July 30, 2015

AESO Stakeholders

Dear Stakeholder:

Re: **Invitation to Participate in Consultation on AESO 2017 Tariff Application**

The AESO is beginning development of its 2017 ISO tariff application, to be filed with the Alberta Utilities Commission ("AUC") by June 30, 2016. The AESO invites stakeholder to a consultation meeting to discuss the scope of proposed changes to be included in the application.

Date:	Wednesday, August 19, 2015
Time:	9:00 AM to 11:00 AM
Place	AESO Boardroom, 25th Floor, 2500, 330 – 5th Avenue SW, Calgary, Alberta
Teleconference:	Phone number 1-866-835-7781 and code 8215976118#
RSVP:	By **Wednesday, August 5, 2015** to Brenda Hill, 403-539-2850 or brenda.hill@aeso.ca

The AESO is interested in hearing stakeholder views on topics to be reviewed for the 2017 tariff application, as discussed further below, as well as appropriate processes to use to review those topics and determined what, if any, related tariff changes should be proposed.

The AESO expects to focus on the following topics in the development of its 2017 tariff application:

(a) transmission cost causation study methodology to reflect current transmission system costs and configuration;

(b) point of delivery ("POD") cost function database update;

(c) directions 5-8 from AUC Decision 2014-242 *2014 ISO Tariff Application and 2013 ISO Tariff Update*, which concerned congestion and the classification of the costs of advancing transmission facility projects at the request of a market participant;

(d) method for cost classification of facilities that are shared by one or-more market participants;

(e) charging a market participant for incurred system-related costs when a connection projects is cancelled; and

(f) structure of Rider C to minimize deferral account imbalances among customers.

The AESO is interested in hearing stakeholder views on the above list of topics to be addressed in the 2017 tariff application, as well as any additional topics stakeholders feel should be included. The AESO has used small working groups for consultation on other recent applications, and suggests working groups may also be appropriate to review at least some of these topics.

 Confidentiality: Public

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If you intend to participant in this consultation meeting, please RSVP by **Wednesday, August 5, 2015** to Brenda Hill, 403-539-2850 or brenda.hill@aeso.ca. If you are unable to attend this meeting and would still like to provide comments to the AESO, please contact me to discuss other ways to become involved in the consultation.

All information relating to the AESO's 2017 tariff consultation will be available on the AESO website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2017 Tariff. As well, new information posted by the AESO on this topic will be mentioned in the AESO stakeholder newsletter, which you can subscribe to by clicking "Sign-up for our stakeholder newsletter" at the lower right of the AESO's home page at www.aeso.ca.

If you need any additional information related to this consultation, please contact me at 403-539-2555 or by email to larhonda.papworth@aeso.ca

Yours truly,

[original signed by]

LaRhonda Papworth
Manager, Tariff Applications

cc: Doyle Sullivan, Director, Regulatory Transmission, AESO
Lee Ann Kerr, Manager, Tariff, AESO
Raj Sharma, Senior Regulatory Analyst, AESO

Consultation on Scope of AESO 2017 Tariff Application

LaRhonda Papworth, Manager, Tariff Applications
Lee Ann Kerr, Tariff Manager
Raj Sharma, Senior Analyst
John Martin, Senior Tariff and Regulatory Advisor

August 19, 2015 — AESO Office, Calgary

Agenda

- Introduction and objectives (slides 1-3)
- Topics Currently in Progress (slides 4-8)
- 2014 Tariff Application Background (slides 9)
- Topics proposed for 2017 Tariff Application(slides 10-17)
- Cost Causation Study (slides 18-20)
- Rates Update (slides 21-24)
- Rider C and Deferral Accounts (slides 25-28)
- Other topics?(slide 29)
- Consultation process and next steps (slides 30-31)
- Discussion and wrap-up (slides 32-33)

Please feel free to ask questions during presentation

Objectives

- Familiarize stakeholders with topics identified by AESO for 2017 tariff application
- Identify additional topics (if any) for 2017 tariff application
- Identify concerns to be addressed for those topics
- Decide consultation process for development of application

Topics Currently in Progress

- Topics currently in progress will be included as approved in decisions resulting from those processes
- Directions 5-8 on advancement costs and related provisions
  – Currently before the Commission in Proceeding 3473
  – Decision expected in late August 2015
- Transmission constraint rebalancing charge
  – Currently before the Commission in Proceeding 20623
  – Decision expected by December 2015
- Interim loss factors in Rates STS, DOS, IOS, XOS
  – Currently before the Commission in Proceeding 790
  – Final loss factors expected to become available in 2016

Topics Currently in Progress (cont'd)

- Changes to ISO rule 505.2 (previously 9.5) on performance criteria for generating unit owner's contribution refund
  - Revision of the rule to adopt an availability criteria rather than energy production as the primary performance criteria
  - Pre-consultation notice to stakeholders posted August 6, 2015
  - Revised rule to be posted in late August in line with existing consultation process for development of ISO rules
  - Revised rule expected to become effective in late 2015
- 2015 tariff update
  - Update of rate and investment levels to reflect 2015 costs
  - Filed on August 18 (Proceeding 20753)
  - Proposed to be effective January 1, 2016

Topics Currently in Progress (cont'd)

- 2013-2014 deferral account reconciliation application
  - Reconciliation of deferral account balances for 2013 and 2014
  - To be filed by end of August
  - Request for interim settlement in November 2015
- 2016 tariff update
  - Update of rate and investment levels to reflect 2016 costs
  - To be filed Q1 2016
  - Expected to be effective April 2016

Topics Currently in Progress (cont'd)

- Terms and conditions alignment filing
  - Revision of tariff provisions to align with AESO initiatives and internal process refinements
    - Improving system access service agreement language
    - Updating provisions to accommodate the market participant choice initiative
    - Revisions to support transmission connected customers of distribution system owners
    - Revisions to support the abbreviated needs approval process
  - To be filed in Q4 2015
  - Expected to be effective April 2016

Topics Currently in Progress (cont'd)

- Energy storage initiative
  - AESO working with the University of Calgary to study the differences between storage and conventional load and generators – target completion is Q4 2015
  - Results from the study will inform study of cost and other impacts in order to accommodate energy storage in ISO tariff
  - Depending on outcome, potential revisions to accommodate energy storage in 2017 tariff application

2014 Tariff Application Background

- 2014 ISO tariff filed with the Commission in July 2013 and became effective July 1, 2015
- Some items to be discussed are in response to Commission directions in Decision 2014-242 on the 2014 ISO tariff application
- Directions 5-8 are still outstanding with a decision from the Commission expected in August 2015

Topics Proposed for 2017 Tariff Application

- Not proposing any major changes
- In response to Commission directions the AESO will address:
  - Contract capacity versus installed capacity for point of delivery cost function
  - 2017-2019 cost causation update
  - Rider C and deferral accounts
- 2017 revenue requirement will initially be a high-level estimate
  - Later updated with transmission facility owners’ 2017 tariff applications
  - Later updated with AESO 2017 budget

Decision 2014-242 Directions 5 to 8

- **Reason**: Respond to Commission directions
- The AESO sought clarification in the 2014 tariff compliance filing on the Commission Directions 5 to 8
- The Commission established a separate module in Proceeding 3473 in its clarifying letter on February 9, 2015
- Decision expected in late August
- AESO will implement and post revised tariff as required

Point of Delivery Cost Function

- **Reason:** Respond to Commission directions
- In Decision 2014-242 the Commission directed:

  The AESO is directed to use the full increased capacity made possible by an upgrade project. If the AESO cannot reasonably determine this capacity level for any given project, then the project should be excluded from the database.

- The AESO complied with this Direction but acknowledged that compliance had resulted in unanticipated impacts, as explored in certain information requests, and that the full impact would not have been clear during the 2014 tariff proceeding

Point of Delivery Cost Function (cont'd)

- The Commission found that the direction had "resulted in unanticipated effects" and implementation should be delayed until "the matter can be thoroughly explored"
- AESO considers two options should be explored
  - Cost function based on contract capacity
  - Cost function based on installed capacity
- Either option should apply to both greenfield and upgrade projects
- Must also consider impact of projects contracting for 0 MW capacity increases
- Should consider implications for cost recovery through rates and investment

Connection Project Database Update

- **Reason:** Update study that underlies tariff
- Update final costs where available for all projects in the connection project database
- Add new projects that have been granted permit and licence
- Update capacities based on outcome of option exploration
- The resulting point of delivery cost function will be used to update:
  - Rate DTS, *Demand Transmission Service*
  - Rate PSC, *Primary Service Credit*
  - Investment levels in section 8 of ISO tariff

Recovery of system-related costs if connection project is cancelled

- **Reason**: Address issue raised in proceeding
- The current ISO tariff provides the authority to collect from a market participant any connection project costs that were classified as system-related if the connection project is subsequently cancelled
- AESO will review and determine if additional clarification is needed
  - Further guidance may come from Commission decision on Directions 5 to 8

Reclassification of Participant-Related Costs as System-Related

- **Reason**: Add clarity to tariff provision
- The current ISO tariff provides the authority to reclassify participant-related costs as system-related and vice versa
- The tariff does not specify details of how the costs are to be classified as participant-related or system-related
- The AESO is proposing to add details on the calculation that are similar to the calculation when facilities are shared between two or more market participants
  - Based on years and MWs

Provision of Historical Billing Data

- **Reason**: Address issue raised in proceeding
- The AESO will provide market participants with multi-year historical billing volume and service detail to enable consultation participants to analyze rate structure and impacts on a quantitative and objective basis
  - Raised in discussions after the 2014 tariff proceeding
  - Would include
    - Volume data (MWh, MW, coincident demand, substation fraction)
    - Service details (DTS, STS, direct-connect)
  - What data fields and what structure should be included?

2017-2019 Cost Causation Study Update

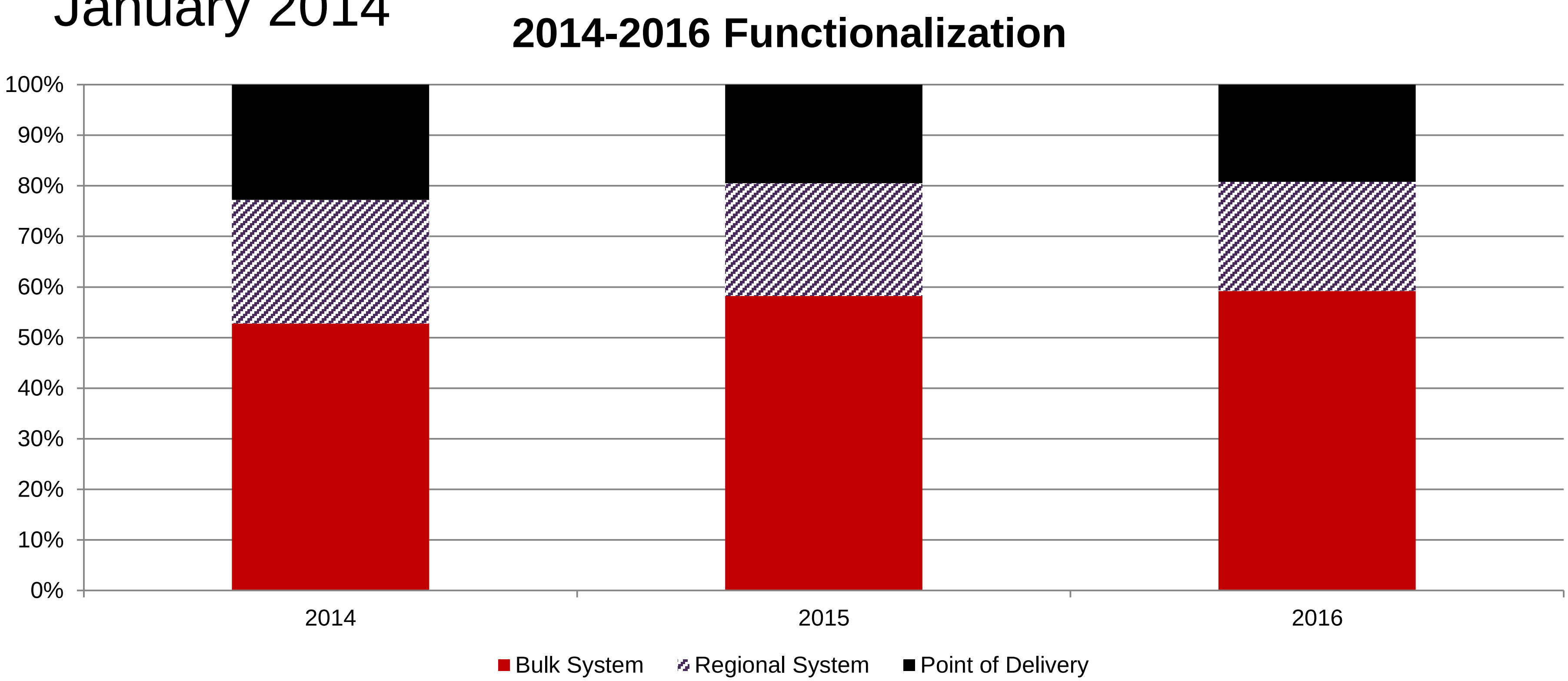
- **Reason**: Update study that underlies tariff
- The AESO included a 2014-2016 cost causation study prepared by London Economics International in its 2014 tariff application
  - The study established the inputs and methodology for a comprehensive cost causation study that used both capital and operating and maintenance cost data
  - A negotiated settlement process was used with participants and approved by the Commission
- The AESO proposes to update the study inputs itself using the identical methodology used for the 2014-2016 cost causation study
- Suggest consideration of negotiated settlement process

2017-2019 Cost Causation Study Update (cont'd)

- Proposed process
  - AESO update inputs for 2017-2019 cost causation study in Q4 2015
  - AESO presents results to stakeholders in January 2016
  - AESO files application to begin negotiated settlement process in February 2016 (in advance of 2017 tariff application)

Cost Causation Study History (cont'd)

- *The 2014-2016 Cost Causation Negotiated Settlement Agreement* was approved as filed November 27, 2013
- In accordance with agreement, an updated study was filed January 2014

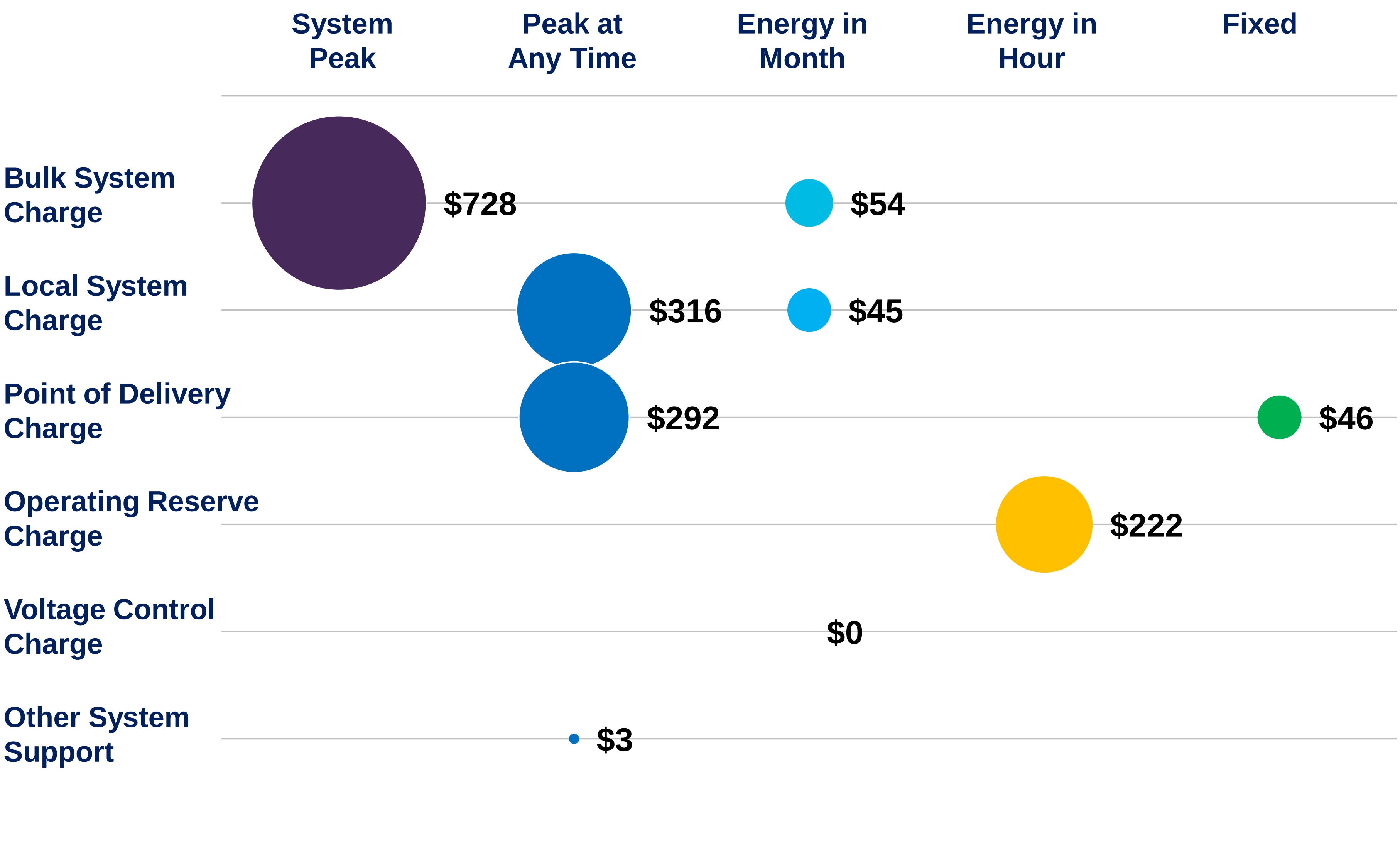


Cost Causation Study History (cont'd)

- 2014-2016 cost classification between demand and energy

2014-2016 Classification	Function	
	Bulk	Regional
Demand	93.1%	87.4%
Energy	6.9%	12.6%

Current 2014 Rate DTS Structure

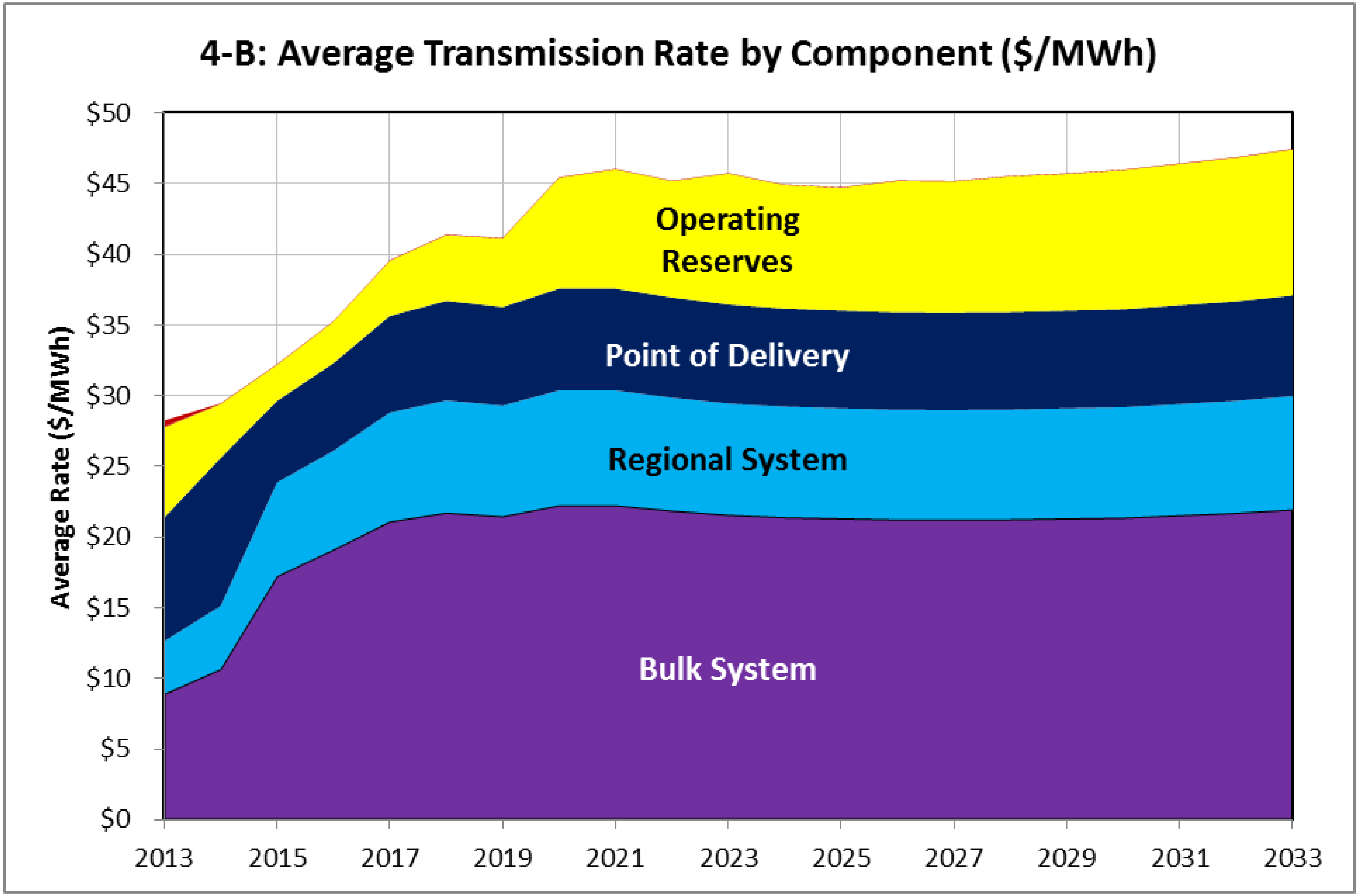


Costs in $ 000 000, based on AESO 2014 ISO Tariff, July 1, 2015

Transmission Rate Impact Projection

- **Reason**: Update information provided with tariff application
- AESO will include updated long-term transmission rate impact projection(TRIP) in 2017 tariff application
- AESO reviewing TRIP workbook development process of providing periodic updates
- Updating and posting now would not result in significant changes to rate impact

Transmission Rate Impact Projection (cont'd)

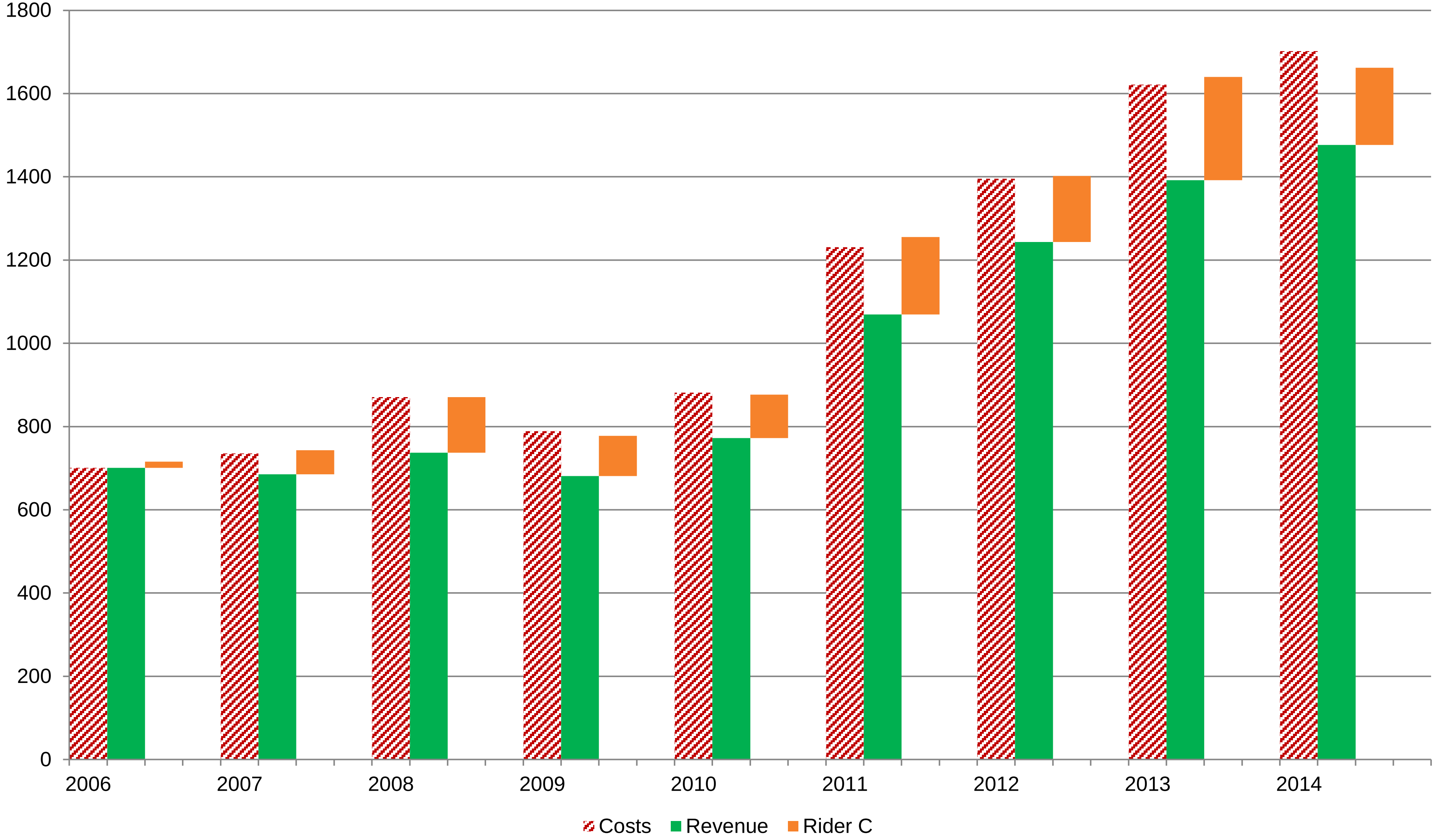


*Current posted TRIP Model

Rider C and Deferral Accounts

- **Reason**: Respond to Commission directions
- In 2014 ISO tariff proceeding, participants submitted that the AESO further examine the Rider C structure to minimize imbalances between market participants
- The Commission directed the AESO to discuss with stakeholders prior to filing its next general tariff application
- The AESO identified the following potential causes of large individual deferral account reconciliation charges or refunds:
  - Different bases for Rider C and Rate DTS components
  - Timing differences between Rider C collections and refunds as compared to production month deferral account reconciliations
  - Variance from forecasts of costs and revenues

Rider C History



Rider C Refinements

- Regular tariff update applications reduce the magnitude of Rider C
  - 2015 tariff update and 2016 tariff update (discussed earlier) should help
- The AESO’s initial investigation suggests a change in Rider C structure (from $/MWh to % of connection charge) would not significantly affect imbalances between market participants

Rider C Refinements (cont'd)

- Rider C has kept deferral account balances small but reconciliations still result in material transfers between customers
- 2013-2014 deferral account reconciliation application planned to be filed late August 2015

Additional topics?

Consultation Process

- How would stakeholders like to be involved?
  - Small working groups? On which topics?
  - Written comment process?
  - General stakeholder sessions?
- Potential stakeholder meetings
  - Late January
  - Written comment process
  - Application preview meeting
    - April?
  - Other comment opportunities?

2017 Tariff Application Schedule

2015

• Aug	1st Stakeholder consultation
• Sep	Comment matrix

2016

• Jan	2nd Stakeholder session
• Feb	File cost application
• Apr	3rd session/Application preview
• Jul	File 2017 Tariff Application
• Jul-Dec	Regulatory review process
• Dec	Refile application with 2017 revenue requirement

Discussion

- Questions?

For More Information

- LaRhonda Papworth
  Manager, Tariff Applications
  403-539-2555 or larhonda.papworth@aeso.ca
- Lee Ann Kerr
  Tariff Manager
  403-539-2741 or leeann.kerr@aeso.ca
- Raj Sharma
  Senior Analyst
  403-539-2632 or raj.sharma@aeso.ca
- All consultation documents can be found on AESO website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2017 Tariff

Thank you

August 26, 2015

AESO Stakeholders

Dear Stakeholder:

Re: **<u>Additional Information for Consultation on AESO 2017 Tariff Application</u>**

On Wednesday, August 19, 2015, the AESO and stakeholders participated in a consultation meeting to discuss the scope of changes to be included in the AESO's 2017 tariff application. This letter follows up on some of the matters discussed at the meeting, provides additional information on the consultation processes tentatively proposed by the AESO, and requests written comments from stakeholders on the tariff consultation.

1 *Transmission System Cost Causation Study*

In the 2014 tariff application, the AESO included a 2014-2016 Transmission System Cost Causation Study prepared by London Economics International. The study established the inputs and methodology for a comprehensive transmission system cost causation study that used both capital cost and operating and maintenance cost data. A negotiated settlement process was established and the resulting negotiated settlement was approved by the Commission.

(a) In its presentation, the AESO proposed to update inputs to the study while using the identical methodology used in the study included in the 2014 tariff application. The AESO would then present results of the updated study to stakeholders in January 2016.

(b) As well, the AESO proposed to file an application to begin a negotiated settlement process for the study-only portion in February 2016.

2 *Point of Delivery Cost Function*

In Decision 2014-242 at paragraph 260, the Commission directed the AESO:

> *… to use the full increased capacity made possible by an upgrade project. If the AESO cannot reasonable determine this capacity level for any given project, then the project should be excluded from the database.*

The Commission subsequently found, in Decision 3473-D01-2015 at paragraph 31, that the direction had "resulted in unanticipated effects" and implementation should be delayed until "the matter can be thoroughly explored". In light of the foregoing:

(a) The AESO considers that two options should be explored: (i) cost function based on contract capacity and (ii) cost function based on installed capacity. Either option should apply to both greenfield and upgrade projects. The AESO also noted that the impact of projects with zero MW incremental contract capacity must be considered. As well, implications for cost recovery through rates and investment need to be considered.

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(b) In consideration of the results from 2(a) above, the AESO will update the connection project database for final costs where available, add new projects for which permit(s) and license(s) under the *Hydro and Electric Energy Act* have been issued, and update capacities. The resulting point of delivery cost function will be used to update Rate DTS, *Demand Transmission Service*, Rate PSC, *Primary Service Credit* and investment levels in section 8 of the tariff.

3 Rider C and Deferral Accounts

In the 2014 tariff proceeding, participants submitted that the AESO should further examine the Rider C structure to minimize imbalances between market participants. The Commission directed the AESO to discuss with stakeholders prior to filing its next general tariff application. The AESO identified the following potential causes of large individual deferral account reconciliation charges or refunds in its 2014 tariff application:

- Different bases for Rider C and Rate DTS components;
- Timing differences between Rider C collections and refunds as compared to production month deferral account reconciliations; and
- Variance from forecasts of costs and revenues.

Regular tariff update applications reduce the magnitude of Rider C and therefore potentially reduce large transfers. The AESO's filing of tariff updates in a timely manner should therefore alleviate stakeholder concerns.

The AESO's initial investigation suggests a change in Rider C structure (from $/MWh to % of connection charge) would not significantly affect imbalances between market participants. The AESO has not identified any improvements to the tariff update, Rider C and deferral account reconciliation processes. The AESO indicated that it could present detailed results of the initial investigation in an upcoming stakeholder session.

4 Other Topics

The AESO also indicated as follows at the consultation meeting:

(a) The AESO will review and determine if additional clarification is needed to the tariff regarding the recovery of system-related costs if a connection project is cancelled. The Commission may provide further guidance on this topic in its decision, expected shortly, to address the AESO's compliance with directions 5 to 8 from Decision 2014-242.

(b) The AESO is proposing to add details of investment calculations upon reclassification of participant-related costs as system-related costs (and vice versa). These calculations would be similar to calculations performed when facilities are shared between two or more marked participants (based on contracted years and MWs)

(c) The AESO will provide market participants with multi-year historical billing detail to enable stakeholders to analyze rate design and its impacts on a quantitative and objective basis. This data could include volume data (MWh, MW, coincident demand, substation fraction) and service details (DTS, STS, direct-connect). The AESO is requesting feedback on the data fields and data structure that will be required.

(d) The AESO is currently reviewing the transmission rate impact project (TRIP) workbook development process, including providing periodic TRIP updates. A TRIP update today would not result in significant changes to rate projections. The AESO is proposing to post an updated TRIP with the 2017 Tariff Application in July 2016.

5 Suggestions from Consultation Meeting

Participants provided initial comments and suggestions on some questions asked by the AESO during the meeting. In particular, the AESO noted the following suggestions:

(a) The current operating reserve charge rate design was identified as an issue by a distribution facility owner (DFO).The DFO explained that regulatory lag results in it holding significant balances for a significant period of time. Some participants were supportive of current operating reserve charge rate design and commented that this is a distribution regulatory process issue.

(b) A participant raised the issue of investment levels not covering 60% of the similar average project costs. The AESO advised that it would not put this forward as a topic for the 2017 tariff application but that it would provide requested information to stakeholders enabling them to develop their proposals, if any.

(c) Participants commented that they support the AESO's focus on filing the comprehensive tariff application and the tariff update applications as soon as possible.

6 Preliminary Proposal for Consultation Process

The AESO will invite written comments on the information presented at the August 19 meeting, using a standard stakeholder comment form. More information is provided in section 7 below.

In addition, based on discussion at the meeting, the AESO proposes the following consultation process for the development of its 2017 tariff application:

(a) The AESO will hold a technical session in January 2016 to present:

  i. results of the updated transmission cost causation study for the 2017 tariff application, including capital-related costs, operating and maintenance costs, cost functionalization, and cost classification;

  ii. results of the thorough exploration of point of delivery cost function and update of the point of delivery cost database; and

  iii. results from AESO's investigation of alternative Rider C structure.

(b) The AESO will use a written comment process and, potentially one or two small working groups to consult on other changes to the tariff. The AESO will provide draft revisions to the tariff with relevant discussion and would then invite stakeholder comments on these draft revisions.

(c) The AESO will hold a general stakeholder consultation meeting in April 2016 to update stakeholders on the progress of the development of the 2017 tariff application.

7 Request for Written Comments

The AESO invites written comments from stakeholders on this discussion of the tariff application scope. The comment form is attached and includes specific topics discussed at the meeting. Stakeholders may provide comments on other tariff application topics using the “Other Comments” section of the comment form.

The AESO requests stakeholders to provide comments by returning the form to larhonda.papworth@aeso.ca by **Friday, September 11, 2015**.

All information relating to the AESO’s 2017 tariff consultation will be available on the AESO website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2017 Tariff. As well, new information posted by the AESO on this topic will be mentioned in the AESO stakeholder newsletter, which you can subscribe to by clicking “Sign-up for our stakeholder newsletter” at the lower right of the AESO’s home page at www.aeso.ca.

If you need any additional information related to this consultation, please contact me by phone (403-539-2555) or by email (larhonda.papworth@aeso.ca).

Yours truly,

[original signed by]

LaRhonda Papworth
Manager, Tariff Applications

cc: Lee Ann Kerr, Tariff Manager
Raj Sharma, Senior Analyst

Stakeholder Comments and AESO Responses on Scope of AESO 2017 Tariff Consultation

Background

On August 19, 2015, the AESO and stakeholders participated in a consultation meeting to discuss the scope of matters to be addressed in the AESO's 2017 tariff application. Based on discussion at the meeting, the AESO invited written comments from stakeholders on the information presented at the meeting and additional information provided by the AESO in a letter on August 25, 2015.

Comments were received from:

- ATCO Electric;
- AltaLink Management Ltd.;
- Capital Power;
- EPCOR Distribution & Transmission Inc. (EDTI);
- Industrial Power Consumers Association of Alberta (IPCCA); and
- Office of the Utilities Consumer Advocate (UCA).

The written comments from stakeholders are consolidated below, together with responses from the AESO, where applicable.

Both the meeting presentation and the letter are posted on the AESO website and can be accessed at www.aeso.ca by following the path Tariff ► Current Consultations ► 2017 Tariff.

Consultation Dates

Date of Request for Comments:	August 25, 2015
Period of Consultation:	August 25 – October 30, 2015

Stakeholder Comments on AESO Information

Stakeholder Comment	AESO Response
1(a) ***In its presentation for the 2017 tariff application, the AESO proposed to update inputs to the past study while using the identical methodology used in the 2014 tariff application. The AESO would then present results of the updated study to stakeholders in January 2016.***	
ATCO Electric: Indifferent ATCO Electric is interested in reviewing and understanding the AESO's updated study. While ATCO Electric supports this approach, ATCO Electric still reserves the right to test the methodology used in the tariff application.	The AESO acknowledges ATCO Electric's comment.
AltaLink: Support If there are no material changes for 2017 that would result in a	The AESO acknowledges AltaLink's

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Stakeholder Comment	AESO Response
material impact to the AESO's 2014 approved study then it would be cost and time effective for all stakeholders if the AESO uses the current approved study with updated inputs.	support.
Capital Power: Support Capital Power looks forward to reviewing the updated cost causation study and attending the January 2016 stakeholder session.	The AESO acknowledges Capital Power's support.
EDTI: No comments.	
IPCAA: No comments.	
UCA: Support The UCA was active in the NSA in the previous tariff and agreed to the voltage based functionalization.	The AESO acknowledges UCA's support.
1(b) As well, the AESO proposed to file an application to begin a negotiated settlement process for the study-only portion in February 2016.	
ATCO Electric: Indifferent At this point, it is difficult for ATCO Electric to support or oppose a negotiated settlement process without having the opportunity to review the application.	The AESO acknowledges ATCO Electric's comment.
AltaLink: Support Efficient, if no one objects to using the same study methodology as used in the 2014 tariff application.	The AESO acknowledges AltaLink's support.
Capital Power: Support Capital Power supports a negotiated settlement process for the study-only portion on the basis that it may streamline the regulatory approval process. Capital Power will determine the extent of its participation, if any, in the negotiated settlement process after reviewing the results of the study.	The AESO acknowledges Capital Power's support.
EDTI: No comments.	
IPCAA: No comments.	
UCA: Support The UCA felt the NSP increased efficiencies in the previous tariff application.	The AESO acknowledges UCA's support.
2(a) In order to thoroughly explore point of delivery cost function impacts, the AESO considers that two options should be explored, (i) cost function based on contract capacity and (ii) cost function based on installed capacity Either option should apply to both greenfield and upgrade projects. The AESO also noted that impact of projects with zero MW incremental contract capacity must be considered. As well, implications for cost recovery through rates and investment need to be considered.	
ATCO Electric: Support ATCO Electric supports this approach and looks forward to	The AESO acknowledges ATCO Electric's support.

