCanada is concerned that the RFQ requirements are too “project specific” and believe that requirements for a Project Development and Execution Plan should be included in the RFP, but not at the RFQ stage. TransCanada encourages the AESO to consider a more generic RFQ process. In other words, once a bidder is “qualified” they should remain qualified for other competitions as long as they maintain their qualifications. This is similar to the Ontario Energy Board process which has already completed an “RFQ” process and has designated Qualified Bidders as “Licensed Transmitters”. The time frame for the RFQ is currently set to occur over the summer months. TransCanada is concerned that potential bidders will not be aware of the RFQ during this time frame or will not be able to respond during July and August due to vacations etc. The Recommendation Paper and RFP should consider the terms for project cancellation, delay in project need, scope changes and force majeure. The Recommendation Paper should also include a template contract for stakeholder review.	See Section 9. of the Recommendation Paper for a discussion of the Process procedures. See Appendix G of the Recommendation Paper for key commercial terms associated with the proposed risk allocation model.

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Stakeholder	Stakeholder Comment[15]	AESO Replies
UCA	The Draft Recommendation Paper does not describe where in the Process a comparison would be made between a benchmarked TFO cost of ownership and the costs of a contract with a successful bidder from the Process. The AESO has indicated that benchmarking will form part of its preparation for the introduction of Competitive Procurement. The UCA believes a discussion of the analysis and the application of the findings in the Process should be included in the Recommendation Paper. The UCA see this as the most meaningful way to demonstrate the value Competitive Procurement is bringing to Alberta electric consumers.	See Section 3. of the Recommendation Paper on legislative amendments and the implications for the AESO. See Section 4.3 of the Recommendation Paper for benchmarking considerations.

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Appendix C

Power Advisory Report

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Review of Experience with Competitive Procurement for Transmission Facilities

Prepared for:

Alberta Electric System Operator

December 14, 2010

Power Advisory LLC

poweradvisoryllc.com
978 369-2465

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1. Introduction and Purpose

Under the *Electric Statutes Amendment Act* (ESA Act), introduced in November 2009, the Government of Alberta is responsible for approving the need for critical transmission infrastructure (CTI). In addition, based on changes implemented by the ESA Act, the Lieutenant Governor in Council (LGIC) may make regulations regarding who may apply to the Alberta Utilities Commission (AUC) for authority to construct and operate transmission facilities. The determination regarding who may apply may be made based on a competitive process or some other method or process.

CTI must be developed in a timely and cost-effective manner. In anticipation of the application of a competitive procurement process for the selection of the party to construct and operate the CTI, the Alberta Electric System Operator (AESO) is developing such a process.

Power Advisory LLC (Power Advisory) was engaged by the AESO to assist it in evaluating the experience in various jurisdictions with the application of competitive procurement processes for transmission facilities, focusing in particular on Texas and the United Kingdom (UK). This report reviews the experiences in Texas and the UK and provides insights that the AESO can employ with respect to developing a process for the competitive procurement of transmission facilities.

1.1 Contents of This Report

This is Power Advisory's review of the experience with competitive procurement processes for transmission facilities. The first chapter is this introduction and reviews our relevant experience. The second chapter reviews the potential role of the entity selected by the AESO in the competitive procurement process (Selected Entity) with respect to the CTI project. Chapter 3 reviews Texas' experience with competitive renewable energy zones. Chapter 4 reviews the UK's experience with competitive procurement of transmission facilities that are built to interconnect offshore wind projects to the UK grid. Chapter 5 briefly reviews the competitive framework developed by the Ontario Energy Board for selecting transmitters that will be designated to develop network transmission facilities. Chapter 6reviews at a high level the framework employed in Brazil for the competitive procurement of transmission facilities. Chapter 7 summarizes our findings and reviews considerations associated with the design of a competitive procurement process for Alberta.

1.2 Relevant Experience of Power Advisory

Power Advisory offers extensive experience with respect to transmission investment analysis and the development and evaluation of competitive procurement frameworks for electricity resources. We reviewed the Electric Reliability Council of Texas's (ERCOT's) competitive renewable energy zones (CREZ) framework for the Ontario Energy Board (OEB or Board) as part of its transmission connection cost recovery review proceeding. In addition, we assisted the OEB with the development of its transmission project development planning process under which licensed transmitters will compete for the right to develop (and ultimately construct and own) transmission facility expansions. For this project we reviewed the criteria that were employed by the Public Utility Commission of

Texas (PUCT) for the selection of transmission service providers to build the required CREZ facilities and also reviewed the framework employed by the United Kingdom's Office of Gas and Electricity Markets (Ofgem) for selecting the parties that would own and operate transmission facilities to connect offshore wind projects to the UK grid. In addition, team members have evaluated proposals to build transmission facilities across North America, including Alberta, and to better integrate these jurisdictions. Team members have also identified barriers to the development of major transmission facilities and outlined policies to address these barriers for Natural Resources Canada. Finally, we have assisted with the development or evaluation of over twenty competitive procurement frameworks for energy facilities.

2. Possible Role of Selected Entity with Respect to CTI Project

In its Discussion Paper (Competitive Procurement Process for Critical Transmission Infrastructure), the AESO outlined two alternatives that resulted in significantly different roles for the Selected Entity, i.e., the party selected by the AESO pursuant to its competitive procurement process. While these alternatives are initial proposals, they are reviewed here because they provide useful context with respect to the processes that were or are being employed in Texas, the UK, Ontario and Brazil.

In the first alternative (the "Own Alternative"), the Selected Entity would enter into a contract with the AESO to design, finance, build, own and maintain the CTI project. The Selected Entity would also prepare and file a Facility Application (FA) with the Alberta Utilities Commission (AUC) for approval. As part of this effort, the Selected Entity would secure land access and obtain rights-of-way for the facilities. The payments made by the AESO to the Selected Entity would be recovered from transmission system users pursuant to AESO's market rules and tariffs.

Under the second alternative (the "EPC Alternative"), the AESO would administer a competitive tender process to select an entity that would essentially provide EPC services for the CTI project. The Selected Entity (known as "EPC Entity" under this alternative) would design and build the CTI project and then transfer the project to the incumbent Transmission Facility Owner (TFO), in exchange for payments from that TFO pursuant to the EPC Contract. Once the project has been placed into service, the incumbent TFO would be remunerated for its costs of owning and operating the project under its AUC approved cost of service. The EPC Entity and the incumbent TFO would coordinate regarding the preparation and filing of the Facility Application.

3. Review of the Texas Competitive Renewable Energy Zones

3.1 Overview of CREZ

As part of a major effort to promote the development of wind energy, Texas developed Competitive Renewable Energy Zones (CREZs) to identify geographic regions with significant wind potential, and to develop the transmission investment required to realize that wind resource potential. The specific objectives of establishing CREZs were to:

- ensure that sufficient transmission infrastructure is built to meet the State's goal for renewable energy;
- improve the coordination between the construction of transmission facilities and the associated renewable generation facilities; and

- avoid duplication in determining the need for new transmission facilities (e.g., between the CREZ case and any subsequent Certificate of Convenience and Necessity (CCN) proceeding).

The CREZ Rule promulgated by the PUCT outlined the process that would be used to designate the CREZs. The CREZ framework expedited the process by which new transmission projects serving renewable energy resources may be approved by the PUCT and reduced the risk that a utility's construction of transmission to serve a potential wind zone might be challenged as not providing benefit to the utility's customers. The identification of CREZs also reduces the development risks for renewable generation by ensuring the development of the transmission required to deliver the output of that generation to loads within Texas.

The PUCT outlined the rationale for CREZs as follows:

> "The rapid development of wind power in West Texas since 2001 has shown that wind farms can be built more quickly than transmission... This timing difference poses a dilemma for planning: it is difficult to know whether a new transmission line will be needed if the generation facilities do not yet exist, but a wind farm is difficult to finance if there is no certainty that sufficient transmission will be available. Senate Bill 20 is an effort to solve this dilemma by authorizing the Commission to identify areas with sufficient renewable energy potential, identify the transmission facilities that could serve the area, and establish the need for new transmission facilities serving the area, even if no specific renewable generation projects exist or are under construction."[1]

The PUCT conducted two rulemakings with significant public participation and conducted three evidentiary hearings. The first two hearings designated the CREZs (i.e., established the zones to be developed) and CREZ Transmission Plan (CTP) (i.e., identified the specific transmission facilities that would be built to realize the wind potential in these zones). The third hearing designated the Transmission Service Providers (TSPs) that would develop and own the transmission facilities included in the CTP. As part of rulemakings, the PUCT followed its typical practice of issuing draft rules and providing opportunities for parties to comment on the rules. Under such rulemakings the PUCT typically issues draft rules, receives comments from interested parties on the draft rules, and reply comments in which parties respond to comments offered by other parties. In addition, the PUCT typically conducts a public hearing at which parties are invited to comment on the rule. Upwards of fifty parties participated in these proceedings. Ultimately, twenty one parties filed statements of interest indicating their intent to file a CTP proposal.

3.2 Institutional Context

The majority of Texas (about 85% of electric load) participates in a market that is overseen by the Electricity Reliability Council of Texas (ERCOT). Unlike most other competitive markets, ERCOT doesn't administer a formal market for the purchase and sale of energy. ERCOT does oversee a balancing energy services market which is used to address variations between the balanced demand and supply schedules provided by market participants and their actual requirements and deliveries.

[1]PUCT, Need for Transmission and Generation Capacity in Texas: Renewable Energy Implementation and Costs, December 2006, p. 14.

ERCOT also oversees various ancillary markets that support the bilateral market.[2]The energy traded through the markets administered by ERCOT represents a relatively small fraction of the total demand in ERCOT. Since ERCOT is located entirely within Texas, it is exempt from FERC oversight or regulation.

The ERCOT market is one of the most competitive wholesale power markets in North America. New generation development since the market was restructured in 1995 has provided about 41,000 MW of capacity, representing almost half of all capacity.[3]

The PUCT oversees the ERCOT market and serves as the market monitor. The PUCT also reviews proposals for the construction of new transmission facilities.

Texas has a renewable portfolio standard (RPS) of 5,880 MW of renewable capacity by 2015 and a target of 10,000 MW by 2025. Given a favourable wind resource, federal renewable energy production tax credit of 2.1 cents/kWh and a market where natural gas-fired generation is the marginal resource for the vast majority of time, there has been considerable wind project development. Transmission congestion in west Texas has become an increasing important issue over time and alleviating this congestion was a critical driver in the CREZ process. As of December 31, 2009, Texas had 8,916 MW of wind capacity in operation, with over 900 MW added in 2009.[4]During at least one period in 2009, wind generation served 25% of customer load.[5]

Transmission costs are paid by load, except for direct interconnection costs which are assigned to the interconnecting generation. The costs of CREZ-related transmission will be rolled into ERCOT-wide transmission rates and paid by load. Transmission is priced using a postage stamp rate, with rates uniform regardless of location.

3.3 The CREZ Framework

Under Senate Bill 20 the PUCT was required to designate CREZs throughout the state and to develop a plan to construct the transmission necessary to deliver the output from renewable energy technologies in these zones. The PUCT directed ERCOT, in its role as coordinator of transmission planning and analysis for the ERCOT region, to complete a study of possible transmission improvements and to provide estimates of the transmission capital costs and forecasted system benefits from the designation of different areas in the state as CREZs. ERCOT (through a consultant with expertise in this area) first identified the areas of the state that contained the best wind resources. Those areas, their wind generation potential, and the expected costs of associated transmission that would be required to develop that generation were identified in a report filed with the PUCT (CREZ Transmission Alternatives Report).[6]The various transmission plans were developed through an open stakeholder process that sought to accommodate many of the potential zones in various combinations.

[2] ERCOT also administers transmission access and coordinates transmission planning.
[3] ERCOT, *2009 Annual Report*, p. 2
http://www.ercot.com/content/news/presentations/2010/2009%20ERCOT%20Annual%20Report.pdf
[4] ERCOT, *2009 Annual Report*, p. 3.
[5] ERCOT, *2009 Annual Report*, p. 8.
[6]ERCOT, "Analysis of Transmission Alternatives for Competitive Renewable Energy Zones in Texas", December 1, 2006.
http://www.ercot.com/content/news/presentations/2006/ATTCH_A_CREZ_Analysis_Report.pdf

ERCOT then identified specific transmission upgrades that would allow varying levels of new wind generation to be installed in these areas of significant wind potential.

The enabling legislation specified the criteria to be used by the PUCT in establishing the CREZs as: (1) sufficiency of renewable energy resources and land areas to develop renewable generating capacity from renewable energy technologies; and (2) the level of financial commitment by generators for each potential CREZ. To assess the level of financial commitment the PUCT indicated that it would consider "existing development, signed and pending interconnection agreements (IAs) for units not yet in service, fees paid by generators for interconnection studies, executed leasing agreements with landowners, voluntary letters of credit assuring the developer's intent to build in the CREZ."[7,8]

Using these criteria, the PUCT designated as CREZs five zones (McCamey, Central, Central West, Panhandle A, Panhandle B) that were identified in the CREZ Transmission Alternatives Report. These five zones are identified in Figure 1 below. To assist in identifying the desired transmission improvements, the PUCT requested ERCOT to perform a "CREZ Transmission Optimization Study". This study identified five alternatives which ranged from $2.95 billion to $6.38 billion and would interconnect from 12,053 to 24,859 MW of wind generation.[9,10]

[7]PUCT, "Rulemaking Relating to Renewable Energy Amendments" (CREZ Rulemaking), December 1, 2006, p. 4.
[8]Developers are required to take service under the CREZ transmission facilities within one year of notification by the TSP that the facilities can accommodate the output of the facilities. Developers risk forfeiting any collateral if they fail to take service within 12-months of such a notification, unless they receive an extension from the PUCT.
[9] ERCOT, CREZ Transmission Optimization Study, April 2, 2008. Included within these CREZ capacity totals is 6,903 MW of existing wind generation or projects that had signed interconnection agreements. Found at: http://www.ercot.com/news/presentations/2008/index
[10]The original CREZ Transmission Optimization Report was a planning-level evaluation to identify which areas of Texas were best suited to the expansion of wind generation and what transmission infrastructure would be necessary to transmit the generation capacity in those regions to the population centers of the state. The study included very preliminary cost estimates and designated the general locations of substations and transmission routes from a planning-level perspective. As a planning study, it didn't consider actual rights of way and estimated transmission line costs on a standard per unit cost for each facility rating. The cost estimates were also in 2008 dollars. The costs estimates did not include any financing costs or contingency allowance.