Stakeholder Comment	AESO Response
understanding the merits of the two options and how the outcome may impact transmission access service payments.	
AltaLink: Support Both options should be reviewed with stakeholders to fully understand the pros and cons of each before establishing a position.	The AESO acknowledges AltaLink's support.
Capital Power: Support Capital Power supports the AESO's proposal to explore point of delivery cost function impacts.	The AESO acknowledges Capital Power's support.
EDTI: No comments.	
IPCAA: No comments.	
UCA: Support The UCA supports the exploration of POD cost function impacts and inquiry into installed capacity measures.	The AESO acknowledges UCA's support.
2(b) In consideration of the results from 2(a) above, the AESO will update the connection project database for final costs where available, add new projects for which permit(s) and license(s) under the Hydro and Electric Energy Act have been issued, and update capacities. The resulting point of delivery cost function will be used to update Rate DTS, Demand Transmission Service, Rate PSC, Primary Service Credit and investment levels in section 8 of the tariff.	
ATCO Electric: Indifferent	
AltaLink: Support See response to 2(a).	The AESO acknowledges AltaLink's support.
Capital Power: Support Capital Power supports the AESO ultimately using the results from stakeholder consultation regarding 2(a) above to update the connection project database and relative items in the tariff.	The AESO acknowledges Capital Power's (qualified) support.
EDTI: No comments.	
IPCAA: No comments.	
UCA: Support The UCA supports the use of the most recent data in determining the POD cost function.	The AESO acknowledges UCA's support.
3(a) The AESO's initial investigation suggests a change in Rider C structure (from $/MWh to % of connection charge) would not significantly affect imbalances between market participants. The AESO has not identified any improvements to the tariff update, Rider C and deferral account reconciliation processes.	
ATCO Electric: Oppose ATCO Electric proposes that the AESO continue working on finding a Rider C structure to minimize imbalances and volatility	The AESO will form a working group to examine and further investigate Rider C structure and Deferral Accounts

Stakeholder Comment	AESO Response
to market participants as there is still significant impact in Rider C adjustments to customers. ATCO Electric would support a consultation process to deal with Rider C redesign.	reconciliation methodology.
AltaLink: Support The AESO and stakeholders should continue to find ways to make improvements to Rider C.	The AESO acknowledges AltaLink's support. Please see AESO's response to ATCO Electric's comment above.
Capital Power: Indifferent Capital Power seeks to review the results from the AESO's initial investigation and understand the basis for this decision prior to taking an initial position.	The AESO acknowledges Capital Power's comment. Please see AESO's response to ATCO Electric's comment above.
EDTI: Oppose It is not clear to EDTI how "***a change in Rider C structure (from $/MWh to % of connection charge)"*** will impact the DFO's ability to accurately recover Rider C costs in the DFO's quarterly Transmission Access Charge rider applications.	Please see AESO's response to ATCO Electric's comment above.
IPCAA: No comments.	
UCA: Indifferent.	
3(b) The AESO indicated willingness to present some detailed results from the initial investigation at an upcoming stakeholder session.	
ATCO Electric: Support ATCO Electric supports this initiative in an effort to find a more appropriate mechanism to deal with deferral account reconciliations.	The AESO acknowledges ATCO Electric's support. As stated in the AESO response to 3(a) above, the AESO would form a working group for this purpose.
AltaLink: Support See response to 3(a).	The AESO acknowledges AltaLink's support. Please see the AESO response 3(a).
Capital Power: Support Capital Power supports the AESO's offer to share the detailed results from its initial investigation of potential changes to the structure of Rider C at an upcoming stakeholder session and looks forward to reviewing the results.	The AESO acknowledges Capital Power's support. Please see the AESO response 3(a).
EDTI: Support EDTI would like to fully understand the impacts of the AESO's proposed change in Rider C structure.	The AESO acknowledges EDTI's support. Please see the AESO response 3(a).
IPCAA: No comments.	
UCA: Support The UCA supports this as it will keep participants informed.	The AESO acknowledges UCA's support. Please see the AESO response 3(a).

Stakeholder Comment	AESO Response
4(a) The AESO will review and determine if additional clarification is needed to the tariff regarding the recovery of system-related costs if a connection project is cancelled. The Commission may provide further guidance on this topic in its decision, expected shortly, to address the AESO's compliance with directions 5 to 8 from Decision 2014-242.	
ATCO Electric: Oppose ATCO Electric will participate in the AUC's forthcoming proceeding covering this issue given Decision 3473-D02-2015	Subsequent to the issuance of Decision 3473-D02-2015, the Commission issued Bulletin 2015-15 on October 22, 2015, announcing the initiation of Proceeding 20922 to address the customer advancement cost component of the ISO tariff. The Commission also indicated the proceeding will not be heard until late in Q1 or early in Q2 of 2016. The AESO, in developing its2017 Tariff Application, will seek to schedule activities to reflect the Proceeding 20922 schedule and avoid overlap and conflict between the proceeding and its consultation activities.
AltaLink: Support AltaLink supports further clarification. However, the Commission indicated in its decision it will provide this guidance as part of its own initiated proceeding on advancement costs.	The AESO acknowledges AltaLink's support. Please see the AESO response to 4(a)
Capital Power: Support Several aspects of AUC Decision 3473-D02-2015 may have implications for the 2017 AESO Tariff Application. Capital Power is interested in the AESO's proposed process for 4(a) in light of Decision 3473-D02-2015 and the Commission's decision to initiate its own proceeding to "address whether and how customer advancement costs can be used to ensure that the future development of transmission projects is achieved in both a timely and an economic manner." Capital Power requests that the AESO provide stakeholders with an update on 4(a) that includes, but is not limited to, the AESO's response to following questions: • How will the 2017 Tariff consultation interface with the Commission-initiated proceeding resulting from 3473-D02-2015? • How will the Commission-initiated proceeding impact the scope of the proposed 2017 Tariff Consultation? • Will project cancellation costs, system project advancement costs, and/or any items pertaining to the AUC directions 5 to 8 from Decision 2014-242 be included in the scope of the 2017 Tariff Consultation?	The AESO acknowledges Capital Power's support. Please see the AESO response to 4(a).
EDTI: No comments.	

Stakeholder Comment	AESO Response
IPCAA: No comments.	
UCA: Support The UCA supports additional clarification on these items.	The AESO acknowledges UCA's support. Please see the AESO response to 4(a).
4(b) The AESO is proposing to add details of investment calculations upon reclassification of participant-related costs as system-related costs (and vice versa). These calculations would be similar to calculations performed when facilities are shared between two or more marked participants (based on contracted years and MWs).	
ATCO Electric: Support ATCO Electric supports this in the context of the work that will be undertaken in 4(a) above.	The AESO acknowledges ATCO Electric's support. The AESO will provide detailed calculations of the methodology for carrying out the calculations. The calculation will be similar to that performed when market participants share facilities, as outlined in subsection 5 of section 9 of the 2014 ISO tariff.
AltaLink: Support It would be helpful for all participants to understand the detailed calculations.	
Capital Power: Support Any reclassification of participant-related costs as system-related costs (and vice versa) should be accompanied with a before and after perspective to provide stakeholders with a view of the impact/re-allocation of costs/charges resulting from the changes. Further, any reclassification of system-related costs should be considered with respect to the Commission's findings in Decision 3473-D02-2015 regarding the application of advancement system costs to generators, and specifically, that "the only recovery of non-radial transmission facility costs from generator market participants that can occur is in accordance with Section 29 of the Transmission Regulation."	The AESO acknowledges Capital Power's support. Please see AESO's response to 4(a) in regards to alignment with Decision 3473-D02-2015.
EDTI: No comments.	
IPCAA: No comments.	
UCA: Support The UCA is concerned with the reclassification of participant-related costs as system-related costs, as system-related costs are borne by the consumers.	The AESO acknowledges UCA's support. Please see AESO's response to 4(a) in regards to alignment with Decision 3473-D02-2015.
4(c) The AESO will provide market participants with multi-year historical billing detail to enable stakeholders to analyze rate design and its impacts on a quantitative and objective basis. This data could include volume data (MWh, MW, coincident demand, substation	

Stakeholder Comment	AESO Response
fraction) and service details (DTS, STS, direct-connect). The AESO is requesting feedback on the data fields and data structure that will be required.	
ATCO Electric: Support This information will assist in understanding the impacts of the proposed changes to the tariff design.	The AESO acknowledges ATCO Electric's support. The AESO continues to solicit feedback on the data fields and data structure required by market participants prior to beginning the data compilation exercise.
AltaLink: Support See response to 4(b).	The AESO acknowledges AltaLink's support. Please see AESO's response to ATCO Electric's comment above.
Capital Power: Support Capital Power supports the AESO providing market participants with multi-year historical billing data to enable stakeholders to analyze rate design and its impacts. Capital Power has no suggestions regarding data fields and structure at this time.	The AESO acknowledges Capital Power's support. Please see AESO's response to ATCO Electric's comment above.
EDTI: No comments.	
IPCAA: No comments.	
UCA: Support The UCA supports having additional data to run their own analysis	The AESO acknowledges UCA's support. Please see AESO's response to ATCO Electric's comment above.
4(d) The AESO is currently reviewing the transmission rate impact projection (TRIP) workbook development process, including providing periodic TRIP updates. A TRIP update today would not result in significant changes to rate projections. The AESO is proposing to post an updated TRIP with the 2017 Tariff Application in July 2016.	
ATCO Electric: Indifferent Updates to TRIP will depend on timing of updated ISO Long-Term Plan expected in January 2016.	The AESO acknowledges ATCO Electric's comment.
AltaLink: Support Updating the model based on material changes makes sense from a practical and resource standpoint.	The AESO acknowledges AltaLink's support.
Capital Power: Support Capital Power supports the AESO updating the TRIP workbook as early as practical in the 2017 Tariff Consultation process, and continuing to provide periodic TRIP updates whenever changes necessitate. The TRIP workbook is a useful document and helps market participants to analyze future transmission cost trends and the impacts of changes to consumer behavior.	The AESO acknowledges Capital Power's support.
EDTI: No comments.	
IPCAA: No comments.	

Stakeholder Comment	AESO Response
UCA: Support Updates to the TRIP model are encouraged by the UCA.	The AESO acknowledges UCA's support. Please see AESO's response to Capital Power's comment above.
5(a) The current operating reserve charge rate design was identified as an issue by a distribution facility owner (DFO). The DFO explained that regulatory lag results in it holding significant balances for a significant period of time. Some participants were supportive of current operating reserve charge rate design and commented that this is a distribution regulatory process issue.	
ATCO Electric: Support ATCO Electric supports a review of the current operating reserve charge rate design in an effort to minimize volatility.	The AESO considers that the current flow-through nature of the operating reserve charge reflects cost causation and avoids cross-subsidies between market participants. However, the AESO is willing as part of consultation to explore alternatives that may be beneficial to distribution-connected consumers, to assess whether changes to the operating reserve charge should be considered.
AltaLink: Indifferent	
Capital Power: Indifferent Capital Power has no comment on 5(a).	
EDTI: Support This issue impacts EDTI. While this issue is related to the regulated nature of the DFO's business, it is a direct result of the rate design that the AESO uses to recover operating reserve costs. EDTI seeks a solution that addresses the issues that impact the DFOs and is not opposed to maintaining the current operating reserve charge rate design for other DTS customers.	The AESO acknowledges EDTI's comment. Please see the AESO response to ATCO Electric's comment above.
IPCAA: No comments.	
UCA: Indifferent The UCA is concerned with increase of decrease in reserves charges.	The AESO acknowledges UCA's comment assuming that "increase or decrease" was intended.
5(b) A participant raised the issue of investment levels not covering 60% of the similar average project costs. The AESO advised that it would not put this forward as a topic for the 2017 tariff application but that it would provide requested information to stakeholders enabling them to develop their proposals, if any.	
ATCO Electric: Support ATCO Electric intends to participate with other TFO's in raising this issue during the hearing and it appreciates the AESO's suggestion to provide requested information to help develop a potential proposal on this issue.	The AESO acknowledges ATCO Electric's support.

Stakeholder Comment	AESO Response
AltaLink: Support Even though the investment level issue is important to AltaLink, having the AESO being open to provide information that will enable AltaLink and others to develop their proposals for the AESO's 2017 tariff will be helpful.	The AESO acknowledges AltaLink's support.
Capital Power: Support Capital Power supports the AESO's offer to provide information to stakeholders to enable them to develop their own proposals, if they so choose.	The AESO acknowledges Capital Power's support.
EDTI: No comments.	
IPCAA: No comments.	
UCA: Indifferent.	
5(c) Participants commented that they support the AESO's focus on filing the comprehensive tariff application and the tariff update applications as soon as possible.	
ATCO Electric: Support ATCO Electric considers timely updates of AESO tariffs results in better reduced true-up balances for ATCO Electric and improves rate signals to customers.	The AESO acknowledges ATCO Electric's support.
AltaLink: Support Filing the AESO's update applications for 2015 and 2016 and a comprehensive application for 2017 as soon as possible would mitigate regulatory lag.	The AESO acknowledges AltaLink's support.
Capital Power: Support Capital Power supports the AESO's expediency in filing the comprehensive tariff application and the tariff update applications.	The AESO acknowledges Capital Power's support.
EDTI: No comments.	
IPCAA: No comments.	
UCA: Support As this proceeding is typically very large, anything to streamline the process is encouraged.	The AESO acknowledges UCA's support.
6(a) In regards to the 2017 tariff application consultation process, the AESO proposed to hold a technical session in January 2016 to present: ***i. results of the updated transmission cost causation study;*** ***ii. results of the thorough exploration of point of delivery cost function and the update of point of delivery cost database; and*** ***iii. results from AESO's investigation of alternative Rider C structure(s).***	
ATCO Electric: Support As the cost study and Rider impact ATCO Electric and end-use	The AESO acknowledges ATCO Electric's support.

Stakeholder Comment	AESO Response
customers, ATCO Electric is interested in participating in the AESO's technical session in January 2016.	
AltaLink: Support Holding a technical session will allow stakeholders an opportunity to discuss and understand these three points.	The AESO acknowledges AltaLink's support.
Capital Power: Support Capital Power supports the AESO's proposal to hold a technical session in January 2016 to present the above items and encourages the AESO to hold meetings and technical sessions whenever practical to introduce changes, proposals, or technical results (such as to introduce the updated TRIP Workbook in July 2016). These types of sessions are helpful to stakeholders and allow them to better understand the context and reasoning behind various updates and changes.	The AESO acknowledges Capital Power's support.
EDTI: No comments.	
IPCAA: No comments.	
UCA: Support Technical meetings are welcome as they will assist the UCA in their understanding of the issues.	The AESO acknowledges UCA's support.
6(b) The AESO will use a written comment process and potentially one or two small working groups to consult on other changes to the tariff. The AESO will provide draft revisions to the tariff with relevant discussion and would then invite stakeholder comments on these draft revisions.	
ATCO Electric: Oppose To promote efficiency, ATCO Electric would recommend a number of dedicated working groups for each major issue with each working group to develop consensus based draft revisions. Revisions for all issues to then be shared and commented on by all stakeholders. This would allow for flexibility in working group participation based on individual expertise for a given issue.	The AESO acknowledges ATCO Electric's comment. As stated in the AESO response to 3(a) above, the AESO will form a working group to examine matters related to Rider C and Deferral Account reconciliations. The AESO intends to hold technical sessions for matters related to the POD cost function and to present the results of the update to the Cost Causation Study. The AESO also intends to solicit written comments, similar to this process, after the conclusion of above mentioned working group and technical sessions.
AltaLink: Support AltaLink supports an AESO led written comment process, but would recommend that stakeholders have the option to participate in any working groups proposed.	The AESO acknowledges AltaLink's support. Please see the AESO response to ATCO Electric's comment above.
Capital Power: Support	The AESO acknowledges Capital

Stakeholder Comment	AESO Response
Capital Power supports the proposed written process and the idea of using smaller working groups on issues where it makes sense.	Power's support.
EDTI: No comments.	
IPCAA: If there are committees / working groups etc. set please include [IPCAA].	Please see the AESO response to ATCO Electric's comment above.
UCA: Support The proposal seems like a reasonable attempt to streamline the process while maintaining the ability for stakeholders to provide input.	The AESO acknowledges UCA's support.
6(c) The AESO will hold a general stakeholder consultation meeting in April 2016 to update stakeholders on the progress of the development of the 2017 tariff application.	
ATCO Electric: Support For reasons explained above, ATCO Electric is interested in participating in upcoming consultation meetings.	The AESO acknowledges ATCO Electric's support.
AltaLink: Support Understanding if the AESO is on track for filing its 2017 tariff by June 30, 2016 will help AltaLink with allocating resources.	The AESO acknowledges AltaLink's support.
Capital Power: Support Capital Power supports this proposal.	The AESO acknowledges Capital Power's support.
EDTI: No comments.	
IPCAA: No comments.	
UCA: Support Progress updates are encouraged.	The AESO acknowledges UCA's support.
Additional comments	
ATCO Electric: None.	
AltaLink: AltaLink supports the AESO continuing to provide advance notice for filing their tariff applications which allows stakeholders the opportunity to provide input into these applications prior to being filed.	The AESO acknowledges AltaLink's support.
Capital Power: Capital Power has no additional comments at this time.	
EDTI: None.	
IPCAA: IPCAA suggested that the AESO begin to immediately capitalize on some of the new features of the EMS system which is to be in place in 2017.	The AESO notes that dynamic line ratings and dynamic scheduling are not dependent on the EMS system (upgrade). The AESO is striving to

Stakeholder Comment	AESO Response
The suggestions were to begin to focus on: – Dynamic Line ratings to increase the utilization of the Alberta Transmission System and – Dynamic Scheduling to increase the efficient utilization of the inter-ties. IPCAA suggested that the AESO consider these in the development of its 2017 tariff application. As the AESO can realize with the downturn in the Alberta economy and likely stalled growth in electrical consumption costs and how they are allocated are of great importance to IPCAA.	implement and utilize these tools subject to resource constraints. The AESO expects that such utilization would be phased-in, beginning in 2017. The AESO considers that such utilization would not significantly affect cost causation and rate design in the 2017 to 2019 period. The AESO expects such utilization to possibly reduce transmission system costs and likely increase transmission system utilization and market efficiency.
UCA: None.	

November 25, 2015

AESO Stakeholders
AESO 2017 ISO Tariff Consultation Participants

Dear Stakeholder:

Re: **Invitation to Participate in Consultation on Deferral Account Reconciliations and Rider C**

As part of consultation for development of its 2017 ISO tariff application, the Alberta Electric System Operator (AESO) is initiating discussion with market participants of annual tariff updates, deferral account reconciliation processes and Rider C design. The AESO is holding a consultation meeting on these topics and invites you to become involved in this consultation.

The meeting is scheduled as follows:

Date:	Monday, December 14, 2015
Time:	9:30–11:30 AM
Place:	AESO Meeting Room 2539, 25th Floor, 330 – 5th Avenue SW, Calgary, Alberta
Teleconference:	Phone number 1-866-835-7781 and code 5565714323
RSVP:	By 5:00 PM on **Wednesday, December 9, 2015** to Brenda Hill, brenda.hill@aeso.ca or 403-539-2850

The AESO expects to discuss the following topics during the meeting:

- interrelationships between annual tariff updates, deferral account reconciliations, and Rider C;
- summary of recent deferral account reconciliations;
- magnitude and frequency of refunds and charges to individual market participants in deferral account reconciliations;
- concerns to potentially be addressed through future changes to Rider C; and
- possible approaches to minimizing impacts of deferral account reconciliations.

The AESO plans to present information on these topics to facilitate discussion, and will post the presentation before the meeting if possible. Stakeholders may provide feedback in person during the meeting or by contacting the AESO after the meeting.

All information relating to the 2017 tariff consultation will be available on the AESO website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2017 Tariff. As well, new information posted by the AESO on this topic will be mentioned in the AESO stakeholder newsletter, which you can subscribe to by clicking “Sign-up for our stakeholder newsletter” at the lower right of the AESO’s home page at www.aeso.ca.

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

If you have any questions on the AESO's 2017 tariff consultation, please contact me at 403-539-2465 in Calgary or by e-mail to john.martin@aeso.ca.

Sincerely,

John Martin
Senior Tariff and Regulatory Advisor

cc: Carol Moline, Director, Accounting & Treasury
LaRhonda Papworth, Manager, Tariff Applications
Raj Sharma, Senior Tariff Analyst

Consultation on Deferral Account Reconciliations and Rider C

LaRhonda Papworth, Manager, Tariff Applications
John Martin, Senior Tariff and Regulatory Advisor
Carol Moline, Director, Accounting & Treasury

December 14, 2015 – Calgary, Alberta

Agenda

- Introductions (slides 1-2)
- Objectives and background (slides 3-6)
- Potential impacts of early filing of tariff updates (slides 7-13)
- Seasonality effects of quarterly Rider C (slides 14-17)
- Potential changes to Rider C (slides 18-21)
- DFO concern with operating reserve hourly flow-through charge (slides 22-23)
- Next steps and discussion (slides 24-26)

Please ask questions during presentation!

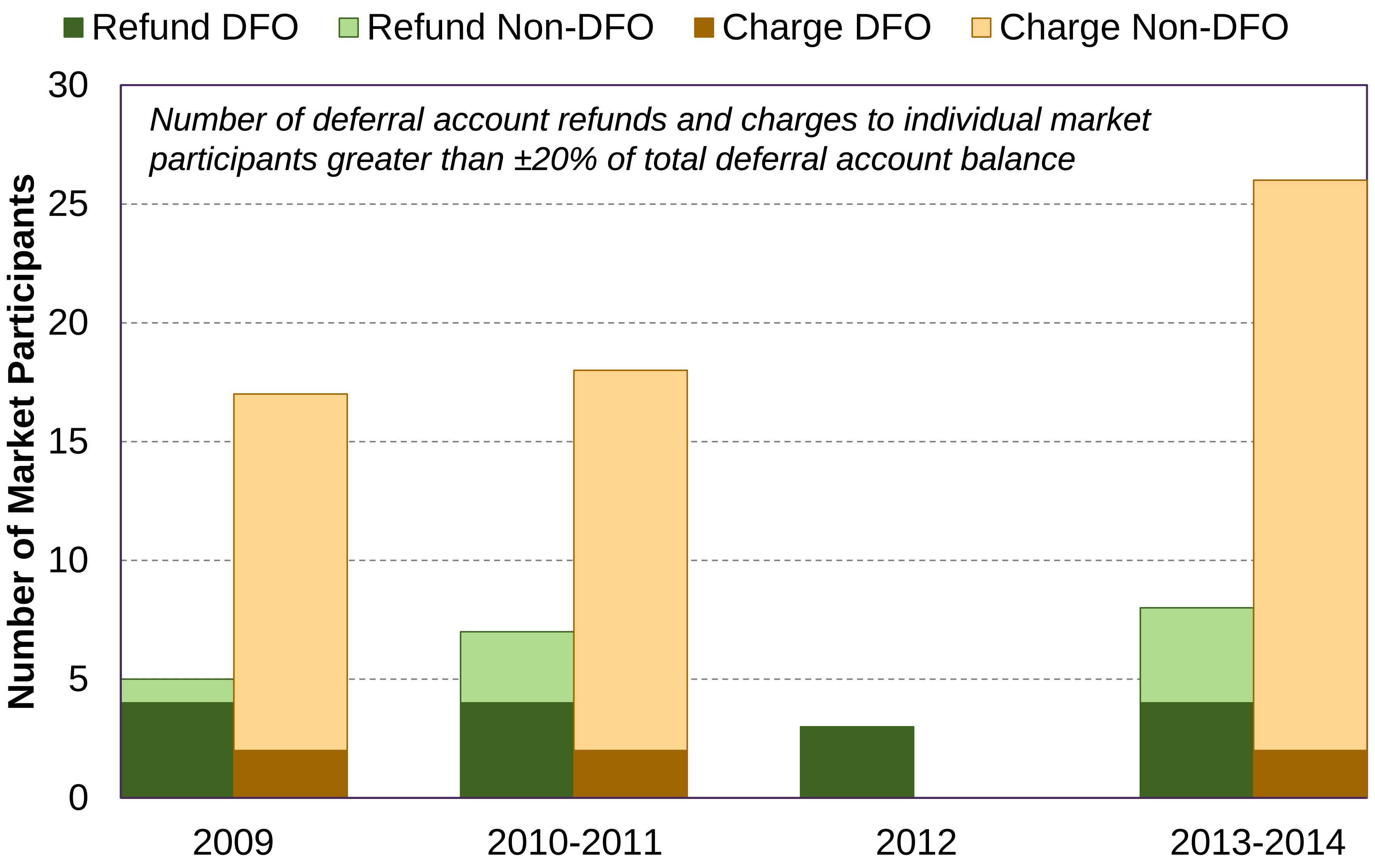
Objectives

- Stakeholders to understand relationships between annual tariff updates, Rider C, and deferral account reconciliations
- AESO to understand concerns to potentially be addressed through future changes to tariff updates, Rider C, and deferral account reconciliations
- Exploration of possible approaches to minimizing impacts of deferral account reconciliations

Why are we talking about deferral account reconciliations and Rider C?

- **Reason**: Respond to Commission directions
- During the AESO's 2014 ISO tariff proceeding, participants submitted that the AESO should further examine the structure of Rider C to minimize imbalances between market participants
- In Decision 2014-242, the Commission directed the AESO "to discuss the related matters of annual tariff updates, deferral account reconciliation processes and Rider C design with stakeholders prior to filing its next comprehensive GTA, and to provide a report on the outcome of any such discussions, including any recommended changes (if any) within its next comprehensive GTA" [paragraph 704, page 139]

Individual refunds and charges frequently exceed 20% of deferral account balance



The AESO investigated potential Rider C changes for its 2014 ISO tariff application

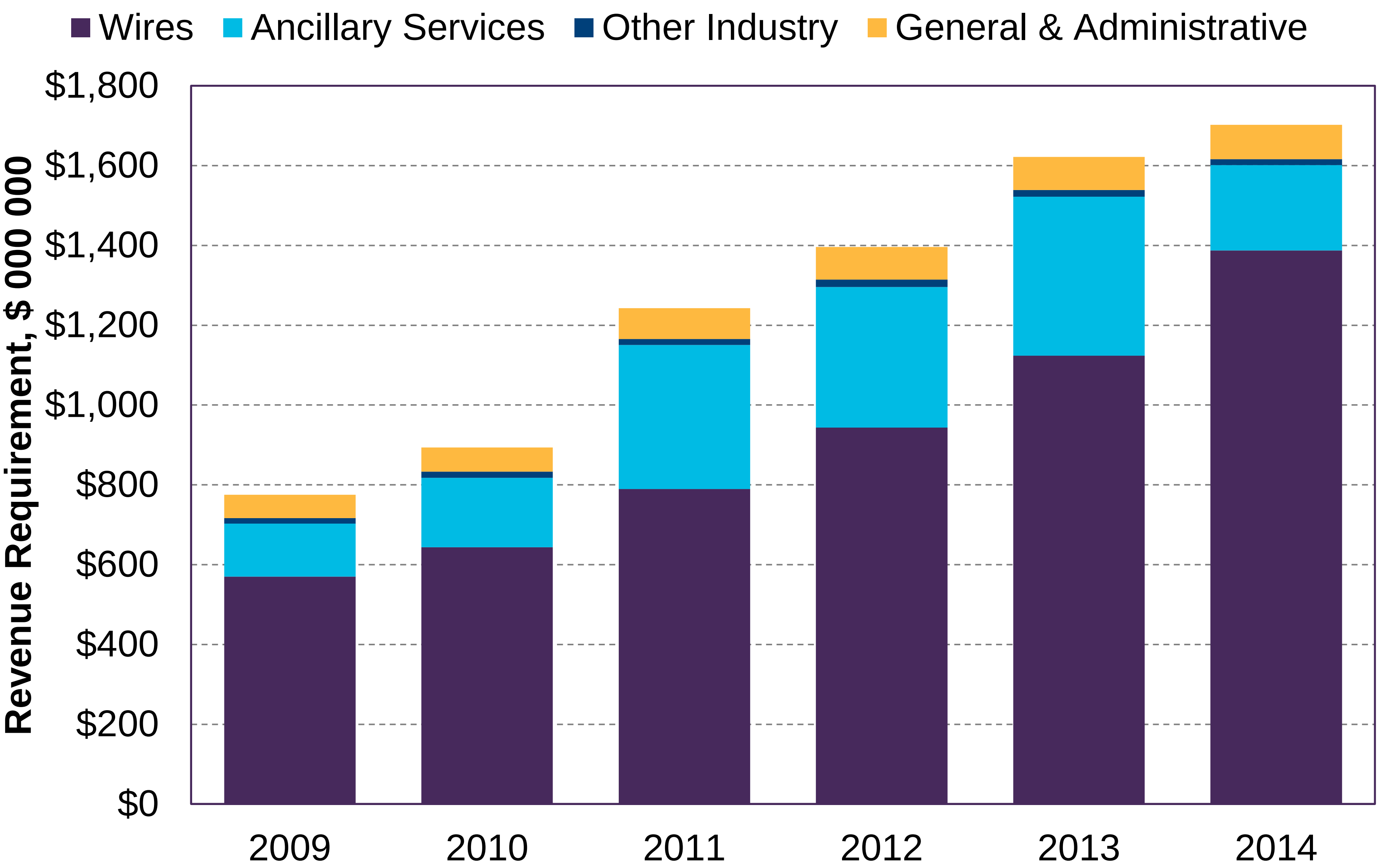
- The AESO considered three facets of the deferral account process may lead to individual charges and refunds being large compared to the net deferral account balance
  - Different bases for Rider C and rate components
  - Timing differences between Rider C collections and refunds compared to production-month reconciliations
  - Variances from forecasts of costs and revenues
- After investigation, the AESO concluded that there do not appear to be any straightforward changes to Rider C that would materially reduce the magnitude of individual charges and refunds that result from a deferral account reconciliation

Tariff updates, Rider C, and deferral account reconciliations are interrelated

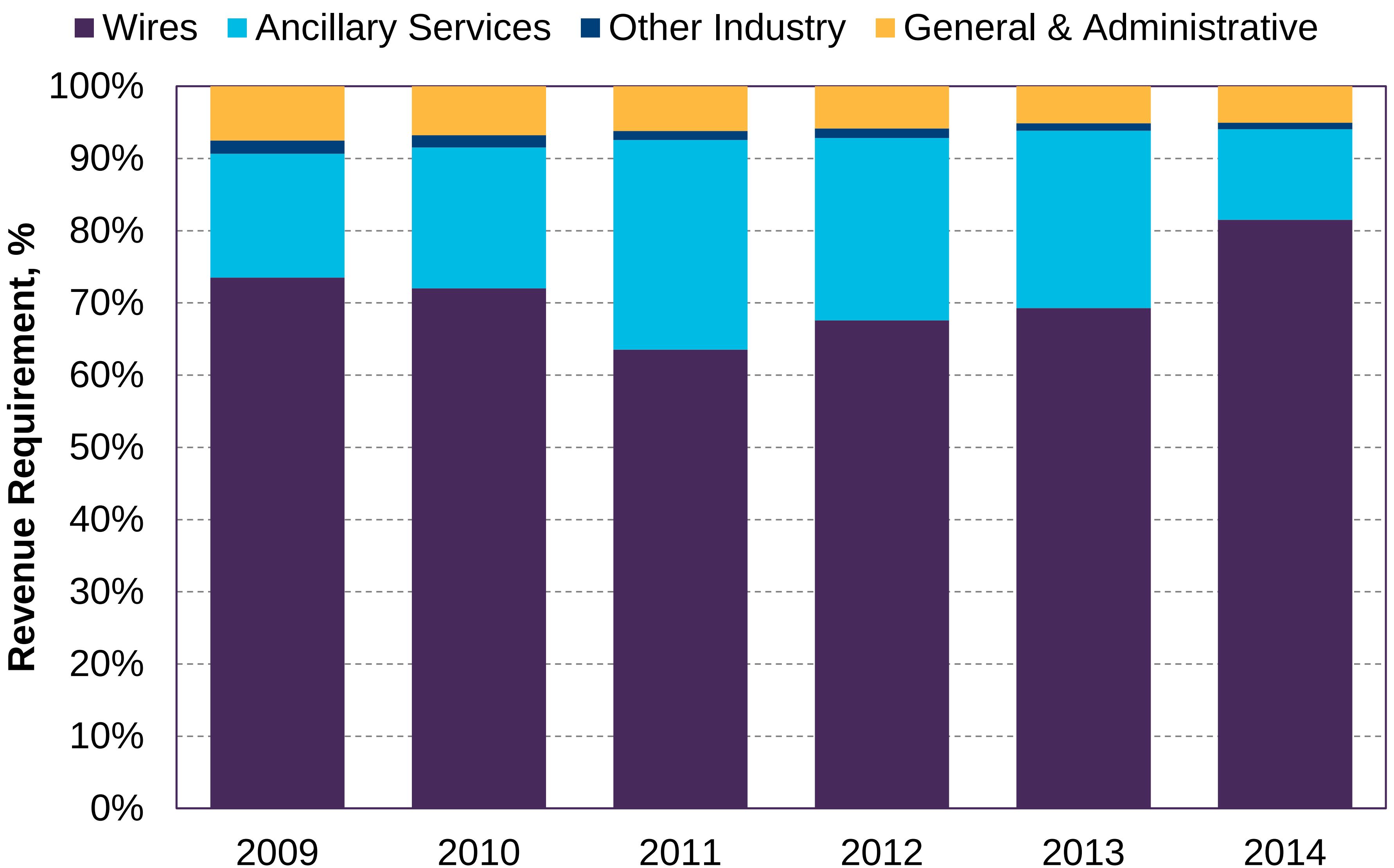
Tariff Update	Rider C	DA Reconciliation
Tariff updates (and applications) match revenues with costs on an annual basis	Rider C manages variances between costs and revenues on a quarterly basis	Deferral account reconciliations re-allocate Rider C revenues and prior year amounts between market participants

- Regular tariff update applications should reduce the magnitude of Rider C
  - The AESO filed a 2015 tariff update in August 2015
  - The AESO plans to file a 2016 tariff update in early 2016

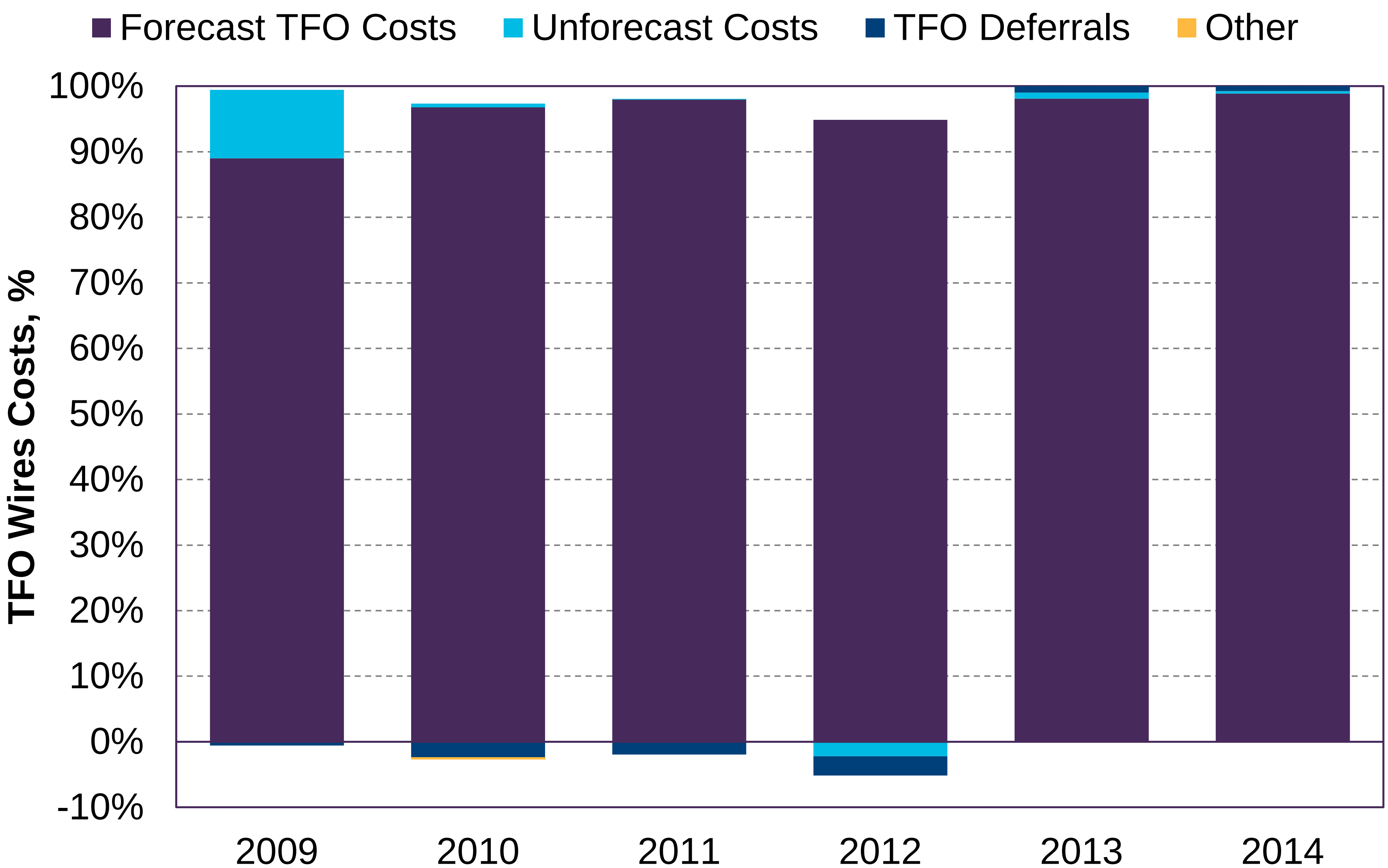
Revenue requirements are established on an annual basis



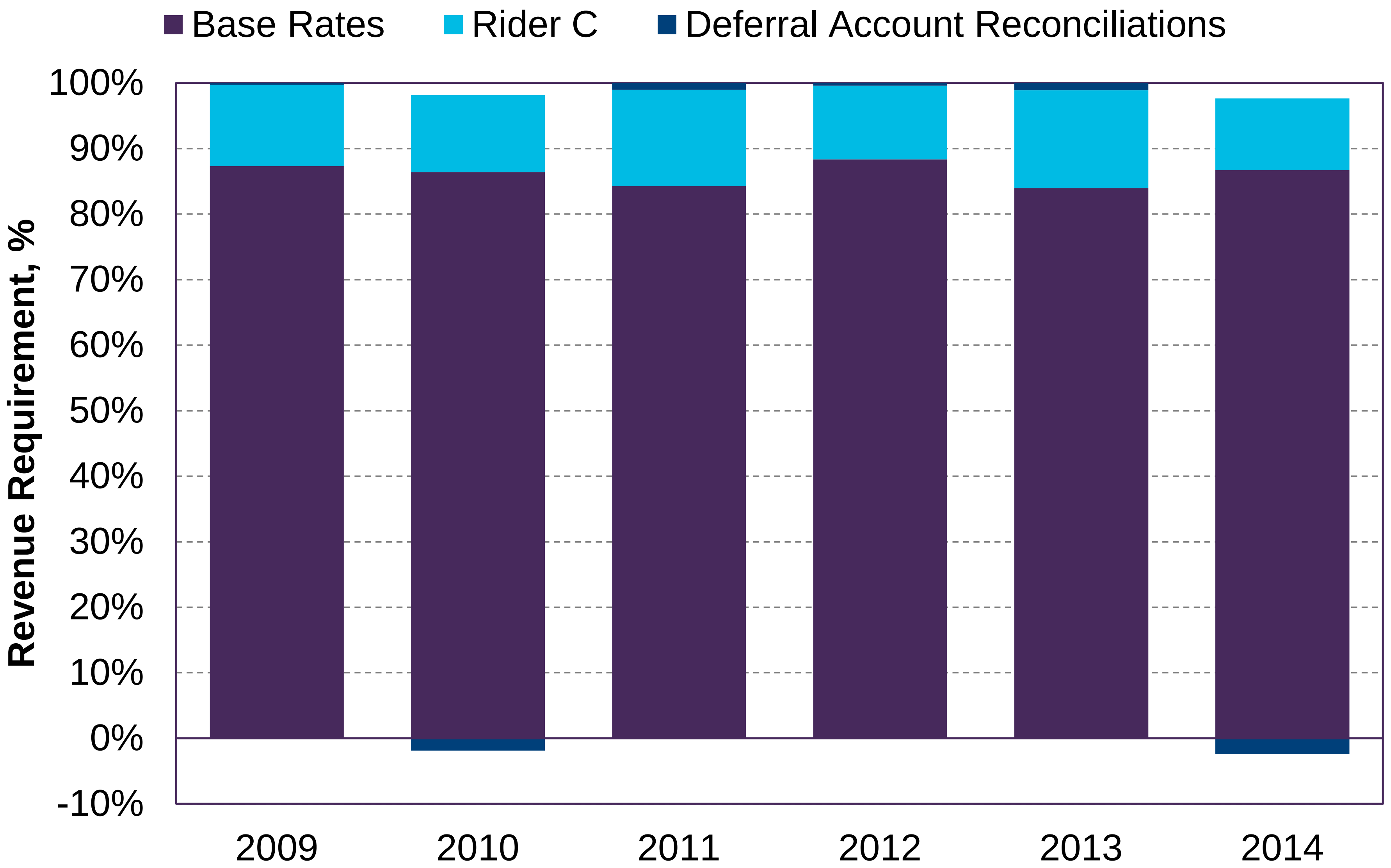
Wires costs represent 70% to 80% of total annual revenue requirement



Annual wires costs can be reasonably forecast



Rates are not keeping pace with costs



Tariff lag results in about 20% shortfall in wires cost recovery

Test Year	2007	2008	2009	2010	2011	2012	2013	2014
Wires Cost	$458.5		$523.7		$786.2		$1,113.4	$1,371.7

Effective Dates	Aug 2008 - Sep 2009	Oct 2009 - Jun 2011	Jul 2011 - Sep 2013	Oct 2013 - Jun 2015	J-D 15

Wires Cost Shortfall	2009	2010	2011	2012	2013	2014
Cost Basis for Rates	$474.8	$523.7	$654.9	$786.2	$868.0	$1,113.4
Forecast Costs for Year	$523.7	$645.3	$786.2	$973.5	$1,113.4	$1,371.7
Inherent Shortfall ($)	($48.8)	($121.6)	($131.3)	($187.3)	($245.4)	($258.3)
Inherent Shortfall (%)	(9%)	(19%)	(17%)	(19%)	(22%)	(19%)

- Wires costs represent most of the revenue collected through Rider C
- Wires cost shortfalls have varied from 17% to 22% over the past five years

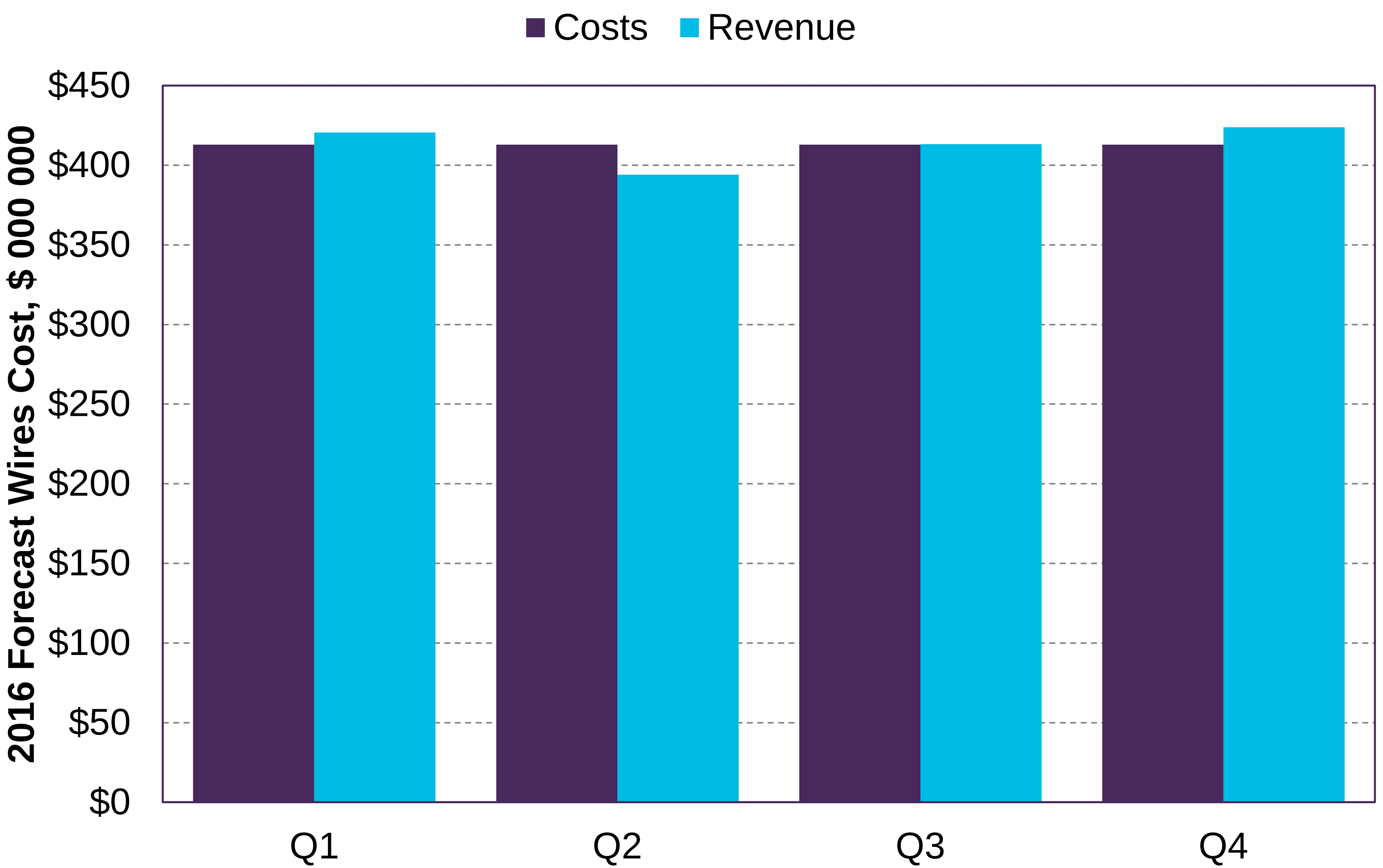
Early filing of tariff updates should reduce amounts collected through Rider C

- Filing tariff updates to achieve an effective date of January 1 of the test year could significantly reduce the amounts collected through Rider C
- Tariff updates would need to be filed in July or August to be approved and implemented by January 1
  - Filing would be at beginning of Budget Review Process, prior to approval of AESO budget
  - Changes that occur during the Budget Review Process would be addressed in deferral account reconciliation
- Early filing may reduce accuracy of wires cost forecasts
- Update approval process may be shortened if filing template can be implemented (similar to distribution system owner transmission deferral account rider process templates)

AESO's deferral account reconciliation model currently includes 2011-2013

- AESO will update model to include 2014
- Model may be able to be used to assess impact of early tariff updates
- Model has so far not revealed any straightforward changes to Rider C that would materially reduce the magnitude of reconciliation charges and refunds
- However, there may a seasonality effect in Rider C that may be easily addressed

Wires cost revenue exhibits seasonal patterns while costs do not



Basing Rider C on forecast year-end balances may reduce seasonal effect

- Rider C must currently be calculated “to restore the deferral account balance to zero (0) over the following calendar quarter, or such longer period as determined by the ISO to minimize rate impact”
- Calculating Rider C to restore the year-end deferral account balance to zero may reduce Rider C amounts
  - AESO may be able to assess impact of change through reconciliation model
- Annual reconciliation approach may also need to be modified
  - Current approach reconciles revenues to costs on a production month basis, which ignores seasonal volume variation

Basing Rider C on year-end balances would not mitigate prior year adjustment impacts

- Prior year adjustments resulting from Commission decisions are currently recovered in one quarter
  - Such adjustments affect forecast deferral account balances at the end of the upcoming quarter
- Even if Rider C was based on year-end balances, prior year adjustments would continue to impact one or two quarters if occurring after Q2 Rider C is posted at beginning of March
  - Should balances from prior year adjustments instead be carried forward to year-end deferral account reconciliations?

Converting Rider C to a percentage basis did not have expected impact

- Rider C is a $/MWh charge or credit, by rate component
- Using the deferral account reconciliation model, converting Rider C to a percentage charge or credit, by rate component, did not have the expected effect
  - Percentage charge or credit would reflect the $/MW basis of the Rate DTS connection charge
  - Percentage charge or credit would also be consistent with impact of cost increases or decreases in a tariff update
- Converting to a percentage basis mitigated reconciliation charges and refunds to some extent, but primarily affected who received charges or refunds
  - Impacts likely limited by timing variances and variances between costs and revenues

Rider C is interim in nature

- Rider C revenues are re-allocated between months and between market participants in deferral account reconciliations
- Is interim nature of Rider C an issue?
- Should Rider C be made final and not reconciled?
  - That is, should Rider C be a prospective rider not subject to retrospective reconciliation?

Rider C is interim in nature (cont'd)

- Should Rider C be eliminated and deferral account balances dealt with solely through reconciliations after year-end?
  - Balances would need to be small as a result of early tariff updates
  - AESO would likely convert Rider C to an emergency cash call rider to be available, for example, if deferral account balances were forecast to exceed a specified year-end threshold

Matters for further exploration and potential quantification

- Impact of early tariff updates
- Impact of seasonal effects
- Impact of converting Rider C to a percentage basis
- Possibility of eliminating quarterly Rider C
- Possibility of moving to prospective Rider C
- Other matters?

DFOs have raised concern with operating reserve hourly flow-through charge

- Distribution facility owners have raised concern with difficulty in forecasting operating reserve charges
  - Results in volatile DFO deferral account balances and volatile DFO quarterly riders
  - Have suggested operating reserve component to DFOs could revert back to a percentage of pool price basis
- AESO considers the issue to primarily be whether the DFO or the AESO should hold operating reserve deferral account balances

DFOs have raised concern with operating reserve hourly flow-through charge (cont'd)

- Reverting to a percentage of pool price basis would likely still result in volatile Rider C charges to DFOs from quarter to quarter and volatile deferral account reconciliations
  - Charges would also reflect pool price volatility
- In general, rates and riders should not differentiate between DFOs and direct connect market participants
  - In particular, transmission-connected customers served through DFO should be charged similarly to direct connect market participants served by AESO
- Direct connect market participants previously expressed preference for hourly flow-through charge
- AESO is unclear of benefits of reverting to percentage of pool price basis for operating reserve charge

Next steps

- AESO to further explore impacts of early tariff updates and seasonal effects
  - Including quantification, if possible
- Based on results, AESO may also consider eliminating quarterly Rider C or moving to prospective Rider C
- Based on results, AESO may also consider converting Rider C to a percentage basis
- AESO will report results of exploration in future 2017 tariff consultation process
  - Will also report on findings in tariff application

Future applications

- AESO will file 2016 tariff update early in Q1 of 2016
- AESO expects to file 2017 tariff update in Q3 of 2016
  - Will be filed independently of 2017 comprehensive tariff application
- 2015 deferral account reconciliation application will be filed in Q2 of 2016
  - AESO proposing to “collapse” application sections for prior years with few adjustments, for efficiency in preparing and reviewing application
  - 2015 reconciliation application will follow methodology of other recent reconciliation applications
- Rider C and process changes, if any are proposed, would be part of 2017 comprehensive tariff application

Questions and discussion

For more information

- Contact:

  LaRhonda Papworth
  Manager, Tariff Applications
  403-539-2555, larhonda.papworth@aeso.ca

  John Martin
  Senior Tariff and Regulatory Advisor
  403-539-2465, john.martin@aeso.ca

- Presentation and other consultation documents will be posted on www.aeso.ca ▶ Tariff ▶ Current Consultations ▶ 2017 Tariff

Thank you

June 21, 2016

AESO Stakeholders
AESO 2017 ISO Tariff Consultation Participants

Dear Stakeholder:

Re: **Invitation to Participate in Consultation on AESO 2017 ISO Tariff Application**

As part of consultation for development of its 2017 ISO tariff application, the Alberta Electric System Operator (AESO) is continuing discussion with market participants on topics to be reviewed for the 2017 ISO tariff application as well as an update on work undergone to date. The AESO is holding a consultation meeting on these items and invites you to become involved in this consultation.

The meeting is scheduled as follows:

Date:	Thursday, July 7, 2016
Time:	2:00–4:00 PM
Place:	AESO Main Boardroom 2539, 25th Floor, 330 – 5th Avenue SW, Calgary, Alberta
Teleconference:	Within Calgary calling area: 403-410-3051, Conference ID 4366631
	Outside Calgary calling area: 1-855-453-6957, Conference ID 4366631
RSVP:	By 5:00 PM on **Monday, July 4 2016** to Brenda Hill, brenda.hill@aeso.ca or 403-539-2850

The AESO expects to discuss the following items during the meeting:

- update on annual tariff updates, deferral account reconciliations, and Rider C;
- update on point of delivery ("POD") cost function database and transmission cost causation study methodology;
- consult on list of topics to be reviewed for the 2017 tariff application, including review of initial work on energy storage tariff treatment including a summary of the two reports attached here:
  - *Modeling Dispatch Operations of Energy Storage Facilities in the Alberta Wholesale Electricity Market*, University of Calgary, May 2016; and
  - *Comparison between Electricity Storage and Existing Alberta Site Dispatch Files*, AESO, January 20, 2016; and
- timeline and next steps for 2017 ISO tariff application.

The AESO plans to present information on these topics to facilitate discussion, and will post the presentation before the meeting if possible and has included the above mentioned reports for review prior to the meeting. Stakeholders may provide feedback in person during the meeting or by contacting the AESO after the meeting.

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www.aeso.ca www.poweringalberta.com

All information relating to the 2017 ISO tariff consultation will be available on the AESO website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2017 Tariff. As well, new information posted by the AESO on this topic will be mentioned in the AESO stakeholder newsletter, which you can subscribe to by clicking “Sign-up for our stakeholder newsletter” at the lower right of the AESO’s home page at www.aeso.ca.

If you have any questions on the AESO’s 2017 ISO tariff consultation, please contact me at 403-539-2555 in Calgary or by e-mail to larhonda.papworth@aeso.ca.

Yours truly,

LaRhonda Papworth
Manager, Tariff Design

cc: Doyle Sullivan, Director – Market and Tariff Design

AESO 2017 ISO Tariff Consultation

July 7, 2016
AESO Office, Calgary

Public

Teleconference Details

Within Calgary calling area:

403-410-3051, Conference ID 4366631

Outside of Calgary calling area:

1-855-453-6957, Conference ID 4366631

Agenda

- Introduction and objectives (slide 4)
- Applications Currently in Progress (slide 5)
- Topics proposed for 2017 Tariff Application (slides 6-10)
- Energy Storage – Tariff Treatment (slides 11-33)
- Rider C/DAR/Rates Update (slides 34-36)
- Consultation process and next steps (slides 37-39)
- Discussion and wrap-up (slide 40)

Please feel free to ask questions during presentation

Stakeholder Session Objectives

- Enhance understanding of ISO tariff application
- Share information prior to filing of 2017 ISO tariff application
- Feedback to ensure tariff application provides all information stakeholders require
- Identify timeline risks for early 2017 filing

Applications Currently in Progress

- Directions 5-8 on advancement costs and related provisions
  – Decision 3473-D02-2015 issued on August 26, 2015
  – Process letter issued on October 22, 2015 with additional information on process in the new year [2016]
  – Awaiting Commission follow-up
- AESO's 2015 Deferral Account Reconciliation Application
  – Currently before the Commission in Proceeding 21735
  – Interim settlement requested for August 2016
  – Two issues: timing and treatment of primary service credit
- Interim loss factors in Rates STS, DOS, IOS, XOS
  – Currently before the Commission in Proceeding 790
  – New methodology expected to become available in 2016

Topics Proposed for 2017 Tariff Application

- Not proposing any rate structure changes
- Refinements to connection process in Sections 4 and 5 of terms and conditions
  - Associated refinements to Sections 8 and 9
- In response to Commission directions the AESO will address:
  - Contract capacity versus installed capacity for point of delivery cost function
  - Rider C and deferral accounts
  - Cost responsibility for generator compliance with the CIP Alberta reliability standards

Update Rates and Investment Levels

- Update transmission cost causation study using previous 2014 ISO tariff application methodology – initiated
  - For years 2018-2020
- Update point-of-delivery (POD) database – initiated
  - Update primary service credit ratio
- Tariff application will be based on 2017 revenue requirement
  - Will be updated with 2018 revenue requirement in compliance filing
- Bill impact analysis
- Rider J – Wind Forecasting Service Cost Recovery Rider

Terms and Conditions Sections 4, 5, 8 and 9

Reason: Alignment with Commission Decision 3473-D02-2015 (Compliance with Directions 5 through 8)

- Address implications for system access, planning and forecasting
- AESO's continuing process to improve and refine the connection process
- Will defer to Commission-initiated proceeding (proceeding #) if started before filing of 2017 tariff application

Terms and Conditions Miscellaneous Revisions

- Update section 10 to include Generating Unit Owner's Contribution (GUOC) rates
- Sections 4 and 5 to address revisions to tariff to align with Market Participant Choice (MPC) and Abbreviated Need Identification Document (ANID) programs
- Clarify for energy storage
- To provide transmission-connected distribution service customer an opportunity to deal directly with a TFO for a connection project
  - Financial obligation and construction contribution provisions that refer to the obligation of the TFO and the market participant
- Updates to Proformas (Appendix B) to reflect current AESO processes

Topics on horizon

- Section 11 – Ancillary Services
  - Review given fairly recent Commission decision on Transmission Constraint Management and length of time since negotiation
- Rider A1 – Transmission Duplication Avoidance Adjustment, Dow Chemical Canada Inc. / Dow Hydrocarbons / ASU2
  - Review given the “Forecast Benefit to ISO” year ends at 2021
- Climate Leadership Plan / Renewables Procurement
  - No knowledge of impact on tariff and will update if necessary when policy impacts are known

Application of ISO tariff to energy storage was identified as an issue early in initiative

- AESO launched energy storage integration initiative in September 2012
- AESO published issue identification paper in June 2013
  - Technical standards for connection and operation of energy storage
  - Application of ISO tariff to energy storage
  - Technical requirements for provision of ancillary services
  - Asset classification
  - Application of market rules to energy storage

AESO established energy storage work group to discuss and prioritize issues

- Work group identified top three priority issues
  - Develop technical and operating requirements to connect and operate energy storage
  - Determine appropriate tariff treatment for energy storage
  - Review technical requirements for provision of operating reserve by energy storage

Priority issue options were summarized in discussion paper published May 2014

- AESO began developing rules for technical and operating requirements
  - Battery facility rules became effective in April 2016
  - Existing rules applicable to other energy storage technologies
- AESO proposed review of requirements for ancillary services
  - Ensure technology neutrality
  - Consider reducing minimum unit size requirements
  - Consider shortening continuous real power requirement
  - Consider new ancillary services products
  - Consider energy storage providing intertie restoration services
  - Assess application of energy offer submission rules
  - Assess asset classification for energy storage

Discussion paper included review of tariff treatment

- ISO tariff reflects legislative requirements and Commission decisions
- Rates DTS and STS apply to sites with load and generation facilities
- Separate class of service for energy storage justified only if different costs are imposed on transmission system
- No justification to treat energy storage solely as generators
- Application of Rates DTS and STS to energy storage would need demonstration of appropriate cost causation basis
- Energy storage could not rely on Rate DOS to be a commercially viable operation

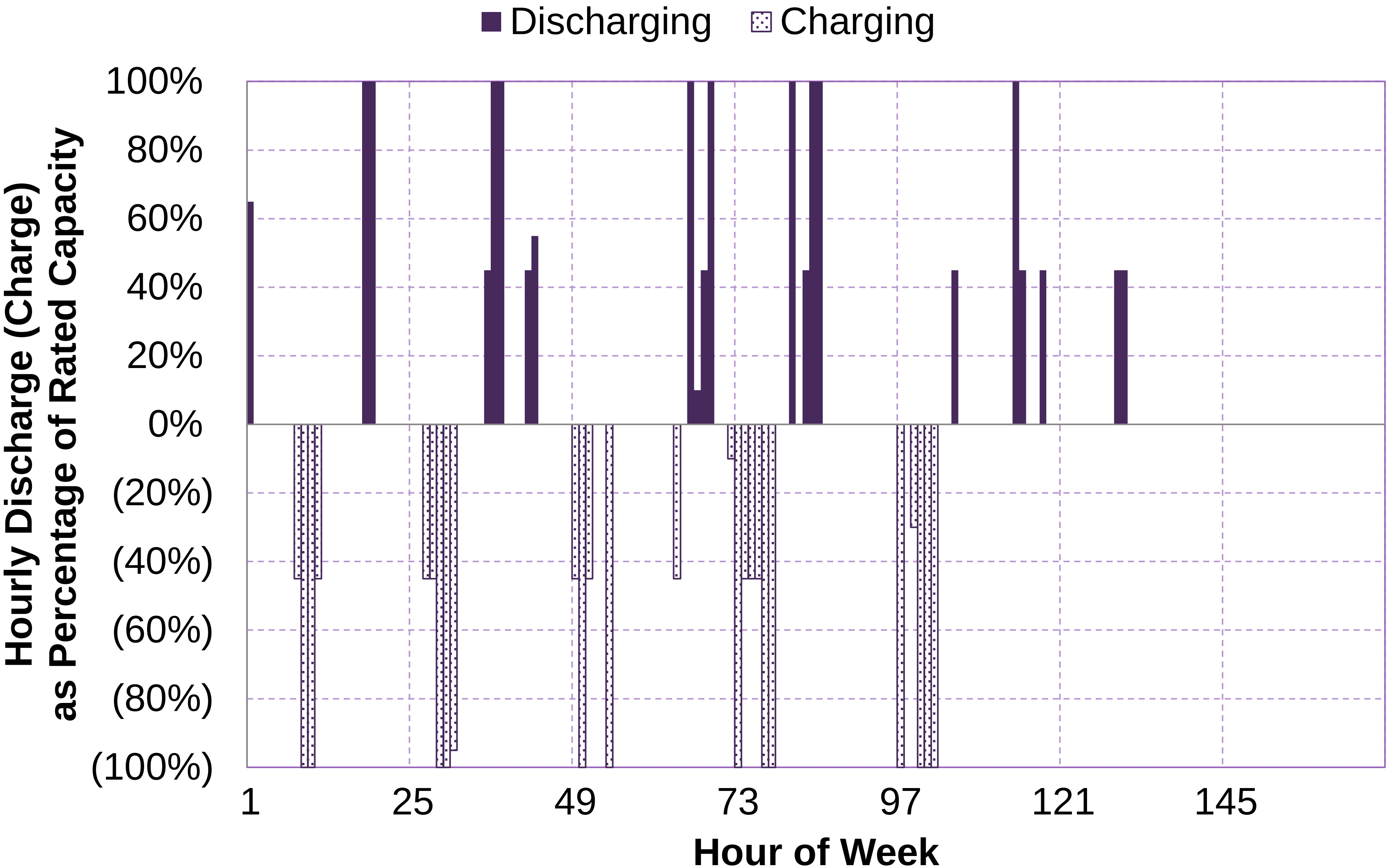
Further tariff work proposed in recommendation paper in June 2015

- Legislation review concluded that energy storage which offers in energy or ancillary services market cannot be a rate regulated transmission facility
  - Energy storage could be a transmission facility to meet reliability requirements but would not offer in markets
- Further study required to assess if Rates DTS and STS would be appropriate for energy storage
- Operational and economic dispatch study proposed to examine how costs should be attributed to energy storage
  - Technical parameters based on input from energy storage project proponents
  - Dispatch modelling completed by University of Calgary
  - Assessment of cost causation completed by AESO

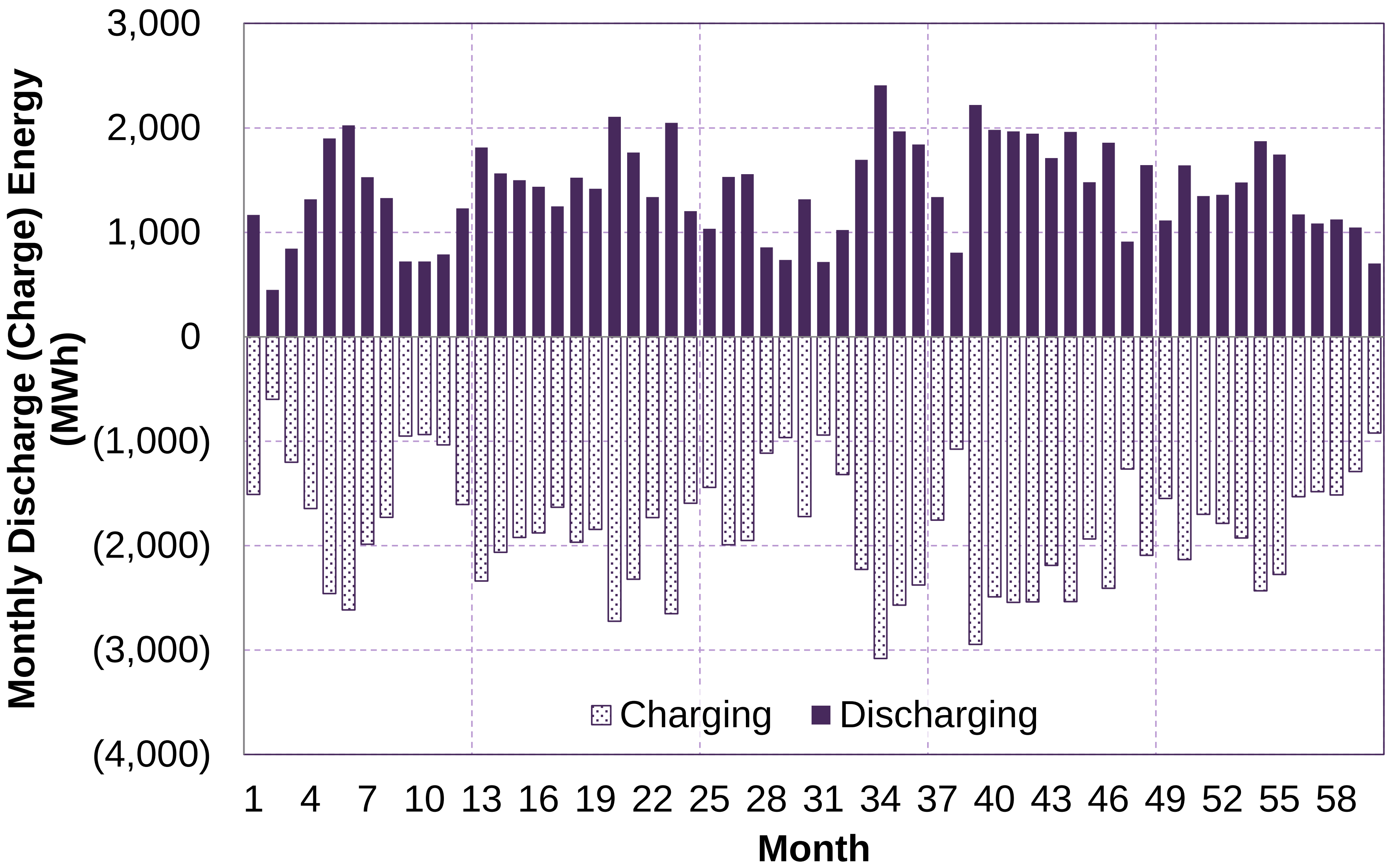
University of Calgary completed dispatch modelling study in May 2016

- Dispatch modelling study report posted in June 2016
  - Modelled the operation of eight energy storage facilities comprising different technologies and sizes
  - Based on actual hourly merit orders over 260 weeks from January 2010 to December 2014
  - Predicted operation of energy storage attempting to maximize profit through energy price arbitrage
- Comprehensive set of results provided to AESO
- Examples, trends, and observations provided in report

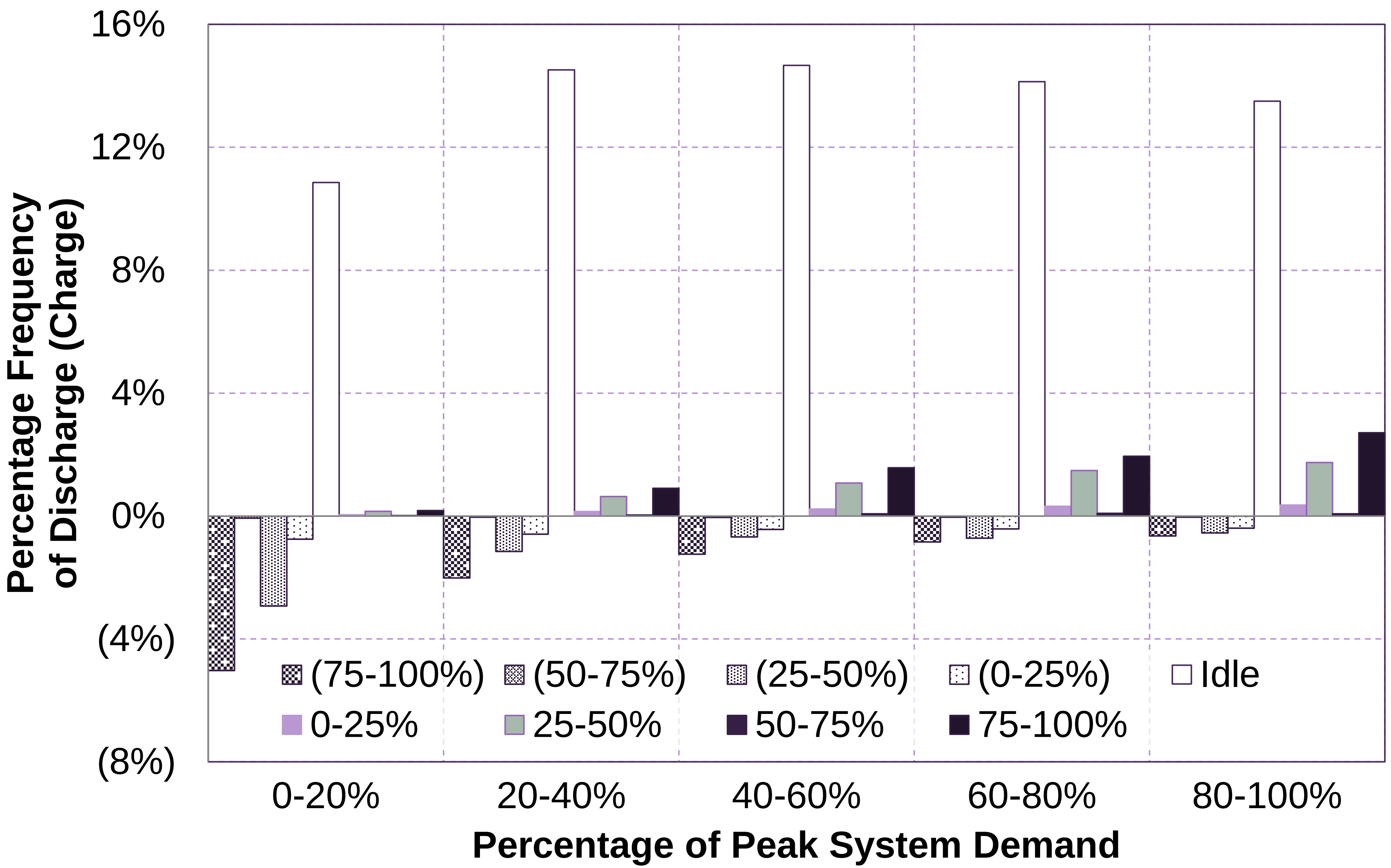
Dispatch modelling showed typical daily discharge-charge cycle



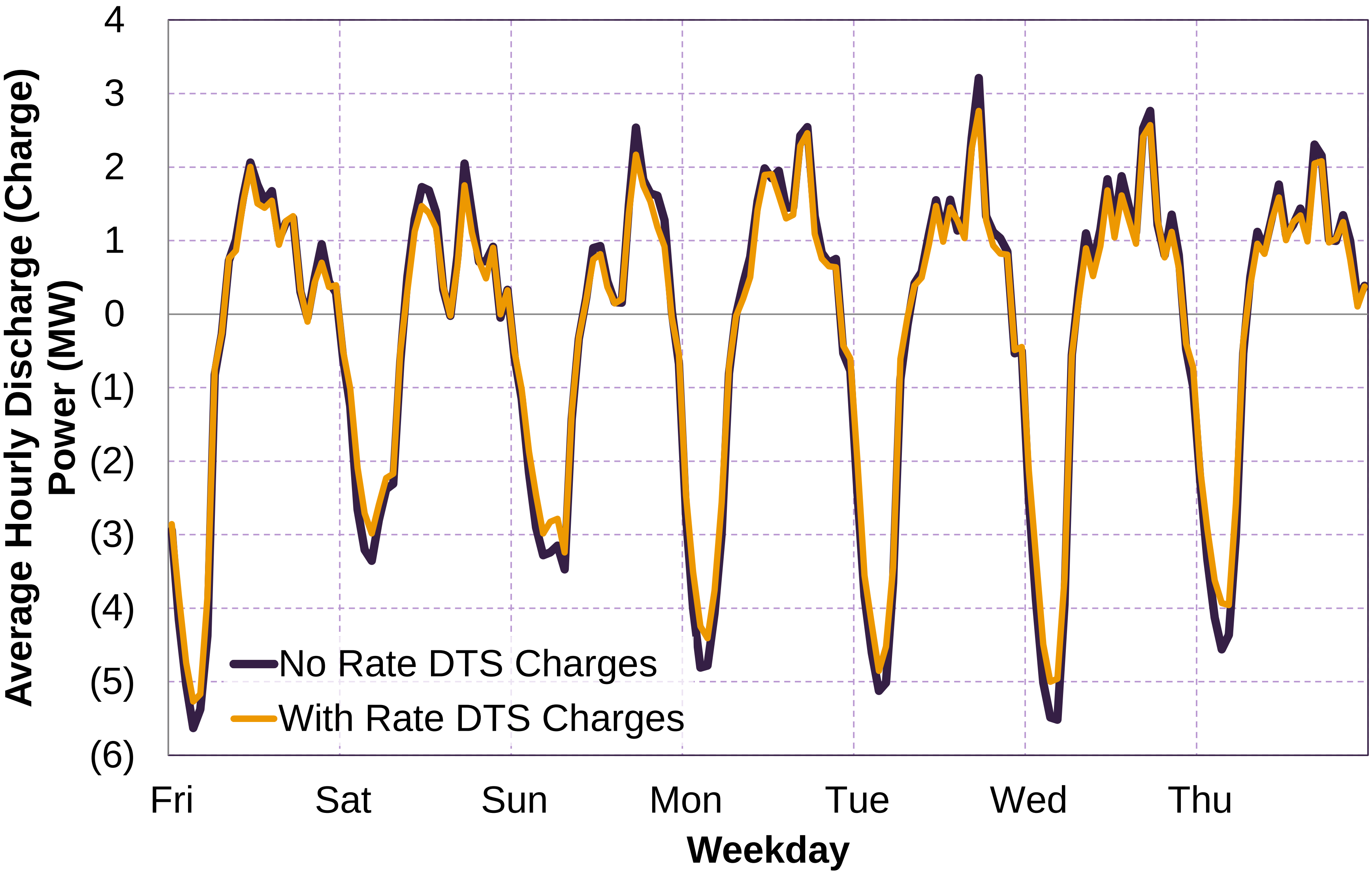
Dispatch modelling showed large monthly variability with no strong seasonal pattern



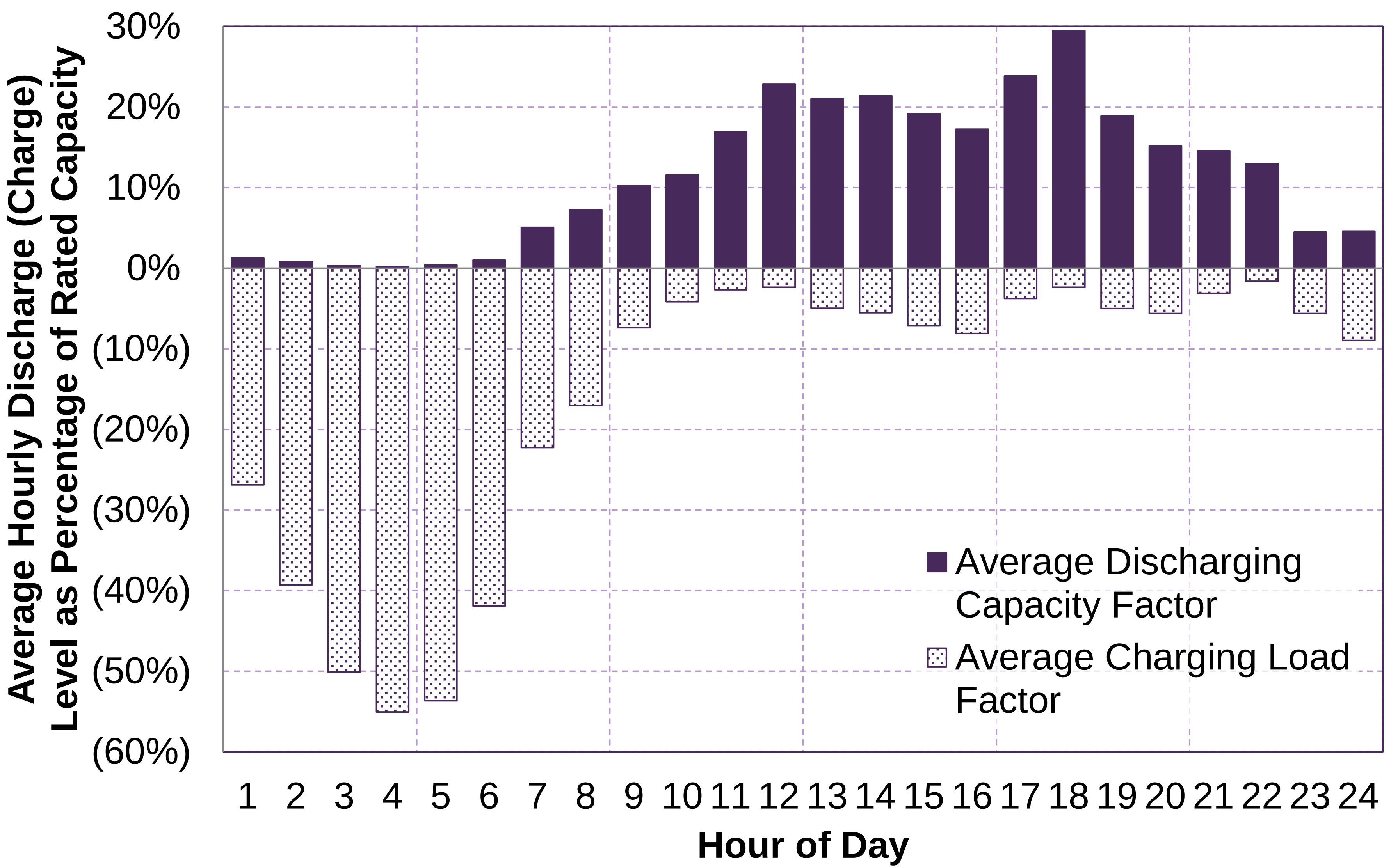
Dispatch modelling showed indirect correlation with system demand