Figure 1

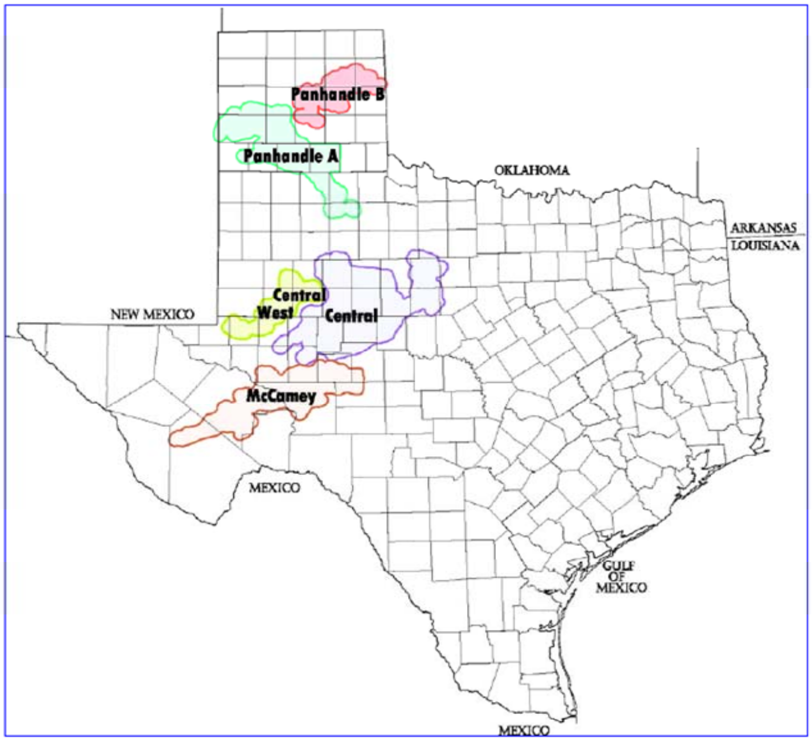


Figure 1: Competitive Renewable Energy Zones

A fundamental element of this process was to promote competition in the construction and ownership of these projects. The PUCT sought to encourage new entrants given the magnitude of required investment, the scope of the required facilities and short time frame for placing the projects into service. The PUCT also believed that new entrants would promote innovation and spread the risks associated with this required level of investment.

Therefore, the PUCT also instituted a rulemaking to set the criteria for selecting the transmission service providers (TSPs) that would build and own the transmission projects identified in the CREZ Final Order.[11] These criteria are reviewed below. The framework outlined by the PUCT required a prospective TSP to first demonstrate that it has the ability to construct, operate and maintain the facilities. With these criteria established and the corresponding rules adopted, parties interested in constructing CTP projects filed expressions of interest with the PUCT. The PUCT then selected the TSPs employing the criteria that it developed. The selection of TSPs took about 12 months from issuance of the criteria to selection.

Once a preferred TSP is selected for a specific CTP facility that TSP must prepare and file the CCN required for that project. After the TSP files the CCN application, generation developers in the relevant CREZ must post a letter of credit or other collateral equal to 10% of their share of CREZ

[11] http://www.puc.state.tx.us/rules/subrules/electric/25.216/34560adt.pdf

facility costs.[12] If this requirement isn't satisfied then the PUCT can reconsider the CREZ designation.[13]

The CREZ Final Order also identifies a set of transmission improvements, the cost of which will be rolled into the uniform transmission tariff. "Each new or upgraded line will be identified by voltage level, and by where the line will connect to the existing grid. Some of the transmission improvements may not be in close proximity to the intended development, and may serve purposes in addition to facilitating renewable energy development in the zone. The order will also include an estimate of the maximum generation capacity that the CREZ can accommodate once the improvements identified in the order are in service."[14]

The TSP may propose modifications to the parameters included in the CREZ order if its study reveals alternatives that would reduce costs or increase the amount of generating capacity that the transmission improvements for the CREZ can accommodate.

3.4 Criteria for Selecting TSPs

The PUCT established a multi-step process to select the TSPs to build the CTP facilities. First the PUCT initiated a proceeding inviting the interested TSPs to file CTP proposals. For existing CTP facilities that required an upgrade or modification, the existing owner of the facility was the Designated TSP for the CTP facility, unless the owner requested that a different Interested TSP be selected or good cause existed to select another transmission service provider. For new CTP facilities, the PUCT selected a Designated TSP based on the criteria discussed below.

The rules for selecting the TSPs specify that they will be selected based on the interested TSP's:

- "current and expected capabilities … to finance, license, construct, operate, and maintain the CTP Facility or Facilities in the most beneficial and cost effective manner and the expertise of the Interested TSP's staff,
- projected capital costs and operating and maintenance costs for each CTP Facility,
- proposed schedule for development and completion of each CTP Facility,
- financial resources,
- expected use of historically underutilized businesses unless the Interested TSP is an electric cooperative or municipally owned utility, and
- understanding of the specific requirements to implement the CTP Facilities in its CTP Proposal and, if applicable,
- previous transmission experience and maintenance costs for its existing transmission facilities."[15]

The rules also require that the prospective TSPs provide:

- "a description of the interested TSP's CCN process;

[12] This financial security is ultimately returned to the generation developers if they build their project and connect to the network.
[13] Rule 25.17 (c)(6)
[14] CREZ Rulemaking, p. 5.
[15] http://www.puc.state.tx.us/rules/subrules/electric/25.216/25.216.pdf

- a general description of the proposed structure, conductor types, and right-of-way;
- the projected in-service date;
- the type of resources contemplated for licensing, design, engineering, material and equipment procurement, right-of-way and land acquisition, construction, and project management;
- the type of resources contemplated for operating and maintaining each CTP facility;
- the capability and experience of the TSP to comply with all on-going scheduling, operating, and maintenance activities required;
- resumes for key management personnel;
- a demonstration that the TSP's business practices are consistent with good utility practices for proper licensing, designing, right-of-way acquisition, constructing, operating, and maintaining CTP facilities;
- a summary of law violations found or current investigations;
- the estimated direct costs to construct representative structures;
- a detailed estimate of the anticipated average annual operating and maintenance cost;
- the actual average direct operating and maintenance cost if the TSP is an incumbent utility;
- the overhead rate for managing third-parties and the willingness to maintain the overhead rate;
- the TSP's preexisting procedures and historical practices, or a detailed description of the plans for acquiring right-of-way and land and managing right-of-way and land acquisition for transmission facilities;
- the TSP's preexisting procedures and historical practices, or a detailed description of its plan for mitigating the impact of transmission facilities on affected landowners and for addressing public concerns regarding transmission facilities;
- a proposed financial plan that confirms the TSP has adequate capital resources and no significant negative impact on the creditworthiness or financial condition will occur as a result of the construction, operation, and maintenance of the CTP facilities;
- an affidavit by an officer stating that the information in the application is true and that the TSP will comply with the rules and PURA (Public Utility Regulatory Act);
- other evidence the TSP provides supporting its selection; and,
- unless the TSP is an electric cooperative or municipally owned utility, a description of the use of historically underutilized businesses."[16]

The PUCT also requested utilities to indicate the cost of financing $100 million (municipal utilities) and $500 million (privately held) of debt given their credit rating for 1, 3, 5, 10 and 30 year terms. Interestingly, the privately held TSPs were also required to indicate their proposed return on equity if they were selected. The rules also specify additional financial criteria and general requirements including how investment grade status is established and requiring a summary of any history of bankruptcy, dissolution, merger or acquisition of the TSP.

[16]http://www.puc.state.tx.us/rules/subrules/electric/25.216/34560adt.pdf, p. 4 as sited in http://www.lcra.org/library/media/public/docs/energy/crez/PUCFinalOrder.pdf, p. 4

The PUCT summarized the financial factors considered as:

- "the current and expected capabilities of each interested TSP to finance, license, construct, operate, and maintain CTP facilities in the most beneficial and cost-effective manner;
- each interested TSP's projected costs for financing, construction, and operation and maintenance;
- an interested TSP's average direct operating and maintenance costs-per-mile of same-voltage transmission lines during the last five calendar years (when applicable);
- an interested TSP's estimated overhead rate for managing third parties (when applicable); and
- each interested TSP's current and projected financial resources."[17]

The PUCT also noted that

- "regarding each TSP's current and projected financial resources, of particular concern are each TSP's demonstration of available, adequate resources to finance requested CTP facilities;
- a TSP's current credit rating by a nationally recognized credit agency (when applicable); and
- whether each TSP's creditworthiness or financial condition would suffer a significant negative impact as a result of its being assigned varying sizes of CTP facilities."[18]

3.4.1 Other Criteria for Specific Types of CTP Projects

While considerable weight was given to the financial capability of the prospective TSP and its demonstrated ability to secure appropriate financing, consideration was also given to (i) balancing financial requirements with available resources, (ii) the selection of multiple TSPs for the projects and (iii) the proximity of facilities to each other and resulting economies. The order issued by the PUCT doesn't specify the relative weights applied to these different considerations, which are further discussed below.

Given the magnitude of required investment and current financial market conditions, the PUCT recognized "the importance of striking the proper balance between selecting a large pool of TSPs to participate in the CTP in order to spread financial risk, introduce novel technologies, and diversify sources of skills and materials against selecting a small number of TSPs in order to avoid unnecessary complexity and coordination difficulties".[19]

The PUCT also noted that "given the current economic climate and the strong qualifications of many of the interested entities in this docket, the proper balance will be struck through the selection of several incumbent TSPs as well as the strongest new entrants."[20]

The PUCT also sought to assign geographically proximate projects to the same TSP when possible. The PUCT noted that

> "Ensuring that each selected TSP's projects are close together (or in the case of incumbent TSPs, are at least close to their pre-existing service areas) provides several advantages. Economies of scale can be better employed. For example, multiple

[17] http://www.lcra.org/library/media/public/docs/energy/crez/PUCFinalOrder.pdf, p. 8.
[18] http://www.lcra.org/library/media/public/docs/energy/crez/PUCFinalOrder.pdf, p. 8.
[19] http://www.lcra.org/library/media/public/docs/energy/crez/PUCFinalOrder.pdf, p. 9.
[20] http://www.lcra.org/library/media/public/docs/energy/crez/PUCFinalOrder.pdf, p. 9.

> facilities can be addressed by a single service center. Additionally, the difficulties of coordinating with multiple TSPs during the planning, certification, construction, and operation and maintenance stages will be reduced. Furthermore, the TSPs will not be required to familiarize themselves with multiple regions of the state."[21]

The PUCT also considered the size and resources of the TSP relative to the facilities to be assigned. The PUCT noted that its

> "allocations of CTP facilities should reflect each TSP's demonstration of significant experience with large-scale energy projects, the capacity to finance a large CREZ assignment without a significant negative impact on creditworthiness or financial condition, the importance of experience working with landowners and other members of the public to reach mutually beneficial arrangements, and the capability to expand their operations to include CTP facilities promptly and effectively. While the size of an interested TSP's current service area was considered when applicable, this was not the sole determining factor used by the Commission when determining the appropriate total amount of each TSP's assignment."[22]

3.5 Selection of TSPs

3.5.1 Overview of PUCT Process

The cost of service for the CREZ facilities will ultimately be established when the TSPs file for recovery of the costs of the facilities after the start of commercial operation. At this point the PUCT will evaluate the prudence of the construction costs of these facilities, as necessary. As a result, the Interested TSP's proposed costs of constructing the CREZ facilities was given less weight in the PUCT's selection process. Interested TSP's were required to identify which CREZ facilities they sought to build and the estimated costs of building these facilities. From this information PUCT staff was able to calculate the construction cost/mile of the CREZ facilities that each Interested TSP was proposing to build. This information was considered by the PUCT when selecting TSPs. TSPs are required to provide firm cost estimates and project schedules six months after the CCN is approved. These cost estimates and project schedules will be monitored and TSPs will be required to explain material variances from these estimates.

The PUCT's primary consideration in the selection process for TSPs was their financial capability.[23]Given the magnitude of required investment, the PUCT sought broad participation in the development and construction of the CREZ facilities. Only one new entrant wasn't selected given concerns with its financial capability. Based on guidance provided by new entrants, the PUCT believed that they required an investment of approximately $500 million to make participation in the process sufficiently attractive. To some degree facilities were allocated to incumbent TSPs based on their financial capabilities with less well capitalized TSPs being allocated a smaller share of the facilities.

[21]http://www.lcra.org/library/media/public/docs/energy/crez/PUCFinalOrder.pdf, p. 10.
[22]http://www.lcra.org/library/media/public/docs/energy/crez/PUCFinalOrder.pdf, p. 10-11.
[23] Phone call with Brian Almond, Director of Transmission Analysis, Public Utility Commission of Texas, November 19, 2010.

For much of this period, TSPs financial capabilities were constrained by the ongoing financial crisis. As a result, TSPs ability to fund major new investment was limited by available cash, lines of credit, and limited borrowing. This increased the need for participation by a greater number of TSPs.

3.5.2 TSPs Selected

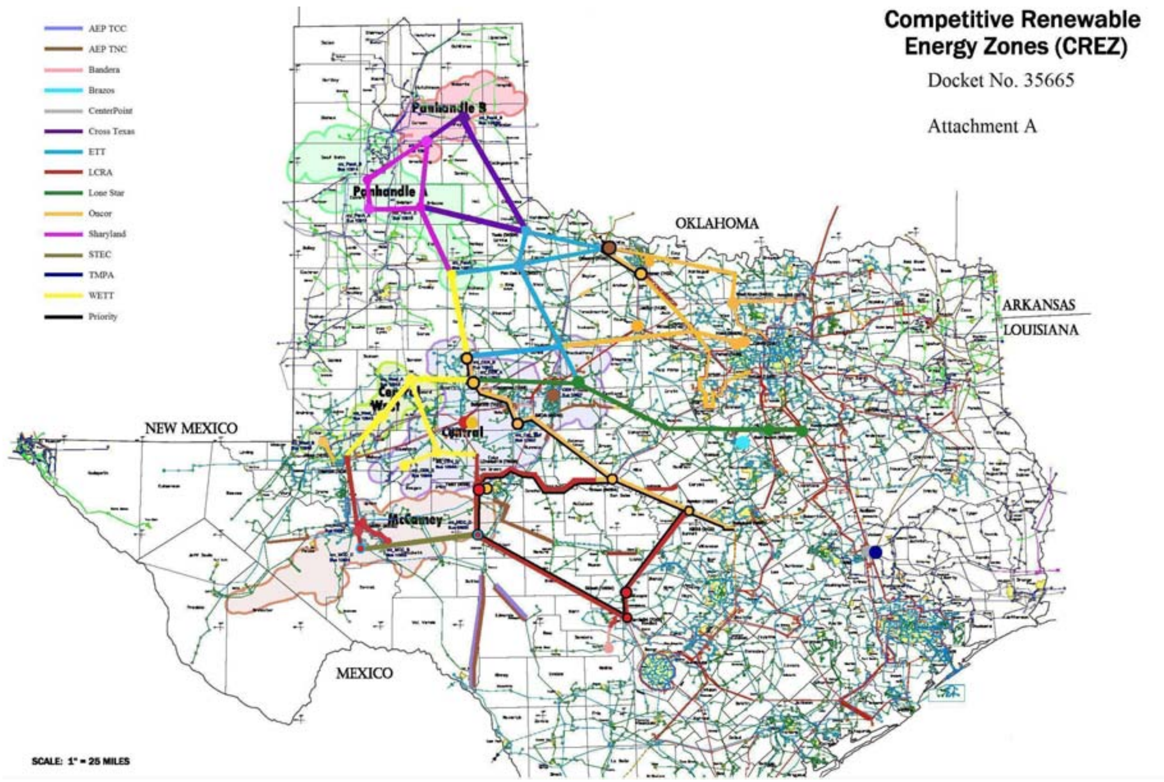
On May 15, 2009, the PUCT issued its Order on Rehearing selecting the TSPs that would be responsible for developing and constructing the various CTP facilities.[24] Fourteen different entities were selected to develop and construct various segments of the CTP facilities. Only one party that sought to develop and construct these facilities wasn't selected. It was an affiliate of Babcock & Brown whose share price declined precipitously and debt was downgraded below investment grade.

Three categories of CREZ projects were identified in Docket No. 33672: Default Projects; Priority Projects; and Subsequent Projects. Default Projects are those projects that refit, rebuild, or enhance existing transmission infrastructure. These projects were awarded to the TSPs that owned the existing infrastructure. A number of the CREZ Default Projects have been completed and others are in various stages of completion. The CREZ Priority Projects are those necessary to alleviate current or projected transmission congestion issues and were determined to have the highest priority for completion. The CREZ Priority Projects were awarded to two incumbent utilities, Oncor Electric Delivery LLC (Oncor) and LCRA Transmission Services Corporation (LCRA TSC). The CREZ Subsequent Projects consist of the remaining CREZ transmission projects not identified as either Default or Priority.

The major CTP facilities and the TSP that was designated to build them are identified in Figure 2. Responsibility for specific projects in the CTP was assigned to AEP Texas Central Company, AEP Texas North Company, Bandera Electric Cooperative, Brazos Power Electric Cooperative, CenterPoint Energy Houston Electric, Texas Municipal Power Agency, LCRA Transmission Services, Oncor Electric Delivery Company, Cross Texas Transmission, Electric Transmission Texas, Lone Star Transmission, Sharyland Utilities, South Texas Electric Cooperative, and Wind Energy Transmission Texas. Four of these entities can be considered new entrants: (1) Cross Texas Transmission is part of the LS Power Group, a generation and transmission project developer; (2) Electric Transmission Texas is a joint venture of subsidiaries of American Electric Power (AEP) and MidAmerican Energy Holdings Company, which are vertically integrated electric utilities with AEP having electric service territories in Texas; (3) Lone Star Transmission is a subsidiary of NextEra Energy, Inc., the competitive renewable and clean energy subsidiary of FPL Group which also owns FPL, a rate regulated utility that operates in Florida; and (4) Wind Energy Transmission Texas which is a joint venture between Brookfield Asset Management and IsoluxCorsanConcesiones, S.A., a subsidiary of IsoluxCorsan Group, a large Spanish engineering, construction services and real estate development firm.

[24] Parties to a proceeding are able to request a rehearing. Therefore, the PUCT issues an order on rehearing restating its decision when such requests are made.

Figure 2



3.6 CCNs and Project Development Process

With some exceptions for the enhancement of existing infrastructure, a TSP must submit its application for a transmission project to the PUCT in order to receive a CCN which allows the TSP to proceed with construction of the project and to exercise the power of eminent domain where necessary. CCN applications are contested cases that generally focus on the transmission line route that will be selected from the alternative routes proposed by the TSP. There isn't a separate environmental assessment process at which environmental issues will be considered. CCN applicants are required to identify one route as their preferred route. The PUCT may approve the CCN application by selecting one of the routes, approve it in part, or deny the application. The PUCT is statutorily required to process applications for CREZ-related CCNs within 180 days of receipt of a complete application. This expedited deadline helps to accelerate the development of those facilities and reduces the financial risks to the TSP. Once the PUCT issues an order approving a route for a transmission project, the TSP may then proceed to acquire the necessary right of way (ROW).

A majority of the CREZ Default Projects did not require a CCN and have proceeded to completion or are in the process of being completed. All of the CREZ Priority and Subsequent projects required CCN applications. With the exception of one project, which is pending, all of the CREZ Priority Project CCNs have been resolved and are proceeding toward ROW acquisition and construction. Similarly, all CCNs for the Subsequent projects (with the exception of one) have been approved by the PUCT and are proceeding towards ROW acquisition and construction. For the one application for a Subsequent project that was denied by the PUCT, ERCOT has subsequently determined that alternative enhancements to existing transmission infrastructure could substitute for the construction of the line in the short term. The Commission is currently studying ERCOT's alternative proposal to determine if the project is still needed.

PUCT staff indicated that all of the new entrants have performed well and brought new ideas and approaches that yielded savings. In particular, one new entrant proposed spun concrete poles which reduced construction costs, accelerated construction schedules and reduced siting issues with affected landowners. With the PUCT mandated to approve or disapprove CCNs for CREZ facilities within 180 days (rather than the one year deadline typical for other projects), the PUCT organized two workshops for the new entrant TSPs to review CCN filing requirements and also provided a pre-filing review of the routing description, given its importance to the CCN process.

3.7 Differences between CREZ and Alberta CTI

There are fundamental differences between Texas' CREZ and Alberta's CTI. The CREZ was a comprehensive resource planning, investment analysis, facility selection and transmission service procurement process. The CTP facilities will represent $5 billion (US$) in investment in numerous separate, but interconnected transmission facilities. The CREZ process took five years from the passage of Senate Bill 20 to the filing of CCNs. A schedule of the CREZ process including the various critical PUCT decisions is provided in Appendix A.

The CREZ process was focused on enabling the required investment and significant volume of construction activity to occur over a compressed time period. The focus was on attracting capital during a time significant financial constraints and promoting innovation through the introduction of new entrants. The net result is that 14 different parties were designated as TSPs for the relevant facilities. By enabling broad participation with respect to the permitting, construction, ownership and operation of the CTP facilities, there was little competitive tension. Savings were provided by innovation rather than reductions in the cost of capital through the application of project finance.

The PUCT played a central role in the CREZ process and was assisted by ERCOT given its role as transmission planner for the market area. The AESO's role in the competitive procurement of the CTI is more limited, with a focus on determining a person who is eligible to apply for, and who ultimately assumes responsibility, in whole or in part, for all or some of designing, constructing, financing, owning and operating the new CTI.

4. UK: Regime for Tendering Offshore Wind Transmission Investment

This chapter reviews the process and decision criteria that are employed by the Office of Gas and Electricity Markets (Ofgem), the UK electricity and gas regulator, to select transmission companies to own and operate the high voltage offshore transmission facilities that are required to integrate the expected generation from offshore wind facilities.

Electricity generated from offshore wind projects is expected to make an important contribution to the achievement of the UK's share of the European Union's target of generating 20 per cent of energy from renewable sources by 2020. To enable the development of these generation resources, the requisite offshore electricity transmission infrastructure must be developed in a timely and cost-effective manner.

One of the initial steps in this process was the awarding of offshore leases by The Crown Estate who is responsible for administering Crown-owned land in the UK. The Crown Estate announced the first round of UK offshore windfarm development in December 2000. This first round was intended serve as a "demonstration" round, enabling developers to gain necessary experience. The projects that were awarded contracts in the first round, nine projects totaling 2,064 MW, are identified in Table 1. Following the success of this first round the Department of Trade and Industry (DTI) requested The Crown Estate to begin a competitive tender process for a second round of larger sites in July 2003. Fifteen projects representing 7.2 GW were awarded Crown Estate Agreements for Lease in this second round. In June 2008, The Crown Estate announced proposals for the third round of offshore leases for windfarms totaling 32.2 GW which are targeting providing 25% of the UK's electricity requirements by 2020.

Table 1: First Round Offshore Wind Projects

Project Name	Size (MW)	Status/COD
Barrow	90	Operational
Robin Rigg East and West	180	Operational
Gunfleet Sands 1 & 2	164	Operational
Sheringham Shoal	315	April 2011
Ormonde	150	March 2011
Greater Gabbard	504	November 2010
Thanet	300	May 2010
Walney 1	178	October 2010
Walney 2	183	August 2011
Total	2,064	

Source: Ofgem

The UK Department of Energy and Climate Change (DECC) and Ofgem have estimated that the transmission infrastructure investment to interconnect these three rounds could represent up to £15 billion, over $23 billion US at current exchange rates.[25] Given the magnitude of potential investment, the UK Government found that a more dynamic approach was required to develop the transmission infrastructure and sought "an open, competitive approach that is built on encouraging innovation and new sources of technical expertise and finance."[26] Ofgem notes that it "consulted extensively on the design of the competitive Tender Process".

Ensuring that the process was as competitive as possible was a primary concern. To this end, Ofgem precluded any exclusive relationships with critical equipment venders who could otherwise forestall competition and National Grid was precluded from participating. Ofgem noted that it would be difficult to police such a requirement.

[25] http://www.ofgem.gov.uk/Networks/offtrans/pdc/cdr/cons2009/Documents1/Main.pdf
[26] http://www.ofgem.gov.uk/Networks/offtrans/pdc/cdr/cons2009/Documents1/Main.pdf

4.1 Key Issues for Ofgem's Tendering Process

One of the critical issues for the tendering process developed by Ofgem was to ensure sufficient coordination between the offshore generation project developer who created the need for the offshore transmission facilities, the prospective bidders, and the National Electric Transmission System Operator (NETSO) who is responsible for determining how these facilities would connect with the existing transmission grid. These offshore transmission facilities are the sole means by which the generation project developer will be able to deliver the project's renewable energy to the grid so these facilities must be in-service on a timely basis and be reliable.

In response, Ofgem and the DECC developed and introduced a new regulatory regime for offshore electricity transmission. A key part of the new regime is that offshore electricity transmission licenses will be granted following a competitive tender process run by Ofgem. In essence, in the transitional regime the successful bidders will receive a transmission license which allows them to provide transmission services and an entitlement to an associated 20 year revenue stream in return for purchasing the transmission assets from the offshore wind generator and operating them in accordance with the obligations of the license.

The competitive tender process employed by Ofgem will result in the grant of an offshore transmission license to the successful bidder. Offshore transmission licenses include a number of special conditions which set out the specific obligations and rights of the licensee. These define, among other things, the revenue stream that the Offshore Transmission Owner (OFTO) will receive for 20 years.

Under the transitional arrangements employed for rounds one and two, generation developers construct transmission assets which are then transferred to an OFTO selected through Ofgem's tender process. Hence, construction risks remain with the generation developer. The developer transfers ownership of the completed transmission asset to a licensed OFTO at a price set by Ofgem based on the cost to construct following an assessment of costs. Ofgem assessment is of "the economic and efficient costs of developing the assets to be transferred for each project."[27] This assessment is necessary because these costs are not subject to the same competitive tension as they would be under the enduring regime. Therefore, for transitional projects, the role of the OFTO is to finance, own, maintain and operate an asset that has been or will be constructed by the generator developer.

Under the enduring regime that is being employed for round three, an OFTO will have the option to design and construct offshore transmission assets as well as financing, operating, maintaining and owning them or to just finance, operate or maintain the facilities.

4.2 Overview of the Process

Based on the experience in the transitional regime, Ofgem is considering amending the key stages of the enduring tender process. In order to ensure that costs are minimized for all parties, Ofgem may revise the process to identify those applicants which are best placed to participate in the Invitation to

[27] Ofgem, "Offshore Transitional Tenders First Round Transitional Projects Tender Guidance Note on Process to Asset Transfer", pg. 6.

Tender (ITT) stage, as soon as possible. In order to identify those qualified applicants, the Pre-Qualification (PQ) stage may be made more onerous. Since the Tendering Rules from Ofgem do not yet reflect these refinements, the detailed process that will be used for the enduring regime remains unclear. Ofgem expects to issue a final decision regarding the process in December 2010.

Ofgem has not yet released details regarding the process that will be employed for the enduring regime. The information provided herein regarding the anticipated stages for the enduring regime is based on information available regarding the transitional regime. The transitional regime had the following stages:

- Pre-Qualification (PQ),
- Qualification to Tender (QTT),
- Invitation to Tender (ITT),
- Best and Final Offer (BAFO) (optional),
- Preferred Bidder, and
- Successful Bidder to whom a license would be granted

Ofgem may eliminate the QTT stage in the enduring regime.

The number of participants is reduced at each of these stages. Pre-Qualification is open to all and will produce a list of qualified bidders. The Invitation to Tender is then issued to the short list of qualified bidders. The bids are scored against criteria specified in the bid documents. Ofgem may, after evaluating the bids, ask for a Best and Final Offer, or it may directly choose a Preferred Bidder. It may also designate a reserve bidder who would be approached if Ofgem is unable to come to an agreement with the Preferred Bidder.

For the transitional regime, Ofgem developed tender rules to inform the interested parties regarding how it would run the tender process.[28] Prior to development of the tender rules, regulations were promulgated to provide a foundation for these tender rules.[29] The regulation describes the stages of the process and the application of the criteria at each stage. The regulation does not list any criteria, but does state that the criteria to be used in bid evaluation will be set out in the bidding documents.

To date, Ofgem has initiated two rounds of competitive tenders and awarded licenses for the first round under the transitional regime. The second round was initiated on November 17, 2010. The schedule for these first two transitional regime tenders is shown below in Table 2. Not surprisingly, the second round tender reflects a considerably accelerated schedule.