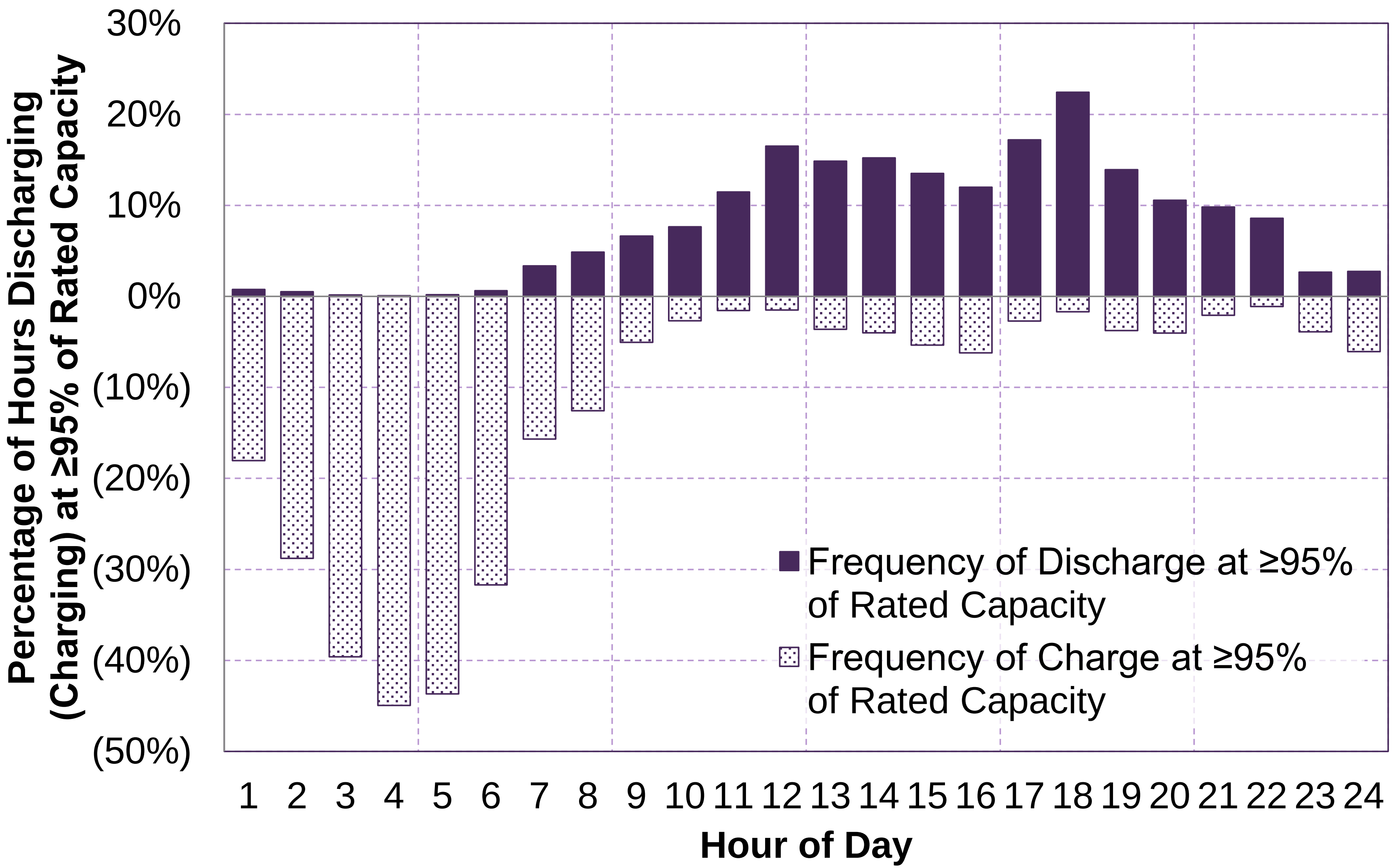
Rate DTS charges had a small impact on power flow



Hourly load factor when charging averaged from less than 10% to more than 50%



Charging at rated capacity occurred for up to 6% of daytime hours



Cost causation considerations for energy storage are similar to those for load

- Cost causation basis for bulk system charge is coincidence with system peak
  - The Commission has found that system peaks are important in the planning of the bulk transmission system [Decision 2007-106]
  - If an energy storage facility charges during system peak, it could cause bulk system costs
- Cost causation basis for regional system charge is load in any hour
  - The Commission has directed the AESO to use NCP [non-coincident peak] demand, together with a ratchet, to collect regional system costs [Decision 2007-106]
  - If an energy storage facility charges in any hour, it could cause regional system costs

Cost causation considerations for energy storage are similar to those for load (cont'd)

- Cost causation basis for point of delivery charge is load in any hour
  - The Commission has directed the AESO to use a multi-tiered NCP [non-coincident peak] demand, together with a ratchet, to collect point of delivery costs [Decision 2007-106]
  - If an energy storage facility charges in any hour, it could cause point of delivery costs
- Cost causation basis for operating reserve charge is load in the hour in which costs are incurred
  - The Commission has approved the hourly allocation of operating reserve costs [Decision 2010-606]
  - Contingency reserve volumes vary directly with hourly load and hourly generation [Reliability Standard BAL-002-WECC]

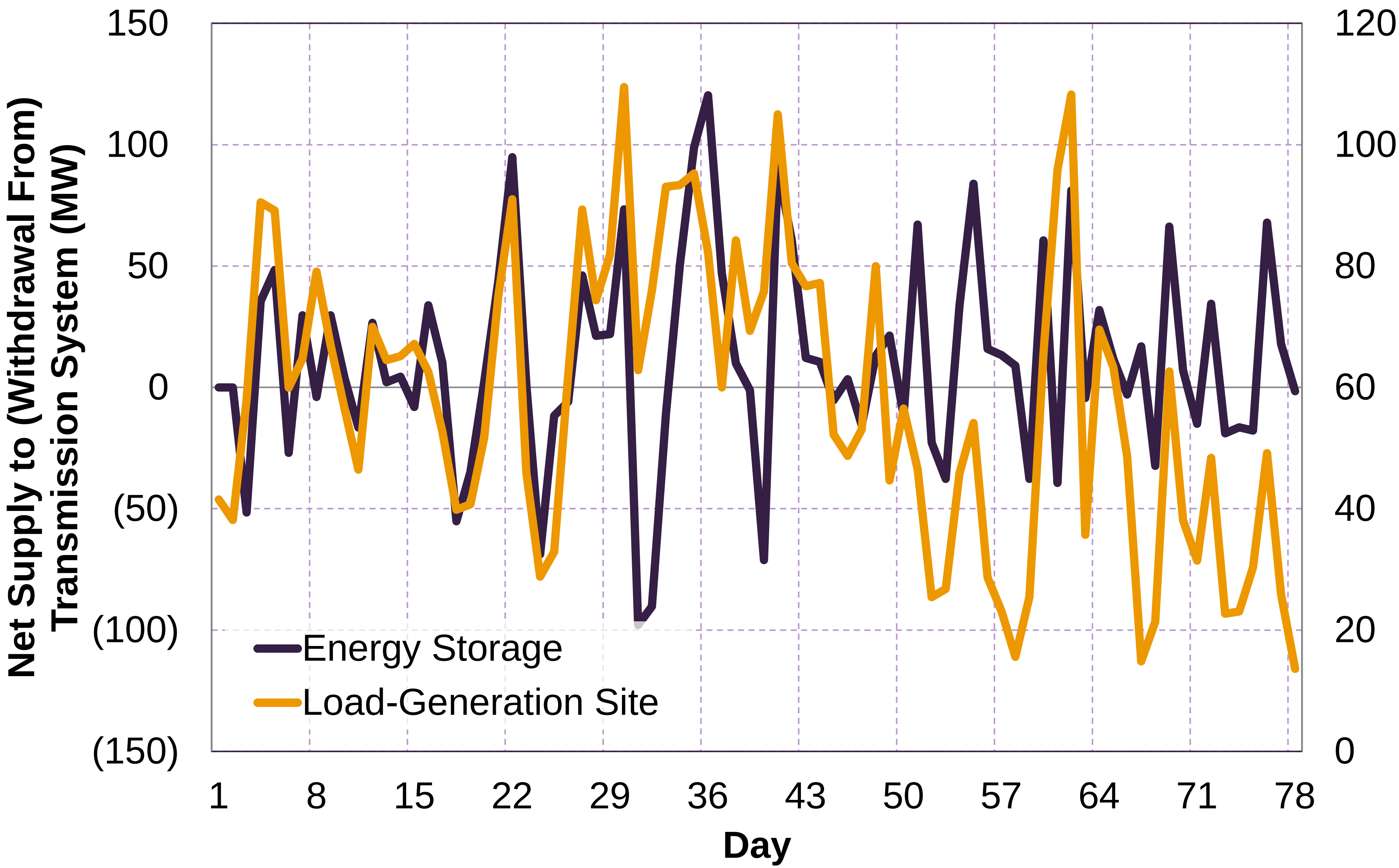
Cost causation considerations for energy storage are similar to those for load (cont'd)

- Cost causation basis for transmission constraint rebalancing charge is load in the hour in which costs are incurred
  - The Commission has approved the hourly allocation of constraint rebalancing costs [Decision 20623-D01-2015]
- Voltage control charge recovers transmission must-run costs as a variable cost through a $/MWh energy charge [Decision 2005-096]
  - Cost causation basis reflects variable nature of transmission must-run costs that are impacted by many factors
- Other system support services charge recovers miscellaneous fixed costs through a $/MW demand charge [Decision 2005-096]
  - Cost causation basis reflects fixed nature of costs

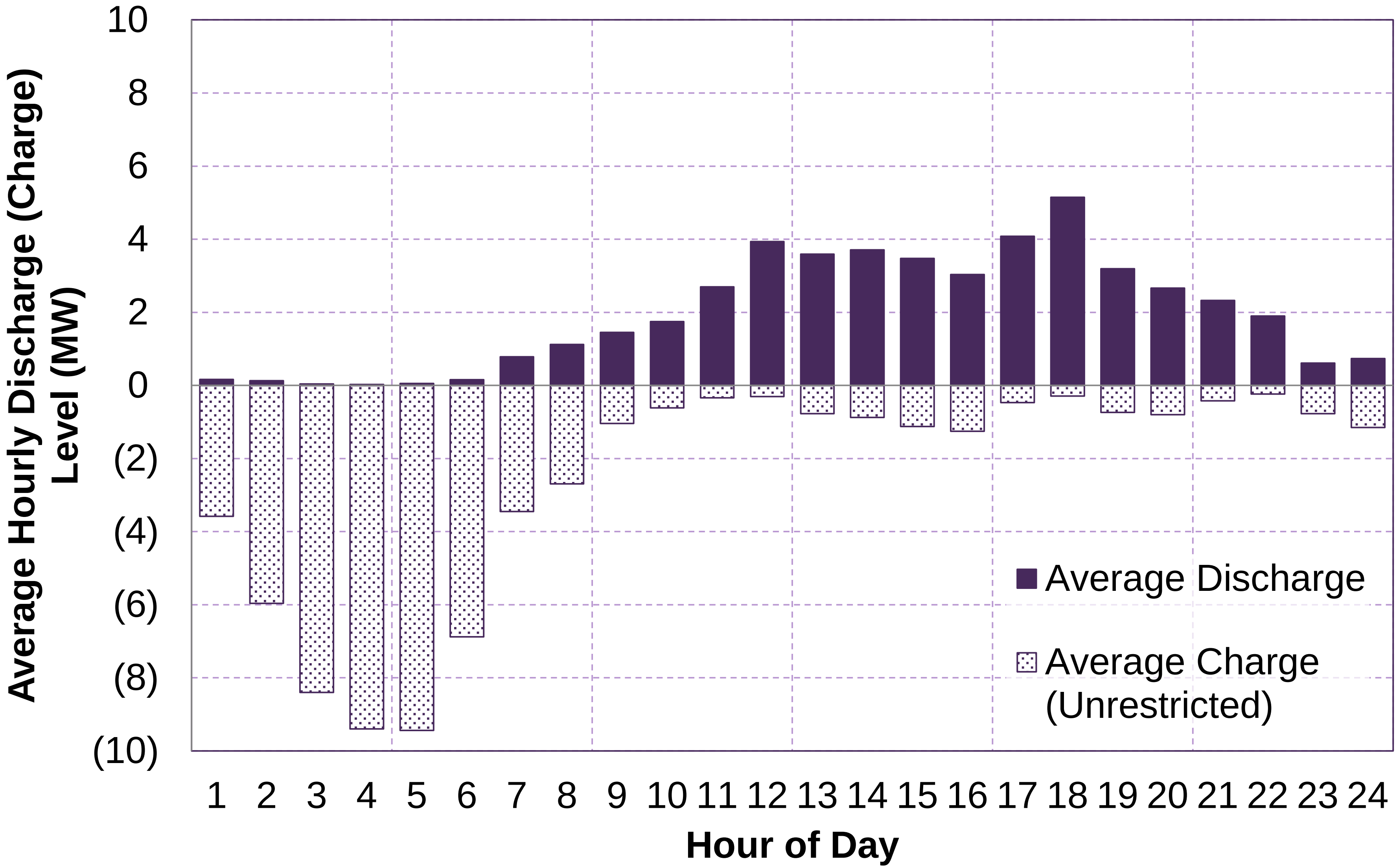
Cost causation review suggests Rate DTS appropriately applies to energy storage

- Rate DTS would apply only in hours in which an energy storage facility is charging
  - Rate STS would apply in hours in which it is discharging
- Many of the components of Rate DTS can be avoided or reduced by the energy storage participant
- The Commission has previously found the combination of Rates DTS and STS to be appropriate for sites that include load and generation
  - The Commission expressed concerns that a standby rate may not accurately reflect the costs that may be imposed by standby loads [Decision 2007-106]

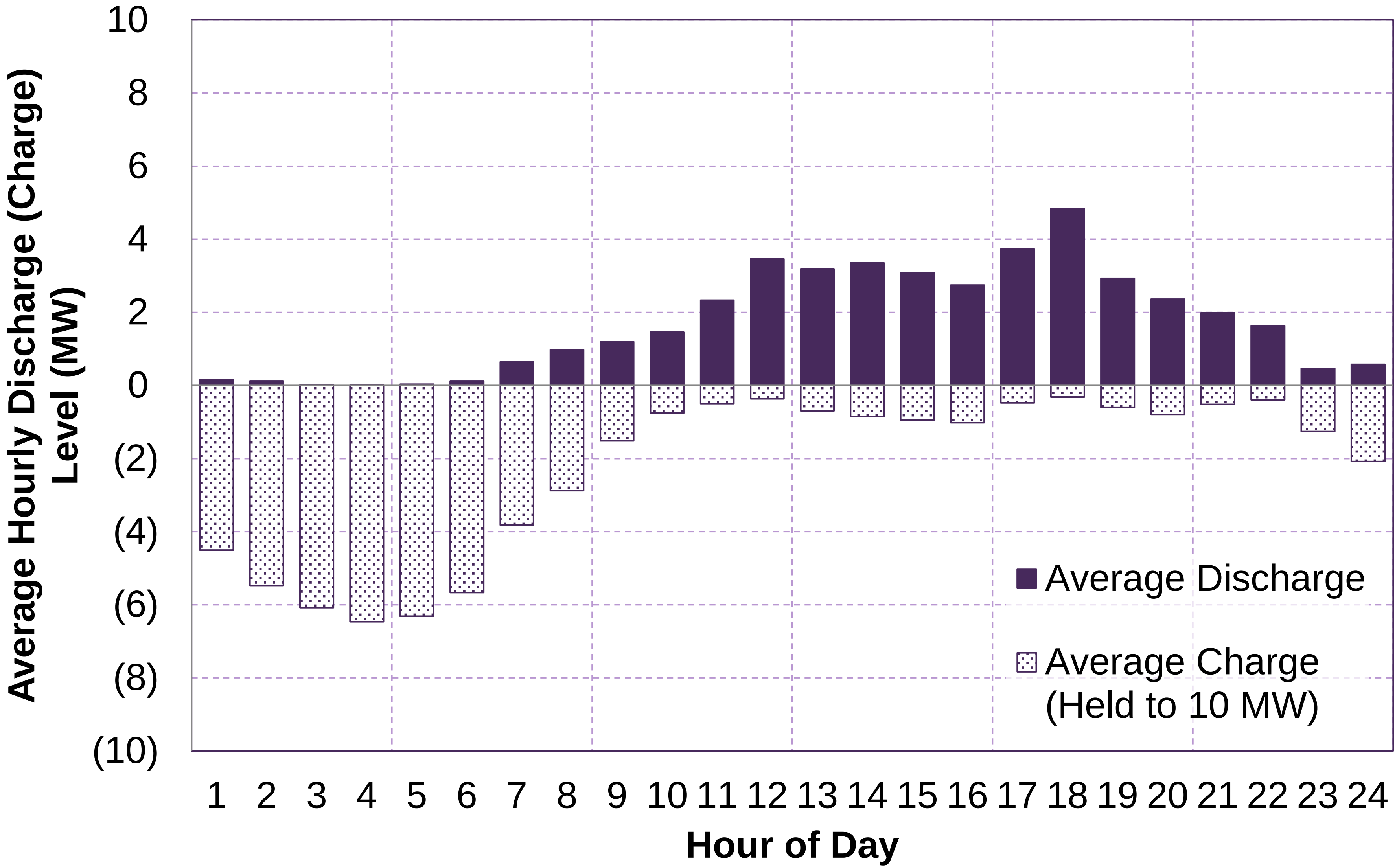
AESO comparability study found similarities between storage and load-generation sites



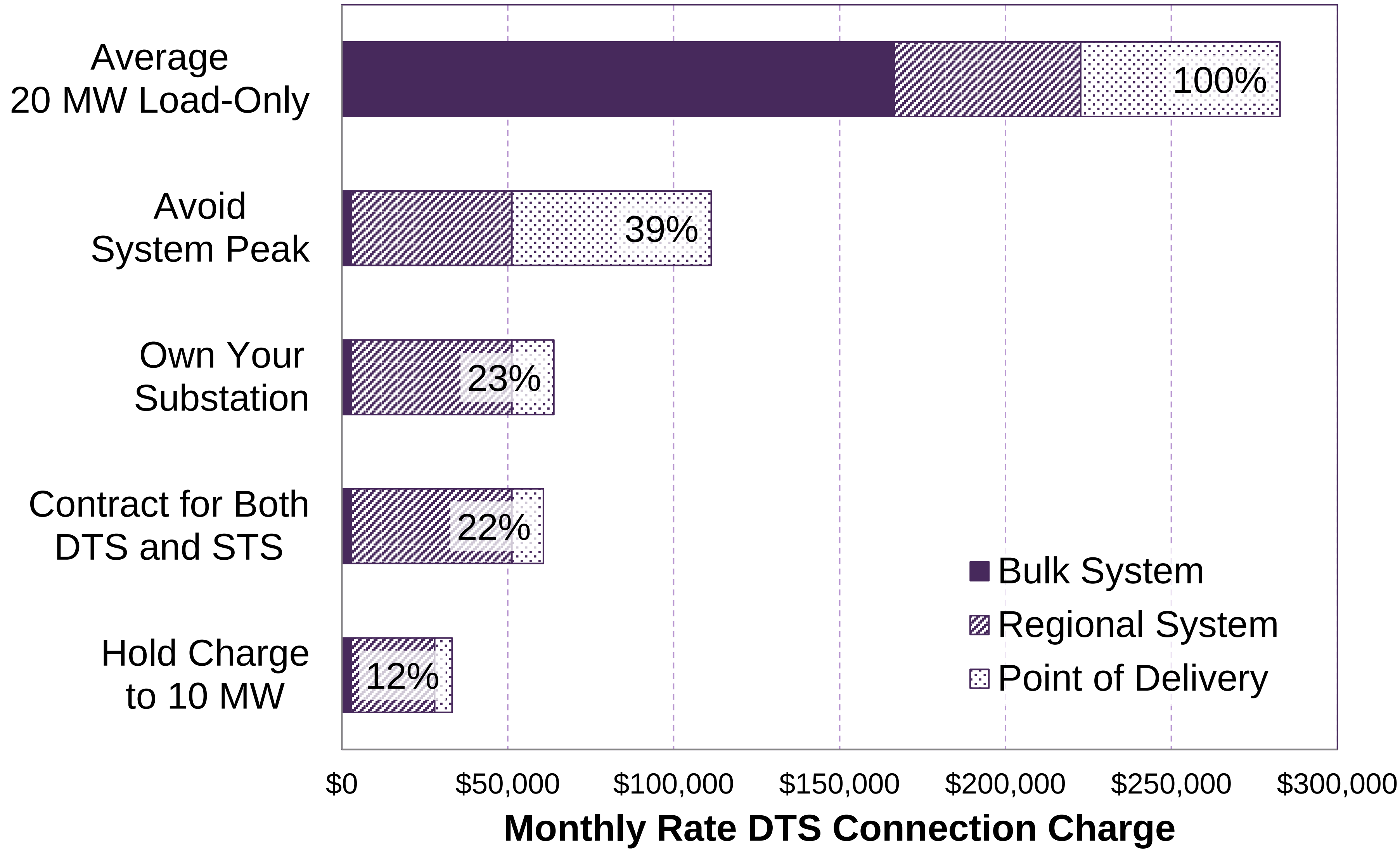
20 MW energy storage facility had average discharge-charge pattern with no restrictions



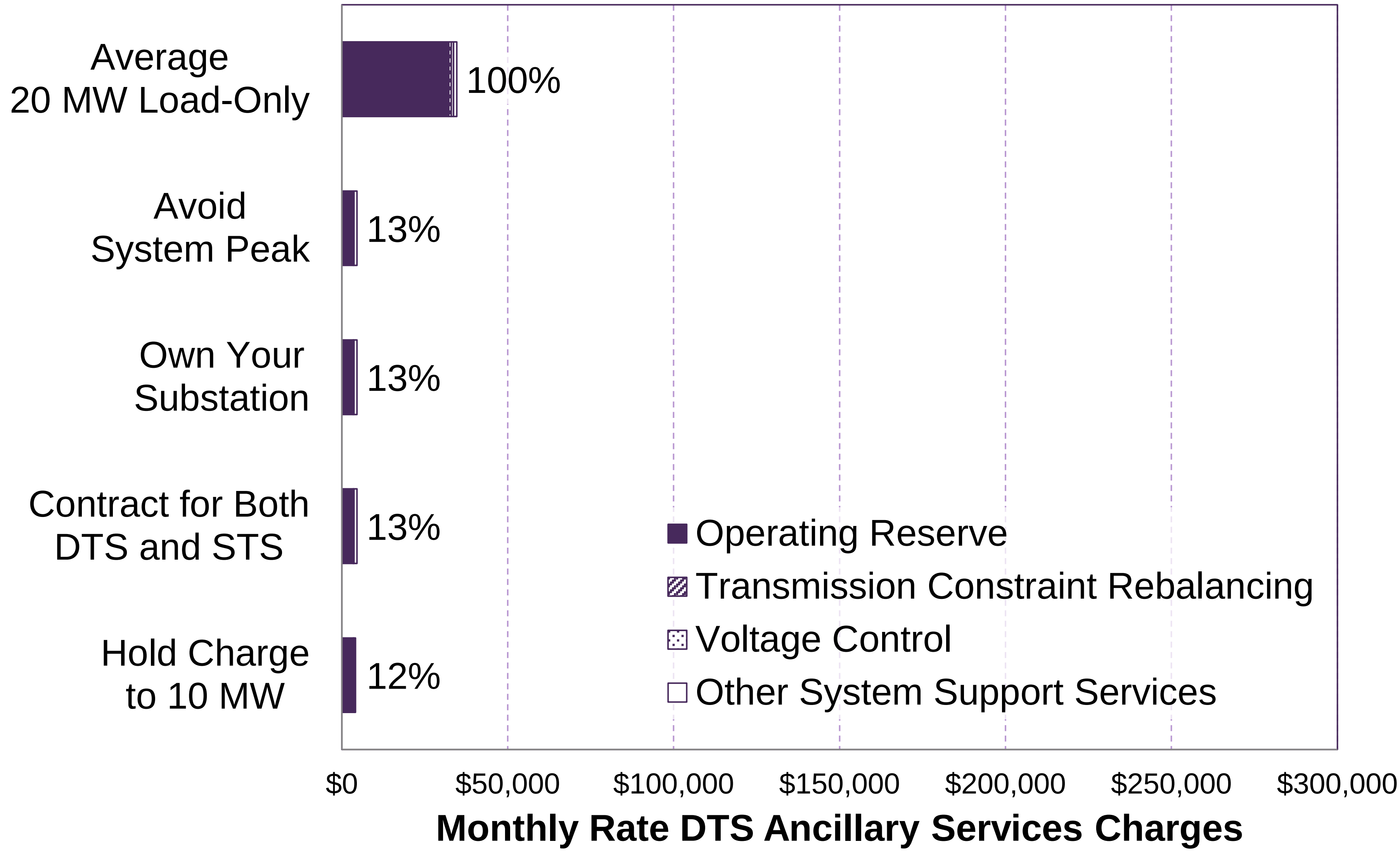
Discharge-charge pattern remained similar when charge level was held to 10 MW



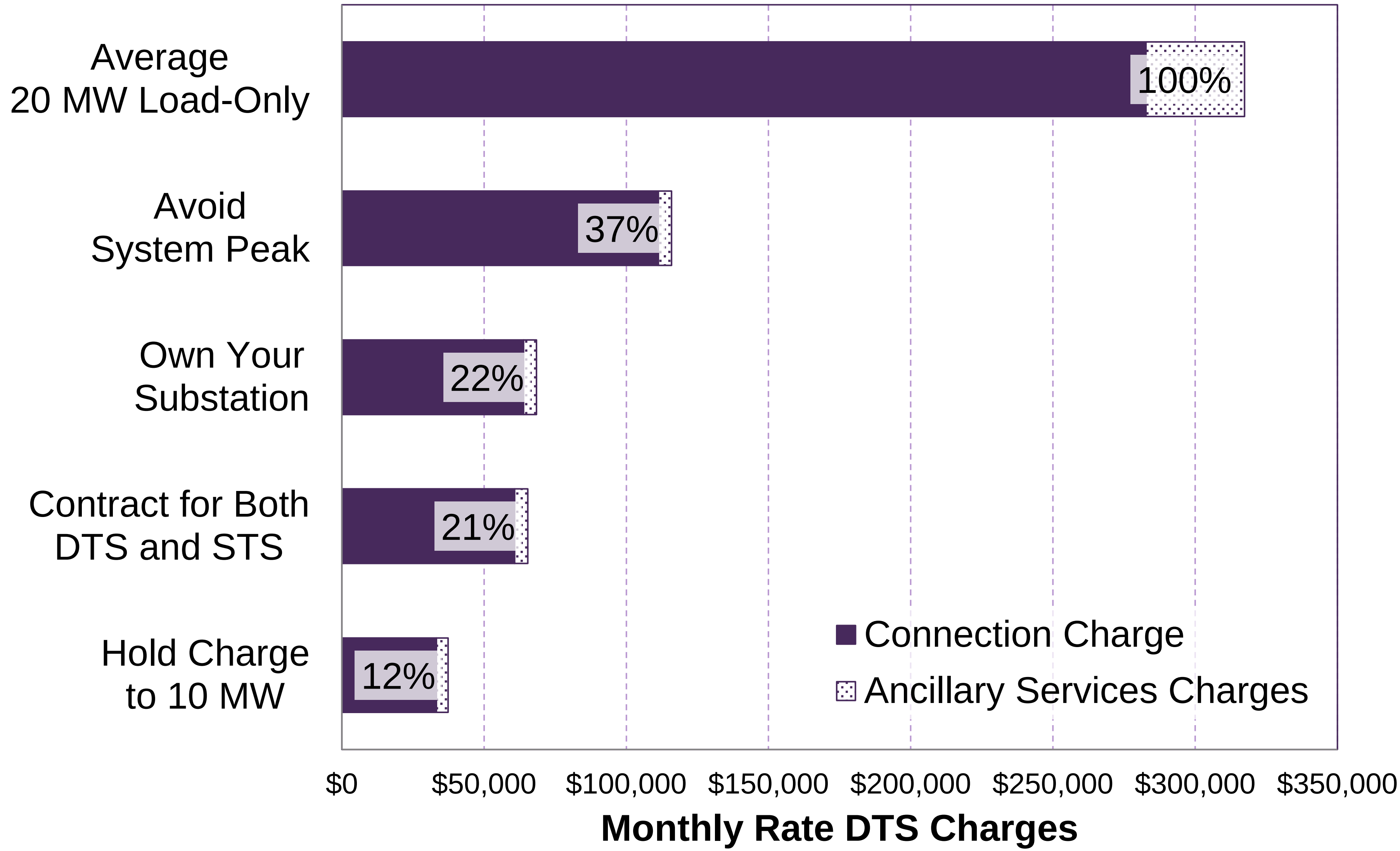
Connection charge for 20 MW storage could be 12% of charge for load-only service



Ancillary services charges for 20 MW storage could be 12% of load-only



Total Rate DTS charges for 20 MW storage could be 12% of total charges for load-only



AESO will propose Rate DTS apply to energy storage facilities when charging

- AESO will discuss use of Rates DTS and STS for energy storage facilities when charging and discharging, respectively, in its tariff application
- Rates and terminology in tariff will be updated to address energy storage facilities
  - Primarily affects applicability subsections in tariff
- Stakeholders will have opportunity to ask information requests and submit evidence on other approaches during regulatory proceeding before the Commission

Rider C / DAR Process Update

- Identified in prior work that regular tariff update applications should reduce the magnitude of Rider C
  - The AESO filed 2015 tariff update in August 2015, approved by the Commission and effective January 1, 2016
  - The AESO filed 2016 tariff update in February 2016, approved by the Commission and effective April 1, 2016
- The AESO plans to file upcoming 2017 tariff update in Q3 2016
  - Update of rate and investment levels to reflect 2017 costs
  - Proposed to be effective January 1, 2017

Rider C/DAR Process Update (cont'd)

Further work required to investigate other Rider C structure impacts – to the end of 2016:

- Impact of early tariff updates
- Impact of seasonal effects
- Impact of converting Rider C to a percentage basis
- Possibility of eliminating quarterly Rider C
- Possibility of moving to prospective Rider C

Rider C/DAR Process Update (cont'd)

- Incorporation of primary service credit (Rate PSC) amounts in deferral account reconciliation and allocation methodology has been questioned in 2015 deferral account reconciliation proceeding
- AESO is reviewing whether modifications of Rider C or deferral account reconciliation methodology are needed to clarify treatment of Rate PSC amounts
  - Current tariff only includes Rates DTS and FTS in deferral account reconciliation and allocation methodology

Consultation Process Plan

- Consultation on Scope
  - Share information on topics to be covered in ISO tariff application (to end of July 2016)
- Specific Topic Consultation
  - Begin in September 2016 to address transmission cost causation study results
  - POD cost function database results
  - Sections 4, 5, 8 and 9 of terms and conditions
  - Rider C/DAR
  - CIP Standards cost recovery
- Application Preview
  - Early 2017

2017 ISO Tariff Application Schedule

2016

- Jul 7 — 2^{nd} general consultation session
- Jul – ? — 2015 DAR Regulatory Process
- Q3 — File 2017 Tariff Update Application
- Q4 — Specific topic consultation

2017

- Q1 — Application preview
- Q1 — File 2017 Tariff Application
- Q2 — File 2016 DAR Application
- Q2 – Q3 — Regulatory review process
- Q4 — Compliance filing

Next Steps

- The AESO will invite participants to respond to this presentation through a comment matrix in the next few weeks. To allow transparency, the AESO will post all comments on AESO's website following the receipt of participants' input.

- For more information:
  Contact LaRhonda Papworth - Manager, Tariff Design
  403-539-2555 or larhonda.papworth@aeso.ca

- All consultation documents can be found on AESO website at www.aeso.ca by following the path Tariff ► Current Consultations ► 2017 Tariff

Discussion

- Questions?

Public

Request for Stakeholder Comments on Scope of AESO 2017 ISO Tariff Consultation

Background

On July 7, 2016, the AESO and stakeholders participated in a consultation meeting to discuss (1) the scope of changes to be included in the AESO's 2017 ISO tariff application, (2) AESO's proposed energy storage tariff treatment, (3) Rider C/deferral account reconciliation process update, and (4) AESO's consultation plan. Based on discussion at the meeting, the AESO invites written comments from stakeholders on the information presented at the meeting. The meeting presentation is posted on the AESO website and can be accessed at www.aeso.ca by following the path Tariff ► Current Consultations ► 2017 Tariff.

Please use the comment form below when submitting comments to the AESO on the 2017 ISO tariff consultation scope and other matters. Please ensure that your comments represent all interests within your stakeholder organization with respect to the consultation. Please provide comments or questions no later than **September 1, 2016**, to LaRhonda Papworth at larhonda.papworth@aeso.ca or 403-539-2555.

Consultation and Stakeholder Identification

Date of Request for Comments:	July 26, 2016
Period of Consultation:	July 7 – September 1, 2016
Comments From:	
Date:	
Contact:	
Phone:	
Email:	

Stakeholder Comments on AESO Information

Stakeholder Comment
2017 ISO Tariff Application Topics
1(a) In its presentation for the 2017 ISO tariff application, the AESO proposed the following topics would be included in the application: ***i. Not proposing any rate structure changes;*** ***ii. Refinements to the connection process in Section 4 – System Access Service Requests and Section 5 – Financial Obligations for Connection Projects as well as associated refinements to Section 8 – Construction Contributions for Connection Projects and Section 9 – Changes to System Access Service After Energization; and*** ***iii. In response to directions from the Commission the AESO will address contract capacity versus installed capacity for point of delivery cost function, Rider C – Deferral Account Adjustment Rider and deferral accounts, and cost responsibility for generator compliance with the CIP Alberta reliability standards.***

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Stakeholder Comment

Stakeholder Comments:

1(b) The 2017 ISO tariff application will also include:

- ***i. Updates to the transmission cost causation study (for years 2018 – 2020) using the previous 2014 ISO tariff application methodology;***
- ***ii. Updates to the point-of-delivery (POD) database, including an update to the primary service credit ratio;***
- ***iii. The 2017 revenue requirement and will be updated with 2018 revenue requirement in compliance filing;***
- ***iv. Bill impact analysis; and***
- ***v. Update to Rider J – Wind Forecasting Service Cost Recovery Rider***

Stakeholder Comments:

TERMS AND CONDITIONS REVISIONS

2(a) The 2017 ISO tariff application will require changes to the ISO tariff's terms and conditions to align with the Commission's Decision 3473-D02-2015 (Compliance with Directions 5 through 8). These changes will have implications for system access, planning and forecasting and are part of AESO's continuing process to improve and refine the connection process. This will work will defer to the Commission-initiated proceeding (Proceeding 20922) if the Proceeding 20922 starts before filing of the 2017 ISO tariff application.