Table 2: Ofgem Transitional Regime Tendering Schedule

Milestone	Round One Tender	Round Two Tender

[28] http://www.ofgem.gov.uk/NETWORKS/OFFTRANS/OTT/TENDOCS/Documents1/Offshore%20Electricity%20Transmission%20Tender%20Rules.pdf

[29] Statutory Instruments 2009 No. 1430 "The Electricity (Competitive Tenders for Offshore Transmission Licenses) Regulations 2009". Made 1 June 2009.http://www.opsi.gov.uk/si/si2009/uksi_20091340_en_3#pt7-l1g12

Tender Commencement/Pre-Qual Issued	July 22, 2009	November 17, 2010
Qualification to Tender Issued	September 24, 2009	January 25, 2011
Invitation to Tender Issued	December 22, 2009	Early April 2011
Decision on Preferred Bidder	August 5, 2010	Late July 2011

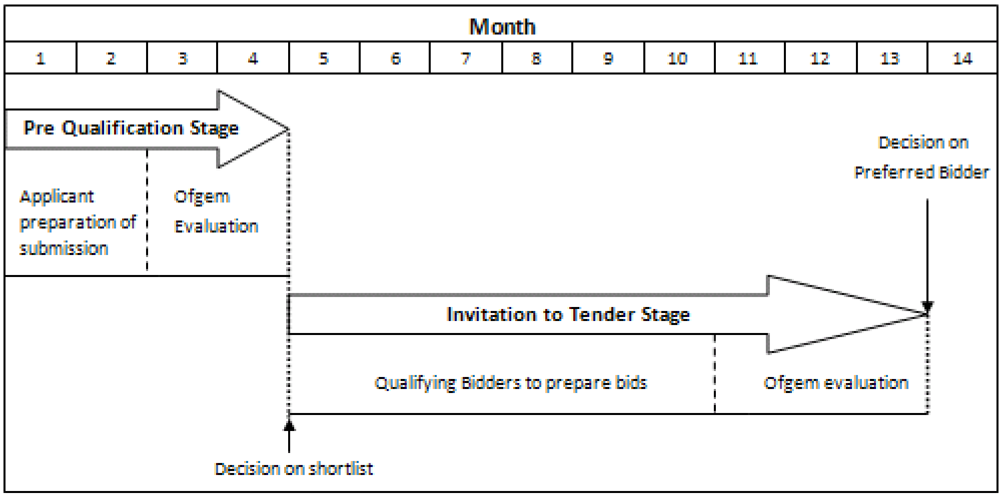
Source: Ofgem

The stage descriptions below draw on and cite the tender documents issued by Ofgem for the transitional regime. Since tender documents have not been released for the enduring regime, it isn't clear how the different criteria that are currently part of the Qualification to Tender stage will be considered as part of either the Pre-Qualification or the Invitation to Tender stages. However, we expect that many of these criteria are likely to be considered in the Pre-Qualification stage, and hence, the discussion of the criteria that were considered in the Qualification to Tender stage in the transitional regime is deferred to the discussion of the Pre-Qualification stage.

4.3 Expected Schedule

The schedule for the enduring regime is shown below in Figure 3. This schedule indicates that the process from initiation of the Pre-Qualification Stage to the Invitation to Tender Stage will take about 13 months to the end of the Invitation to Tender stage.

Figure 3: Competitive Tendering Process for Offshore Wind Transmission Investment



Source: Ofgem

4.4 Stage Descriptions

4.4.1 Pre-Qualification

As discussed, the PQ stage of the tender process may be revised to make it a more onerous single stage that would establish the short list for the ITT stage. The PQ stage would require demonstration of both past experience of designing and constructing relevant assets and the presentation of initial project specific design proposals. In order to facilitate the preparation of PQ submissions, project specific information will be made available to applicants at the start of the PQ stage in the form of a preliminary offering memorandum and in the transitional regime a sale and purchase agreement (SPA) that has been populated by the developer and provides information specific to its offshore wind project and the required transmission facilities. This information would be provided by generation developers as part of the tender entry conditions and applicants would need to sign a confidentiality agreement in order to access this information. In addition, each applicant is provided with (i) a pre-qualification questionnaire that must be completed, (ii) details regarding payments for this tender stage, and (iii) general instructions. Applicants are also required to provide £5,000 to Ofgem in this stage as earnest money and to help cover tender costs.

Applicants would be given 2 months to prepare their PQ submissions and Ofgem will require 2 months to evaluate them.

The selection is based on the applicant's economic and financial standing, legal standing, and management and operational capability.[30]The evaluation process section from the Pre-Qualification

[30]Ibid., pg. 12.

stage of the transitional regime, including the criteria used, is presented below drawing heavily upon the tender documents.[31]

Evaluation Process

(A) Evaluation Criteria

The purpose of the Pre-Qualification Stage is to determine those Applicants that meet the criteria to be Qualifying Applicants by assessing whether an Applicant has sufficient economic and financial standing, management and operational capability and legal standing, based on the Applicant's current standing and track record, to satisfy Ofgem that the Applicant is capable of (i) taking over ownership of the Qualifying Project(s) for which it wishes to be invited to tender and (ii) assuming the responsibilities and duties associated within being an OFTO. Where the Applicant is a consortium, this assessment will be based on the current standing and track record of the consortium taken as a whole.

Applicants are required to demonstrate through their responses to certain questions that they meet the criteria. The criteria relevant to each section of the Pre-Qualification Questionnaire are set out below, focusing on the five sections that have substantive elements.

Section 2 – Organizational structure

An Applicant must provide details and evidence of its ownership and organizational structure.

Section 3 – Economic and financial standing

An Applicant must demonstrate that it has the necessary financial strength to be considered viable to support the proposed expenditure level (on the basis of the aggregate of Ofgem's estimated transfer values for the Qualifying Project(s) for which the Applicant wishes to be invited to tender).

Section 4 – Management and operational capability

An Applicant must demonstrate that it has the necessary expertise to manage and operate an essential services asset or regulated infrastructure asset of similar size and complexity to the Qualifying Project(s) for which the Applicant wishes to be invited to tender.

Section 5 – Legal standing, pending litigation and potential conflict issues

An Applicant must demonstrate that it satisfies the minimum legal requirements in order to be granted an Offshore Transmission License, that it is not involved in any relevant material litigation and that it does not have any potential conflicts of interest which materially detract from its ability to tender for, manage and operate the nominated Qualifying Project(s).

[31] Ofgem "Pre-Qualification Document 2009 Transitional Tenders", issued 22 July 2009, pp. 10-11. Material cited is copyrighted by the Crown.
http://www.ofgem.gov.uk/Networks/offtrans/rott/Documents1/Pre%20Qualification%20Document%202009%20Transitional%20Tenders.pdf

At this stage of the Tender Process, Applicants are required to provide a methodology statement for managing conflicts of interest, for information purposes only. However, Ofgem reserves the right to evaluate this information as part of future stages if the Applicant is taken forward.

Section 6 – Certificate

A duly authorized officer of the Applicant is required to confirm the statements in section 6. An Applicant who does not satisfy the criteria in section 6 will have its Pre-Qualification Submission rejected and such Pre-Qualification Submission will not be considered further. An Applicant will not be required to initial and sign where it can demonstrate that any relevant bankruptcy or other insolvency related claim is vexatious or not material in the context. In evaluating an Applicant's response to statement (C), Ofgem will consider whether an Applicant's explanation raises or fails to answer concerns over its ability to service the anticipated financial liabilities of an OFTO.

(B) Applicants are also required to provide information in response to certain questions in the Pre-Qualification Questionnaire which may be used by Ofgem to contextualize a wider evaluation.

Some of the questions contained within the Pre-Qualification Questionnaire are included in order to allow the Applicant to demonstrate that it meets the minimum legal requirements required of all licensees.[32]

The Pre-Qualification document also says that the submissions will first be checked for compliance with all requirements. Then they will be evaluated against the criteria on a pass/fail basis, and all submissions which pass all of the criteria will be invited to the next (Qualification to Tender) stage.

The criteria in this stage relate to the general capability of the firm both organizationally and legally. They include questions relating to the legal status of the bidder and its potential conflicts of interest in addition to asking for demonstrations of technical competence.

4.4.2 Qualification to Tender (Transitional Regime only)

The evaluation criteria part of the Qualification to Tender document has eleven sections, of which seven contain scored criteria.[33]The first two provide general information and instructions and the last two pertain to certifications and confidentiality requirements. In the discussion below, weights are indicated for each section that deals with scored criteria. The relevant sections are quoted below. Details are retained only for the scored sections.[34]

QTT Evaluation Criteria

Section 3 - Project IRR and Tender Revenue Stream (25% Weighting)

[32]Ibid., pp. 10-11.
[33]http://www.ofgem.gov.uk/Networks/offtrans/rott/Documents1/Qualification%20to%20Tender%20Document%202009%20Transitional%20Tenders.pdf
[34]Ofgem, "Qualification to Tender Document 2009 Transitional Tenders", issued 24 Sept 2009. Criteria and weighting are on pp 12-13. Material is Crown copyright.

The Qualifying Applicant must provide an indicative annual Tender Revenue Stream for the relevant Qualifying Project incorporating its proposed Project IRR and other relevant assumptions.[35]Qualifying Applicants will be evaluated on the basis of their project IRR together with their approach to deriving the Tender Revenue Stream.

Section 4 - Financing strategy (25% Weighting)
The Qualifying Applicant must provide its proposed financing strategy. Qualifying Applicants will be evaluated on the basis of the coherence, deliverability and viability of the proposed financing strategy in support of their Project IRR and Tender Revenue Stream. The response should include evidence of support including, where appropriate, indicative terms.

Section 5 – Financial and commercial risk management (10% Weighting)
The Qualifying Applicant must demonstrate an understanding of the key risks that could have a financial and/or commercial implication for the relevant Qualifying Project. Qualifying Applicants will be evaluated on the basis of their understanding and proposed approach to managing and mitigating these.

Section 6 - Shareholding/consortium structure (5% Weighting)
The Qualifying Applicant will be evaluated on the basis of the robustness and clarity of its proposed shareholding/consortium organizational and contractual structure.

Section 7 - Management capability statement (20% Weighting)
The Qualifying Applicant must demonstrate its capabilities through experience-based management approaches to key aspects of the role to be undertaken by an OFTO and the specifics of operating within the offshore transmission regime.

Qualifying Applicants will be evaluated on the basis of their understanding of the requirements and the coherence and viability of their proposals in relation to the relevant Qualifying Project.

Section 8 - Take over and operational plan (10% Weighting)
The Qualifying Applicant must demonstrate, with regard to its management approach, its understanding and approach to acquiring a business or assets from a third party and developing and evolving an operations plan for newly acquired assets.

Qualifying Applicants will be evaluated on the basis of the coherence and deliverability of their approach in relation to the relevant Qualifying Project.

Section 9 – Sale & Purchase Agreement (5% Weighting)
The Qualifying Applicant must demonstrate its understanding of the scope and considerations associated with the Model SPA in the context of the project specific information provided through the tender process to date. The Qualifying Applicant will be evaluated based on their clear and

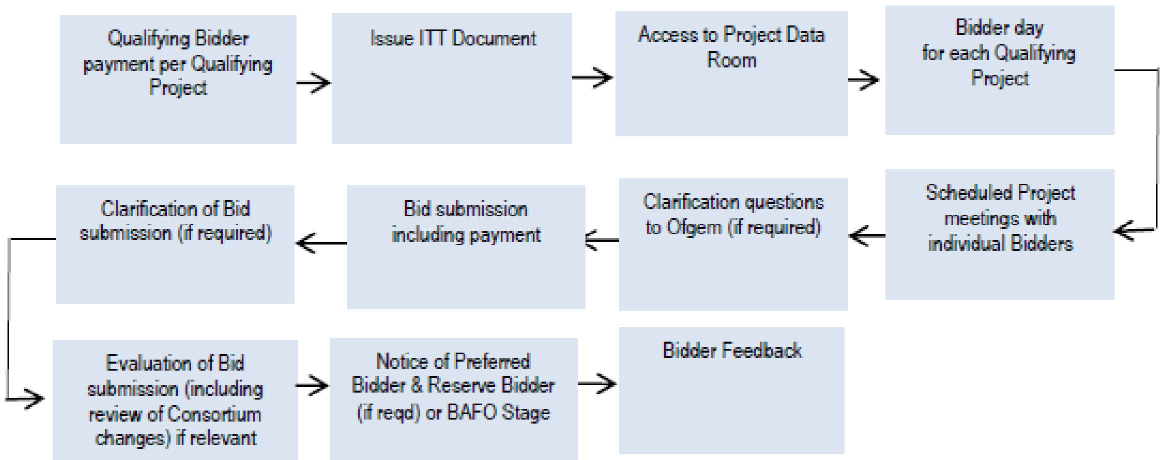
[35] These other relevant assumptions are not specifically identified.

considered identification of key commercial issues associated with the Qualifying Project and its transfer via an SPA. A legal markup of the Model SPA is not required.

4.4.3 Invitation to Tender

Figure 4 below summarizes the key steps in the Invitation to Tender stage.

Figure 4: Key Steps in the Invitation to Tender Stage



Source: Ofgem, Tender Rules

Ofgem found that the ITT stage for the enduring regime requires Qualifying Bidders to submit detailed design plans for the projects for which they wish to bid and that the design plan must be based on the generation developer's requirements and information provided to them regarding any preconstruction works. As part of their submissions, Qualifying Bidders may need to consider a number of issues including:

- alternative transmission asset designs;
- cable route options, appropriate AC/DC solutions;
- analysis of onshore connection points;
- ancillary services studies; and
- possible engagements with third parties such as the NETSO (in order to obtain information regarding the feasibility of proposed design plans).

After identification of the bidders on the short list, the ITT phase begins with establishment of a data room to which the short listed bidders have access.

The ITT is designed to enable the short-listed qualifying bidders to submit their detailed proposals against a number of criteria, including their required revenue stream for the project. The key elements of this stage are:

- Qualifying bidders will be provided with access to a fully populated data room for the specific project(s) for which they have been shortlisted,
- Qualifying bidders will be invited to submit a detailed bid for each project for which they have been shortlisted,
- Assessment will be based on the qualifying bidders' responses against a number of detailed criteria, including their required revenue stream and their managerial, operation and legal capability,
- Assessment will be on a scored basis against the criteria,
- Where a qualifying bidder has been shortlisted for more than one project, they will be required to submit an ITT bid for each project individually but may also submit a variant bid for a combination of projects. However, any variant bid submitted must, at a minimum, identify the required revenue stream on a per project basis, and
- Where a qualifying bidder wishes to change its consortium, it must notify Ofgem, who will use its discretion to permit the change having regard to whether the change would be fair and equitable to all other qualifying bidders for that project.

The outcome of the ITT Stage will be the identification of the Preferred Bidder for each project. Ofgem's selection of proposals is based on a 60/40 price/non-price weighting. Where appropriate, a Best and Final Offer Stage will be run to identify the Preferred Bidder. The Best and Final Offer Stage can be used to bid against a limited number of revised issues. This stage would take one month in total. Once the Preferred Bidder is appointed, the time to license award would vary on a case by case basis, depending on project specific issues.

4.5 Performance Incentive

Under the existing mechanism 10% of the licensee's yearly base revenue is exposed to a performance incentive for availability. The incentive reflects a target monthly availability of 98% (having adjusted for factors beyond the OFTO's control). The objective is to ensure that planned and unplanned outages should occur, on average, in no more than 2% of a relevant period. A maximum penalty/ collar (i.e., 10%) determines the maximum proportion of an OFTO's revenue stream which may be exposed to the performance incentive in each period and a system of performance credits and debits incentivizes the OFTO to improve performance in excess of the availability target and, without adversely impacting on financial viability, maintains incentives to restore availability once the collar has been met.

4.6 Results of Competitive Tender

Ofgem selected Balfour Beatty Capital, Macquarie Capital Group and Transmission Capital Partners as winners of a competitive tender, to own and operate the first seven out of nine offshore transmission links. Ofgem reported that investor appetite for offshore wind transmission projects is currently greater than the pipeline in the UK. Ofgem said strong competition has attracted almost £4billion of investment proposals for the nine transmission links, which it said are only worth around £1.1billion. The competitive tendering process produced savings of approximately £350 million.[36,]

[36]http://www.oilvoice.com/n/Ofgem_Launches_3bn_UK_Offshore_Wind_Transmission_Tender/1a0b6861c.aspxThis figure was confirmed by Stephen Beel of Ofgem (Phone Conversation November 30, 2010.)

[37]The appetite represented offers of commitment from equity, corporate finance and commercial debt finance providers as well as European Investment Bank funds. There were five consortia pursuing the transmission assets, with 13 pre-qualified entities. The success of this process is causing Ofgem to consider its application for major onshore transmission investments.

At the time of this announcement a Best and Final Offer process was to be run for the Ormonde facilities (Transmission Capital Partners was subsequently identified as the preferred bidder) and the ITT was to be rerun for the Great Gabbard facilities with four bidders participating, two of which hadn't been awarded licenses.

4.7 Conclusions

Ofgem's competitive procurement process is patterned after the process that is typically used for the sale of generation assets. The first round is a qualifications process which focuses on identifying a short list of interested parties. Critical issues in the selection of the short list are ensuring that the parties have the required financial capability to close the transaction and the technical capability to operate the asset. Indicative bids are used as a measure of the parties' initial estimate of the value of the asset, but are subject to additional due diligence and further analysis. Where's the purchase price offered is typically the primary consideration in selecting the asset buyer, Ofgem employed a broader range of considerations given the importance in ensuing that the OFTO has the required capability. To the degree that Ofgem develops greater confidence in the depth of qualified prospective bidders, it may elect to more heavily weigh the tender revenue stream in future tenders.

Recognizing that the discussion above is based on the tender documents applicable to the transitional regime, Power Advisory anticipates that the stages and criteria for the enduring regime would be modified to reflect the greater scope of responsibility for the successful bidder (*e.g.*, designing transmission facilities to deliver the output of the generation, obtaining permits for the construction and operation of the transmission facilities, potentially greater coordination with the generation developer, etc.). Given the relatively specialized nature of these transmission projects (and the large amount of generation investment that will be dependent on the timely completion and reliable operation of the transmission facilities), relatively high weights may be assigned to the technical and construction capabilities of the applicants.

5. Ontario: Transmission Development Planning Guidelines

With the passage of the *Green Energy and Green Economy Act, 2009 (*GEGEA*)*, Ontario has committed to the aggressive development of renewable energy resources under a Feed-in Tariff (FIT). However, the ability of existing and approved transmission facilities in Ontario to accommodate more generation is limited. In September 2009, the Minister of Energy and Infrastructure requested that Hydro One Networks, Inc., which owns the vast majority of transmission in the province, begin development work on twenty transmission facilities that would enable the development and interconnection of more renewable energy resources. Recently, the Ministry of Energy released its

[37]The £350m savings were calculated by comparing the average annual revenue bids for the nine offshore transmission links (based on the bids received) with the annual revenues allowed for onshore Transmission Owners during the last transmission price control review.

Long Term Energy Plan which indicated that of these twenty potential projects five projects were being actively pursued, one of which will be subject to the designation process outlined below. Significant investment in transmission infrastructure will be required to accommodate current FIT applicants as well as future renewable generation projects.

As a result of the *GEGEA*, the *Ontario Energy Board Act* contains new provisions that require licensed transmitters, when mandated by the Board, to develop transmission plans for review and approval by the Board. The Board issued its policy with regard to transmission project development planning in August 2010.[38]Thereby outlined its objectives as to:

- allow transmitters to move ahead on development work in a timely manner;
- encourage new entrants to transmission in Ontario bringing additional resources for project development; and
- support competition in transmission in Ontario to drive economic efficiency for the benefit of ratepayers.[39]

This policy was part of an effort by the OEB to provide greater regulatory predictability given the magnitude of anticipated transmission investment and reflects the belief by the OEB that the currently regulatory framework serves both customers and utilities well.

The general approach outlined by the OEB is to conduct a formal hearing to designate a transmitter that will be responsible for undertaking the development of a specific transmission facility. New entrant transmitters (entities that don't already own and operate transmission facilities in Ontario) must be licensed in order to participate in the designation process. The licensing process allows the OEB to evaluate the financial viability and technical capabilities of the new entrant transmitters.

The designation process would be used for enabler facilities (i.e., transmission facilities that would connect clusters of renewable generators to the existing transmission network) and network expansions (i.e., expansion of the network through major new network facilities).[40]
In its role as the transmission planner for Ontario, the Ontario Power Authority will administer an Economic Connect Test (ECT) to determine which transmission system investments are needed to connect economically a FIT project. The results of the ECT will be used to identify the enabler facilities and network expansions that would be developed by designated interested transmitters. Specifically, when the OEB receives the results of the ECT from the OPA, it will begin a competitive process to designate a transmitter to undertake development on any new enabler facilities or network expansions identified. If a recently approved Integrated Power System Plan is available, the transmission recommendations contained in that plan may be used for the designation process.

All licensed transmitters will be invited to submit plans in the form outlined by the OEB's filing requirements, with a deadline for filing plans ranging from three (the default period) to six months

[38] Ontario Energy Board, *Board Policy: Transmission Project Development Plans*, (EB-2010-0059), August 26, 2010.
[39] OEB, op. cit., p. 1.
[40] As implied, this process doesn't apply to the reinforcement of existing network facilities. To promote a greater role for competition, new lines on existing or widened corridors are viewed as expansions, and thus, may be developed through a competitive process.

(for more complex facilities). Only the transmitter that is successful in being designated will be able to recover the costs of preparing a plan. If no plans are received for a project, the incumbent will be directed to file a plan and would be able to recover the costs of plan preparation. Thus, the preparation, submission and evaluation of the project-specific plans is, in effective, the competitive process for identifying the preferred transmission developer.

The OEB will designate a transmitter based on the evidence in the proceeding regarding the proponent's organization and experience, technical capability, financial capacity, schedule, costs, landowner and other consultations. The specific filing requirements are outlined by the OEB in a separate document.[41] The OEB's assessment will take into account the individual circumstances of the project. The general information required along with the elements of the OEB's evaluation of applicants are reviewed below.

Technical capability is assessed in terms of the Applicant's ability to engineer, plan, construct, operate and maintain the project, based on experience with projects of equivalent nature, magnitude and complexity.

Financial capability is assessed in terms the applicant's financial capability necessary to develop, construct, operate and maintain the project. In addition, the applicant is required to demonstrate its existing financial capacity, its ability to access the debt and equity markets and the terms and conditions of any financing.

The applicant is also required to submit a project development schedule identifying major development milestones and proposed dates for completing those milestones, as well as a project construction schedule identifying major construction milestones and proposed dates for completing those milestones. The proposed schedules and milestones will be reviewed and assessed by the OEB.

With respect to costs, the Applicant is required to provide: (1) an estimated budget for the development of the project up to the submission of the leave to construct application; (2) an estimated budget for any further development of the project after leave to construct has been granted; (3) an estimated budget for the construction of the project; and (4) the estimated average annual cost of operating and maintaining the project.

Finally, the Applicant must demonstrate the ability of its management team to conduct successful consultations with landowners, First Nations and Métis and other relevant parties.

The transmitter designated for a particular project will be assured of recovery of the budgeted amount for project development through the submission of the leave to construct. Material overages will be at risk until a future prudence review. When subsequent analysis by the OPA suggests that the project has ceased to be needed or is no longer economically viable, the transmitter will be entitled to appropriate wind-up costs.

[41] Ontario Energy Board, Filing Requirements: Transmission Development Plans, August 26, 2009.

The Board order of designation will have conditions such as performance milestones based on the project schedules (in particular, a deadline for submission of the application for Leave to Construct) and reporting requirements on progress and spending that, if not met, will result in the designation being rescinded and will put further expenditures at risk. Final project selection will take place after the application for Leave to Construct has been submitted.[42]

5.1 Differences between the OEB's Designation Process and Alberta CTI

The process that the OEB has outlined for designating transmitters applies only to the transmission development planning for the relevant facilities. These development costs are likely to represent from 5 to 10% of the total project costs. While it is likely that the designated transmitter will have a competitive advantage when seeking to construct the required facilities, designation as the transmitter to develop a facility doesn't guarantee that the transmitter will receive approval under the leave to construct process. As such there Isa need to consider the critical issues regarding the capabilities of the transmitter to finance, construct and maintain the required transmission facilities.

6. Transmission Procurement in Brazil

6.1 Overview of Process

Brazil has implemented a competitive bidding process to assign the rights to construct, own and operate transmission facilities. Under the Brazilian system, utility companies may compete in auctions for long-term contracts to construct, own and operate transmission facilities with rights guaranteed as long as thirty years. The practice began in 1999, when federal agencies started auctioning concessions to private transmission developers. In 2004, Law 10.848 reinforced the concept by establishing auctions as the primary procurement mechanism for new generation projects.[43] The auction system serves as an important policy initiative to stimulate investment in Brazil's transmission infrastructure and rectify its systemic weaknesses.

The auctions are part of the Transmission Expansion Program (PET) enunciated by the state-directed Energy Research Company (ERE) and the Plan of Transmission and Reinforcement (PAR) set by the National Electric System Operator (ONS).[44]

These policies emphasize three objectives to strengthen the grid:

- Plan viable and cost-effective transmission expansion projects;
- Encourage competition for transmission rights; and
- Reduce barriers for new developers entering the market.

The auctions are managed by the Electricity Regulatory Agency (ANEEL) and planned by the subsidiary Power Commercialization Chamber (CCEE). The process is open to public, private, and international developers. Parties must first submit an application to ANEEL and found to be

[42] The Leave to Construct is issued by the OEB and it focuses primarily on the need for the facility. There is a separate Environmental Assessment process which is typically conducted after the Leave to Construct.
[43]http://web.ing.puc.cl/~power/paperspdf/IAEE2010.pdf
[44]http://www.aneel.gov.br/area.cfm?idArea=585&idPerfil=12

qualified. Companies may participate individually or as a consortium. The winning bidder for each auction is determined on the basis of lowest annual revenue requirements.

6.2 Institutional Context

The Ministry of Mines and Energy (MME) is responsible for energy policy in Brazil. The MME carries out studies and planning while the control, design, and implementation over policies falls to the regulator.[45] Hydroelectric power satisfies over 80% of demand and produces nearly 90% of electricity generated nationally. A significant share of power comes from the 14 GW Itaipu Dam, a joint enterprise shared with Paraguay, accounting for 25% of all Brazil's generation. Despite abundant water-based resources, the country has only partially realized its hydroelectric potential and remains a net importer of electricity.[46] As generation expands, the transmission network will face the persistent challenge of connecting the multitude of power sources in the interior with population and industrial centers in the East.

Since the late 1990s, the Brazilian government has gradually pushed for increased private investment in energy. Private ownership, however, has mostly applied to generation, as the transmission network is almost exclusively controlled by state corporations. Electrobrás, the dominant public utility, owns and operates two-thirds of the country's transmission capacity. In recent years, the rapid growth of Brazil's generating capacity has fueled the need for transmission upgrades. Additionally, a massive blackout in November 2009 only heightened concerns over the country's long-term resource sufficiency. An abrupt failure in the grid connected to the Itaipu Dam caused power outages in 18 of 26 states, São Paulo and Rio de Janeiro, and most of Paraguay. Although downplayed by state officials, the incident suggested a greater, inherent vulnerability in Brazil's interconnected transmission system.[47]

6.3 The Auction Framework

The CCEE, under the oversight of ANEEL, designs periodic auctions for designated transmission investments. ANEEL conducts the auction using a silent bid, sealed letter format. The bidder proposing the lowest revenue requirement over the lifetime of the contract is selected and wins the right to construct the transmission project.[48]

ANEEL describes the following rules:

> The financial offer with the value of the Allowed Annual Revenue (RAP) for each lot must be submitted in a sealed envelope by the participant. If the difference between the lowest bid and other bids is greater than 5%, the lowest bidder wins the tender. If the difference is less than or equal to 5% or if there is a tie among the lowest bids, the auction continues, with

[45]http://www.ieee.org/portal/cms_docs_pes/pes/subpages/meetings-folder/2004_Denver/Track1/Pres_4-Brazil.pdf, p. 4
[46]http://www.aneel.gov.br/biblioteca/trabalhos/trabalhos/Artigo_003_Serrato.pdf, p. 4
[47]http://www.nytimes.com/2009/11/12/world/americas/12brazil.html
[48] ANEEL defines Average Revenue Allowed as "the annual revenue the developer the bearer is entitled for the provision of public transmission service to users from the commercial operation of the facility. Its value is that obtained as a result of the auction, with annual update by the Consumer Price Index (IPCA) of the Brazilian Institute of Geography and Statistics (IBGE) and review, every five years, under a concession contract."
http://www.aneel.gov.br/aplicacoes/noticias_area/dsp_detalheNoticia.cfm?idNoticia=3552

> successive moves made on the speakerphone. The director of the auction session may set minimum amounts to be provided between a bid and others. The bidder submitting the lowest value wins. In case of any bidder bids on speakerphone, that who has submitted the lowest per envelope will be the winner. If there is a tie in figures submitted by envelope without speakerphone, the winner will be determined by lottery promoted by the director of the session.[49]

Contracts typically grant concessions spanning up to 30 years. The winning RAP covers the entire cost of development, maintenance, and repairs throughout the contract term. Upon completion of the project, the ONS assesses penalties for periods of inoperability. Additionally, the contract holder is obligated to satisfy interconnection requests from generators, distributors, and other transmission developers. The company is entitled to payments for such interconnections and may sign bilateral agreements with customers.[50]

Historically, ANEEL has announced auctions intermittently according to its planning and development schedule. In 2009, auctions for 3,400 km of transmission projects were held in March and November. In 2010, auctions for 2,000 km were held in June and September with another auction for 700 km scheduled in December.

6.4 Selection of Developers

Transmission developers must demonstrate legal, financial, and technical competencies to merit consideration. ANEEL also includes provisions for financial interests and non-developer entities.