Stakeholder Comments:

2(b) Other changes to the ISO tariff's terms and conditions will include:

- ***i. Updates to Section 10 – Generating Unit Owner's Contribution (GUOC) to include GUOC rates; and***
- ***ii. Changes to sections 4 and 5 to address revisions to align with Market Participant Choice (MPC) and Abbreviated Need Identification Document (ANID) programs;***
- ***iii. Clarifications for energy storage;***
- ***iv. Allow transmission-connected distribution service customer an opportunity to deal directly with the transmission facility owner (TFO) directly for a connection project; and***
- ***v. Updates to proformas (Appendix B) to reflect current AESO processes.***

Stakeholder Comments:

TOPICS ON THE HORIZON

3(a) Other topics may be included in the 2017 ISO tariff application. The AESO is determining resources and timeline impacts for these items at this time:

- ***i. Section 11 – Ancillary Services review given fairly recent Commission decision on Transmission Constraint Management (TCM) and the length of time since this section was***

Stakeholder Comment

negotiated;

ii. ***Rider A1 – Dow Chemical Canada Inc./Dow Hydrocarbons/ASU2 review given the "Forecast Benefit to ISO" year ends at 2021 as written currently; and***

iii. ***Climate Leadership Plan / Renewable Electricity Program impacts and tariff are not known at this time. Any tariff revisions required will be made once policy is finalized.***

Stakeholder Comments:

ENERGY STORAGE

4(a) Dispatch Modelling Study results and analysis:

i. ***Dispatch modelling showed indirect correlation with system demand;***

ii. ***Rate DTS charges had a small impact on power flow;***

iii. ***Hourly load factor when charging averaged from less than 10% to more than 50%; and***

iv. ***Charging at rated capacity occurred for up to 6% of daytime hours.***

Stakeholder Comments:

4(b) Cost causation considerations for energy storage are similar to those for load:

i. ***If an energy storage facility charges during system peak, it could cause bulk system costs;***

ii. ***If an energy storage facility charges in any hour, it could cause regional system costs;***

iii. ***If an energy storage facility charges in any hour, it could cause point of delivery costs;***

iv. ***Load in the hour causes operating reserve charge costs in that hour;***

v. ***Load in the hour also causes transmission constraint rebalancing costs in that hour;***

vi. ***Variable nature of transmission must-run costs are appropriately recovered through a $/MWh energy charge; and***

vii. ***Fixed nature of other system support services costs are appropriately recovered through a $/MW demand charge.***

Stakeholder Comments:

4(c) Cost causation review suggests Rate DTS appropriately applies to energy storage:

i. ***Rate DTS would apply only in hours in which an energy storage facility is charging and Rate STS would apply in hours in which the facility is discharging;***

ii. ***Many of the components of Rate DTS can be avoided or reduced by the energy storage participant; and***

iii. ***The Commission has previously found the combination of Rates DTS and STS to be appropriate for sites that include load and generation.***

Stakeholder Comments:

4(d) Rate DTS charges for a 20 MW storage service could be reasonably reduced compared to

Stakeholder Comment

a 20 MW load-only service by the energy storage facility:

i. ***avoiding system peak;***

ii. ***owning its own substation;***

iii. ***contracting for both DTS and STS; and***

iv. ***limiting charging rate to 50% of the discharging rate.***

Stakeholder Comments:

Rider C / Deferral Account Reconciliation Process Update

5(a) ***In prior work, the AESO identified, and consulted with stakeholders, that regular tariff update applications should reduce the magnitude of Rider C. The AESO plans to file an upcoming 2017 tariff update application in Q3 2016. The 2017 tariff update application will include an update of rate and investment levels to reflect 2017 costs and proposed to be effective January 1, 2017***

Stakeholder Comments:

5(b) ***Further work is required to investigate other Rider C structure impacts. This work is ongoing until the end of 2016 and will review the impact of early tariff updates, seasonal effects, converting Rider C to a percentage basis as well as review the possibility of eliminating quarterly Rider C and possibility of moving to prospective Rider C.***

Stakeholder Comments:

5(c) ***Incorporation of primary service credit (Rate PSC) amounts in deferral account reconciliation and allocation methodology has been questioned in the 2015 deferral account reconciliation proceeding. AESO is reviewing whether modifications of Rider C or deferral account reconciliation methodology are needed to clarify treatment of Rate PSC amounts.***

Stakeholder comments:

2017 ISO Tariff Application Consultation Process Plan

6(a) ***AESO is proposing the following steps for consultation on the 2017 ISO tariff application:***

i. ***Consultation on scope;***

ii. ***Specific topic consultation to begin in September to address transmission cost causation study results, POD cost function database results, Sections 4, 5, 8 and 9 of terms and conditions, Rider C/DAR process and CIP standards generator cost recovery; and***

iii. ***Application preview (early 2017).***

Stakeholder Comments:

Stakeholder Comment
Additional Comments

Please return this form with your comments by **September 1, 2016**, to:

LaRhonda Papworth
Manager, Tariff Design
Email: larhonda.papworth@aeso.ca
Phone: (403) 539-2555
Fax: (403) 539-2524

Consolidated Stakeholder Comments on Scope of AESO 2017 ISO Tariff Consultation

Background

On July 7, 2016, the AESO and stakeholders participated in a consultation meeting to discuss (1) the scope of changes to be included in the AESO's 2017 ISO tariff application, (2) AESO's proposed energy storage tariff treatment, (3) Rider C/deferral account reconciliation process update, and (4) AESO's consultation plan. Based on discussion at the meeting, the AESO invited written comments from stakeholders on the information presented at the meeting. The written comments from stakeholders are consolidated below.

The meeting presentation is posted on the AESO website and can be accessed at www.aeso.ca by following the path Tariff ► Current Consultations ► 2017 Tariff.

Stakeholder Comments on AESO Information

Stakeholder Comment
2017 ISO Tariff Application Topics
1(a) In its presentation for the 2017 ISO tariff application, the AESO proposed the following topics would be included in the application: ***i. Not proposing any rate structure changes;*** ***ii. Refinements to the connection process in Section 4 – System Access Service Requests and Section 5 – Financial Obligations for Connection Projects as well as associated refinements to Section 8 – Construction Contributions for Connection Projects and Section 9 – Changes to System Access Service After Energization; and*** ***iii. In response to directions from the Commission the AESO will address contract capacity versus installed capacity for point of delivery cost function, Rider C – Deferral Account Adjustment Rider and deferral accounts, and cost responsibility for generator compliance with the CIP Alberta reliability standards.***
Alberta Direct Connect Consumers Association ("ADC"): ADC supports the AESO in not proposing any rate structure changes. ADC offers to work collaboratively with the AESO to address concerns with Rider C and deferral account matters.
The Alberta Storage Alliance ("ASA"): [blank]
Capital Power: Capital Power supports inclusion of the above topics in the 2017 General Tariff Application ("GTA").
Ed dePalezieux: A thorough analysis will be required to assess installed capacity vs. contract capacity. Will have comments once the structure of the analysis and outcomes are made clear.
EPCOR Distribution & Transmission Inc. ("EDTI"): [blank]

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www.aeso.ca   www.poweringalberta.com

ENMAX Corporation (“EEC”):

EEC supports review of the cost responsibility for generator compliance with the CIP Alberta Reliability Standards (“ARS”). Participants who are obligated to comply with CIP ARS should have their costs recovered through the ISO Tariff.

Industrial Power Consumers Association of Alberta (“IPCAA”):

- IPCAA is supportive of the current rate structure in terms of it promoting “user pays” principles.
- If the AESO is contemplating a working group on Rider C, deferral accounts or cost responsibility for generator compliance with the CIP standards, IPCAA would like to participate.
- IPCAA does not support consumers being allocated the cost responsibility for generator CIP compliance.

NextEra Energy Canada:

[blank]

NRStor Inc.:

[blank]

Renewable Energy Systems Canada Inc. (“RES”):

[Letter submitted by RES. Letter content included in “Other Comments” at the end of the consolidated stakeholder comments]

Rocky Mountain Power (2006) Inc. (“RMP”):

[blank]

Temporal Power Ltd.:

[blank]

1(b) The 2017 ISO tariff application will also include:

i. Updates to the transmission cost causation study (for years 2018 – 2020) using the previous 2014 ISO tariff application methodology;

ii. Updates to the point-of-delivery (POD) database, including an update to the primary service credit ratio;

iii. The 2017 revenue requirement and will be updated with 2018 revenue requirement in compliance filing;

iv. Bill impact analysis; and

v. Update to Rider J – Wind Forecasting Service Cost Recovery Rider

Alberta Direct Connect Consumers Association (“ADC”):

ADC is supportive of the items included in the 2017 ISO tariff application.

The Alberta Storage Alliance (“ASA”):

The Alberta Storage Alliance (ASA) is an industry group aiming to educate stakeholders on the benefits that energy storage technology can bring to the Alberta electricity system. Our membership includes a variety of key stakeholders in the Alberta market including utilities, technology manufacturers, developers, independent power producers, engineering firms, etc. The ASA is advocating a technology neutral approach to assessing the services offered by various energy assets; we believe smart regulations can unlock the growth of a new energy storage industry in the province while providing improved flexibility and resiliency to the electricity grid. Further information on the ASA and our initiatives can be found on our website (http://albertastoragealliance.com/) and in our recently released White

Paper: Energy Storage – Unlocking the Value for Alberta's Grid.

The ASA is encouraged to see that the AESO is opening a dialogue on how to best manage the integration of energy storage assets in the Alberta market. However, the ASA believes changes to rate structures should be given further consideration before any final decision is made. Energy storage technologies perform fundamentally differently from traditional energy assets governed by current rate structures. Energy storage technologies are highly flexible assets, acting as both load and generation with unique operational characteristics that can serve to benefit the Alberta market.

The ASA will continue to work with the AESO and other stakeholders to identify services and applications where energy storage can offer benefits to Alberta's electric grid. As part of this collaboration, we recommend conducting a technical review to determine what services (existing or new) are required to help maintain a reliable electric grid going forward. Part of this assessment should include a review of whether assets solely providing system stability services should be exempt from certain prohibitive tariffs. For example, a Standard Transmission Service rate for grid-connected storage offering only Operating Reserves would avoid "double charging" such assets under existing regulations and tariffs. Other jurisdictions (CAISO, PJM, IESO, etc.) have introduced legislation to address the perceived "double counting conundrum" whereby storage facilities must pay retail rates for loading and generating, despite operating to provide reliability services to the grid. The ASA believes changes to the rate structure should be considered in order to ensure that energy storage technologies are being valued on their unique merits rather than being penalized for their fundamental operational differences relative to incumbent technologies.

Capital Power:

Capital Power supports inclusion of the above topics in the 2017 GTA.

Please provide an estimated date when the updated cost causation study will be provided to stakeholders for review. Capital Power requests that the AESO hold a stakeholder session following the study's release to review the results and address stakeholder questions.

Capital Power requests that the AESO commit to providing an updated Transmission Rate Impact Projection ("TRIP") model as part of the AESO's 2017 GTA. The TRIP model is a comprehensive and detailed document that is helpful to market participants in assessing long-term transmission cost projections and the impacts of rate and tariff design changes. A stakeholder session to review the updated TRIP model would be beneficial.

Ed dePalezieux:

Agree that the AESO should perform the cost causation study in-house.

EPCOR Distribution & Transmission Inc. ("EDTI"):

[blank]

ENMAX Corporation ("EEC"):

[blank]

Industrial Power Consumers Association of Alberta ("IPCAA"):

- Will the updates to the transmission cost causations study require external consultants? What is the expected timeline on this project?

NextEra Energy Canada:

[blank]

NRStor Inc.:

NRStor Inc. (NRStor) is a member of The Alberta Storage Alliance (ASA). The ASA is an industry group aiming to educate stakeholders on the benefits that energy storage technology can bring to the Alberta electricity system. Our membership includes a variety of key stakeholders in the Alberta market including utilities, technology manufacturers, developers, independent power producers, engineering firms, etc. NRStor, alongside the ASA, is advocating a technology neutral approach to assessing the services offered by various energy assets; we believe smart regulations can unlock the growth of a new energy storage industry in the province while providing improved flexibility and resiliency to the electricity grid. Further information on the ASA and its initiatives can be found on its website (http://albertastoragealliance.com/) and in its recently released White Paper: Energy Storage – Unlocking the Value for Alberta's Grid.

NRStor is encouraged to see that the AESO is opening a dialogue on how to best manage the integration of energy storage assets in the Alberta market. However, NRStor believes changes to rate structures should be given further consideration before any final decision is made. Energy storage technologies perform fundamentally differently from traditional energy assets governed by current rate structures. Energy storage technologies are highly flexible assets, acting as both load and generation with unique operational characteristics that can serve to benefit the Alberta market.

As a member of the ASA, NRStor will continue to work with the AESO and other stakeholders to identify services and applications where energy storage can offer benefits to Alberta's electric grid. As part of this collaboration, we recommend conducting a technical review to determine what services (existing or new) are required to help maintain a reliable electric grid going forward. Part of this assessment should include a review of whether assets solely providing system stability services should be exempt from certain prohibitive tariffs. For example, a Standard Transmission Service rate for grid-connected storage offering only Operating Reserves would avoid "double charging" such assets under existing regulations and tariffs. Other jurisdictions (CAISO, PJM, IESO, etc.) have introduced legislation to address the perceived "double counting conundrum" whereby storage facilities must pay retail rates for loading and generating, despite operating to provide reliability services to the grid. NRStor believes changes to the rate structure should be considered in order to ensure that energy storage technologies are being valued on their unique merits rather than being penalized for their fundamental operational differences relative to incumbent technologies.

Renewable Energy Systems Canada Inc. ("RES"):

[Letter submitted by RES. Letter content included in "Other Comments" at the end of the consolidated stakeholder comments]

Rocky Mountain Power (2006) Inc. ("RMP"):

RMP has been an advocate for changes to the AESO's rate structure. Specifically, RMP has advocated that the AESO develop and implement Energy Storage Opportunity Service ("ESOS") rates. The AESO has refused to do so as indicated in 1(a) i. above. In addition, in the AESO's 2017 ISO Tariff Consultation held on July 7th, 2017, on slide # 33 the AESO states:

AESO will discuss use of Rates DTS and STS for energy storage facilities when charging and discharging, respectively, in its tariff application

•*Rates and terminology in tariff will be updated to address energy storage facilities Primarily affects applicability subsections in tariff*

•*Stakeholders will have opportunity to ask information requests and submit evidence on other approaches during regulatory proceeding before the Commission*

In other words, the AESO has decided that it will NOT consider, discuss nor contemplate any alternative tariff structure, or types transmission rates, that could apply to grid connected energy storage facilities. RMP wonders why the AESO is even asking for comments on its position regarding the appropriateness of the DTS rate for energy storage facilities because clearly the AESO has decided that it will apply a combination of the DTS and STS rates for energy storage facilities without any further discussion.

RMP disagrees with the AESO's decision to apply DTS and STDS rates to grid connected energy storage facilities without further consultation. RMP recommends that the AESO engage in a true consultative process regarding the appropriate rates for grid connected energy storage facilities. The Collaborative Industry Dialogue and Issue Resolution ("CIDIR") process that the AESO is part of would be a good forum for engaging in real consultation regarding the appropriate rates to be applied to energy storage facilities of all types. CODIR consultations could result in substantially reduced time and litigation expenses for the AESO, its ratepayers, storage proponents and all other industry stakeholders.

Temporal Power Ltd.:

Temporal Power Ltd. (Temporal) is a member of The Alberta Storage Alliance (ASA). The ASA is an industry group aiming to educate stakeholders on the benefits that energy storage technology can bring to the Alberta electricity system. Our membership includes a variety of key stakeholders in the Alberta market including utilities, technology manufacturers, developers, independent power producers, engineering firms, etc. Temporal, alongside the ASA, is advocating a technology neutral approach to assessing the services offered by various energy assets; we believe smart regulations can unlock the growth of a new energy storage industry in the province while providing improved flexibility and resiliency to the electricity grid. Further information on the ASA and its initiatives can be found on its website (http://albertastoragealliance.com/) and in its recently released White Paper: Energy Storage – Unlocking the Value for Alberta's Grid.

Temporal is encouraged to see that the AESO is opening a dialogue on how to best manage the integration of energy storage assets in the Alberta market. However, Temporal believes changes to rate structures should be given further consideration before any final decision is made. Energy storage technologies perform fundamentally differently from traditional energy assets governed by current rate structures. Energy storage technologies are highly flexible assets, acting as both load and generation with unique operational characteristics that can serve to benefit the Alberta market.

As a member of the ASA, Temporal will continue to work with the AESO and other stakeholders to identify services and applications where energy storage can offer benefits to Alberta's electric grid. As part of this collaboration, we recommend conducting a technical review to determine what services (existing or new) are required to help maintain a reliable electric grid going forward. Part of this assessment should include a review of whether assets solely providing system stability services should be exempt from certain prohibitive tariffs. For example, a Standard Transmission Service rate for grid-connected storage offering only Operating Reserves would avoid "double charging" such assets under existing regulations and tariffs. Other jurisdictions (CAISO, PJM, IESO, etc.) have introduced legislation to address the perceived "double counting conundrum" whereby storage facilities must pay retail rates for loading and generating, despite operating to provide reliability services to the grid. Temporal believes changes to the rate structure should be considered in order to ensure that energy storage technologies are being valued on their unique merits rather than being penalized for their fundamental operational differences relative to incumbent technologies.

TERMS AND CONDITIONS REVISIONS

2(a) The 2017 ISO tariff application will require changes to the ISO tariff's terms and conditions to align with the Commission's Decision 3473-D02-2015 (Compliance with Directions 5 through 8). These changes will have implications for system access, planning and forecasting and are part of AESO's continuing process to improve and refine the connection process. This will work will defer to the Commission-initiated proceeding (Proceeding 20922) if the Proceeding 20922 starts before filing of the 2017 ISO tariff application.

Alberta Direct Connect Consumers Association ("ADC"):

No Comment.

The Alberta Storage Alliance ("ASA"):

The ASA recognizes the importance of system access, planning and forecasting and believes the inclusion of energy storage technologies will be crucial in this process. The ASA has released a White Paper outlining its recommendations for the Alberta electricity sector. A key recommendation was for the AESO to collaborate with the ASA in order to conduct a detailed technical review of energy storage technologies to determine what services (existing or new) are required to help maintain a reliable electric grid, and to understand the services and applications where energy storage can offer benefits to the Alberta grid. Ontario's IESO recently released a technical report on energy storage, which focuses on the reliability needs of the local power system and the potential for energy storage technologies to address those needs, which we believe is worth referencing in this dialogue.

The ASA believes energy storage technologies should be given due consideration as an alternative to incumbent technologies during system planning and forecasting efforts. We look forward to collaborating further with the AESO on this matter.

Capital Power:

Several aspects of the Commission's Decision 3473-D02-2015 will have implications for the AESO's 2017 GTA and some elements of that Decision remain unresolved and part of the active AUC Proceeding #20922, as stated above by the AESO. Capital Power asks the AESO to confirm that its proposed approach to deal with these issues ahead of Proceeding 20922 is procedurally correct.

The AESO's response to the Commission's directions in Decision 3473-D02-2015 has not been communicated to stakeholders. Capital Power requests that the AESO provide stakeholders with a preliminary list of its positions as they relate to the various topics outlined by the Commission in AUC Bulletin 2015-15 and elaborated in Section 6 of Decision 3473-D02-2015, and how the AESO plans to integrate these positions into its Tariff via changes to the terms and conditions.

While issues related to the application of system project advancement costs to load remain unresolved, Capital Power submits that the Commission was clear in Decision 3473-D02-2015 that system project advancement costs should not be applied to generators. Section 6.7 of Decision 3473-D02-2015 provides the Commission's views on this matter and paragraph 191 is particularly helpful in summarizing the Commission's discussion. Paragraph 191 states that "the only recovery of non-radial transmission facility costs from generator market participants that can occur is in accordance with Section 29 of the Transmission Regulation," and hence, "AESO tariff provisions designed to allocate the cost of advancing system transmission projects can only be applied to load market participants and not to generator market participants."

Capital Power asks the AESO to confirm whether or not it has accepted the Commission's views on the application of advancement costs to generators and whether or not it plans to re-open this issue in the 2017 GTA. Capital Power does not support re-opening the issue of applying system project advancement costs to generators in the 2017 GTA.

Ed dePalezieux:

Agree that the Commission needs to clarify its intent. Difficult to start this work without clarification from the Commission on the desired outcome and process.

EPCOR Distribution & Transmission Inc. ("EDTI"):

If Proceeding 20922 has not been initiated prior to filing the 2017 ISO tariff application, does the AESO propose to include amendments to the ISO tariff's terms and conditions to align with Directions 5-8 of Decision 3473-D02-2015? If yes, will the AESO consult on those proposed amendments prior to filing the 2017 tariff application?

ENMAX Corporation ("EEC"):

[blank]

Industrial Power Consumers Association of Alberta ("IPCAA"):

Agreed. No need to address the same issue in multiple proceedings.

NextEra Energy Canada:

[blank]

NRStor Inc.:

NRStor recognizes the importance of system access, planning and forecasting and believes the inclusion of energy storage technologies will be crucial in this process. The ASA has released a White Paper outlining its recommendations for the Alberta electricity sector. A key recommendation was for the AESO to collaborate with the ASA in order to conduct a detailed technical review of energy storage technologies to determine what services (existing or new) are required to help maintain a reliable electric grid, and to understand the services and applications where energy storage can offer benefits to the Alberta grid. Ontario's IESO recently released a technical report on energy storage, which focuses on the reliability needs of the local power system and the potential for energy storage technologies to address those needs, which we believe is worth referencing in this dialogue.

NRStor believes energy storage technologies should be given due consideration as an alternative to incumbent technologies during system planning and forecasting efforts. We look forward to collaborating further with the AESO on this matter.

Renewable Energy Systems Canada Inc. ("RES"):

[Letter submitted by RES. Letter content included in "Other Comments" at the end of the consolidated stakeholder comments]

Rocky Mountain Power (2006) Inc. ("RMP"):

RMP recommends that the AESO include grid connected energy storage projects as alternatives to additional transmission capacity in its planning and forecasting processes.

Temporal Power Ltd.:

Temporal recognizes the importance of system access, planning and forecasting and believes the inclusion of energy storage technologies will be crucial in this process. The ASA has released a White Paper outlining its recommendations for the Alberta electricity sector. A key recommendation was for the AESO to collaborate with the ASA in order to conduct a detailed technical review of energy storage technologies to determine what services (existing or new) are required to help maintain a reliable electric grid, and to understand the services and applications where energy storage can offer benefits to the Alberta grid. Ontario's IESO recently released a technical report on energy storage, which focuses on the reliability needs of the local power system and the potential for energy storage technologies to address those needs, which we believe is worth referencing in this dialogue.

Temporal believes energy storage technologies should be given due consideration as an alternative to incumbent technologies during system planning and forecasting efforts. We look forward to collaborating further with the AESO on this matter.

2(b) Other changes to the ISO tariff's terms and conditions will include:

- ***i. Updates to Section 10 – Generating Unit Owner's Contribution (GUOC) to include GUOC rates; and***
- ***ii. Changes to sections 4 and 5 to address revisions to align with Market Participant Choice (MPC) and Abbreviated Need Identification Document (ANID) programs;***
- ***iii. Clarifications for energy storage;***
- ***iv. Allow transmission-connected distribution service customer an opportunity to deal***

	directly with the transmission facility owner (TFO) directly for a connection project; and
v.	***Updates to proformas (Appendix B) to reflect current AESO processes.***

Alberta Direct Connect Consumers Association ("ADC"):

No Comment

The Alberta Storage Alliance ("ASA"):

The ASA is supportive of the AESO's efforts to clarify and clearly define energy storage technologies and include rule provisions for their participation in the wholesale energy and operating reserves markets. The lack of these rule provisions is currently an important barrier for energy storage (particularly with respect to the ancillary services markets), and revisions to the market rules should consider storage as another capable technology that can satisfy the appropriate technical requirements. We believe this rule development should be accelerated to allow for the inclusion of energy storage in the Alberta market. The ASA believes this is a starting point for the province to understand what services energy storage is capable of providing. The ASA would be pleased to engage with the AESO on building these definitions and providing any further information required.

Capital Power:

Capital Power supports inclusion of these topics and requests that updated GUOC rates and the rationale behind them be provided to stakeholders by the AESO as soon as practical in its 2017 GTA consultation

Ed dePalezieux:

Market Participant choice has not been successful in terms of customers choosing this option. It may be time well spent to assess this option and how to make it more compelling as opposed to a simple alignment of sections 4 and 5. Potentially greater tariff changes are required to make this program attractive.

EPCOR Distribution & Transmission Inc. ("EDTI"):

[blank]

ENMAX Corporation ("EEC"):

EEC supports a review of Section 10 to include GUOC rates, and to ensure that any changes align with ISO Rule 505.2, if required.

Industrial Power Consumers Association of Alberta ("IPCAA"):

IPCAA is supportive of allowing transmission-connected distribution customers an opportunity to deal directly with TFOs for connection projects.

NextEra Energy Canada:

[blank]

NRStor Inc.:

NRStor is supportive of the AESO's efforts to clarify and clearly define energy storage technologies and include rule provisions for their participation in the wholesale energy and operating reserves markets. The lack of these rule provisions is currently an important barrier for energy storage (particularly with respect to the ancillary services markets), and revisions to the market rules should consider storage as another capable technology that can satisfy the appropriate technical requirements. We believe this rule development should be accelerated to allow for the inclusion of energy storage in the Alberta market. The ASA believes this is a starting point for the province to understand what services energy storage is capable of providing. As a member of the ASA, NRStor would be pleased to engage with the AESO on building these definitions and providing any further information required.

Renewable Energy Systems Canada Inc. ("RES"):

[Letter submitted by RES. Letter content included in "Other Comments" at the end of the consolidated stakeholder comments]

Rocky Mountain Power (2006) Inc. ("RMP"):

It would be very helpful to know what "clarifications" the AESO is planning on making to its tariff terms and conditions so that these "clarifications" can be discussed prior to the 2017 rate filing. However, the AESO seems to have precluded ANY further discussion about energy storage rates.

Temporal Power Ltd.:

Temporal is supportive of the AESO's efforts to clarify and clearly define energy storage technologies and include rule provisions for their participation in the wholesale energy and operating reserves markets. The lack of these rule provisions is currently an important barrier for energy storage (particularly with respect to the ancillary services markets), and revisions to the market rules should consider storage as another capable technology that can satisfy the appropriate technical requirements. We believe this rule development should be accelerated to allow for the inclusion of energy storage in the Alberta market. The ASA believes this is a starting point for the province to understand what services energy storage is capable of providing. As a member of the ASA, Temporal would be pleased to engage with the AESO on building these definitions and providing any further information required.

TOPICS ON THE HORIZON

3(a) Other topics may be included in the 2017 ISO tariff application. The AESO is determining resources and timeline impacts for these items at this time:

i. Section 11 – Ancillary Services review given fairly recent Commission decision on Transmission Constraint Management (TCM) and the length of time since this section was negotiated;

ii. Rider A1 – Dow Chemical Canada Inc./Dow Hydrocarbons/ASU2 review given the "Forecast Benefit to ISO" year ends at 2021 as written currently; and

iii. Climate Leadership Plan / Renewable Electricity Program impacts and tariff are not known at this time. Any tariff revisions required will be made once policy is finalized.

Alberta Direct Connect Consumers Association ("ADC"):

ADC supports reviewing Rider A1 in this proceeding as Dow Chemical Canada ULC is an ADC member. We offer to work collaboratively with the AESO to ensure clarity beyond 2021 is resolved in this application.

The Alberta Storage Alliance ("ASA"):

The ASA believes the effects of the province's Climate Leadership Plan / Renewable Electricity Program should be evaluated before finalizing the AESO's decision on any related energy storage tariff. An influx of variable renewable energy generation may require additional flexibility to maintain system reliability. Energy storage technologies have been deployed and proven in other markets to meet critical reliability needs and defer or avoid major transmission/distribution system upgrades associated with the deployment of renewables. Energy storage can enable renewable generation and also stimulate further GHG emissions benefits to the province. There are four key areas where Alberta's Electricity System will need solutions as additional renewable generation is built and coal generation is retired, where storage can provide significant value:

1. Renewables integration;
2. Price volatility;
3. Supply adequacy; and

4. Grid reliability.

We believe the AESO should consider how energy storage technologies can better enable the Climate Leadership Plan when considering the next steps for this consultation process. The ASA would like to see energy storage facilities included in a process to determine the lowest-cost and most efficient infrastructure alternatives going forward

Capital Power:

In regard to 3(a)(i), please confirm exactly what changes or revisions the AESO is considering to Section 11 of the Tariff in light of the Commission decision on TCM.

In regard to 3(a)(iii), Capital Power understands that potential tariff impacts related to the Alberta Climate Leadership Plan ("ACLP") and the AESO's Renewable Electricity Program ("REP") are not known at this time and supports the AESO's approach to consider such revisions once policy is finalized. Capital Power encourages the AESO to engage and consult with stakeholders in making these determinations once policy is finalized.

Ed dePalezieux:

[blank]

EPCOR Distribution & Transmission Inc. ("EDTI"):

[blank]

ENMAX Corporation ("EEC"):

EEC supports a review of Section 11, specifically given the Transmission Constraint Management (TCM) decision, just to ensure there is no redundancy or overlap with the Tariff and the Rule.

Industrial Power Consumers Association of Alberta ("IPCAA"):

- The AESO's tariff should not be delayed by the REP. Revisions can be incorporated when the REP is formally launched.
- Re: AS Review – the AESO's list of what will be considered is fairly comprehensive. Some review is certainly warranted: technology neutrality, reducing minimum unit size requirements are likely easy changes and could (and should) be made quickly. Designing new AS products (perhaps to incorporate wind) will be a much larger project. Consider dividing the options into what can be achieved promptly and what will need a larger consultation process.

NextEra Energy Canada:

[blank]

NRStor Inc.:

NRStor believes the effects of the province's Climate Leadership Plan / Renewable Electricity Program should be evaluated before finalizing the AESO's decision on any related energy storage tariff. An influx of variable renewable energy generation may require additional flexibility to maintain system reliability. Energy storage technologies have been deployed and proven in other markets to meet critical reliability needs and defer or avoid major transmission/distribution system upgrades associated with the deployment of renewables. Energy storage can enable renewable generation and also stimulate further GHG emissions benefits to the province. There are four key areas where Alberta's Electricity System will need solutions as additional renewable generation is built and coal generation is retired, where storage can provide significant value:

1. Renewables integration;

2. Price volatility;

3. Supply adequacy; and

4. Grid reliability.

We believe the AESO should consider how energy storage technologies can better enable the Climate Leadership Plan when considering the next steps for this consultation process. NRStor would like to see energy storage facilities included in a process to determine the lowest-cost and most efficient infrastructure alternatives going forward.

Renewable Energy Systems Canada Inc. (“RES”):

[Letter submitted by RES. Letter content included in “Other Comments” at the end of the consolidated stakeholder comments]

Rocky Mountain Power (2006) Inc. (“RMP”):

RMP suggests that the AESO immediately engage in industry consultation regarding the provision and use of ancillary services by energy storage projects. RMP notes that storage projects can provide ancillary services while in both storage and generation modes and therefore can provide a much broader range of ancillary services than can a typical generation facility. A 100MW generating and storage facility can provide a band of 200MW of ancillary services (+100MW in generation mode to -100MW when switched to storage mode) while a 100MW generation facility can provide only a band of 100MW of ancillary services. Allowing energy storage facilities to apply its full band of ancillary services could free up some generation resources to do what they do best, generate electricity. In addition, the AESO should consider the implementation of long term competitively determined contracts for the provision of ancillary services. Ancillary services need not be procured on only a one day forward basis in order to be the least cost service for ratepayers. By entering in to long term AS purchase agreements, the AESO will enable more participants in the AS market thereby potentially leading to lower AS prices. Long term contracts for AS services helps new project entrants by providing creditworthy backed revenue guarantees for project developers which allows them to finance a good portion of their facilities using debt rather having to rely on higher cost equity. Competitively procured long term AS contracts may be just as competitive as day forward or “spot pricing” AS purchase arrangements.

RMP also suggests that the AESO consider potential impacts of the Climate Leadership Plan / Renewable Electricity Program before finalizing its decision on energy storage tariffs. The impacts of the Climate Plans on existing transmission and distribution infrastructure should be considered, particularly when a storage facility might be considered in lieu of reinforcements to existing transmission facilities. In addition, the AESO should consider the impact the Governments Climate Leadership Plan/Renewable Electricity Program will have for new infrastructure requirements to support the influx of variable renewable generation. Energy storage facilities should be included in a process to determine the least cost transmission infrastructure solutions for the future grid.

Temporal Power Ltd.:

Temporal believes the effects of the province’s Climate Leadership Plan / Renewable Electricity Program should be evaluated before finalizing the AESO’s decision on any related energy storage tariff. An influx of variable renewable energy generation may require additional flexibility to maintain system reliability. Energy storage technologies have been deployed and proven in other markets to meet critical reliability needs and defer or avoid major transmission/distribution system upgrades associated with the deployment of renewables. Energy storage can enable renewable generation and also stimulate further GHG emissions benefits to the province. There are four key areas where Alberta’s Electricity System will need solutions as additional renewable generation is built and coal generation is retired, where storage can provide significant value:

1. Renewables integration;
2. Price volatility;
3. Supply adequacy; and
4. Grid reliability.

We believe the AESO should consider how energy storage technologies can better enable the Climate Leadership Plan when considering the next steps for this consultation process. Temporal would like to see energy storage facilities included in a process to determine the lowest-cost and most efficient infrastructure alternatives going forward.

ENERGY STORAGE

4(a) Dispatch Modelling Study results and analysis:

i. Dispatch modelling showed indirect correlation with system demand;

ii. Rate DTS charges had a small impact on power flow;

iii. Hourly load factor when charging averaged from less than 10% to more than 50%; and

iv. Charging at rated capacity occurred for up to 6% of daytime hours.

Alberta Direct Connect Consumers Association ("ADC"):

No comment.

The Alberta Storage Alliance ("ASA"):

The ASA would like to commend the AESO for commissioning the Dispatch Modelling Study and engaging leading academic institutions in the space. This is an important first step in understanding how energy storage assets will be integrated into the electricity system. However, as a collaboration of industry participants, the ASA believes there is still significant uncertainty around the conclusions inferred from this research. We recommend further dialogue take place with the ASA and industry stakeholders, the AESO, the University of Calgary, and other interested stakeholders to better understand the underlying assumptions and conclusions being drawn from this research. The ASA believes that making impactful market decisions from a single commissioned study is not adequate to reach conclusions on such complex topics.

A primary issue for consideration is that the researchers used a 'perfect information model' with 20/20 hindsight of market conditions. While useful for drawing some indicative conclusions, this type of modeling does not accurately reflect how an energy storage facility would be operated on a day-to-day basis under real conditions. There are a number of operational (e.g. state of charge limitations, duty cycle considerations, etc.) and market considerations that specific owners may respond to differently. We recommend the AESO consider following up on this first phase of research to conduct a more detailed technical review and request further input from industry participants including the ASA.

The ASA will continue to work with the AESO and other stakeholders to identify services and applications where energy storage can offer benefits to Alberta's electric grid. As part of this collaboration, we recommend conducting a technical review to determine what services (existing or new) are required to help maintain a reliable electric grid going forward. Part of this assessment should include a review of whether assets solely providing system stability services should be exempt from certain prohibitive tariffs. For example, a Standard Transmission Service rate for grid-connected storage offering only Operating Reserves would avoid "double charging" such assets under existing regulations and tariffs. The ASA believes changes to the rate structure should be considered in order to ensure that energy storage technologies are being valued on their unique merits rather than being penalized for their fundamental operational differences relative to incumbent technologies.

It is imperative that the AESO consider reviewing the stacked benefits or multiple value streams that storage can provide to all levels of the supply chain (from generation to consumption). The ASA's recently released White Paper details the variety of benefits that storage can provide to the grid. There are four key areas where Alberta's Electricity System will need solutions as additional renewable generation is built and coal generation is retired, where storage can provide significant value:

1. Renewables integration;
2. Price volatility;

3. Supply adequacy; and

4. Grid reliability.

Capital Power:

Capital Power has no comments on the dispatch modeling results.

Ed dePalezieux:

[blank]

EPCOR Distribution & Transmission Inc. ("EDTI"):

[blank]

ENMAX Corporation ("EEC"):

We have no specific comments on the modelling results, other than to note that if the primary use of the storage is commodity price arbitrage, past market conditions may not indicate future dispatch of storage facilities.

Industrial Power Consumers Association of Alberta ("IPCAA"):

No comments.

NextEra Energy Canada:

i. Dispatch modeling showed indirect correlation with system demand;

Response: The analysis showed that storage devices both supply power to the grid and purchase power from the grid. Given that the modeled operation of storage was based on price arbitrage the results predictably indicate that storage will generally charge during off peak hours and discharge in on peak hours. It is unclear how the specific results are tied to the policy decision that energy purchases from a storage asset trigger DTS charges. The AESO did not appear to consider a charging pattern that would not trigger DTS charges, i.e. it appears as though the concept that power consumption from the grid equates to DTS charges was a foregone conclusion, especially given that the analysis illustrated very little consumption during peak periods.

The dispatch modeling did not reflect the realistic operation of a storage device in the Alberta market for a number of reasons. First, and most importantly, temporal arbitrage in isolation is very unlikely to be the profit maximizing choice for storage facilities. Contingency reserves, regulating reserves, system services such as intertie restoration and potentially renewable integration services will provide market opportunities with dramatically different operating patterns. Second, the analysis presumes perfect knowledge and does not reflect the reality of operating in an uncertain environment. Third, the analysis does not reflect the reality that a storage operator will respond to whatever tariff signals are in place. The current uncertainty around system peak charges would result in a strong aversion to charging during on peak hours due to the risk of incurring system peak costs.

The study also does not compare a storage asset's operation with that of a peaking generation asset. The study strongly reinforced the conclusion that a storage asset will be motivated by energy market price signals to the extent it is engaging in price arbitrage. While other markets such as regulating reserves are likely to prove more attractive and would result in different operating patterns.

NextEra requests that the AESO provide clarification on whether the storage load pattern study was provided to determine the applicability of DTS to storage charging hours. If yes, can the AESO also clarify what charging pattern would not have indicated DTS charges are appropriate?

ii. Rate DTS charges had a small impact on power flow;

Response: Even with the concerns raised above regarding the study, it illustrated a material economic inefficiency associated with DTS charges. Further, given the uncertainty associated with coincidental peak charges, a rational operator would respond to DTS charges by entirely avoiding charging during any hours that approached peak demand, regardless of other economic drivers such as market price.

According to the provincial transmission development policy[1], the transmission tariff should not introduce distortions to the energy only market operation (see page 5). The University of Calgary paper utilized by the AESO suggests that energy market flows from storage devices are reduced by an average of over 11% in each direction due to the tariff. This does not account for uncertainty combined with the fact that energy arbitrage is only a single element of the likely operation.

It is also clear that the tariff treatment sets a strong preference for traditional generators to fill the role of peaking capacity. The analysis indicates profitability for storage assets is reduced by 16% on average via the tariff. The AESO did not provide evidence that traditional generation provides incremental system value that justifies this differential, and further did not value the benefit storage alone can add via temporal arbitrage (amongst other unique attributes).

Clearly, in the instance of storage devices, the tariff introduces a distortion that reduces the overall efficiency of the market. Storage devices facilitate efficient market operations in a manner similar to both export capability and peaking generation combined, yet the AESO did not examine appropriate tariff treatment within this market context.

The most egregious impact of the proposed DTS tariff for storage assets is that it places them at a significant disadvantage in the regulating reserve market when the NRC/AESO study[2] suggests these assets are uniquely beneficial due to their rapid response times. Other markets have demonstrated the benefits energy storage can provide. PJM for example[3,4] has added over 280 MW of grid-connected energy storage to their regulation market. PJM used to procure 1% of their peak and valley load (~900 MW of Regulation on average per hour), but as a result of the changes to the performance based regulation market it has been reduced to 700 MW on peak and 525 MW off peak (664 MW on average) which is nearly a 30% drop.

DTS, and in particular the coincident peak demand charge, would effectively become a large random cost faced by a storage device in the regulating reserve market. A storage device selling regulating reserves will logically operate both in a charge and discharge state, driven by AESO automated dispatches in response to variable system conditions. The AESO DTS proposal amounts to systematically discouraging participation from storage assets in the regulating reserve market, and in particular during on peak hours. In this regard, the proposal does not support market fairness and efficiency.

It also must be noted that the AESO's current initiative to develop technology neutral technical standards for system reserves will be moot if the transmission tariff precludes storage participation.

1 (http://www.energy.alberta.ca/Electricity/pdfs/transmissionPolicy.pdf)

2 Regulating Reserve Performance Assessment for the Alberta Electric System Operator, March 18, 2016. National Research Council Canada.