Investors and other groups must demonstrate minimum qualifications:

> The participation in the auction is franchised to any interested party (institution), even to investors or companies that do not operate in the electricity sector, and in this case, they should demonstrate technical qualification to operate and keep the development by assigning a qualified technical person in charge…The participants should be previously qualified, according to the terms of the invitations to bid, and should constitute, if they win, a partnership of specific proposal, in order to explore the concession, if they are not the transmission concession holders.[51]

Several months prior to auction, ANEEL will announce a shortlist of eligible participants. To enter the auction, parties then submit a Bid Guarantee equaling 1% of the estimated investment value of the contract. Upon completion, the winning bidder must deposit a guarantee of 5% of the investment value.

6.5 Success of Program

The auction system has been highly successful in procuring transmission projects. Since 1999, auctions have been responsible for at least 20,000 km of transmission projects totaling over $13

[49]http://www.aneel.gov.br/aplicacoes/noticias_area/dsp_detalheNoticia.cfm?idNoticia=3611
[50]http://www.aneel.gov.br/biblioteca/trabalhos/trabalhos/Artigo_003_Serrato.pdf, p. 9-13
[51]http://www.aneel.gov.br/area.cfm?idArea=585&idPerfil=12

billion. According to ANEEL, more than half of the projects bid to 2007 are operational with most of remaining under scheduled development. ANEEL touts the high level of participation as indicative of a robust competitive process.[52] In recent auctions, twenty to thirty firms have participated, mostly originating from South America, Spain, and Portugal.

Potential questions relate to optimal auction design and the competitive balance of companies. Despite a prequalification process, the process has allowed parties to participate who have been unable to deliver. In response, ANEEL has explicitly blocked certain companies from participation for apparent rules violations.[53] There is evidence of consolidation in the market. Several state corporations in Brazil have bolstered their influence by purchasing smaller private firms in recent years. Moreover, Chinese transmission giant, the state-owned State Grid Corporation, has recently agreed to purchase seven Spanish-owned and Brazilian-based transmission firms.[54]

7. Implications for AESO's Competitive Procurement Process for CTI

In its Discussion Paper, the AESO outlined two alternatives: the Own Alternative and EPC Alternative, which were reviewed briefly in the second chapter. Both the PUCT and Ofgem implemented competitive procurement frameworks that employed the "Ownership" model where the successful bidder ultimately owns and operates the transmission facilities. Power Advisory believes that this outcome isn't surprising since much of the value of a competitive process arises from the competition to "finance and own", where proponents primarily compete on the basis of their cost of capital, with additional (and important) competitive benefits from competition to "construct". Under Ofgem's transitional regime, the economic focus is almost exclusively on the cost savings from the competition to finance. Operating and maintenance costs are considered but since these costs typically represent a relatively small portion of the project's total cost of service, they ultimately receive less weight than the financing costs. As discussed further below, the process employed by the PUCT didn't fully consider the potential differences among bidders with respect to financing and construction costs, given the large number of capital intensive projects that were to be completed in a compressed time period.

The savings from competition to design and permit are real, but must be weighed relative to the potential incremental risk premiums that would added to the estimated capital cost (with a resulting increase in the project's revenue requirements) as bidders seek to manage the uncertainty associated with the design and route of the facilities.

7.1 Contrasting the PUCT and Ofgem Processes

There are a considerable number of differences between the competitive procurement processes employed by the PUCT and Ofgem. These differences stem in large part from the magnitude of required investment (almost $5 billion for the CREZ facilities over a compressed time period, with multiple projects being "bid out" in parallel) and the scope of the required facilities (i.e., fewer routing options for offshore transmission facilities and as a result greater certainty regarding routing).

[52] http://www.aneel.gov.br/aplicacoes/noticias_area/dsp_detalheNoticia.cfm?idNoticia=3552
[53] http://www.bnamericas.com/news/electricpower/Aneel_shortlists_27_for_transmission_auction
[54] http://www.chinadaily.com.cn/bizchina/2010-05/19/content_9867687.htm

The most significant difference between these two processes is that the PUCT's selection process focused primarily on financial capability of the bidder, given that the cost of service for the required facilities would be established at a later date pursuant to traditional cost-of-service ratemaking. Whereas, Ofgem's process considered a broader range of capabilities and considerations and most importantly, required the bidders to commit to a specific revenue requirement for the facilities. As a result, Ofgem's process resulted in greater competitive tension where proponents effectively bid their cost of capital and construction costs (under the enduring regime). As such, ensuring the competitiveness of the tender process was more critical for Ofgem.

The process employed by Ofgem is patterned after the process typically used for generation asset sales and has proven to be effective in securing value for sellers. Using a two-stage process simplifies the administration of the process, by limiting the participation in the second round (when considerably more administrative support is required) to qualified bidders.

The selection process employed by the PUCT was considerably less transparent than used by Ofgem in the UK. In particular, while the PUCT clearly outlined the evaluation criteria that it would use to evaluate interested TSPs, the weighting of those criteria wasn't clearly identified. Ultimately, the PUCT's evaluation was primarily on the basis of financial capability, with facilities awarded to all parties that were deemed qualified to bid. The large number of selected bidders helped to ensure the availability of sufficient financial and technical resources to achieve the aggressive completion schedule for the $5 billion worth of investment required by the CREZ facilities.

Table 3 below summarizes and compares the allocation of certain project risks, and the sources of competitive efficiencies, in the competitive procurement processes used by the PUCT and Ofgem.

Table 3: Comparison of Allocation of Selected Risks and Sources of Efficiencies in Competitive Procurement Processes

Jurisdiction	Texas	United Kingdom	
Characteristic\Regime	CREZ	Transitional	Enduring
Bidders responsible for developing transmission?	Yes	No	Yes
Bidders responsible for demonstrating proposed route is the best alternative?	Yes	No	Yes
Bidders bear construction cost risks?	Limited	No	Yes
Scope for design/technology innovation by bidders	Yes	No	Yes
Presence of performance/availability incentives	No	Yes	Yes

Ofgem's enduring regime represents one end of the spectrum, in that the winning bidder may be responsible for the design, routing, permitting, construction, financing, operation and maintenance of the facilities required to meet the identified transmission need, all in exchange for contractual revenue that is fixed at the time of contract award. Hence, the winning bidder would bear all of the development, construction, financing and ownership risks, and the revenues stream proposed by the bidders will reflect their assessment (and valuation) of those risks. While this regime reduces risks to the ultimate ratepayers (and increases the scope and scale of competitive pressures on the bidders), it may result in higher expected costs, due to the transfer of risk to bidders.

At the other end of the spectrum, Ofgem's transitional regime removes the development risks from the bidders, since they would be taking ownership of completed transmission assets. In this regime, risks and competitive pressures are focused on the financing and ownership of the completed transmission assets, resulting in a simplified competitive process, but with reduced opportunities for efficiencies and cost savings from competitive tensions in the development stage.

The CREZ regime represents an intermediate framework, with relatively greater emphasis on transferring risks to bidders in the development stage, and less risk (and competition) in the financing and ownership of the assets (*e.g.*, winning bidders for the CREZ facilities did not need to value or internally price long-term interest rate risk, due to the planned use of traditional cost-of-service ratemaking). Similarly, the absence of performance incentives (and penalties) places the operational risks on the Texas ratepayers, rather than the assets owners.

Greater transparency allows bidders to better assess tradeoffs associated with better scores on different evaluation criteria. Specifically, bidders are better able to understand the most important areas on which they should focus when preparing their proposals and whether further technical analysis of CTI project alternatives would significantly enhance their proposal. On the other hand, less transparency with respect to the specific weights for the evaluation criteria would provide the AESO with greater flexibility when assessing proposals. Since (a) the first CTI competitive process will be the AESO's first competitive transmission procurement process and (b) it is difficult to anticipate differences among bidders and thus, the weights that should be assigned to these differences, greater flexibility in the evaluation criteria may be appropriate.

Appendix A: Key Dates for the CREZ Process

2005: Senate Bill 20 enacted which directs the PUCT to implement CREZ

12/1/06: ERCOT files CREZ alternatives with the PUCT

12/1/06: CREZ Rule adopted by PUCT outlining process for establishing CREZs

11/07: Interim order issued designating CREZs in five areas

4/2/08: ERCOT files study with PUCT with four scenarios identifying transmission required for CREZs designated by the PUCT

5/15/08: Petition by PUCT staff to commence proceeding to select Transmission Service Providers (TSPs) to build CREZ Transmission

5/22/08: Order Adopting Rules for Selecting TSPs for CREZ Transmission issued

7/17/08: PUCT selects CREZ scenario 2, providing over 18,000 MW of wind generation and costing approximately $4.9 billion

CREZ's selected based on renewable energy resource potential and the level of financial commitment by generators for each potential CREZ, including deposits for interconnection agreements and studies, financial commitments to landowners

7/21/08: Statements of Interest Filed by TSPs

9/08: Parties interested in being designated as TSPs for CREZ facilities filed detailed CREZ Transmission Plans

10/7/08: PUCT issues final order: Order on Rehearing Designating CREZs

TSPs required to file Certificate of Convenience and Need (CCN) Applications within 12 months of this order (10/7/09)

11/6/08: Default projects (upgrades or modifications) assigned to incumbent TSPs

12/1 – 12/5/08 Hearings on the merits of specific TSPs building CREZ Transmission

3/30/09: PUCT issued Final Order establishing two dockets for sequencing and scheduling: Priority Projects CCNs due October 7, 2009; ERCOT to establish sequencing schedule within 60 days for "Subsequent Projects"

5/15/09: Final Order on Rehearing Designating TSPs for CREZ facilities

5/29/09: ERCOT files sequencing recommendations for CREZ Transmission facilities

10/7/09: Deadline for Filing CCNs for priority projects (i.e., projects that will also relieve congestion that is preventing the delivery of energy from existing wind projects)

TSPs that fail to file CCN within the deadline may have this designation revoked

There is 181 day deadline for the PUCT for processing CCNs

45 days after CCN filed Developers are required to post a letter of credit or other collateral equal to 10% of the developer's pro rata share of the cost of the CREZ Transmission facilities. Direction provided in specific docket regarding which CREZ transmission facilities will trigger specific developers to provide security.

12/31/2013 Final CREZ Transmission Facilities scheduled to be in-service

Appendix D

Proposed Structure of the RFQ

The RFQ will be sent to reputable domestic and international transmission developers and other interested parties. To ensure broad participation, the RFQ tender notice will also be published in professional journals and websites and will provide some indicative project value, together with a comprehensive explanation of the geographical significance and importance of the project to the development of infrastructure in Alberta. Respondents will have adequate time to thoroughly prepare their responses.

The RFQ that will be sent to interested parties will include, but is not limited to, the following sections:

RFQ Introduction/Background: This section will describe the purpose of the RFQ, administrative matters and a background on the Project. A brief chronology of, and relevant reference to, the Provincial Energy Strategy and ESA Act will be provided to familiarize interested parties with the regulatory framework for Alberta's electric industry. This section will include reference to regulatory documents such as the EUA, T-Reg and *Hydro Electricity and Energy Act* (HEEA). Land rights and environment-related legal and regulatory documents will be identified. Information will be provided on the AESO's upfront work on developing the Process including stakeholder consultations. Reference links to publicly available documents will be incorporated into the RFQ document.

Description of the RFQ Competitive Selection Process: Selection criteria for developing a short list of [3] proponents will be described in detail and the selection process will include an assessment of ownership and organizational structure, management and operational experience, regulatory experience, technical record and capability, financial viability and capability, consultation and relationship management, development and innovation and cost optimization. The AUC-approved procedures, including the decision-making process, will be provided. See Appendix E for a more detailed list of selection criteria.

This section will also contain details of the honorarium payable to those respondents selected as short-listed proponents who have not been selected as the Preferred Proponent at the RFP stage but have complied with the terms of the RFP. A high-level summary of the RFP process including the proposed arrangements for collaborative discussions with Proponents and a high-level description of the RFP submission requirements will also be provided.

The Project: A high-level description of the Project will be provided, including the scope of the Project, a high-level description of the responsibilities of the Proponents, the Study including the start and end points of the route, high-level technical requirements and estimated in-service dates. It will include the location of interconnections with the Alberta interconnected electric system and the requirements thereof, as well as a high-level description of the operating and dispatch protocol.

This section will also include a summary of key commercial terms of the Project in a draft term sheet.

RFQ Requirements: This section will contain the boilerplate RFQ terms and conditions language.

RFQ Evaluation and Response Format:

2500, 330-5th Avenue SW, Calgary, Alberta T2P 0L4 Phone: 403-539-2450 Fax: 403-539-2949
www.aeso.ca www.poweringalberta.com

Respondents will be asked to submit the following information and documentation in a specific response format to substantiate their qualifications:

Ownership and Organizational Structure: Description of the respondent's legal business standing and how it proposes to organize for this particular project. If the respondent is a consortium, it must provide detailed information on ownership structure, roles and responsibilities and relationship with the parent companies along with the consortium's track record as a whole and the record of the constituent members of the consortium. An assessment will be made of whether or not the proposed respondent team is capable of delivering the Project from an organisational and consortium arrangement perspective based on an assessment of:

- the respondent's past experience in similar competitive processes;
- the experience of the key individuals; and
- the respondent's nominated completed projects.

Financial Viability and Capability: Demonstration that the respondent is financially viable and has the necessary financial strength to provide the debt financing, the equity and an ability to obtain robust security to ensure completion of the construction and energization of the Project. Financial statements will be reviewed along with an assessment of the respondent's past experience from its nominated completed projects and an assessment of its proposed financing plan for this Project.

Technical Record and Capability: Demonstration that the respondent has the appropriate experience and management and technical capabilities to develop, own, operate and maintain critical infrastructure assets of similar magnitude and complexities. An assessment will be made of whether or not the proposed respondent team is capable of delivering the Project from a project management, design, construction, operations and maintenance perspective based on an assessment of:

- the respondent's past experience in similar competitive processes;
- the experience of the key individuals; and
- the respondent's nominated completed projects.

Consultation and Relationship Management and Development: An assessment will be made of the respondent's proposed plan and its strength and demonstrated ability to undertake the required consultation and relationship development for the Project, including affected landowners, First Nations, Métis and other affected stakeholders.

Innovation and Cost Optimization

Assessment of the extent to which innovative features in the proposal are considered by AESO to add value and are of benefit to ratepayers.

Proponent Agreement:

At the RFQ stage the respondents will be required to:

a) provide an executed copy of a Proponent Agreement under which a proponent is obliged to participate in the RFP process if shortlisted and submit a compliant proposal; and

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b) confirm the Proponent will provide to AESO, as a condition of participation in the RFP process, security in the form of a letter of credit in the amount of $● to secure its undertaking to participate in the RFP process in accordance with the terms of the RFP.

The item (b) security will be returned to the Proponent upon confirmation from AESO that the Proponent has submitted a compliant proposal to the RFP.