3 Regulation Performance Metrics, July 19, 2016, 2016.

4 2010 ISO/RTO Metrics Report PJM Highlights, (http://www.ferc.gov/EventCalendar/Files/20110120100702-6-PJM-print.pdf)

iii. Hourly load factor when charging averaged from less than 10% to more than 50%;

The specific operating parameters found by the study are interesting but are flawed for the reasons previously outlined. Further, the AESO does not indicate to what extent these findings influenced its decision to implement DTS charges. To reiterate, it is not clear what charging pattern could have triggered a decision other than that DTS charges would be triggered by charging.

iv. Charging at rated capacity occurred for up to 6% of daytime hours.

See (iii.)

NRStor Inc.:

NRStor would like to commend the AESO for commissioning the Dispatch Modelling Study and engaging leading academic institutions in the space. This is an important first step in understanding how energy storage assets will be integrated into the electricity system. However, as an industry participant, NRStor believes there is still significant uncertainty around the conclusions inferred from this research. We recommend further dialogue take place with the ASA and industry stakeholders, the AESO, the University of Calgary, and other interested stakeholders to better understand the underlying assumptions and conclusions being drawn from this research. NRStor believes that making impactful market decisions from a single commissioned study is not adequate to reach conclusions on such complex topics.

A primary issue for consideration is that the researchers used a 'perfect information model' with 20/20 hindsight of market conditions. While useful for drawing some indicative conclusions, this type of modeling does not accurately reflect how an energy storage facility would be operated on a day-to-day basis under real conditions. There are a number of operational (e.g. state of charge limitations, duty cycle considerations, etc.) and market considerations that specific owners may respond to differently. We recommend the AESO consider following up on this first phase of research to conduct a more detailed technical review and request further input from industry participants including NRStor and other members of the ASA.

As a member of the ASA, NRStor will continue to work with the AESO and other stakeholders to identify services and applications where energy storage can offer benefits to Alberta's electric grid. As part of this collaboration, we recommend conducting a technical review to determine what services (existing or new) are required to help maintain a reliable electric grid going forward. Part of this assessment should include a review of whether assets solely providing system stability services should be exempt from certain prohibitive tariffs. For example, a Standard Transmission Service rate for grid-connected storage offering only Operating Reserves would avoid "double charging" such assets under existing regulations and tariffs. NRStor believes changes to the rate structure should be considered in order to ensure that energy storage technologies are being valued on their unique merits rather than being penalized for their fundamental operational differences relative to incumbent technologies.

It is imperative that the AESO consider reviewing the stacked benefits or multiple value streams that storage can provide to all levels of the supply chain (from generation to consumption). The ASA's recently released White Paper details the variety of benefits that storage can provide to the grid. There are four key areas where Alberta's Electricity System will need solutions as additional renewable generation is built and coal generation is retired, where storage can provide significant value:

1. Renewables integration;
2. Price volatility;
3. Supply adequacy; and
4. Grid reliability.

Renewable Energy Systems Canada Inc. ("RES"):

[Letter submitted by RES. Letter content included in "Other Comments" at the end of the consolidated stakeholder comments]

Rocky Mountain Power (2006) Inc. ("RMP"):

It appears the AESO is using the results of the Dispatch Modeling study to justify their decision not to make any changes to its rate structures, particularly the DTS rate rather than consider the results as the basis for considering other rate structures. RMP believes that by doing so the AESO has missed or glossed over are a number of issues that might, if considered, affect the decision that the DTS rate should be applied to grid connected energy storage facilities.

4(a) i. (Please refer to slide # 19 in the AESO's July 7th presentation.) This slide purports to show that under the scenario of storage facility owners maximizing energy price arbitrage revenue, storage operators will more often store energy at their maximum storage rate when system demand is low (presumably because energy prices are low) and will more often generate at close to their maximum generating capacity when system demand is high (presumably because energy prices are high). Please note this slide does NOT show that energy service providers will never store at or near their peak storage rate when demand is high. (Slide 4 seems to suggest that energy service providers will store at their peak rate about 1% of the time when system demand is at its highest rate.) That means that about 1% of the time, the bulk system charge, by far the largest component of the DTS rate, will apply. One might ask why this would happen. The bulk system charge is calculated as $10,175/MW/Month multiplied by the maximum rate of energy taken off the system by the storage service operator during the 15 minute Coincident Metered Demand period in a given month. (An energy charge applies as well but for the ease of explanation, that component is ignored here.) Therefore, if a 100MW storage facility charges at its max rate (100MW) during a period of monthly coincident demand, it will be charged $1,017,500 for bulk system transmission charge in that month, plus all the other components of the DTS rate. Again, why would a storage operator store during a coincident peak demand period? This event could easily occur in a spring, summer or fall month when the 15 minute system peak demand in any of those months is far less than the highest peak demand incurred during the year because energy prices might still be quite low during that spring, summer or fall month high demand 15 minute period. A storage operator looks at energy prices for signals as to whether it should store energy or discharge energy. Low prices during a "shoulder month" could occur because the total amount of generation available during that period did not go down even though average and peak demand in a shoulder month does fall. Therefore, a storage operator seeing low prices acts rationally and stores energy, but in a low demand month could be subject to the bulk system demand charge of in excess of $1,000,000. However, in a winter period it might happen that the storage operator stored at exactly the same rate at the same energy price but would NOT be subject to the bulk system demand charge. Obviously the "stress" caused to the transmission system by the storage operator taking power off the system during the shoulder month is NOT the same as "stress" caused to the transmission system if the storage operator took energy off the system during the highest peak demand in the year, yet the storage operator will be charged as if it is the same. This seems counter intuitive particularly in light of the Alberta government's renewable energy policy. Might it not make sense for storage operators to take power off the system during periods of high monthly, but low compared to the annual AIL peak, demand periods in order to preserve some semblance of minimum prices for renewable energy generators. (There are a number of empirical and theoretical studies that show electricity prices will trend to zero for significant periods of time as more renewable generation is added to a marketplace.) It is very conceivable that an event of very low energy prices could be coupled with peak demand in a month and that the storage operator acting rationally, and to the benefit of all generators, could be faced with very large bulk transmission charges as a result. This could occur even though the transmission system was well below its maximum transmission capacity, even taking into account ambient temperature line deratings. Strict application the DTS rate would result in higher transmission rates for storage operators at times when the transmission system is nowhere near peak demand.

4(a) ii – (Please refer to slide #20). This slide needs to be explained or eliminated. There is no explanation about how the DTS rate is applied in the Dispatch Modeling operating algorithm. A Dispatch algorithm might be as simple as - store power when prices are less than $20/MWH and discharge power when energy prices are greater than $100/MWH. If the comparable algorithm then becomes store when the energy price plus the DTS rate is less than $20/MWH and discharge when the energy price plus STS is greater than $100/MWH, then it might be possible to compare the two scenario's. As it stands, the AESO seems to be using this slide as a justification for the AESO's position regarding the DTS rate. However, without an explanation of what algorithms are being compared in slide 20 it is impossible to pass judgement on whether slide # 20 in fact shows what the AESO wants it to show.

RMP as a proponent for the ASISt compressed air energy storage facility has done similar analyses as that performed for the AESO. How the DTS rate is applied in the analysis is crucial to the end result. Since the bulk system charge may be incurred without the storage operator knowing until the end of a month, short term store and generation decisions, which are usually based only on incremental costs, would not be changed. However, after the fact application of the bulk system charge would result in a 100MW storage operator being in excess of $1,000,000 poorer at the end of the month. Obviously, had the storage operator known or predicted that an additional $1,000,000 of transmission charges would be incurred during a 15 minute store decision, that store decision would have been substantially altered.

4(a) iii (Please refer to slide #21.) This slide should be deleted. This slide purports to show that hourly store and discharge capacity factors are low. The implication seems to be that because an hourly average capacity factor is low, the DTS rate charged to the energy storage operator will also be low. RMP has already demonstrated above that a storage operator might charge at its max rate for one hour during a low demand month and therefore incurs the bulk system charge in that month. However, the storage operator may never charge during that hour again for the rest of the year therefore resulting in a very low average capacity factor for that hour, … even though it had incurred the bulk system charge in that low demand month when it had charged for one hour. Simply put, this slide proves nothing related to the application of the DTS rate and should be eliminated.

4(a) iv – (Please refer to slide # 22.) RMP does not understand the relevance of this slide in the context of the DTS rate discussion.

Temporal Power Ltd.:

Temporal would like to commend the AESO for commissioning the Dispatch Modelling Study and engaging leading academic institutions in the space. This is an important first step in understanding how energy storage assets will be integrated into the electricity system. However, as an industry participant, Temporal believes there is still significant uncertainty around the conclusions inferred from this research. We recommend further dialogue take place with the ASA and industry stakeholders, the AESO, the University of Calgary, and other interested stakeholders to better understand the underlying assumptions and conclusions being drawn from this research. Temporal believes that making impactful market decisions from a single commissioned study is not adequate to reach conclusions on such complex topics.

A primary issue for consideration is that the researchers used a ‘perfect information model’ with 20/20 hindsight of market conditions. While useful for drawing some indicative conclusions, this type of modeling does not accurately reflect how an energy storage facility would be operated on a day-to-day basis under real conditions. There are a number of operational (e.g. state of charge limitations, duty cycle considerations, etc.) and market considerations that specific owners may respond to differently. We recommend the AESO consider following up on this first phase of research to conduct a more detailed technical review and request further input from industry participants including Temporal and other members of the ASA.

As a member of the ASA, Temporal will continue to work with the AESO and other stakeholders to identify services and applications where energy storage can offer benefits to Alberta’s electric grid. As part of this collaboration, we recommend conducting a technical review to determine what services (existing or new) are required to help maintain a reliable electric grid going forward. Part of this assessment should include a review of whether assets solely providing system stability services should be exempt from certain prohibitive tariffs. For example, a Standard Transmission Service rate for grid-connected storage offering only Operating Reserves would avoid “double charging” such assets under existing regulations and tariffs. Temporal believes changes to the rate structure should be considered in order to ensure that energy storage technologies are being valued on their unique merits rather than being penalized for their fundamental operational differences relative to incumbent technologies.

It is imperative that the AESO consider reviewing the stacked benefits or multiple value streams that storage can provide to all levels of the supply chain (from generation to consumption). The ASA’s recently released White Paper details the variety of benefits that storage can provide to the grid. There are four key areas where Alberta’s Electricity System will need solutions as additional renewable generation is built and coal generation is retired, where storage can provide significant value:

1. Renewables integration;
2. Price volatility;
3. Supply adequacy; and
4. Grid reliability.

4(b) Cost causation considerations for energy storage are similar to those for load:

i. If an energy storage facility charges during system peak, it could cause bulk system costs;

ii. If an energy storage facility charges in any hour, it could cause regional system costs;

iii. If an energy storage facility charges in any hour, it could cause point of delivery costs;

iv. Load in the hour causes operating reserve charge costs in that hour;

v. Load in the hour also causes transmission constraint rebalancing costs in that hour;

vi. Variable nature of transmission must-run costs are appropriately recovered through a $/MWh energy charge; and

vii. Fixed nature of other system support services costs are appropriately recovered through a $/MW demand charge.

Alberta Direct Connect Consumers Association ("ADC"):

ADC agrees.

The Alberta Storage Alliance ("ASA"):

Again, the ASA would like to recognize the AESO's efforts to study and understand the operations of and effects of energy storage facilities. However, we recommend further collaborative dialogue take place between regulators, academics and industry stakeholders to better understand the underlying assumptions and conclusions being drawn from this research. From the ASA's perspective, we believe the research completed by University of Calgary in many ways supports the notion that modified rates for storage facilities are necessary. We believe the AESO should fully explore diverse perspectives on this research, in collaboration with all stakeholders, prior to finalizing any decisions on rate structures for energy storage facilities.

The ASA also encourages the AESO to consider the many system-wide infrastructure benefits energy storage brings to the system. As Alberta's grid evolves, Alberta will almost certainly require solutions in four key areas: renewables integration, managing price volatility, maintaining supply adequacy, and ensuring grid reliability. Energy storage can play an important role on the system by providing proven solutions to each of these challenges.

Energy storage technologies can balance the grid by storing excess electricity and reinjecting it at a more optimal time. The successful deployment of energy storage in electricity systems around the world has demonstrated its ability to swiftly react to system needs, making storage a compelling solution for Alberta. The ASA is keen to work with the AESO to better identify how these benefits, and resulting cost savings, are passed through to ratepayers.

Capital Power:

Capital Power supports the AESO's conclusions above that support the claim that cost causation considerations for energy storage are similar to those for load.

Ed dePalezieux:

[blank]

EPCOR Distribution & Transmission Inc. ("EDTI"):

[blank]

ENMAX Corporation ("EEC"):

EEC supports a review of the transmission cost implications of energy storage in the ISO tariff, primarily to ensure that the treatment of energy storage is consistent with FEOC.

Industrial Power Consumers Association of Alberta ("IPCAA"):

Agreed.

NextEra Energy Canada:

Cost causation on the power grid is not a function of the direction of flow. Both load and generation impose similar costs on the system – it is a policy decision that load faces the majority of overall transmission costs in Alberta. The AESO has not presented any evidence that a site that has power flowing in two directions creates materially different physical costs than a site from which power only flows outwards. Both require transmission capacity to reach end use customers and both can be subject to congestion depending on system configuration and power flows. Providing the incremental service of absorbing power for later use should not be viewed as a negative from the system perspective relative to a generator.

The AESO tariff could easily recognize the inherent difference between storage assets and end use load. The AESO already recognizes a range of load types within its tariff structure (DTS, XOS, DOS and behind the fence) so there is a clear precedent that not all types of load are equivalent in terms of treatment.

NextEra requests that the AESO consider cost causation and storage assets in the context of efficient energy market operations. Storage assets purchase power from the grid in support competitive outcomes and within the context of the Alberta transmission policy are not similar to end use customers.

i. If an energy storage facility charges during system peak, it could cause bulk system costs;

Response: Bulk system costs can be created by load or generation for any given hour depending on the system configuration at that time. It is a policy question as to whether charging storage assets DTS supports the development of an efficient system. In effect, does exposing storage assets to DTS costs and behavioral incentives support the market or are other signals such as the spot market price or regulating reserve signal the appropriate driver for storage assets? Further, given a reasonable must offer/bid- must comply rule for storage assets; they can be managed very differently than end use loads.

It must also be recognized that the transmission tariff could incent storage assets to locate in areas that would minimize or even reduce overall transmission costs. This siting signal could easily be implemented through a energy storage tariff similar to STS System Contribution charge that incents efficient siting for generation but modified to recognize that storage has two-way capability.

Storage assets have the potential to create material positive externalities for the market in terms of reduced regulating reserve costs, two-way flexibility to integrate renewables, high ramp rates, improved spot market function with temporal arbitrage, capability to manage congestion more cost effectively and generation capacity for peak load reliability. A barrier to entry for storage assets via tariff design is not in the interest of minimizing system costs and improving the efficiency of the market.

ii. If an energy storage facility charges in any hour, it could cause regional system costs;

See response (i).

iii. If an energy storage facility charges in any hour, it could cause point of delivery costs;

See response (i).

iv. Load in the hour causes operating reserve charge costs in that hour;

Response: It is not clear that this is a reasonable assumption. A tariff and operational construct that treats storage akin to behind the fence load is entirely appropriate. In this instance, the AESO would not be contractually obligated to serve storage as load in the event of a contingency. From a system perspective storage load that can be contractually curtailed can be treated the same as behind the fence load that does not trigger reserve requirements. This will not create incremental reliability concerns and a tariff construct can be created that is consistent with WECC standards.

v. Load in the hour also causes transmission constraint rebalancing costs in that hour;

Response: Storage devices could easily be integrated into the existing constraint management framework. They could be subject to a must offer/bid - must comply rule that would allow them to be part of the current rebalancing protocol that utilizes the energy market merit order to rebalance the market. A must offer- must bid rule is a very reasonable constraint on storage that would not be reasonable or feasible for all end use customers. This is an important distinction that highlights the fact that storage devices are not similar to end use loads within the market framework and can in fact reduce transmission constraint rebalancing costs rather than cause them.

As an example, without a storage asset in a potential supply constraint zone, the cost of managing the constraint is the cost of paying an out of merit generator to operate. In addition, there is an economic opportunity cost for the generator that did not get to operate, but the market does not price this cost. If a storage asset exists behind the constraint, it could have a bid to purchase electricity that would resolve or reduce the constraint. There would be no out of market payment from load (the storage asset would receive 'discounted' power from constrained generators). In this example, the cost of the constraint is lower for both generators and load. At worst, the storage asset has no impact on congestion costs in the event it does not have the capability to act as a load in a given event.

Similarly, in the event the storage asset is downstream from the constraint it can do nothing but reduce the cost of the resolving the constraint if it has a must bid requirement. In effect, the constraint management framework could be to dispatch down load bids prior to dispatching out of merit generation. In this case again no out of market payment would be made to resolve the constraint, the storage device would not consume power and the cost of constraints would be reduced relative to the status quo. This is akin to opportunity service.

vi. Variable nature of transmission must-run costs are appropriately recovered through a $/MWh energy charge;

Response: Storage assets will not add to existing transmission must run costs if it is located in a reasonable manner. The AESO can utilize a similar framework to the Generator System Contribution Payment to incent appropriate location of storage assets.

vii. Fixed nature of other system support services costs are appropriately recovered through a $/MW demand charge;

Response: Presumably this statement is in respect of services such as black start service. This is again an unreasonable cost for a storage asset to bear in the same manner as an end use customer. A storage asset is in the same position as a generator in these conditions, i.e. there is no market in which to sell its product. A storage device will not add to these costs, and, in fact, may be helpful in restoration depending on its state of charge

NRStor Inc.:

Again, NRStor would like to recognize the AESO's efforts to study and understand the operations of and effects of energy storage facilities. However, we recommend further collaborative dialogue take place between regulators, academics and industry stakeholders to better understand the underlying assumptions and conclusions being drawn from this research. NRStor believes the research completed by University of Calgary in many ways supports the notion that modified rates for storage facilities are necessary. We believe the AESO should fully explore diverse perspectives on this research, in collaboration with all stakeholders, prior to finalizing any decisions on rate structures for energy storage facilities.

NRStor also encourages the AESO to consider the many system-wide infrastructure benefits energy storage brings to the system. As Alberta's grid evolves, Alberta will almost certainly require solutions in four key areas: renewables integration, managing price volatility, maintaining supply adequacy, and ensuring grid reliability. Energy storage can play an important role on the system by providing proven solutions to each of these challenges. Energy storage technologies can balance the grid by storing excess electricity and reinjecting it at a more optimal time. The successful deployment of energy storage in electricity systems around the world has demonstrated its ability to swiftly react to system needs, making storage a compelling solution for Alberta. As a member of the ASA, NRStor is keen to work with the AESO to better identify how these benefits, and resulting cost savings, are passed through to ratepayers.

Renewable Energy Systems Canada Inc. ("RES"):

[Letter submitted by RES. Letter content included in "Other Comments" at the end of the consolidated stakeholder comments]

Rocky Mountain Power (2006) Inc. ("RMP"):

RMP would like to note that the AESO's cost causation analysis was an internally undertaken analysis. There was no discuss or consultation with energy storage stakeholders. Please see RMP's comments in to items 1(a) and 1(b). Again, because of the lack of consultation RMP feels compelled to object in the strongest manner to what it perceives as the AESO attempt to justify a decision already taken without really considering the many differences and advantages grid connected storage offers to the transmission system.

4(b) i – The AESO states - energy storage can cause bulk system costs during a system peak. RMP suggests the AESO analysis is flawed. In the storage dispatch analysis, did any store decisions EVER cause a new peak in system demand? The AESO's Annual Market Statistics shows that the peak AIL in the winter of 2015 was 10,982MW and 10,520 in the summer of 2015. It is RMP's understanding that transmission systems are built to serve the maximum demand, or peak load demand at any given point in time. The transmission system is not built to serve a lesser number than the highest peak load. Therefore, it is reasonable to ask - in the Dispatch Modeling and in the subsequent internal Cost Causation review, did the store decisions produced by the modeling process ever result in the peak AIL being increased by even 1MW in either the summer or the winter? In theory, of course, any time an individual or a company draws power off the grid there is a chance that it **might** increase the peak AIL and therefore cause bulk system costs. In reality though, and RMP thought this was what the Dispatch Model study was designed to answer, **did** simulations ever cause an increase in the peak AIL? A traditional customer has the right to add to overall system demand at any time. A storage operator operating under a transmission opportunity service would never have the right to add to system demand peaks and therefore would never cause bulk system charge costs.

4(b) ii – The AESO states storage operators could cause regional system costs. Of course storage operators could cause regional system costs. That is in part why the AESO requires, as part of its connection process, extensive power flow analyses. Those power flow analyses are designed to determine if regional transmission systems need to be augmented to allow the storage operator to operate within a given region. Simply because that is determined to hold true, does not lead necessarily to a decision to continue to apply the DTS rate unchanged. There are a myriad of other factors and benefits that flow from storage facilities. For example, in item 4 (b) vi the AESO argues that transmission must run balancing costs need to be applied in the DTS rate. Perhaps a storage facility can eliminate the transmission must run generation facility and reduce costs overall. The AESO needs to start thinking about storage as a **benefit** and a cost to the system and should look at all aspects of its transmission rates in this context.

4(b) iii The AESO states that storage facilities could cause point of delivery costs. Again, of course this is true. It is not clear, however, how the AESO would apply point of delivery interconnection charges as part of the DTS rate AND require the storage facility to provide for transmission costs that are incurred by the TFO to accept the generation or discharge side of the storage facility. It is RMP`s understanding that if point of delivery costs are incurred by the TFO for a generating facility, then the generator pays those costs to the TFO and are rebated those costs over a 10 year period. However, if point of delivery or substation costs are already included in the DTS calculation, why would the generation or discharge side of the storage facility have to provide for any substation costs. It is NOT clear what the AESO intends. In addition, the AESI has suggested that a storage operator can reduce its DTS charges by reducing its storage rate to half the rate the discharge rate. Under the AESO's construct, a 100MW storage facility would be made up of 100MW of discharge or generation capacity and 50MW of storage capacity. However, if this were to occur how does one calculate the costs that would be chargeable to the discharge side of the facility and therefore payable to the TFO, and what costs should be included in the DTS point of delivery charge?

4(b) iv, v, vi, and vii - Similar comments apply to the remaining components of the DTS rate. At the risk of repetition, the AESO should have consulted with stakeholders before making its decision to retain the DTS rate. The AESO needs to look at storage at more than just a cost to the system. It can also supply substantial benefits and those also need to be taken into account when trying to determine the best rate to be applied for grid connected storage facilities.

Temporal Power Ltd.:

Again, Temporal would like to recognize the AESO's efforts to study and understand the operations of and effects of energy storage facilities. However, we recommend further collaborative dialogue take place between regulators, academics and industry stakeholders to better understand the underlying assumptions and conclusions being drawn from this research. Temporal believes the research completed by University of Calgary in many ways supports the notion that modified rates for storage facilities are necessary. We believe the AESO should fully explore diverse perspectives on this research, in collaboration with all stakeholders, prior to finalizing any decisions on rate structures for energy storage facilities.

Temporal also encourages the AESO to consider the many system-wide infrastructure benefits energy storage brings to the system. As Alberta's grid evolves, Alberta will almost certainly require solutions in four key areas: renewables integration, managing price volatility, maintaining supply adequacy, and ensuring grid reliability. Energy storage can play an important role on the system by providing proven solutions to each of these challenges. Energy storage technologies can balance the grid by storing excess electricity and reinjecting it at a more optimal time. The successful deployment of energy storage in electricity systems around the world has demonstrated its ability to swiftly react to system needs, making storage a compelling solution for Alberta. As a member of the ASA, Temporal is keen to work with the AESO to better identify how these benefits, and resulting cost savings, are passed through to ratepayers.

4(c) Cost causation review suggests Rate DTS appropriately applies to energy storage:

i. Rate DTS would apply only in hours in which an energy storage facility is charging and Rate STS would apply in hours in which the facility is discharging;

ii. Many of the components of Rate DTS can be avoided or reduced by the energy storage participant; and

iii. The Commission has previously found the combination of Rates DTS and STS to be appropriate for sites that include load and generation.

Alberta Direct Connect Consumers Association ("ADC"):

ADC agrees that the DTS tariff should apply to all participants with DTS service. The tariff offers significant opportunities to reduce costs through management of load.

The Alberta Storage Alliance ("ASA"):

The ASA believes the DTS and STS rates in their current form do not reflect the true benefits and costs that storage facilities add to the system and can be prohibitive for private sector players looking to deploy energy storage. The University of Calgary research shows that the DTS/STS rates effectively double charge and dis-incentivize storage. The ASA is seeking to engage with the AESO to develop a tariff that accurately considers both the benefits and costs energy storage can bring to the system. The ASA looks forward to the opportunity to continue this dialogue with the AESO.

Capital Power:

Capital Power agrees with the AESO that its review supports the proposal that Rate DTS would apply to an energy storage facility when charging and that Rate STS would apply in hours in which it is discharging. Capital Power believes that the AESO has demonstrated from a tariff perspective that energy storage facilities should be treated similarly to dual-use customers and that the proposal in 4(c)(i) is the appropriate tariff treatment for energy storage.

Ed dePalezieux:

[blank]

EPCOR Distribution & Transmission Inc. ("EDTI"):

[blank]

ENMAX Corporation ("EEC"):

[blank]

Industrial Power Consumers Association of Alberta ("IPCAA"):

See 4(d) below.

NextEra Energy Canada:

Response: As noted in previous comments, rate DTS is not appropriate for a storage asset for a range of reasons. Cost causation is not similar to end use load customers for the reasons outlined. It is important to recognize that storage load is not responding to the same signals as an industrial site with both load and generation, nor does it create the same requirements for transmission infrastructure or system services. In fact, an appropriately designed storage tariff will result in lower overall system costs and can potentially reduce total infrastructure requirements. The combination of STS and DTS charges for a storage asset creates an entry barrier, distorts appropriate spot market responses in the event they are developed, and materially disadvantages storage in the regulating reserve market, despite evidence these assets are uniquely suited for regulating service.

An appropriate storage tariff must move beyond the simple position that energy consumption by definition creates DTS charges and move towards a tariff model that recognizes the function of storage within the overall policy framework.

NRStor Inc.:

NRStor believes the DTS and STS rates in their current form do not reflect the true benefits and costs that storage facilities add to the system and can be prohibitive for private sector players looking to deploy energy storage. The University of Calgary research shows that the DTS/STS rates effectively double charge and dis-incentivize storage. As a member of the ASA, NRStor is seeking to engage with the AESO to develop a tariff that accurately considers both the benefits and costs energy storage can bring to the system. NRStor and the ASA look forward to the opportunity to continue this dialogue with the AESO.

Renewable Energy Systems Canada Inc. ("RES"):

[Letter submitted by RES. Letter content included in "Other Comments" at the end of the consolidated stakeholder comments]

Rocky Mountain Power (2006) Inc. ("RMP"):

RMP respectfully disagrees with Items 4 (c) i and ii for all of the reasons provided in the preceding sections.

4(c) iii. Simply because the AUC has previously found the combination of Rates DTS and STS to be appropriate for sites that include load and generation does not mean that it will do so again, … or has the AESO already discussed this issue with the AUC and been told that the status quo will prevail? It is RMP's belief that well founded arguments in favor of Energy Storage Opportunity Service Rates, particularly in light of the changing power generation and transmission system world, could very well be approved by the AUC. However, without any further discussion the AESO has decided to march forward with no change to its rates forcing energy storage proponents to fight this issue out through a lengthy and costly litigious process.

Temporal Power Ltd.:

Temporal believes the DTS and STS rates in their current form do not reflect the true benefits and costs that storage facilities add to the system and can be prohibitive for private sector players looking to deploy energy storage. The University of Calgary research shows that the DTS/STS rates effectively double charge and dis-incentivize storage. As a member of the ASA, Temporal is seeking to engage with the AESO to develop a tariff that accurately considers both the benefits and costs energy storage can bring to the system. Temporal and the ASA look forward to the opportunity to continue this dialogue with the AESO.

4(d) Rate DTS charges for a 20 MW storage service could be reasonably reduced compared to a 20 MW load-only service by the energy storage facility:

- ***i. avoiding system peak;***
- ***ii. owning its own substation;***
- ***iii. contracting for both DTS and STS; and***
- ***iv. limiting charging rate to 50% of the discharging rate.***

Alberta Direct Connect Consumers Association ("ADC"):

ADC supports the DTS tariff structure. It has been tested before the AUC and has been demonstrated to reflect cost causation principles.

The Alberta Storage Alliance ("ASA"):

As an industry consortium, the ASA believes that DTS and STS rates in their current form can be prohibitive to the deployment of energy storage facilities. We believe there are challenges with the assumptions used in 4d. Forecasting system peak can be extremely difficult and reducing the charging rate by half may not make sense in many scenarios for asset owners; this would need to be evaluated on a project specific basis. We recommend the AESO explore these items further and conduct additional consultations with industry and academic stakeholders to more thoroughly explore the impacts of the rates on storage facilities from all perspectives. The ASA is seeking to develop a tariff that accurately reflects energy storage technologies' benefits and values them on their unique merits rather than being penalized for their fundamental operational differences relative to incumbent technologies.

Capital Power:

Capital Power agrees with the AESO that many of the components of Rate DTS may be avoided or reasonably reduced by an energy storage participant.

Ed dePalezieux:

[blank]

EPCOR Distribution & Transmission Inc. ("EDTI"):

[blank]

ENMAX Corporation ("EEC"):

We would like to investigate further whether these results hold true at smaller facilities and if the same opportunities exist. As a note, we hope that the operation of the storage system would be at the discretion of the owner and that the tariff wouldn't limit charge or discharge rates, but rather allow the storage owner to operate in the manner they feel appropriate.

Industrial Power Consumers Association of Alberta ("IPCAA"):

- IPCAA will be interested to hear the perspective of energy storage proponents on this proposal.
- The AESO should be working to ensure that its tariff structure does not discourage energy storage.
- Consumers can see significant benefits associated with the use of energy storage.

NextEra Energy Canada:

Response: It is not reasonable that the introduction of a tariff that distorts rational energy market behavior for the sole purpose of avoiding said tariff is a logical outcome from a system perspective.

Further, to the extent that these set of statements are true for a storage asset participating entirely in temporal arbitrage, it is not reasonable to assume that a storage asset selling regulating reserves or potential services associated with increased renewable penetration will be afforded the same opportunity. In addition, avoiding the tariff reduces the energy market value of a storage asset from both a system perspective and a profitability perspective. This has the sole impact of making these assets more expensive, and the AESO has not demonstrated a corresponding system benefit.

It is concerning that the AESO suggests a storage asset should limit its charging rate solely as a means to reduce tariff charges. This is clearly an inefficient outcome for the system, as presumably the storage device would be responding to market signals to charge at a greater rate. If the system can accommodate the more rapid rate, and the storage device has the capability to charge at the more rapid rate, it is clearly a poor outcome if tariff design prevents a rational market response.

On the flip side, the AESO has not considered the benefits storage assets create for the system and placed them in the context of generation assets. In particular, the analysis provided by the University of Calgary[5] illustrates that storage assets can arbitrage prices across time and act as peak capacity. The NRC analysis[6] illustrates storage assets can improve system performance due to their flexibility. Storage assets could also be used to help integrate renewables, compete with other resource types to supply peak capacity, reduce congestion and generally support the market by bringing a new type of competitor to the system. The AESO is undertaking initiatives in other areas such as the technical standards for reserve providers in an effort to reduce barriers to non-traditional technologies yet the proposed tariff design for storage assets does not recognize this goal.

Overall, the proposed tariff increases the hurdle for storage assets to participate in the market, and it is not clear that the analysis to support the imposition of the DTS tariff extended beyond the concept that power purchased from the grid triggers DTS charges by definition. End use customers are best served by efficient investment signals that do not discriminate between technologies.

[5] Modeling Dispatch Operations of Energy Storage Facilities in the Alberta Wholesale Market, May 2016.

[6] Regulating Reserve Performance Assessment for the Alberta Electric System Operator, March 18, 2016. National Research Council Canada.

NRStor Inc.:

As an industry participant, NRStor believes that DTS and STS rates in their current form can be prohibitive to the deployment of energy storage facilities. We believe there are challenges with the assumptions used in 4d. Forecasting system peak can be extremely difficult and reducing the charging rate by half may not make sense in many scenarios for asset owners; this would need to be evaluated on a project specific basis. We recommend the AESO explore these items further and conduct additional consultations with industry and academic stakeholders to more thoroughly explore the impacts of the rates on storage facilities from all perspectives. NRStor is advocating the development of a tariff that accurately reflects energy storage technologies' benefits, and values them on their unique merits rather than being penalized for their fundamental operational differences relative to incumbent technologies.

Renewable Energy Systems Canada Inc. ("RES"):

[Letter submitted by RES. Letter content included in "Other Comments" at the end of the consolidated stakeholder comments]

Rocky Mountain Power (2006) Inc. ("RMP"):

4(d) i – please see earlier RMP arguments about avoiding system, peak. It is RMP's understanding that system peaks are determined monthly. Under the AESO's strict application of the DTS rate it appears that each storage operator would have to forecast when a monthly system peak might occur in order to reduce the DTS rate to an economically acceptable level. As noted before, storage operators tend to focus on energy prices and incremental transmission costs when making store and discharge decisions. As a result, would it not make more sense to design ESOS rates and have the AESO control those periods storage operators cannot store energy?

4(d) ii – please earlier comments about point of delivery cost complexities associated with the application of both the DTS and STS rates.

4(d) iii – RMP disagrees. RMP strongly believes ESOS rates should be designed and applied for by the AESO. RMP also believes that the ESOS Rate should be no greater than the EOS rate.

4(d) iv – Please see earlier comments about this issue. This seems like an artificial construct that allows the AESO to demonstrate that a storage operators transmission costs are not too high. Does the AESO also suggest that other entities that take power off the grid limit their offtake to half of what they might desire? RMP as a storage project proponent had actually determined some time ago that it could reduce its transmission costs by reducing the rate at which it stores energy. While we thank the AESO for its insight, we fail to understand why it should be necessary to have to do so all the time. Do energy exporters have to reduce the amount of energy that they wish to draw into the neighbouring jurisdictions by 50%? If not, why should storage operators have to do so? Admittedly, EOS users are limited to the amount of capacity that is available to export power. RMP does not have a problem with this concept commonly called in Alberta Opportunity Service. RMP`s problem is understanding why the AESO is unwilling to even entertain the same concept for grid connected storage facilities.

Temporal Power Ltd.:

As an industry participant, Temporal believes that DTS and STS rates in their current form can be prohibitive to the deployment of energy storage facilities. We believe there are challenges with the assumptions used in 4d. Forecasting system peak can be extremely difficult and reducing the charging rate by half may not make sense in many scenarios for asset owners; this would need to be evaluated on a project specific basis. We recommend the AESO explore these items further and conduct additional consultations with industry and academic stakeholders to more thoroughly explore the impacts of the rates on storage facilities from all perspectives. Temporal is advocating the development of a tariff that accurately reflects energy storage technologies' benefits, and values them on their unique merits rather than being penalized for their fundamental operational differences relative to incumbent technologies.

Rider C / Deferral Account Reconciliation Process Update

5(a) ***In prior work, the AESO identified, and consulted with stakeholders, that regular tariff update applications should reduce the magnitude of Rider C. The AESO plans to file an upcoming 2017 tariff update application in Q3 2016. The 2017 tariff update application will include an update of rate and investment levels to reflect 2017 costs and proposed to be effective January 1, 2017***

Alberta Direct Connect Consumers Association ("ADC"):

ADC supports timely tariff updates to minimize the revenue collected through Rider C.

The Alberta Storage Alliance ("ASA"):

[blank]

Capital Power:

Capital Power supports the AESO's approach for the purpose of mitigating Rider C amounts.

Ed dePalezieux:

If the TRIP model was up to date Customers would already anticipate the level of rate impact for 2017. Please comment on the AESO's use of the TRIP model in signaling future rates to its customers.

EPCOR Distribution & Transmission Inc. ("EDTI"):

[blank]

ENMAX Corporation ("EEC"):

[blank]

Industrial Power Consumers Association of Alberta ("IPCAA"):

IPCAA supports regular tariff updates that reduce the magnitude of Rider C.

NextEra Energy Canada:

[blank]

NRStor Inc.:

[blank]

Renewable Energy Systems Canada Inc. ("RES"):

[Letter submitted by RES. Letter content included in "Other Comments" at the end of the consolidated stakeholder comments]

Rocky Mountain Power (2006) Inc. ("RMP"):

No comment.

Temporal Power Ltd.:

[blank]

5(b) Further work is required to investigate other Rider C structure impacts. This work is ongoing until the end of 2016 and will review the impact of early tariff updates, seasonal effects, converting Rider C to a percentage basis as well as review the possibility of eliminating quarterly Rider C and possibility of moving to prospective Rider C.

Alberta Direct Connect Consumers Association ("ADC"):

ADC has historically paid millions of extra costs due to the structure of Rider C only to have the dollars returned through the deferral account process much later. ADC supports all efforts to have Rider C changed from an energy charge to something that better reflects the tariff structure.

The Alberta Storage Alliance ("ASA"):

[blank]

Capital Power:

Capital Power looks forward to reviewing the results of the AESO's investigation and will use these results to determine its level of participation in working groups, etc. related to the issue going forward. Capital Power requests that the AESO hold a stakeholder session to review the results of its investigation.

Ed dePalezieux:

[blank]

EPCOR Distribution & Transmission Inc. ("EDTI"):

[blank]

ENMAX Corporation ("EEC":

[blank]

Industrial Power Consumers Association of Alberta ("IPCAA"):

If the AESO is planning a working group to investigate Rider C structure impacts, IPCAA would participate.

NextEra Energy Canada:

[blank]

NRStor Inc.:

[blank]

Renewable Energy Systems Canada Inc. ("RES"):

[Letter submitted by RES. Letter content included in "Other Comments" at the end of the consolidated stakeholder comments]

Rocky Mountain Power (2006) Inc. ("RMP"):

No comment.

Temporal Power Ltd.:

[blank]

5(c) Incorporation of primary service credit (Rate PSC) amounts in deferral account reconciliation and allocation methodology has been questioned in the 2015 deferral account reconciliation proceeding. AESO is reviewing whether modifications of Rider C or deferral account reconciliation methodology are needed to clarify treatment of Rate PSC amounts.

Alberta Direct Connect Consumers Association ("ADC"):

ADC supports that having the tariff collect the right costs with minimal deferral amounts will satisfy all customer concerns regarding deferral account treatment.

The Alberta Storage Alliance ("ASA"):

[blank]

Capital Power:

Capital Power has no comments on 5(c) at this time and will await the results of the AESO's review.

Ed dePalezieux:

[blank]

EPCOR Distribution & Transmission Inc. ("EDTI"):

[blank]

ENMAX Corporation ("EEC"):

[blank]

Industrial Power Consumers Association of Alberta ("IPCAA"):

IPCAA would appreciate seeing the AESO's analysis on this.

NextEra Energy Canada:

[blank]

NRStor Inc.:

[blank]

Renewable Energy Systems Canada Inc. ("RES"):

[Letter submitted by RES. Letter content included in "Other Comments" at the end of the consolidated stakeholder comments]

Rocky Mountain Power (2006) Inc. ("RMP"):

No comment.

Temporal Power Ltd.:

[blank]

2017 ISO Tariff Application Consultation Process Plan

6(a) AESO is proposing the following steps for consultation on the 2017 ISO tariff application:

- ***i. Consultation on scope;***
- ***ii. Specific topic consultation to begin in September to address transmission cost causation study results, POD cost function database results, Sections 4, 5, 8 and 9 of terms and conditions, Rider C/DAR process and CIP standards generator cost recovery; and***
- ***iii. Application preview (early 2017).***

Alberta Direct Connect Consumers Association ("ADC"):

ADC appreciates the opportunity to participate in further stakeholder consultation.

The Alberta Storage Alliance ("ASA"):

The ASA commends the AESO's willingness and leadership in engaging stakeholders in this process. Subsequently, the ASA strongly recommends that the AESO engage in further collaborative dialogue between regulators, academics and industry stakeholders to better understand the underlying assumptions and conclusions being drawn from research conducted on energy storage facilities. The ASA welcomes all opportunities to work with the AESO and engage in constructive dialogue on this topic.

Capital Power:

Capital Power encourages the AESO to hold meetings and technical sessions whenever practical to introduce changes, proposals, or technical results. These types of sessions are helpful to stakeholders and allow them to better understand the context and reasoning behind various updates and changes.

Capital Power reiterates its comments above regarding the value of an updated TRIP model and encourages the AESO to make this part of its 2017 GTA Consultation Process Plan.

Ed dePalezieux:

Can the AESO please comment on the form of consultation? In past AESO tariff process, on key items, the AESO has formed stakeholder teams that assess and discuss each item in detail. This type of consultation has been very helpful in minimizing the formal regulatory process. Is the AESO forming these types of teams? If so, when will this process start and which topics will form part of this consultation?

EPCOR Distribution & Transmission Inc. ("EDTI"):

[blank]

ENMAX Corporation ("EEC"):

[blank]

Industrial Power Consumers Association of Alberta ("IPCAA"):

- Regulatory lag is a problem for consumers. IPCAA encourages the AESO to attempt to minimize this.
- Consumers are waiting for the AESO to publish an updated TRIP model. While this is not necessarily required as a part of the tariff filing, we have not seen an update since June 2014. Consumers need to understand the impacts to their bills.

NextEra Energy Canada:

[blank]

NRStor Inc.:

NRStor commends the AESO's willingness and leadership in engaging stakeholders in this process. Subsequently, NRStor strongly recommends that the AESO engage in further collaborative dialogue between regulators, academics and industry stakeholders including the ASA to better understand the underlying assumptions and conclusions being drawn from research conducted on energy storage facilities. NRStor and the ASA welcome all opportunities to work with the AESO and engage in constructive dialogue on this topic.

Renewable Energy Systems Canada Inc. ("RES"):

[Letter submitted by RES. Letter content included in "Other Comments" at the end of the consolidated stakeholder comments]

Rocky Mountain Power (2006) Inc. ("RMP"):

RMP recommends that the AESO include an opportunity for consultation for the development of alternative transmission rates that may apply to energy storage service operators. The AESO`s dismissal of any further consultative opportunities for this issue appear high handed, arbitrary, and deliberately confrontational.

Temporal Power Ltd.:

Temporal commends the AESO's willingness and leadership in engaging stakeholders in this process. Subsequently, Temporal strongly recommends that the AESO engage in further collaborative dialogue between regulators, academics and industry stakeholders including the ASA to better understand the underlying assumptions and conclusions being drawn from research conducted on energy storage facilities. Temporal and the ASA welcome all opportunities to work with the AESO and engage in constructive dialogue on this topic.

Additional Comments

Alberta Direct Connect Consumers Association ("ADC"):

[blank]

The Alberta Storage Alliance ("ASA"):

[blank]

Capital Power:

Capital Power has no additional comments at this time.

Ed dePalezieux:

The TRIP model has not seen an update in years, however the assumptions underlying the model have dramatically changed. Customers rely upon this model in making assessments and building longer-term budgets. It is very important that the AESO make updating and publishing the results of the TRIP model a priority. It is disappointing that the AESO was close to publishing these results in as early as March 2016 and then decided to withdraw this work. Please clarify if the AESO views this model as important, and if so, specify a date that it will publish this analysis.

EPCOR Distribution & Transmission Inc. ("EDTI"):

[blank]

ENMAX Corporation ("EEC"):

[blank]

Industrial Power Consumers Association of Alberta ("IPCAA"):

[blank]

NextEra Energy Canada:

[blank]

NRStor Inc.:

[blank]

Renewable Energy Systems Canada Inc. ("RES"):

Renewable Energy Systems Canada Inc. (RES) is a member of the Alberta Storage Alliance (ASA). The ASA is an industry group aiming to educate stakeholders on the benefits that energy storage technology can bring to the Alberta electricity system. Our membership includes a variety of key stakeholders in the Alberta market including utilities, technology manufacturers, developers, independent power producers, engineering firms, etc. RES, alongside the ASA, is advocating a technology neutral approach to assessing the services offered by various energy assets; we believe smart regulations can unlock the growth of a new energy storage industry in the province while providing improved flexibility and resiliency to the electricity grid. Further information on the ASA and its initiatives can be found on its website (http://albertastoragealliance.com/) and in its recently released White Paper: Energy Storage – Unlocking the Value for Alberta's Grid.

RES is encouraged to see that the AESO is opening a dialogue on how to best manage the integration of energy storage assets in the Alberta market. However, RES believes changes to rate structures should be given further consideration before any final decision is made. Energy storage technologies perform fundamentally differently from traditional energy assets governed by current rate structures. Energy storage technologies are highly flexible assets, acting as both load and generation with unique operational characteristics that can serve to benefit the Alberta market.

Please note that RES supports the submission made by the ASA to this consultation and we look forward to a continuing dialogue.

Rocky Mountain Power (2006) Inc. ("RMP"):

[blank]

Temporal Power Ltd.:

[blank]

November 15, 2016

AESO Stakeholders
AESO 2018 ISO Tariff Consultation Participants

Dear Stakeholder:

Re: **Invitation to Participate in Consultation on AESO 2018 ISO Tariff Application**

The AESO continues to consult with market participants on the development of its next comprehensive ISO tariff application, which it now refers to as the 2018 ISO tariff application to reflect the year in which the tariff is expected to become effective (in prior stakeholder communications, this application had been referred to as the 2017 ISO tariff application). The AESO is holding a meeting to provide an update on work completed to date and invites you to attend the following consultation session:

Date:	Monday, December 5, 2016
Time:	1:00 - 4:00 PM
Place:	Meeting Room 6006, 6th Floor, BP Centre, 240 – 4th Avenue SW, Calgary, Alberta Note that the glass doors on the 6th floor are locked; please knock to have them opened.
Teleconference:	Within Calgary calling area: 403-410-3051, Conference ID 4366631
	Outside Calgary calling area: 1-855-453-6957, Conference ID 4366631
RSVP:	By 5:00 PM on **Wednesday, November 30, 2016** to , Tatiana Aparicio-Caris Tatiana.Aparicio-Caris@aeso.ca or 403-539-2664

The AESO plans to discuss the following items during the meeting:

- progress on annual tariff updates, deferral account reconciliations, and Rider C matters;
- technical update on transmission cost causation study results;
- technical update on point of delivery ("POD") cost function database; and
- planned timeline and next steps for 2018 ISO tariff application.

The AESO plans to present information on these topics to facilitate discussion, and will post a presentation before the meeting. Stakeholders may provide feedback in person during the meeting or through written comments to the AESO after the meeting.

All information relating to the 2018 ISO tariff consultation will be available on the AESO website at www.aeso.ca by following the path Rules, Standards and Tariff ► Stakeholder engagement ► 2018 ISO tariff application. As well, new information posted by the AESO on this topic will be mentioned in the AESO stakeholder newsletter, which you can subscribe to at the bottom right of the AESO's home page at www.aeso.ca.

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

If you have any questions on the AESO's 2018 ISO tariff consultation, please contact me at 403-539-2555 in Calgary or by e-mail to larhonda.papworth@aeso.ca.

Yours truly,

LaRhonda Papworth
Manager, Tariff Design

cc: Doyle Sullivan, Director – Market and Tariff Design

AESO 2018 ISO Tariff Consultation

December 5, 2016
AESO Office, Calgary

Agenda

- Introduction and objectives (slide 3-5)
- Rider C / Deferral Account Reconciliation (DAR) / Rates Update (slide 6-62)

  Break
- Transmission cost causation study update (slide 63-71)
- Point-of-delivery cost function database update (slides 72-76)
- Application process and next steps (slides 77-80)
- Discussion and wrap-up (slide 81)

Please feel free to ask questions during presentation

Stakeholder session objectives

- Enhance understanding of ISO tariff application
- Review technical results of a number of analytical exercises by the AESO
- Share information prior to filing of 2018 ISO tariff application
- Gather feedback to ensure tariff application provides all information stakeholders require
- Review application timeline and next steps

Applications currently in progress

- Directions 5-8 on advancement costs and related provisions
  - Decision 3473-D02-2015 issued on August 26, 2015
  - Process letter issued on October 22, 2015 with additional information on process in the new year *[2016]*
  - Awaiting Commission follow-up
- 2015 Deferral Account Reconciliation application
  - Currently before the Commission in Proceeding 21735
  - Interim settlement was approved and occurred in October 2016
  - Hearing scheduled for December 13 and 14, 2016

Applications currently in progress

- 2017 ISO tariff update
  - Currently before the Commission in Proceeding 22093
  - Interim, refundable approval for January 1, 2017 issued by Commission on December 2, 2016
  - Final approval not expected until 2017
- 2017 Rider F, *Balancing Pool Consumer Allocation Rider*, application
  - Bill 34 passed November 29, 2016
  - Awaiting Balancing Pool notification of annualized amount
  - AESO will file as soon as possible, in December, and applicable for settlement periods from January 1 – December 31, 2017

Evaluation of Potential Changes to Deferral Account Reconciliations and Rider C

John Martin, Senior Tariff and Regulatory Advisor

Topics

- Background and overview of evaluation approach
- Impact of early tariff updates
- Impact of changing Rider C structure
- Impact of changing to production year basis

break

- Impact of changing to net revenue allocation methodology
- Possible future changes to Rider C
- Timing and implementation options

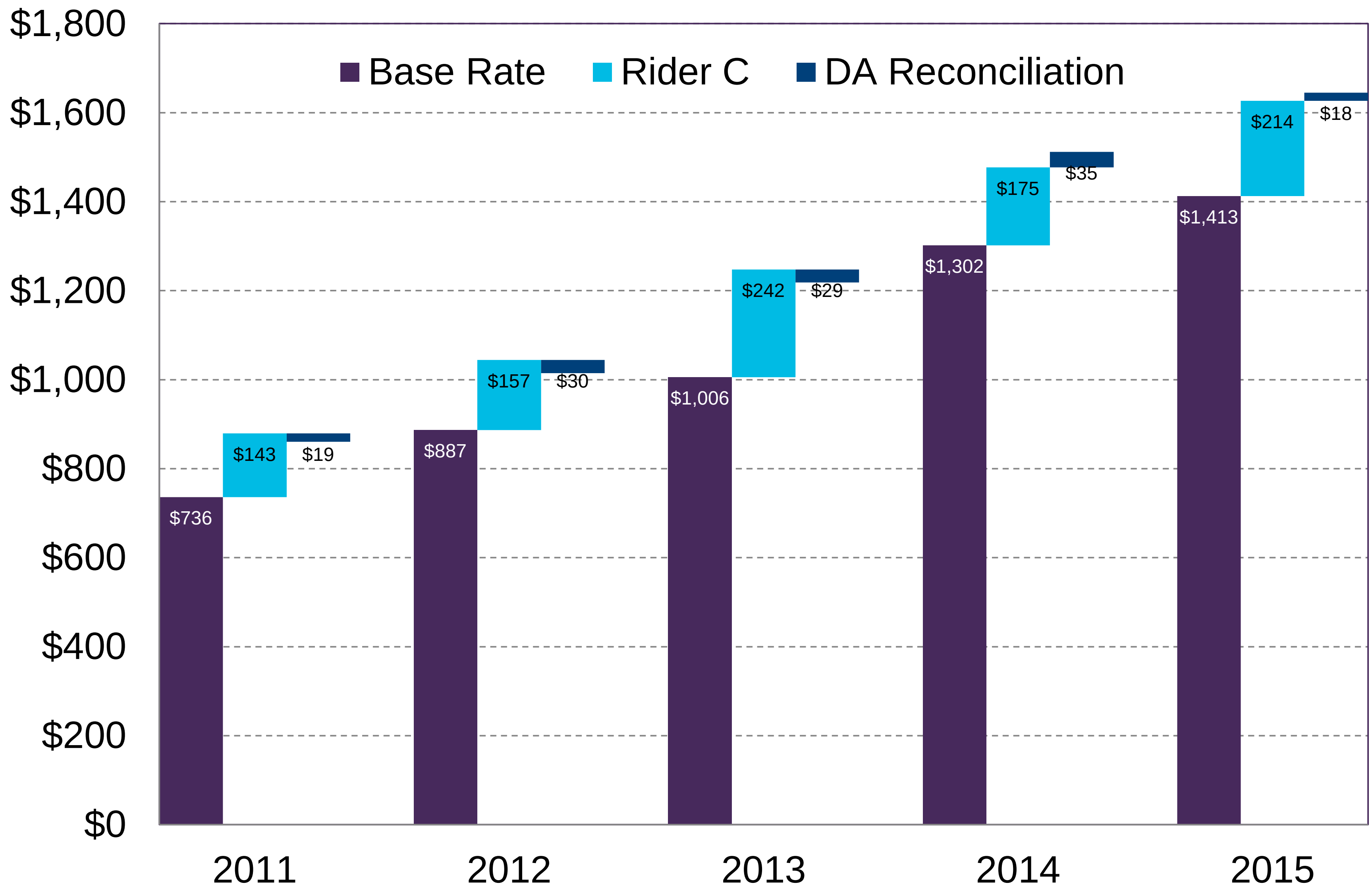
Please ask questions during presentation!

Commission directed AESO to investigate Rider C in Decision 2014-242

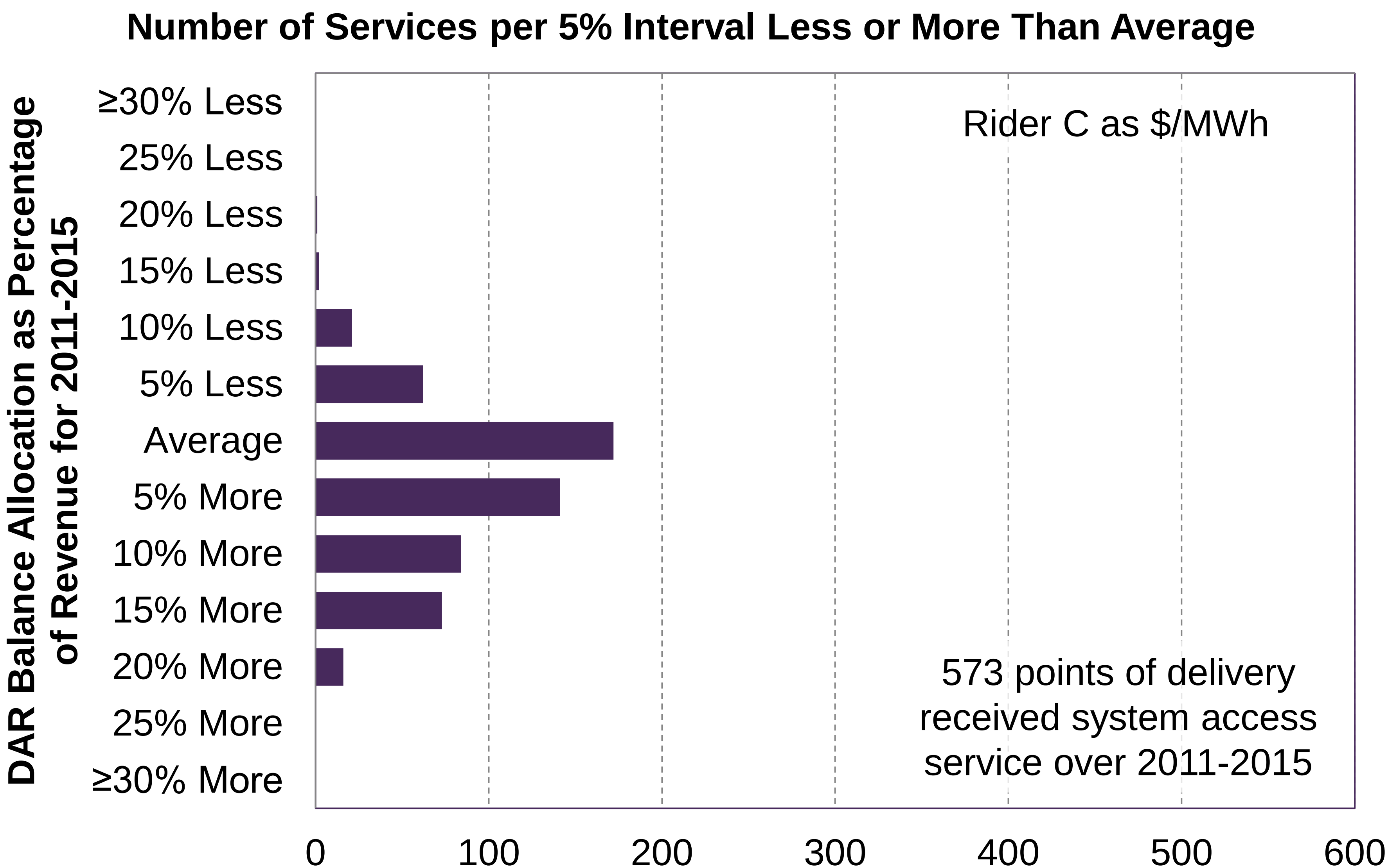
- *The Commission acknowledges the view expressed by both the ADC and the DUC that the AESO should be directed to examine further the structure of Rider C with an eye to minimizing imbalances among customers. Therefore, the Commission directs the AESO to discuss the related matters of annual tariff updates, deferral account reconciliation processes and Rider C design with stakeholders prior to filing its next comprehensive GTA, and to provide a report on the outcome of any such discussions, including any recommended changes (if any) within its next comprehensive GTA.*

[Decision 2014-242, paragraph 704]

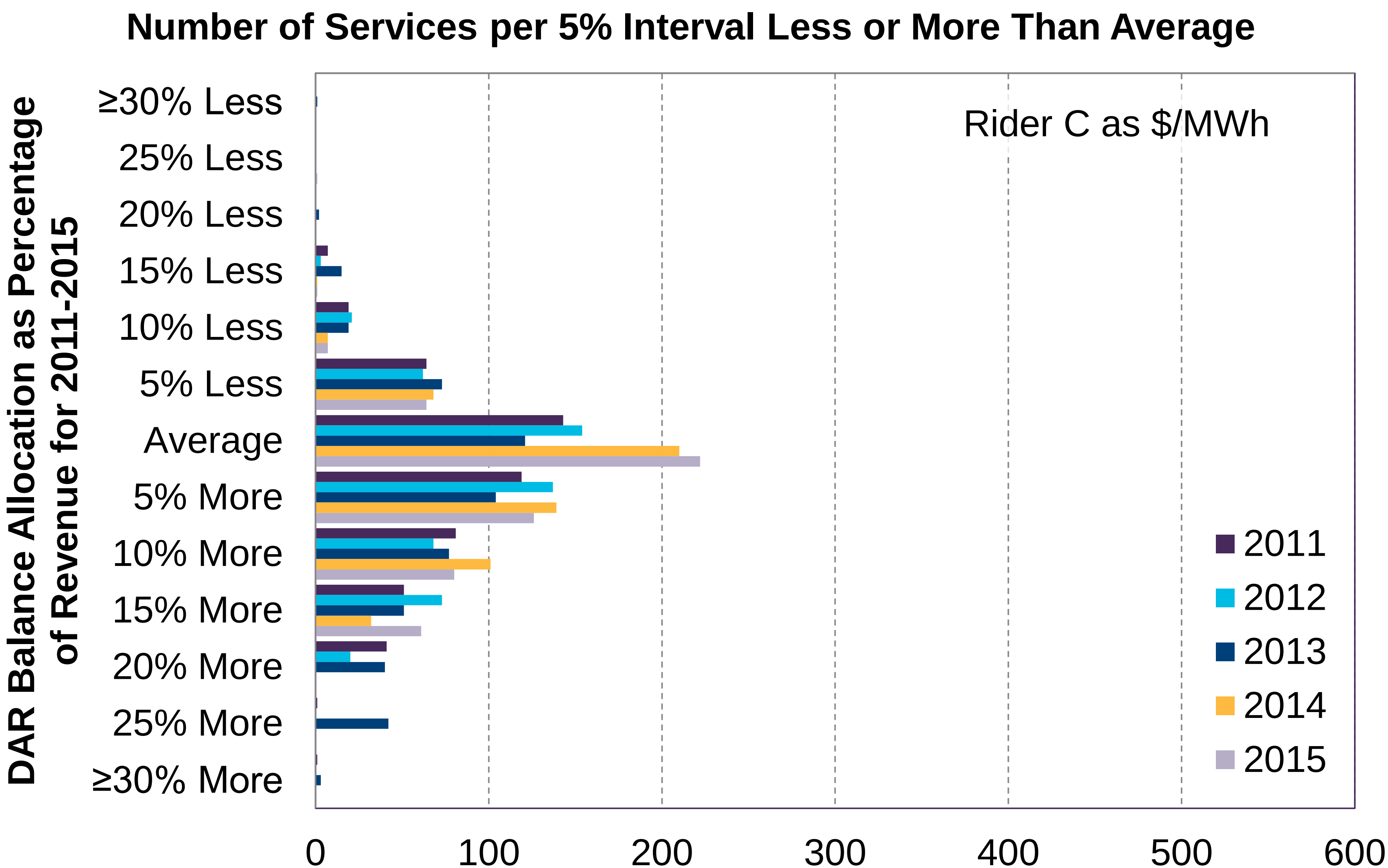
Net amounts allocated through annual reconciliations have been small …



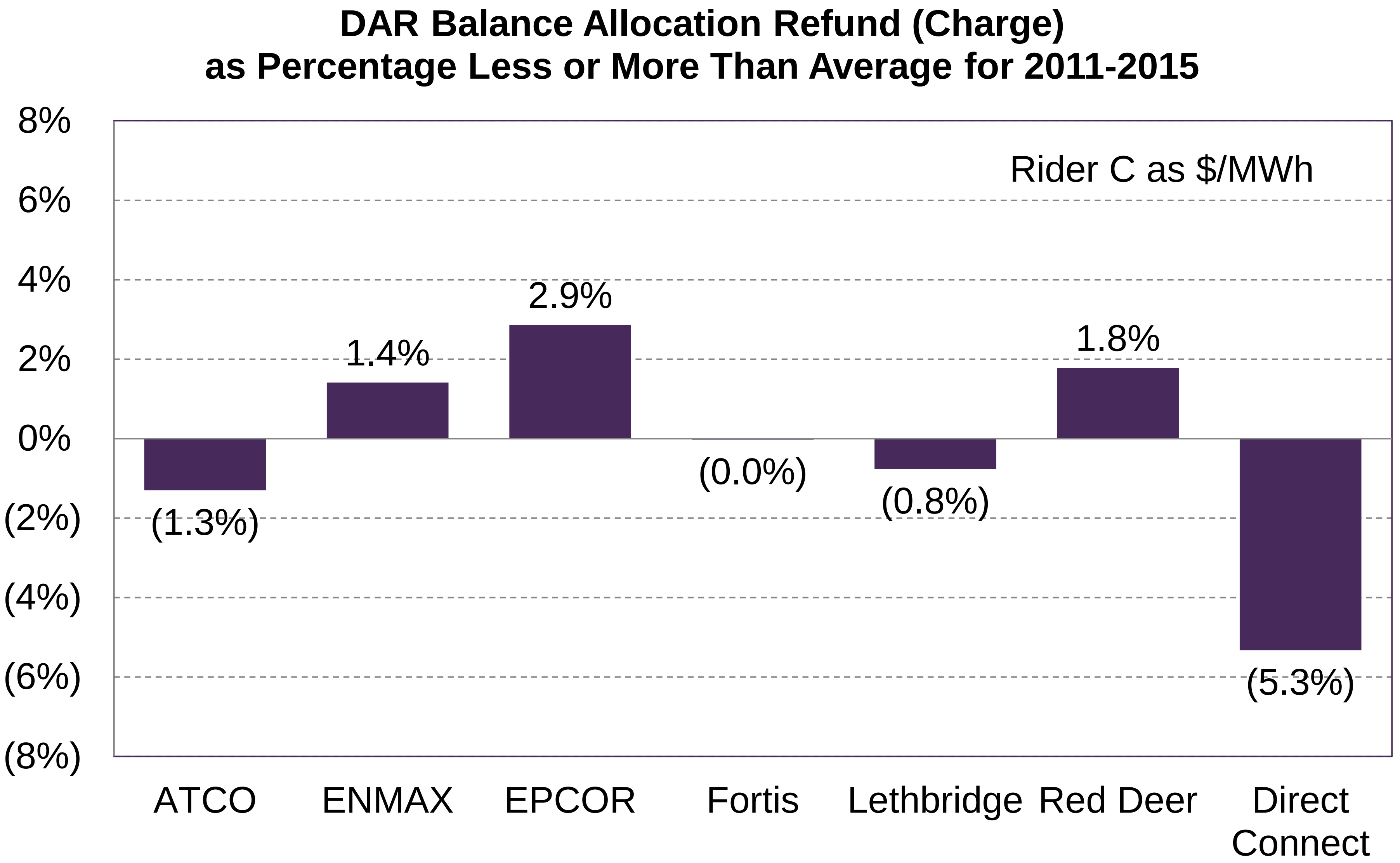
But allocations to individual services have varied over a much wider ±20% range



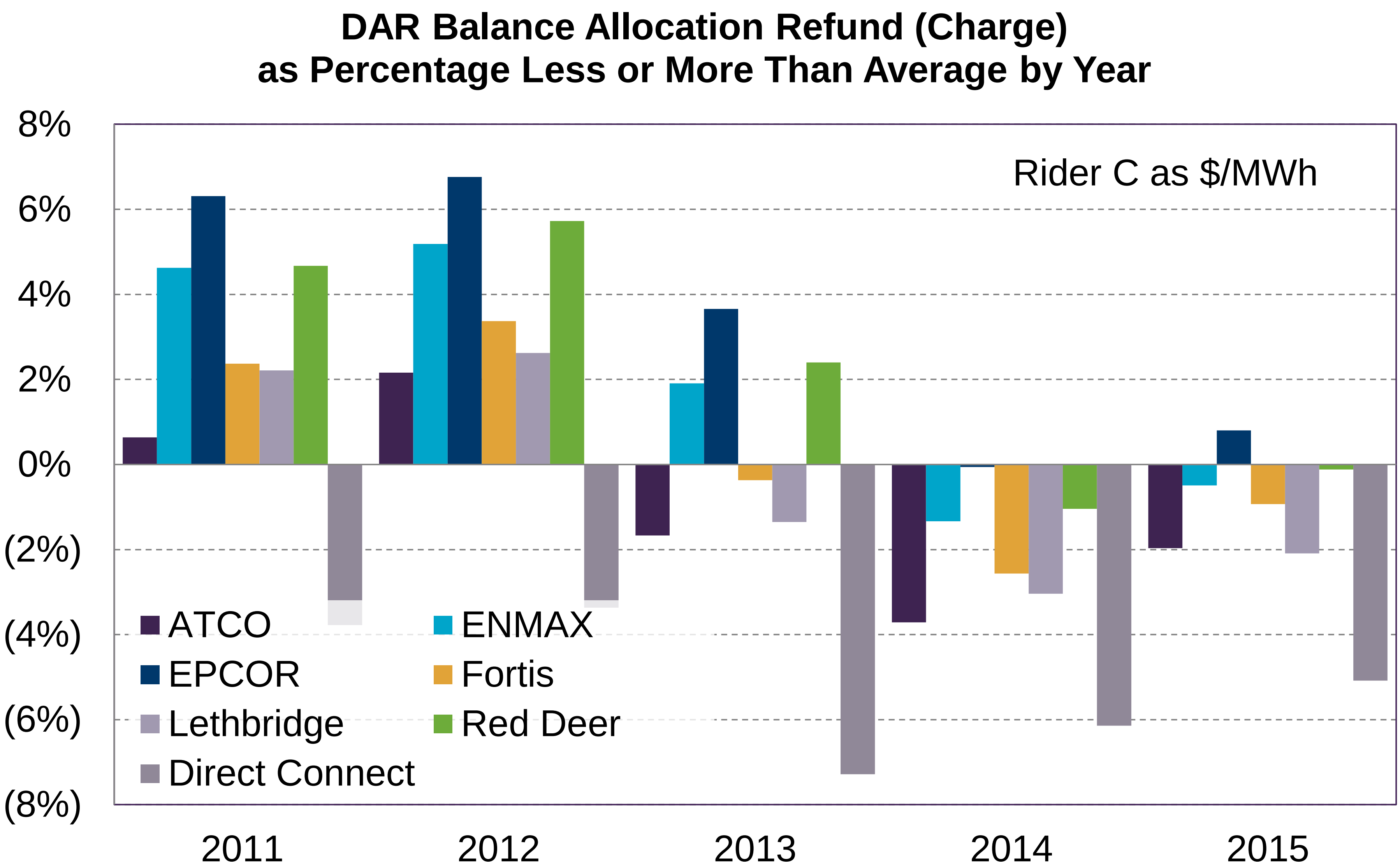
Variability has been similarly wide for individual years



Allocations have also varied between customers



Variability in allocation has similar pattern in individual years



In consultation for 2018 tariff application, AESO proposed Rider C evaluation

- Develop model of deferral account reconciliation for 2011-2015
- Assess impact of early tariff updates
- Evaluate potential changes to Rider C structure
  – Convert to percentage basis (from current $/MWh basis)
- Consider annual basis for Rider C and annual reconciliation to eliminate seasonal effects
- Possibility of eliminating Rider C or moving to prospective Rider C
- Note that this discussion addresses only connection charge component of deferral account balance
  – Connection charge account for 95% of deferral account balance

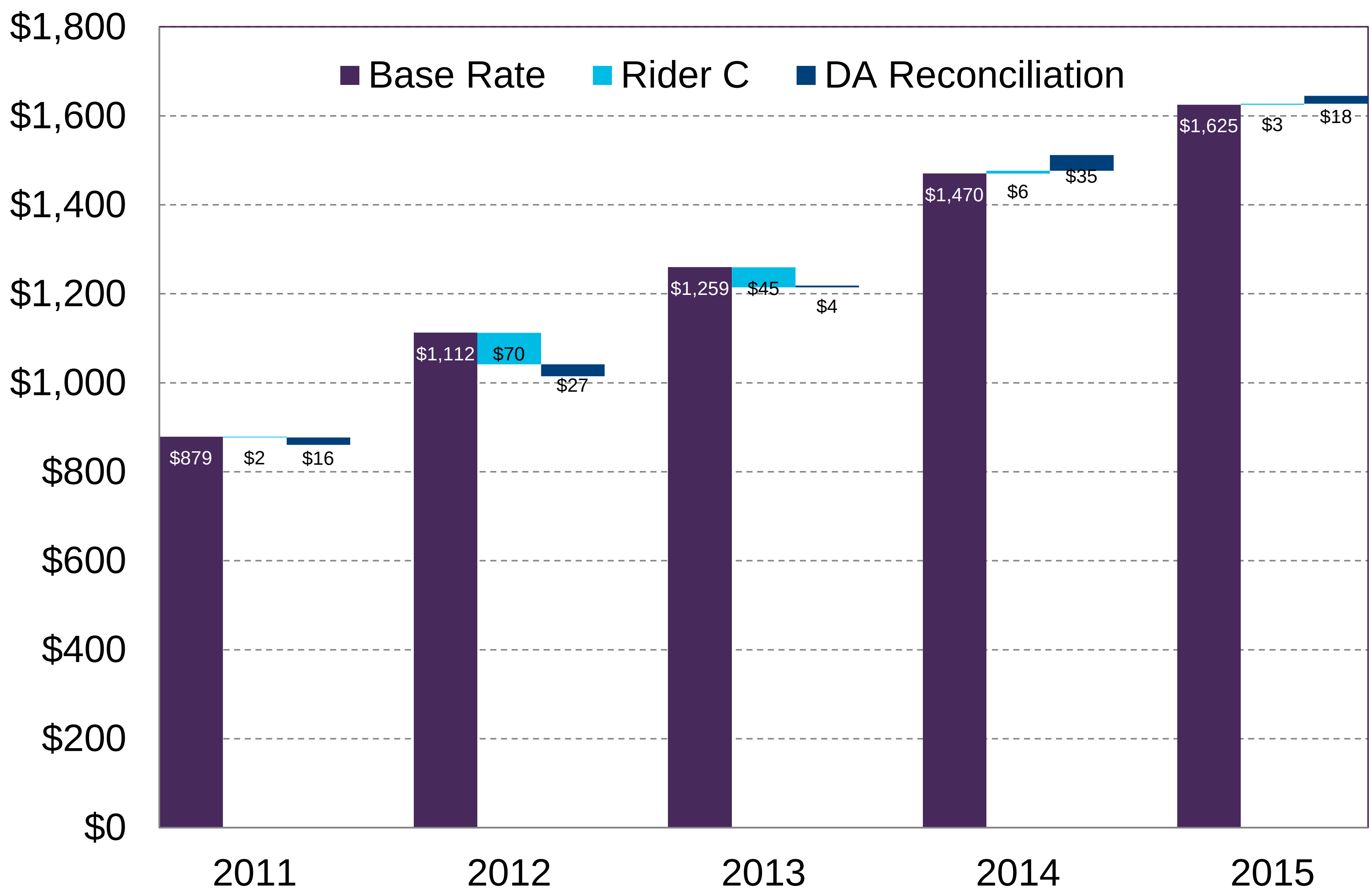
AESO has simulated Rider C and deferral account reconciliation in Excel

- Simulation model covers five years (2011-2015)
- Includes charges and allocations to over 570 individual services
- Closely replicates deferral account reconciliation for 2011, 2013, and 2014
  - Uses calculated instead of “frozen” Rider C during 2012
  - Uses final settlement data for all months of 2015
  - Simulation matches deferral account balance allocation over all settlement points within ±2%
- Allows assessment of impact of changes to Rider C and to deferral account reconciliation methodology
- Will not be made public as data is commercially sensitive

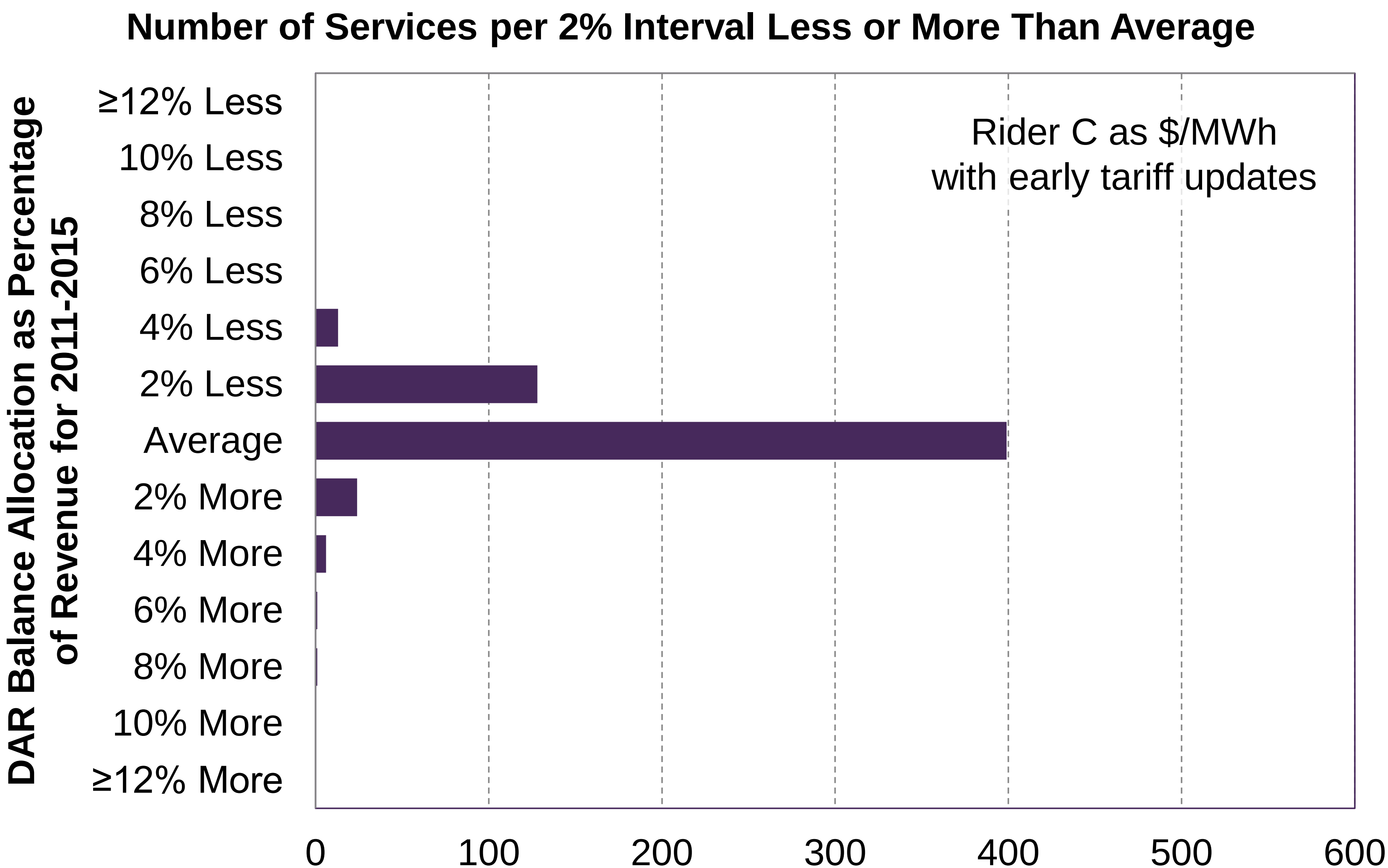
First consideration

Impact of Early Tariff Updates

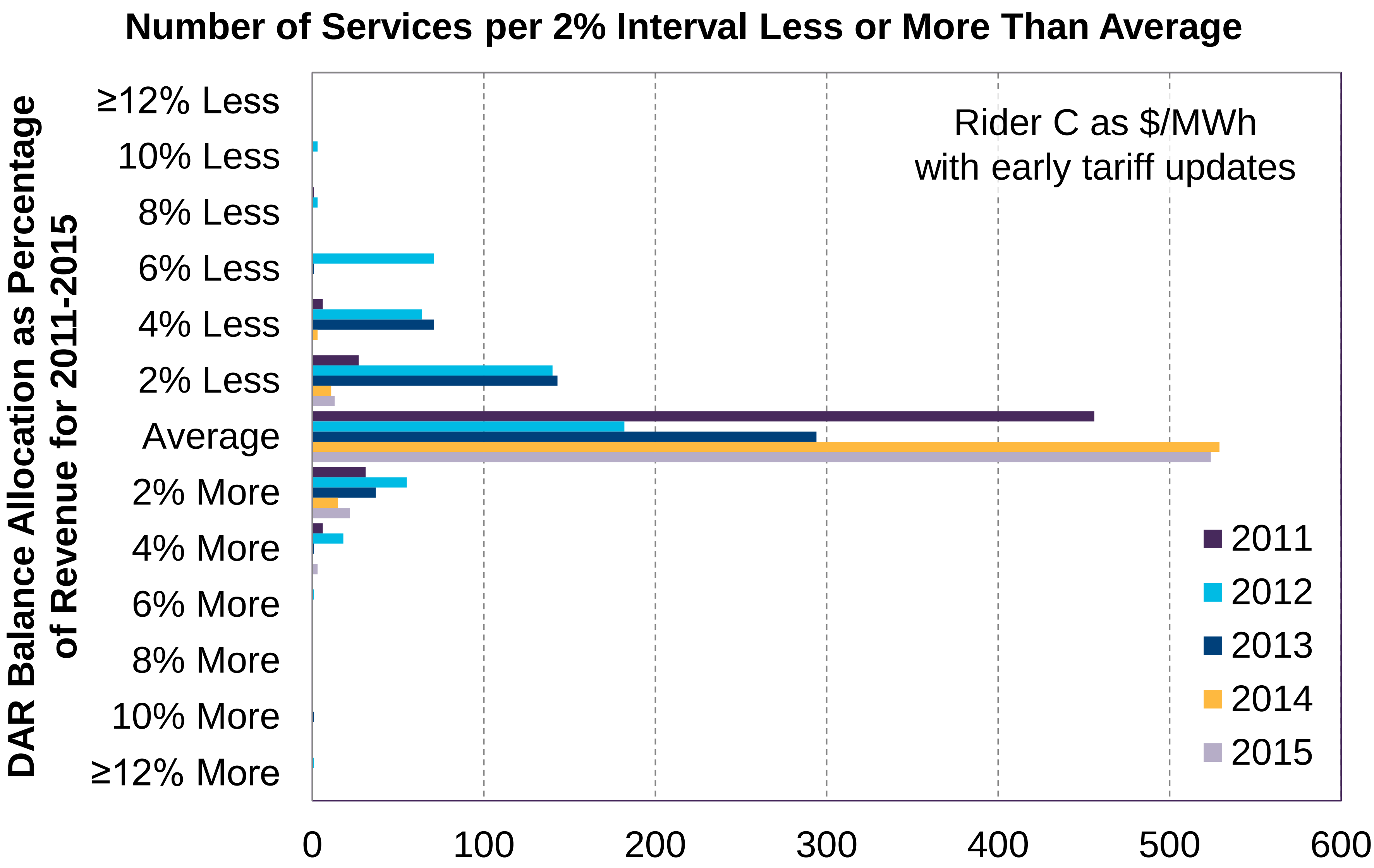
Early tariff updates can significantly reduce Rider C charges and credits