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Appendix E

RFQ Selection Criteria

AESO will evaluate RFQ Responses by applying the Selection Criteria and weighting in the following table.

The AESO may in its absolute discretion, after reviewing the contents of the Response to the RFQ, discontinue the evaluation of that Response if the Respondent is determined to be unable to demonstrate its (i) technical capability, (ii) ability to raise sufficient capital to fund the estimated equity requirement or (iii) financial viability.

AESO Factor	Expertise	Selection Criteria	Rationale	Draft Weighting
	Introduction and nominated projects	Each response will contain the following information: • Proposed Respondent Team • Contact Information; and • Nominated Projects	Not scored as this is an summary instruction	N/A
Ownership and organizational structure	Respondent team	Strength and demonstrated ability to undertake the complete Project, including: a) experience working together on similar scope projects in similar climates and the capacity to assemble and manage a consortium team that will integrate required expertise for the overall benefit of the Project; b) relevant competitive procurement experience, capacity and availability	An assessment of the team's ability to deliver the overall project is required as due diligence that the team is capable of delivering the project from an organizational and consortium arrangement perspective.	20

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AESO Factor	Expertise	Selection Criteria	Rationale	Draft Weighting
		of the Key Individuals; c) ability to meet Project schedule; and d) Project understanding.		
Financial viability and capability	Financial capacity and experience	Strength and relevance of demonstrated experience, track record and capability relating to: a) financial capacity; b) financing experience; and c) financing plan.	Required to assess whether the team has demonstrated the ability to deliver the project, including: the ability to provide debt financing, equity and required security; the ability to assess the previous financing experience of the team members; and the robustness and deliverability of the proposed financing. Assessment of financial strength (balance sheet) as an indication of ability to manage transferred risks and remain solvent.	25
Technical record and capability	Engineering design development and construction	Strength and demonstrated ability relating to the design and construction of projects with similar seasonal/climatic conditions, Alberta project experience, transmission and utilities project experience, regulatory experience, approvals and permitting experience, geotechnical experience and flexibility to adapt to changing requirements including the following: a) experience and capacity to assemble and manage a design team with applicable experience and	To assess the extent to which the team and its key individuals have demonstrated the ability to successfully design and construct similar projects, which would indicate a capability to meet the specifications of the AESO and its stakeholders.	15

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AESO Factor	Expertise	Selection Criteria	Rationale	Draft Weighting
		expertise, and an approach to design, including innovation, that will achieve optimal efficiency for the Project; b) experience and capacity to assemble and manage a construction team with applicable experience and expertise; c) experience and capacity of the Key Individuals on the design and construction teams; and d) demonstrated ability to meet or exceed the project schedule.		
Technical record and capability	Operations and major maintenance	Strength and demonstrated ability relating to the operations and major maintenance of projects with similar seasonal/climatic conditions, Alberta project experience, transmission and utilities project experience, regulatory experience and flexibility to adapt to changing requirements including the following: a) experience and capacity to assemble and manage the operations and major maintenance team that will provide services over the term of the Project Agreement; b) experience and capability in the	To assess the ability of the team members and proposed Key Individuals to assemble a team capable of providing O&M and major maintenance over a long-term contract and with suitable similar experience, thereby increasing the likelihood of successful O&M.	15

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AESO Factor	Expertise	Selection Criteria	Rationale	Draft Weighting
		integration of design and construction with ongoing operations and maintenance to minimize life-cycle costs; and c) experience and capacity of identified Key Individuals for operations and major maintenance.		
Consultation and relationship management/development	Stakeholder consultation	Strength and demonstrated ability to undertake the required consultation for the Project, including with: a) affected landowners; b) First Nations; c) Métis; and d) other potentially affected stakeholders.	To assess the ability of the team members and its proposed Key Individuals to consult with and develop relationships with potentially affected stakeholders as this will be important in a long-term contract.	20
	Innovation and cost optimization	Discretionary points to award for innovation/added value.	Provides flexibility to reward added value.	5
TOTAL				**100**

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Appendix F

Proposed Structure of the RFP

The RFP will be issued to those Respondents who have been shortlisted from the RFQ stage to proceed to the RFP stage, subject to those Respondents providing the AESO an executed Proponent Agreement and a Proponent Letter of Credit in accordance the RFP Security Requirements.

The RFP will include, but is not limited to, the following sections:

1. RFP Introduction/Background

This section will describe the purpose of the RFP, summarize administrative matters and provide some background information on the Project. It will also outline the regulatory process which must be followed by the Preferred Proponent.

A detailed description of the Project will be provided, including the scope of the Project, the responsibilities of the Proponent, the Study, maps showing the expected start and end points, technical specifications and estimated in-service dates. The RFP will identify that the AESO will **not** define the route of the Project and that each Proponent must develop a Preferred and Alternative route.

The AESO will provide a detailed description of the risks which are retained by the AESO and which ones are shared between the AESO and the Proponent. This will include a description of the mechanisms which will be used to calculate the cost adjustments for shared risks. Unless expressly identified, all other risks associated with the Project will be transferred to the Proponent.

2. Business Arrangements

Payments will not commence until energization of the Project. The following payments will be made to the Preferred Proponent:

a) Capital payments of a fixed monthly amount throughout the term of the contract based upon the Preferred Proponent's bid, as adjusted in accordance with the Project Development Agreement as described in Section 6. The payments will be made on a monthly basis.

b) Fixed Operations and Maintenance payments based upon the Preferred Proponent's bid. The Fixed Operations and Maintenance payments will be indexed based upon indices predetermined by the AESO and of which Proponents will be made aware. The payments will be made on a monthly basis.

c) Variable Operations and Maintenance payments based upon the Preferred Proponent's bid as adjusted in accordance with the Project Development Agreement. The Variable Operations and Maintenance payments will be indexed based upon indices predetermined by the AESO and of which Proponents will be made aware. The payments will be made on a monthly basis.

d) Major Maintenance payments based upon the Preferred Proponent's bid as adjusted in accordance with the Project Development Agreement. The Major Maintenance payments will be indexed based

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upon indices predetermined by the AESO and of which Proponents will be made aware. The payments will be made on a monthly basis.

All payments (except Fixed Operations and Maintenance payments) will be adjusted based upon the final route approved by the AUC. These adjustments will account for both changes to the route and the passage of time necessitated by the AUC Facilities Application Process and will be documented in either the Project Development Agreement or the Project Agreement. Please refer to the Adjustment Mechanisms section under the summary of the Project Development Agreement for more information.

With issuance of the RFP there will be a Draft Project Development Agreement and Draft Project Agreement which outlines commercial terms. Proponents will have at least two (2) opportunities to provide comments on the Draft Project Development Agreement and Draft Project Agreement during the RFP preparation stage and will receive the final forms of the Project Development Agreement and Project Agreement prior to RFP submission date. Proponents must submit proposals on the basis that the final Project Development Agreement and final Project Agreement will be executed by the AESO and the Preferred Proponent.

At the end of the 40-year term the Project must meet performance standards outlined in the Project Agreement.

3. Other Matters

This section will deal with administrative matters concerning eligibility, conflict of interest, ownership of documents and intellectual property, collusion, lobbying, amendments to or cancellation of the process and other related administrative matters.

Proponents will be required to perform their own due diligence on the Project and their proposed route, including but not limited to geotechnical risks, environmental issues, land and right-of-way acquisition costs, securing of long lead time items, and other due diligence as required. The Preferred Proponent will be required to maintain mandatory insurance coverage defined by the AESO.

4. Proposal Submission and Selection Process:

This section will provide the Proponents with an overview of the process and the proposed schedule for the RFP process. The overview will include an explanation of what will ultimately involve submission of two (2) packages:

- SR 1 Technical Submission and Indicative Financial Submission, and
- SR 2 Final Offer

Prior to being named the Preferred Proponent, the Preferred Proponent will be required to post a Preferred Proponent Letter of Credit of ● expiring no earlier than [X] days after being selected the Preferred Proponent from a Canadian Bank with a Credit rating of A+ or greater as rated by Standard & Poor or other credit rating agency approved for the selection process. Administrative matters such as information meetings, electronic data rooms and the procedures for questions and comments will be in this section.

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The AESO will pay an honorarium in the amount of ● to each Proponent who submits a compliant SR Package 2 and otherwise complies with the terms of the RFP and who is not selected as the Preferred Proponent.

A Fairness Monitor will oversee and report on the RFP process.

5. RFP Evaluation and Response format:

Proponents will be required to submit two routes (preferred and alternate) at the time of each submission. Proponents will be asked to submit the following information and documentation in respect of both routes in all submissions unless otherwise notified.

a) **SR1: Technical Submission and Indicative Financial Submission**: The technical submission will be evaluated against the technical requirements on a pass/fail basis. The submission will include but is not limited to:

   i. General proponent information
   ii. Two proposed routes
   iii. Design reports
   iv. Construction management plans
   v. Contractors construction schedule
   vi. Safety and emergency plans
   vii. Operational plans
   viii. Maintenance plans
   ix. Communication plans
   x. End of term plans
   xi. Quality management plans

The Indicative Financial Submission, except for the Proponent's financial models and financial capacity, will not be evaluated and is only for informational purposes. The submission will include a financial model for each route consistent with the outlined specifications and will identify all Project costs including equity returns, the Proponent's Project Development Fee (as defined in Appendix G), indicative financing costs based on the proposed financing structure, and details regarding any changes in financial capacity from that provided in the RFQ stage. Committed pricing for debt financing will not be required at the RFP stage.

The Proponent's financial models and financial capacity will be examined on a pass/fail basis.

The submission requires that the Proponent demonstrate its commitment and ability to implement the security packages and insurance packages outlined in Appendix G.

Both routes must pass the SR1: Technical Submission and Indicative Financial Submission as a pre-condition to being invited to submit a Final Offer.

b) **SR2: Final Offer:** The Final Offer will be evaluated on two scoring criteria.

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The first scoring criteria worth [90%] of the total, is the NPV of the Project costs including the Proponent's Project Development Fee, engineering, procurement and construction (EPC) costs, operations, maintenance and major maintenance costs of the two routes for a 40-year period.

The second scoring criteria worth [10%] of the total, is the reasonableness of the indicative financing plan included in the Final Offer. This will **not** be scored based upon the cost of financing. It will be scored on the reasonableness of the indicative financing structure and pricing compared to then current market conditions.

The financial model, the Security Package and the Insurance submissions will be evaluated on a pass/fail basis.

The Final Offer will include all technical information submitted previously and financial models identifying the final details of the financing structure including the committed return on equity and debt to equity ratio, which will form the basis for future debt pricing adjustments.

6. Project Development Agreement

The AESO will enter into a Project Development Agreement (PDA) with the Preferred Proponent. The PDA will identify the responsibilities and the time frame within which the Preferred Proponent undertakes to develop the Project (principally to obtain route approval from the AUC including a permit to construct and a license to operate the Project) and to arrange committed financing for the Project, but could also encompass any other specific development requirements.

The term of the PDA will commence shortly after the Preferred Proponent has received notification that it is the Preferred Proponent and will terminate upon the earlier of:

a) three (3) years or

b) AUC approval of the route; the AESO and the Preferred Proponent settling the Adjusted Project Costs (which are to be determined in accordance with the adjustment mechanisms contained within the PDA), and the Preferred Proponent settling committed financing for the Project.

c) the Preferred Proponent settling committed financing for the Project.

The term of the PDA can be extended by mutual agreement of the parties.

7. Adjustment Mechanisms

Once the route has been approved and the Preferred Proponent has obtained committed financing for the Project, the Preferred Proponent's project costs (per its original Project Costs as submitted with its Final Offer) will be adjusted to reflect the following:

1. Route Adjustment for:
   a. Capital Costs
   b. Variable Operating & Maintenance Costs

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c. Major Maintenance Costs
2. Timing Adjustment – Capital Costs
3. Financing Adjustment – Capital Costs

7.1. Route Adjustment

The Route Adjustment will take into account the following factors:

- Length – proponents will have to bid a cost per kilometre (km) to take into consideration changes in route length.
  - The Preferred Proponent's estimated cost will be adjusted to reflect the increase or decrease in the number of kilometres for the approved route multiplied by the cost per km bid in the Final Offer.
- Surface/Subsurface – proponents will have to bid surface and subsurface condition adjustment factors for five (5) surface and subsurface conditions. Proponents will have to identify the subsurface conditions along their proposed route (e.g., 'x' km of the route is likely to be surface condition 1, 'y' km is likely to be surface condition 2, etc.
  - The Preferred Proponent's estimated cost will be adjusted to reflect the anticipated conditions associated with the approved route.
  - The Preferred Proponent's price will be adjusted to reflect the number of kilometres impacted by the relevant conditions using the surface and subsurface condition adjustment factors.
- Structures – Proponents will have to bid the number and type of structures (e.g., dead end structures, deflection structures, tangent structures) expected.
  - The Preferred Proponent's estimated cost will be adjusted to reflect the differences in the number of structures for the approved route as compared to the proposed route.
- Land and Right-of-Way – The Preferred Proponent's estimated cost will be adjusted to reflect the increase or decrease in land and right-of-way acquisition costs associated with any change in route length.
  - The Preferred Proponent will not be entitled to recover all Route Adjustments so as to encourage Proponents to submit a realistic bid. There will be no adjustments for any changes within ±5% of the Preferred Proponent's Final Offer. For any additional costs beyond the ±5%, the value of the Route Adjustments will be capped at [10%] of the change in construction costs, i.e., if the Route Adjustment results in a 15% or greater increase in cost, Preferred Proponent's will only be able to recover 10% of the cost increase.

7.2. Timing Adjustment

The Timing Adjustment will take into account the following factors associated with the passage of time that are beyond the control of the Preferred Proponent:

- Inflation (Alberta Component) – Proponents bid that portion of their construction costs subject to adjustment for inflation in labour rates. The Preferred Proponent's Final Offer will be adjusted to reflect the change in Alberta labour rates (using an Alberta labour index or construction index) from the date of Final Offer to AUC route approval. There is no cap to adjustments related to Timing Adjustment.

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7.3. Financing Adjustment

The Preferred Proponent will be required to run a funding competition to obtain committed finance and update financing costs (updated financing costs) prior to execution of the Project Agreement and construction start. The outcome of the funding competition will adjust only the pricing of the debt to reflect the then current market conditions and will be based on the financing structure identified in the financial model submitted with the Final Offer.

Changes in the financing structure will not be permitted unless the Preferred Proponent can demonstrate that an alternative financing structure will result in a reduction in the Updated Financing Costs.

Subject to the foregoing, the Project Costs will be updated to reflect the actual financing costs resulting from the funding competition.

8. PDA Termination

In the event that the AESO terminates the PDA, or the PDA expires, or the Project Agreement is not executed, the Preferred Proponent will be paid an amount that will be at least equal to the honorarium paid to the unsuccessful Proponents but not to exceed the Project Development Fee as identified in the Preferred Proponent's financial model submitted with its Final Offer, or the actual costs reasonably incurred by the Preferred Proponent during the term of the PDA.

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Appendix G

Draft Contract Term Sheet

The purpose of this draft contract term sheet is to describe the key commercial terms that will underpin the proposed Competitive Process.

1. PROJECT SCOPE

- Describes the project including its size, timing and estimated cost

2. TERM

- 40 years

Rationale:

- Matches asset life
- Minimizes the impact on the cost to ratepayers as it allows for a longer amortization period to recover capital costs and results in lower annual tariffs
- Preferred Proponent will be incentivized to ensure proper operations and maintenance in order to maximize asset life
- Reduces residual value issues

3. EXTENSION OF CONTRACT

- The AESO has the option to renew the contract for rolling [5]-year terms with payments to cover O&M costs plus an agreed margin
- Five (5) years prior to the end of term, parties to the contract will commence discussion on life extension issues
- Determination of payments will either be subject to cost-of-service regulation or work will be put out to competitive bid.

Rationale:

- Preferred Proponent incentivized to ensure proper O&M in order to maximize asset life
- Payments reduced as capital has been recovered in the initial term payments

4. FINANCING

- Preferred Proponent responsible to structure financing at RFP submission
- Proponents are to provide indicative pricing based on a financing structure
- Evaluation of the RFP will be based [90%] on NPV of project costs excluding financing costs (debt costs) and [10%] on the reasonableness of the indicative financing structure (return on equity, debt to equity ratio) and indicative pricing compared to market conditions
- Proponents must fix the equity return and the debt to equity ratio at RFP submission (these will not be adjusted at financial close unless it can be demonstrated that changing the financing structure will result in lower financing costs.

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Prior to construction:

- Preferred Proponent to run a funding competition to get committed pricing for financing based on their original financing structure as per the financial model at RFP submission. If there is a substantial change in the financial markets, bidders may propose an alternative financing structure if they can demonstrate cost savings
- Financing costs will be adjusted accordingly
- Lenders must accept the commercial terms in the final Project Agreement
- The cost of one (1) refinancing for any portions of the debt that have terms shorter than 40 years will be a cost adjustment
- Subsequent refinancing gains will be shared

Rationale:

As there is a long lead time [between 2 to 3 years] from RFP submission to the start of construction, it will be difficult to evaluate or rely on the financing costs provided at the RFP stage as:

- Lenders will not be able to hold pricing or terms over such a long period of time
- Appropriate external benchmarks are not available to adjust financing costs from RFP submission to financial close
- Proponents are not able to assume the risks and costs of changes in financial markets which may include: changes in capital structure, changes in availability and term of funding sources and/or instruments, e.g., bond and bank debt, changes in the required developer security package and changes in interest rates
- The above structure is designed to reduce gaming at RFP as the financing solution and pricing will be scored based only on how closely they reflect current market conditions
- The indicative terms and financing structure provided at the RFP stage will form the basis for the pricing adjustments prior to construction
- Debt market capacity issues are reduced as proponents will not need full debt commitments from a large number of lenders as they will work with a small number of potential lead arrangers to help structure the financing terms and provide indicative pricing
- If there are major changes in the financial market and lenders are unwilling to accept the same commercial terms, there is a risk that there could be significant changes to the financial terms (resulting in increased financing cost), or that lenders may require changes to the commercial terms (which may impact the project costs)

5. PERFORMANCE STANDARDS

- To be determined by the AESO

6. PAYMENT MECHANISM – GENERAL PRINCIPLES

- Payments commence post-energization and will be made monthly over the Term (40 years)
- Payments will consist of the following:

  1. Capital payments of a fixed monthly amount throughout the term of the contract based upon the Preferred Proponent's bid and adjusted for route, timing and financing changes, as adjusted in accordance with the Project Development Agreement. The payments will be made on a monthly basis.
  2. Fixed Operations and Maintenance payments based upon the Preferred Proponent's bid. The Fixed Operations and Maintenance payments will be indexed based upon indices predetermined by the

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accordance with the Project Development Agreement. The payments will be made on a monthly basis.
2. Fixed Operations and Maintenance payments based upon the Preferred Proponent's bid. The Fixed Operations and Maintenance payments will be indexed based upon indices predetermined by the AESO and of which Proponents will be made aware. The payments will be made on a monthly basis.
3. Variable Operations and Maintenance payments based upon the Preferred Proponent's bid and adjusted for route changes as adjusted in accordance with the Project Development Agreement. The Variable Operations and Maintenance payments will be indexed based upon indices predetermined by the AESO and of which Proponents will be made aware. The payments will be made on a monthly basis.
4. Major Maintenance payments based upon the Preferred Proponent's bid and adjusted for route changes as adjusted in accordance with the Project Development Agreement. The Major Maintenance payments will be indexed based upon indices predetermined by the AESO and of which Proponents will be made aware. The payments will be made on a monthly basis.

The O&M stream will be reset after year 20:

- utilizing benchmarking study, or
- as a result of three competitive tenders on O&M work

The capital costs, variable O&M costs, and major maintenance costs bid by the Preferred Proponent will be adjusted to take into account uncertainty associated with the route and timing issues. The adjustment mechanism will be developed based on the following key principles:

- Risks that are best managed by Proponents will be transferred to Proponents
- Risks that are better retained by ratepayers will be subject to predetermined change mechanisms / variations
- Predetermined adjustments minimize risk and provide greater cost certainty
- Adjustment mechanisms (could be formulaic and/or negotiated) will be developed for risks and will include route and time related adjustments
- Route adjustments will allow for changes in route length and varying geotechnical conditions and the impact of these factors on EPC and O&M
- Time related adjustments will allow for changes in general price increases/decreases, i.e., labour prices
    - Route Adjustment – to take into account changes in route length, surface conditions, number of structures and land acquisition costs. There will be no change to the capital costs if the value of the Route Adjustment is within ± 5% of the original cost estimate (this is to encourage Proponents to submit as realistic a cost estimate as possible). For any additional costs beyond the ±5%, the value of the route adjustments will be capped at [10%] of the change in construction costs (i.e., if the route adjustment results in a 15% or greater increase in costs, bidders will only be able to recover 10% of the cost increase).
    - Timing Adjustment – to take into account timing uncertainty as it relates to construction inflation (labour)
    - Financing Adjustment – as described in Section 4, Financing.
- Proponent will also have to tender a "Project Development Fee" for the costs of developing the project prior to construction commencement (e.g., internal and external due diligence costs and development

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costs such as preliminary design and engineering, geotechnical costs, deposits on long lead items, legal, technical or other advisory fees, but will not include land acquisition costs). The Project Development Fee will not be subject to adjustment.

7. AVAILABILITY AND PERFORMANCE DEDUCTIONS

- Payments will be subject to availability and performance deductions.
- The AESO to determine the appropriate availability deduction thresholds.

The AESO to determine the performance standards (i.e., Key Performance Indicators) and the associated deduction levels for failure to achieve the required performance levels.

8. RELIEF EVENTS

- The Preferred Proponents costs and/or schedule will be adjusted if specified “Relief Events” occur. Relief events will most likely include:
  - Changes in law, e.g., legislative changes or increases in taxes.
  - Force majeure, (these will be narrowly defined events similar to those in a P3 contract, e.g., war, epidemic, nuclear explosion, etc.)
  - Scope change initiated by AESO/AUC
  - Delays resulting from the public sector
  - Other delays or changes that are not within the Preferred Proponent’s control or cannot be reasonably anticipated (e.g., discovery of artifacts)
  - Uninsurable events

Rationale:

- Follows the general principle that risk will only be transferred to the Preferred Proponent when the Preferred Proponent is in the best position to manage that risk

9. SECURITY REQUIREMENTS

Procurement stage:

- Proponent Letter of Credit from shortlisted Respondents prior to receipt of RFP
- Subject to the terms of the RFP, the Proponent Letter of Credit is released if the Proponent is not selected as the Preferred Proponent
- Proponent Letter of Credit is withdrawn if the Proponent does not submit a compliant RFP bid or fails to provide the Preferred Proponent Letter of Credit.
- A Preferred Proponent Letter of Credit will be required when the Preferred Proponent is selected and released after Financial Close when the AESO is satisfied that an amount equivalent to the value of the Preferred Proponents Letter of Credit has been expended or otherwise unconditionally committed to implementation of the Project.

Construction period:

- Parental guarantee for performance subject to a cap on liabilities of between 35% to 50% of EPC contract value
- Surety bonds on materials and labour of between 35–50% of EPC contract value.
- Liquidated damages for schedule delays
- Letter of Credit of between 5–10% of EPC contract value

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Operating period:

- Parental guarantee for performance subject to a cap on liabilities of between 1 to 3 times the annual O&M payment or 1–3x
- Letter of Credit of between 1 to 2.5 times the annual O&M payment or 1–2.5x

The AESO will not require additional security during the construction and operating periods if similar levels of security are provided to project lenders as the AESO would be expected to have the benefit of such security.

10. COMPLETION TESTS

- To be determined by the AESO

11. REPORTING REQUIREMENTS

- To be determined by the AESO

12. INSURANCE

Construction Period:

- "Wrap-up liability" insurance with a single limit of $________ per occurrence
- Course of construction (COC) insurance covering a) materials and property, and b) damage to or loss of CTI, in an amount not less than 100% of the replacement cost
- Professional liability insurance (E&O) covering Proponent's design of the CTI in the amount of $________ per occurrence

O&M Period:

- "All Risk" insurance for damage to or loss of CTI in an amount net less than 100% of the replacement cost
- General liability insurance covering normal business risks with a single limit of not less than $________ per occurrence and a deductible of not more than [$1,000,000]

13. DISPUTE RESOLUTION

- As per current incumbent TFO T&Cs

14. DEFAULT

- Any misrepresentation or breach of warranty made by the Preferred Proponent that would have a material adverse impact on the performance of the Preferred Proponent's obligations in respect of the project.
- Winding-up or liquidation of the Preferred Proponent
- Bankruptcy of the Preferred Proponent
- Abandonment of the project by the Preferred Proponent
- The rolling average Availability, as it relates to the Facilities' Transmission Lines, is less than [X%] for a period of 12 or more consecutive Operating Months.
- Breach of material obligation or covenant
- Persistent failure to meet performance standards or failure to remedy within a reasonable period of time
- Failure to secure AUC FA approval within a specified timeframe

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- Failure to achieve energization within [X] days of a target energization date

15. TERMINATION

Preferred Proponent Default Termination:

- The above defaults will lead to termination
- Preferred Proponent will be paid the residual value of the project less insurance proceeds and all costs incurred by AESO to continue the services under the contract
- Preferred Proponent to transfer all project assets to an entity that will be determined by AESO upon payment (i.e., an incumbent TFO or the Preferred Proponent of an alternative competition)

Rationale:

- Preferred Proponent is at fault and should be responsible for paying all of AESO's costs to continue the services

No Fault Termination:

- where a force majeure event substantially prevents the performance by a party of its material obligations under the contract
- where insurance proceeds are insufficient to cover the cost of the repair of significant damaged facilities
- Preferred Proponent will be paid the balance of any equity investment that has not been recovered, plus outstanding debt principal less the residual value of the project and any insurance proceeds

Rationale:

- This is a shared risk as both parties are not able to manage this risk.

Public Sector Termination:

- The public sector can terminate the contract by providing a notice to the Preferred Proponent.
- Preferred Proponent will be paid the net present value of the remaining balance of the return of and on equity plus outstanding debt principal plus all related breakage costs less the residual value of the project and any insurance proceeds

Rationale:

- Preferred Proponent is not at fault and should be kept whole.

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Appendix H

Land Research Study - *Table of Contents*

- Land
  - Crown lands (vacant and occupied)
  - Freehold lands
  - Terrain mapping
  - First Nations reserve lands
  - Treaty entitlement lands
  - Traditional territories (publically available information)
  - Métis settlement areas
  - Crown dispositions such as agricultural, forest management areas, trapper, guide and outfitter areas
  - Mineral leases or other subsurface dispositions
  - Surface material (such as gravel, sand and clay)
  - Recreationally designated lands
  - Federal and provincial reserve lands
- Environmental information
  - Waterways (including classifications for watercourses and wetlands)
  - Forestry management strategic plans
  - Wildlife information (SARA listed species protected habitat areas etc.)
  - Soil class mapping
  - Vegetation mapping and known locations of rare plant species or plan communities
  - Known historical, archaeological or paleontological areas of importance
- Infrastructure
  - Existing and planned roads and highways (including widenings)
  - Existing and planned transmission utility corridors
  - Existing and planned pipelines
  - Existing and planned electric transmission facilities
  - Existing and planned telecommunications equipment
  - Airports
  - Military bases
  - Sewage treatment facilities
  - Landfills
  - Cemeteries
  - Water treatment plants/reservoirs
- Social
  - Subdivision applications
  - Municipal/urban development plans
  - Annexations
  - Schools/community centres
  - Patterns of dealings (past compensation for infrastructure to landowners)

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Appendix I

Proposed Structure of the EOI

The EOI will be sent to reputable domestic and international transmission developers and other interested parties. The purpose of the EOI is to obtain feedback from candidates likely to participate in the competitive process in order to ensure that the transaction is structured to maximize participation and competition during the later competitive procurement phases of RFQ and RFP.

A draft Table of Contents for the EOI is set out in Schedule ●[ ] to this Appendix.

The EOI sent to interested parties will include, but is not limited to, the following sections:

EOI Introduction/Background: This section will describe the purpose of the EOI process as well as provide a brief description of the primary objectives of the Project itself. This section will also describe the role of AESO in relation to the Project and the role of the AUC so the responsibilities of each party are clear to interested parties.

Project Information: This section will contain information on the background to the Project and will include cross references to additional publicly available information on the development of the Competitive Process and stakeholder consultations so that interested parties who may not have been involved in the stakeholder consultations to date will have full information and be in a position to submit an Expression of Interest.

- The proposed scope of the Project will be described and the proposed responsibilities of the AESO will be clearly set out.

An overview of the proposed process and schedule will be provided. The purpose of providing this level of detail is to give interested parties sufficient information to enable them to confirm their interest in participating in the Project.

EOI Submission Requirements:

This section will specify AESO's preferred format for receipt of responses. The amount of information requested by AESO will recognize that participation in the EOI process is not a prerequisite to participation in later stages of the Competitive Process and that participation in the EOI process itself is not evaluated.

AESO will request general information about the company responding to the EOI, its proposed contact person and its proposed role in the Project. This information will be published to allow teaming.

EOI Information Meeting:

This section will set out details of the information meeting that AESO will hold to share information about the project with interested parties.

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