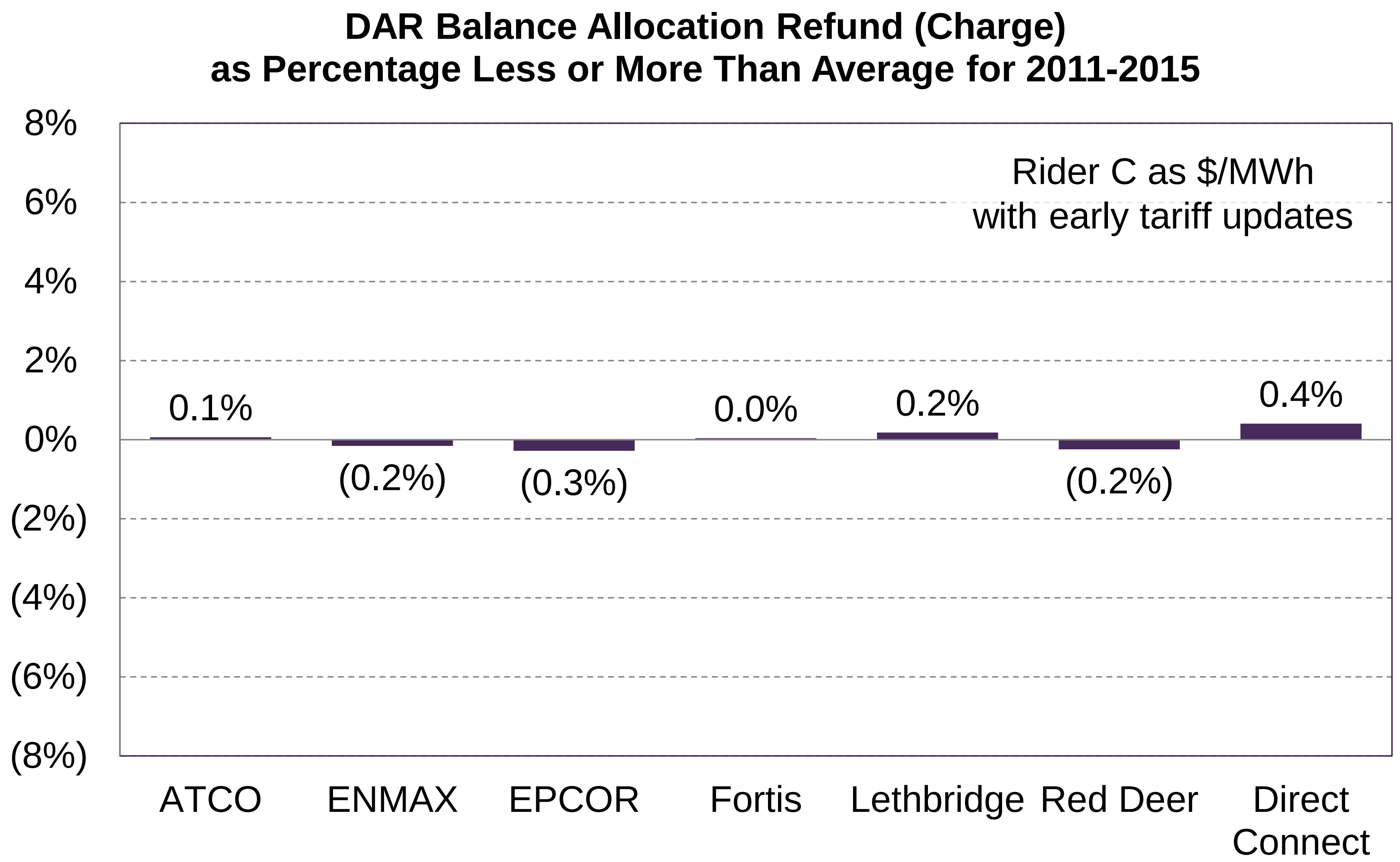
Early tariff updates also reduces variability of allocations to individual services



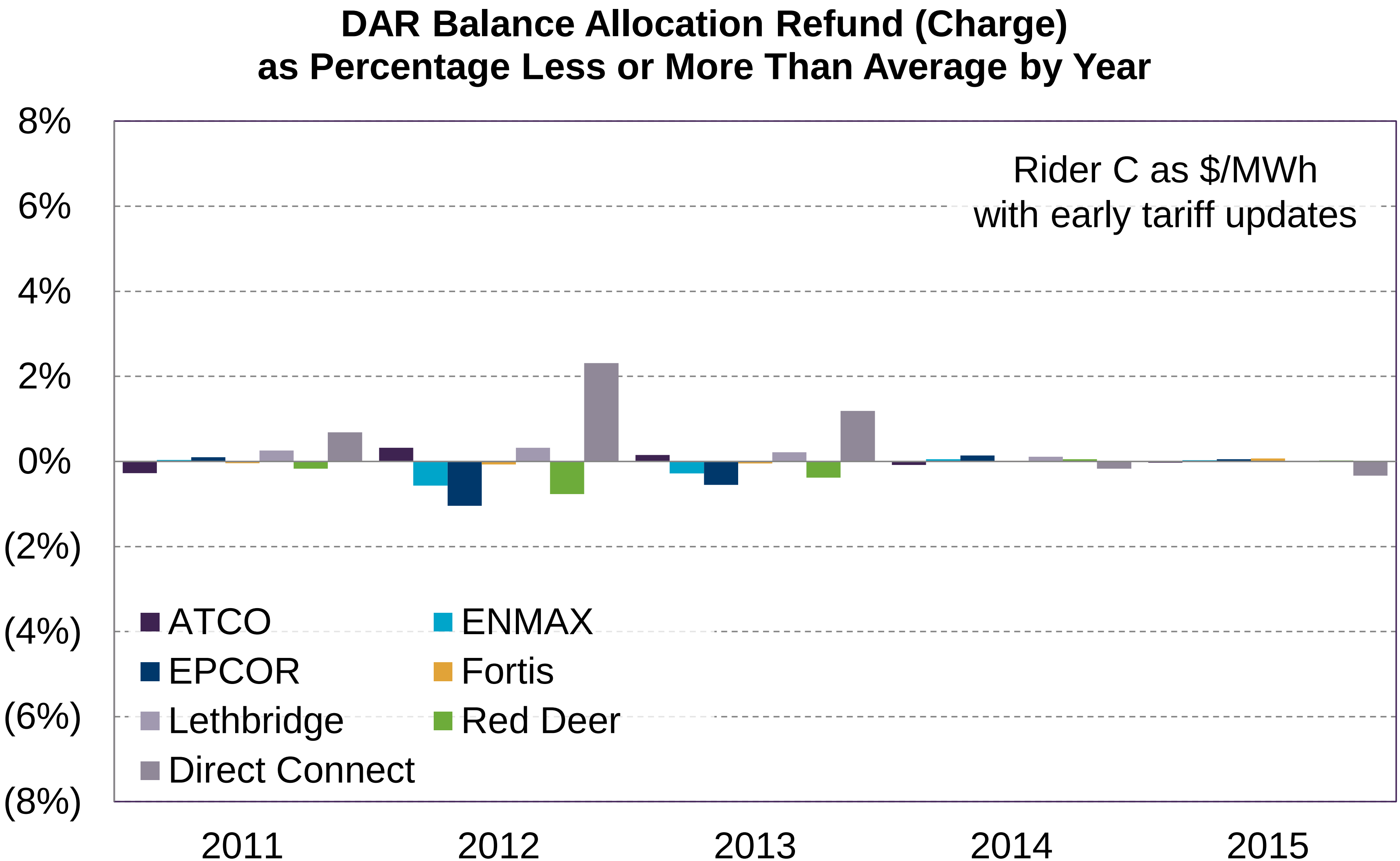
Variability depends on amounts collected through Rider C each year



Early tariff updates similarly reduce allocation variability between customers



Allocation variability between customers is reduced in individual years as well



Conclusion: Early tariff updates significantly reduce transfers between services

- Early tariff updates significantly reduce transfers between services in a deferral account reconciliation
- Early tariff updates do not entirely eliminate transfers between services
- AESO needs to better manage tariff update process
  – Approval of 2017 tariff update prior to January 1 was uncertain due to introduction of issues beyond the scope of a tariff update application

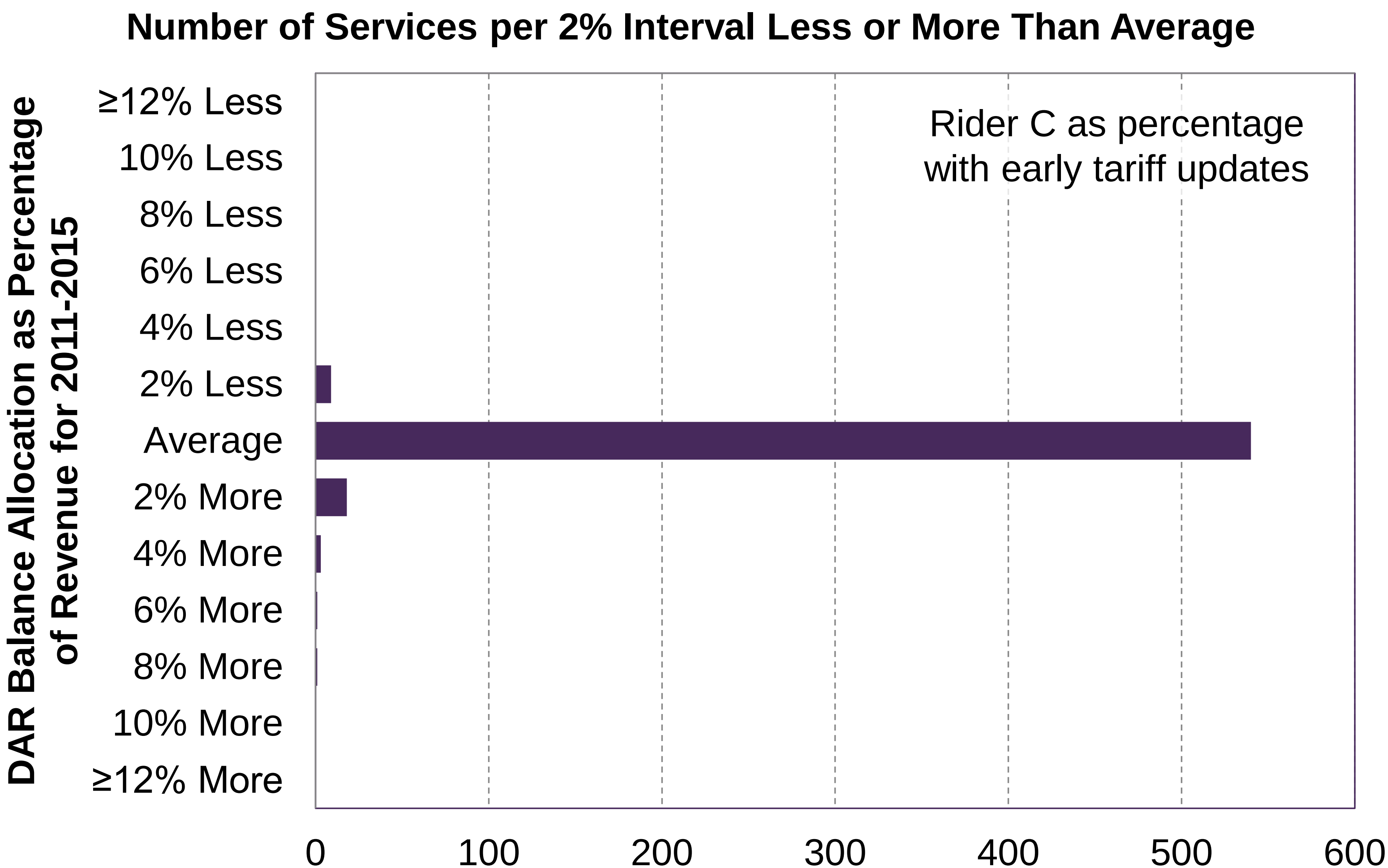
Second consideration

Impact of Changing Rider C Structure

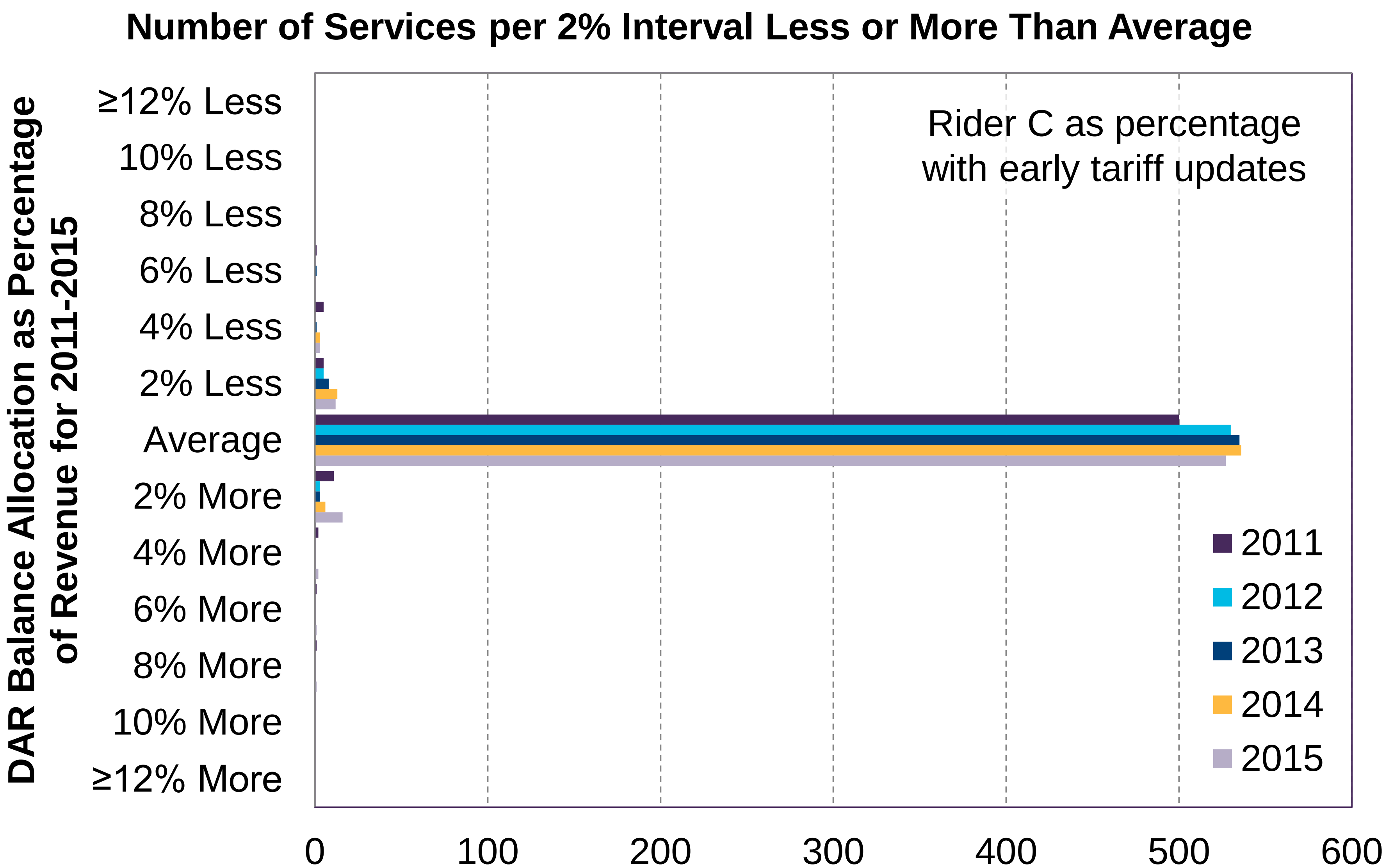
Converting Rider C to a percentage basis primarily impact transfers between services

- Changing the structure of Rider C would have little impact on total amounts collected through Rider C or determined in a deferral account reconciliation
  - Potential small impact from differences in ability to forecast revenue under different structures
- Changing Rider C to a percentage of revenue should reduce transfers in deferral account reconciliation by aligning Rider C with the deferral account balance allocation methodology
  - Previous higher-level analysis had found limited reduction to transfers

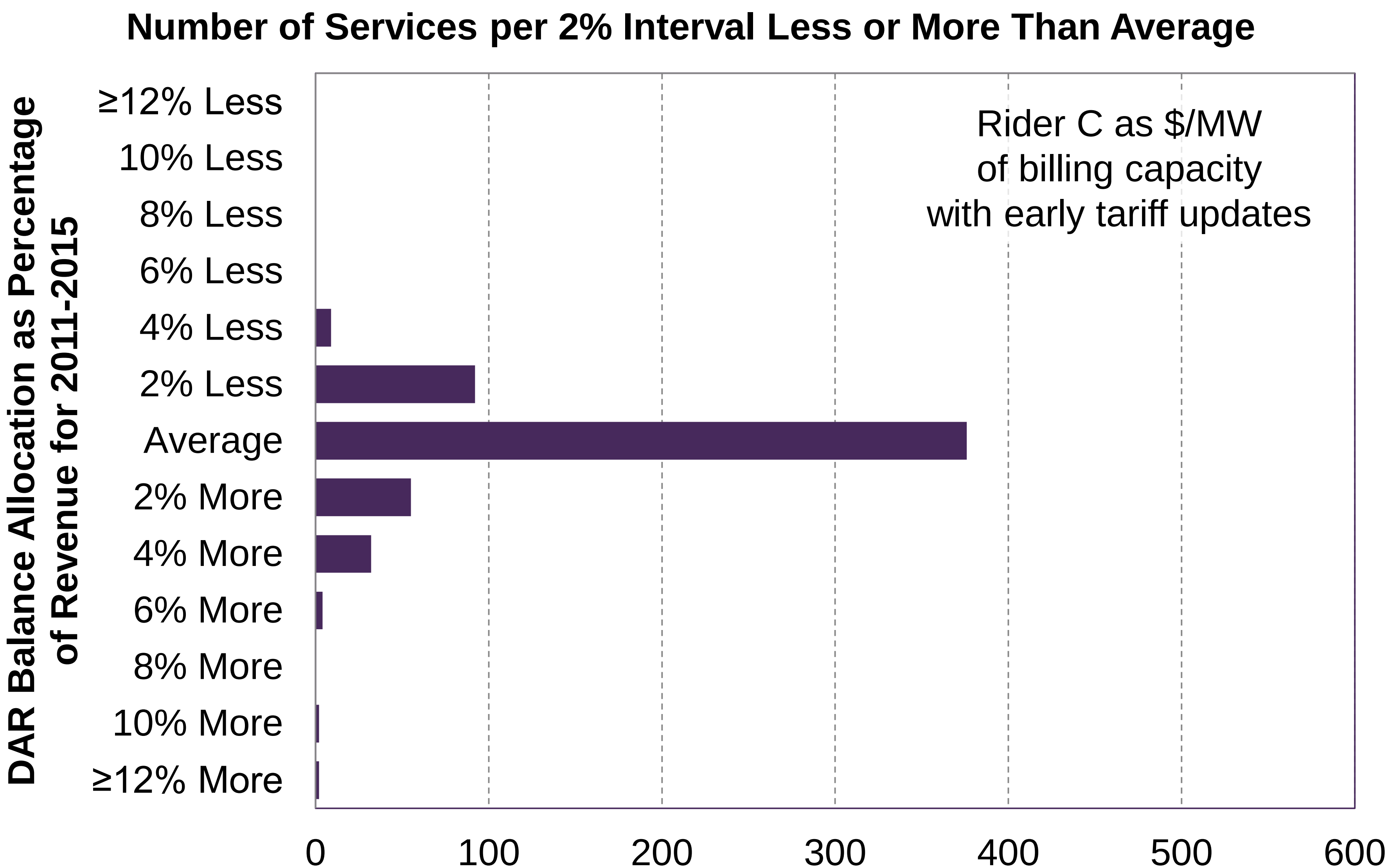
Rider C as percentage significantly reduces variability of allocations to services



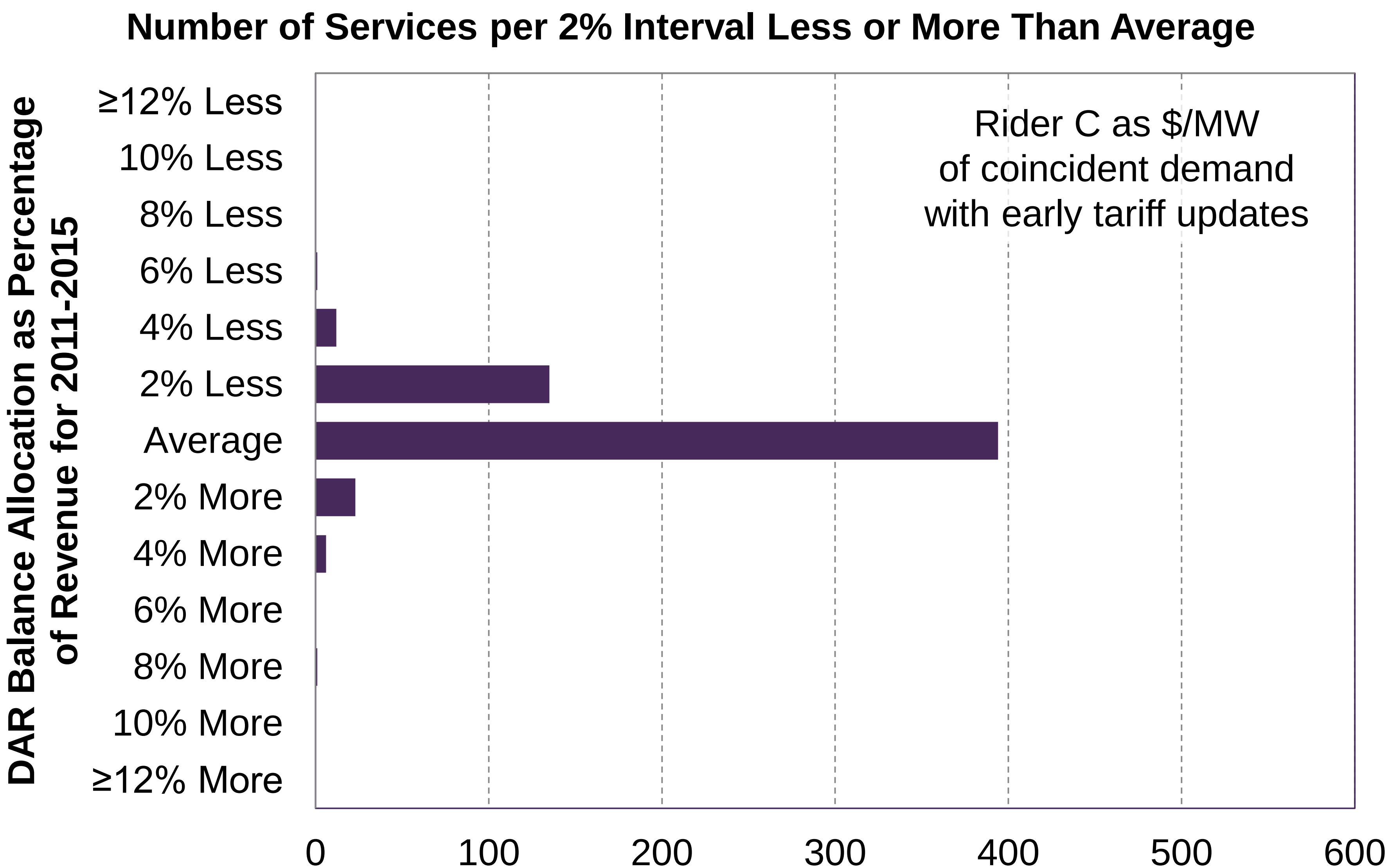
Reduction to variability between services occurs in every year



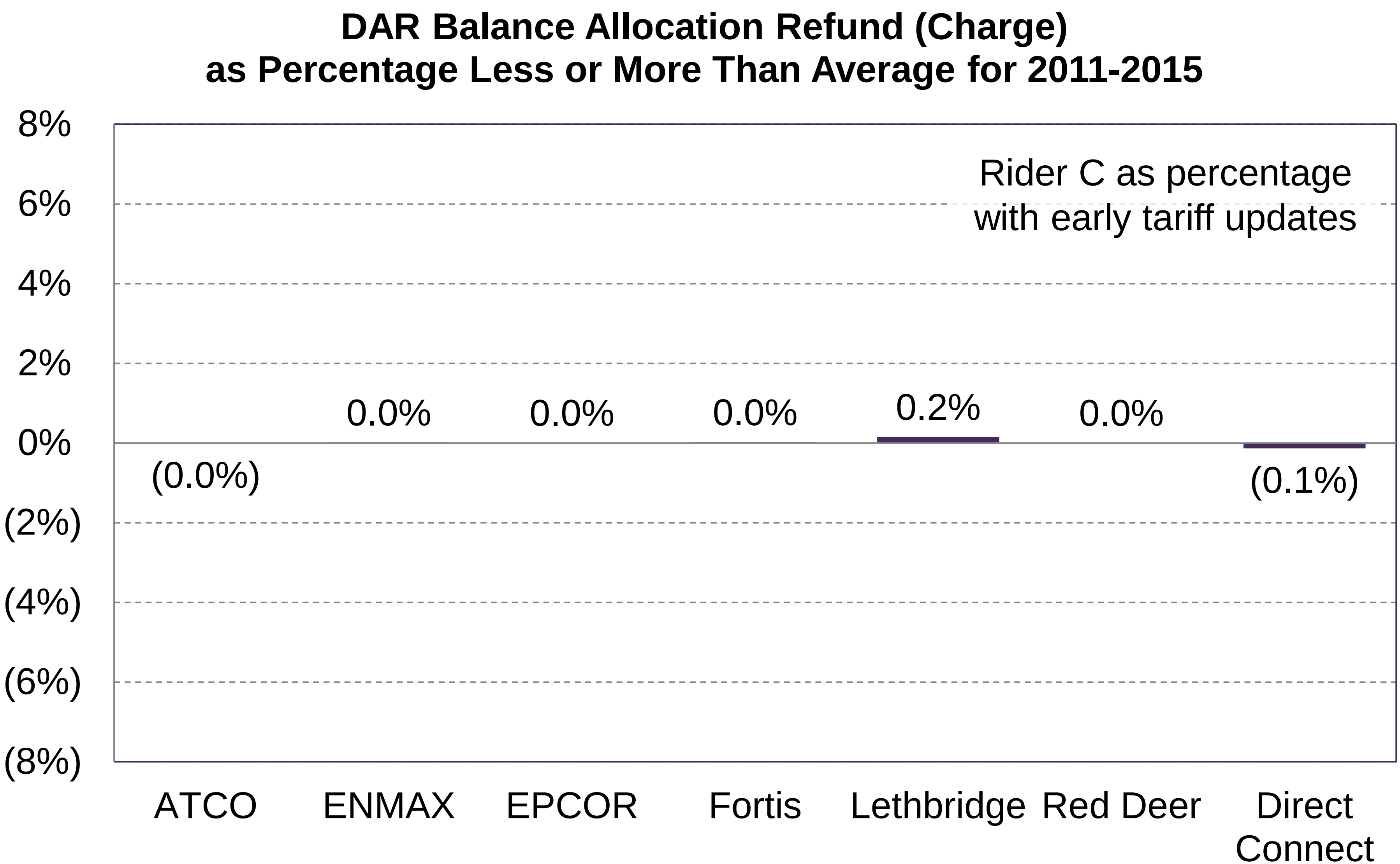
Rider C as $/MW of billing capacity reduces some variability of allocations to services



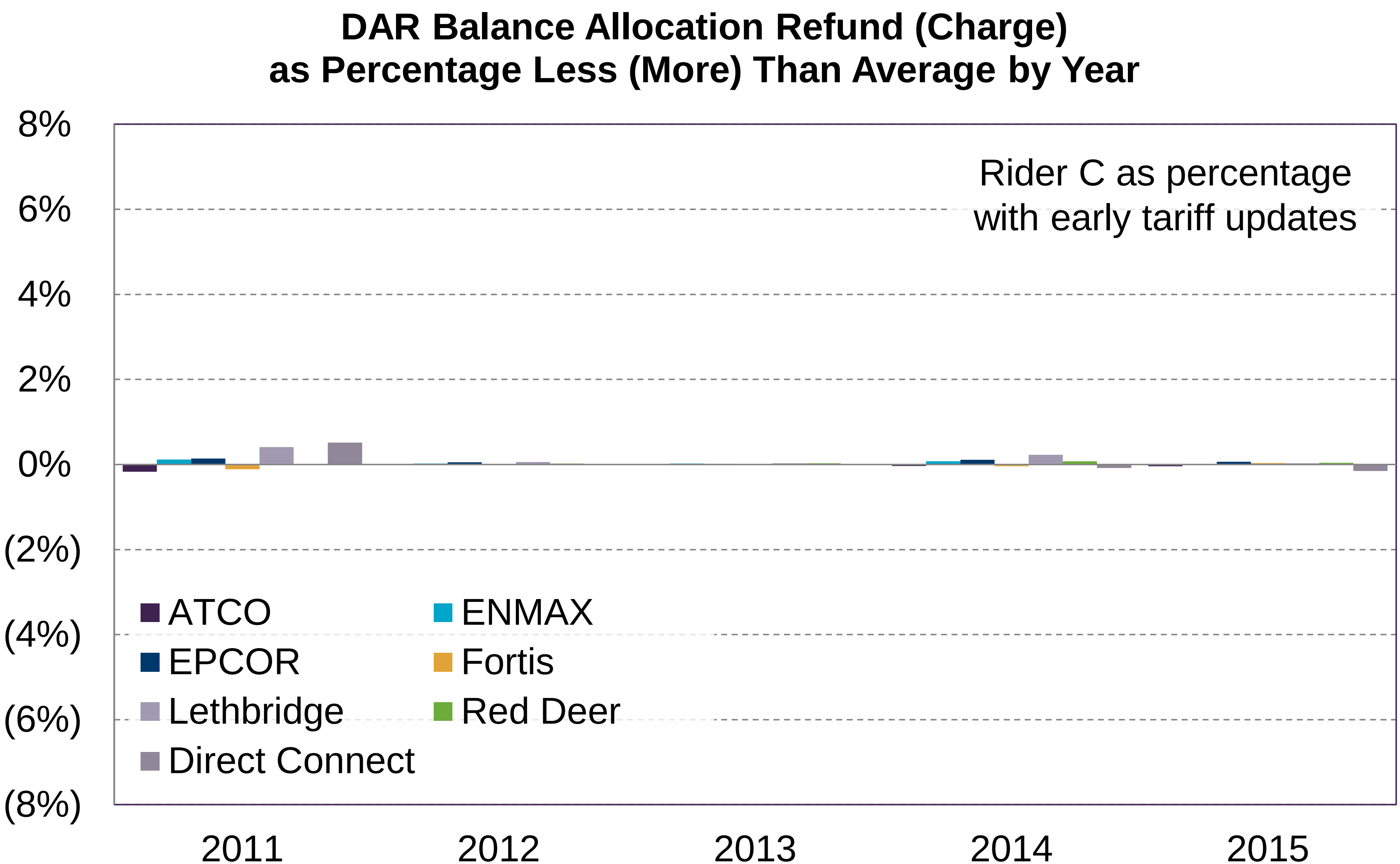
Rider C as $/MW of coincident demand provides minimal reduction to variability



Rider C as percentage also reduces allocation variability between customers



Reduction to variability between customers occurs in every year



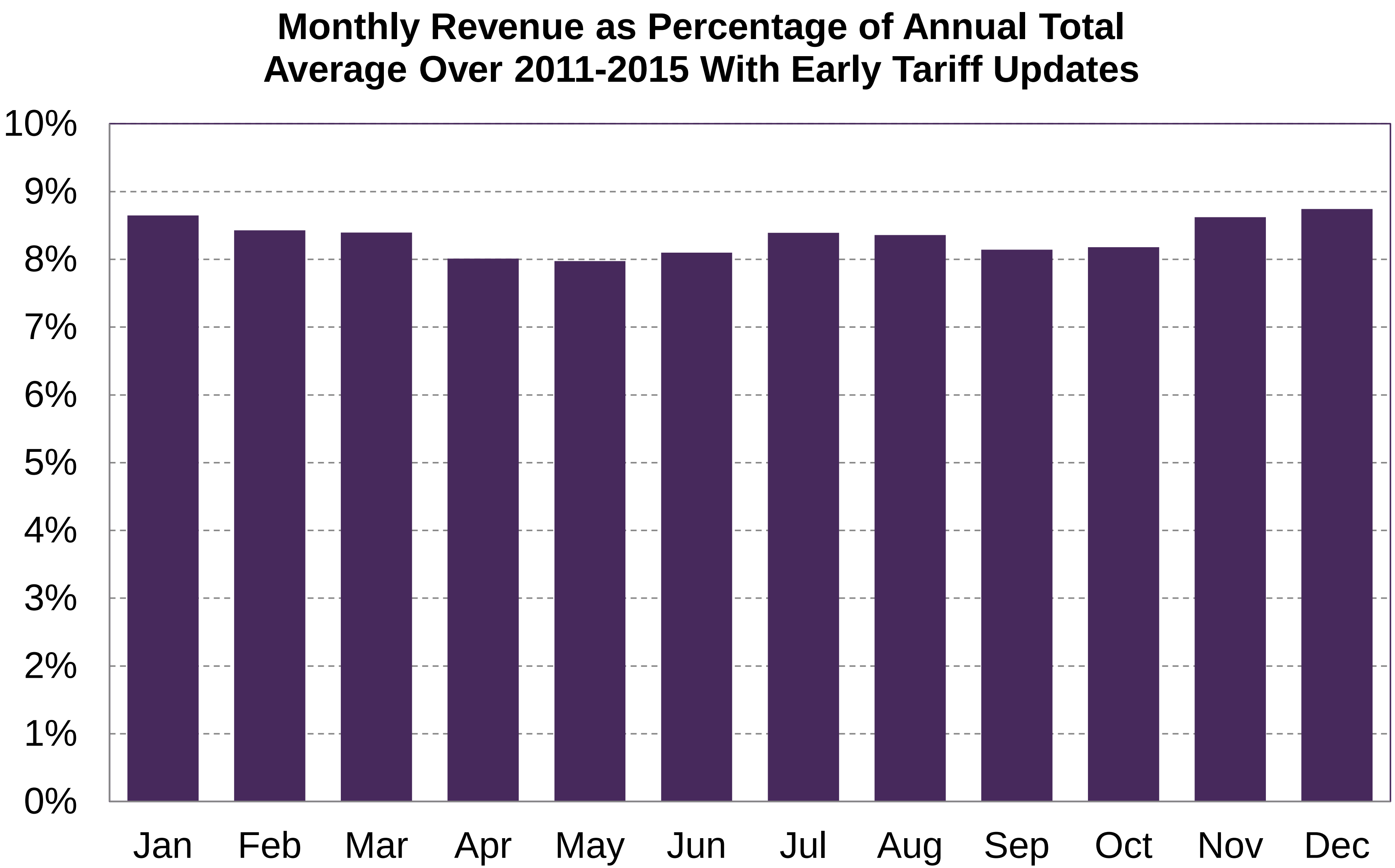
Conclusion: Rider C as percentage almost eliminates transfers between services

- Rider C as percentage almost eliminates transfers between services in a deferral account reconciliation
- Some transfers between services still exist but are small

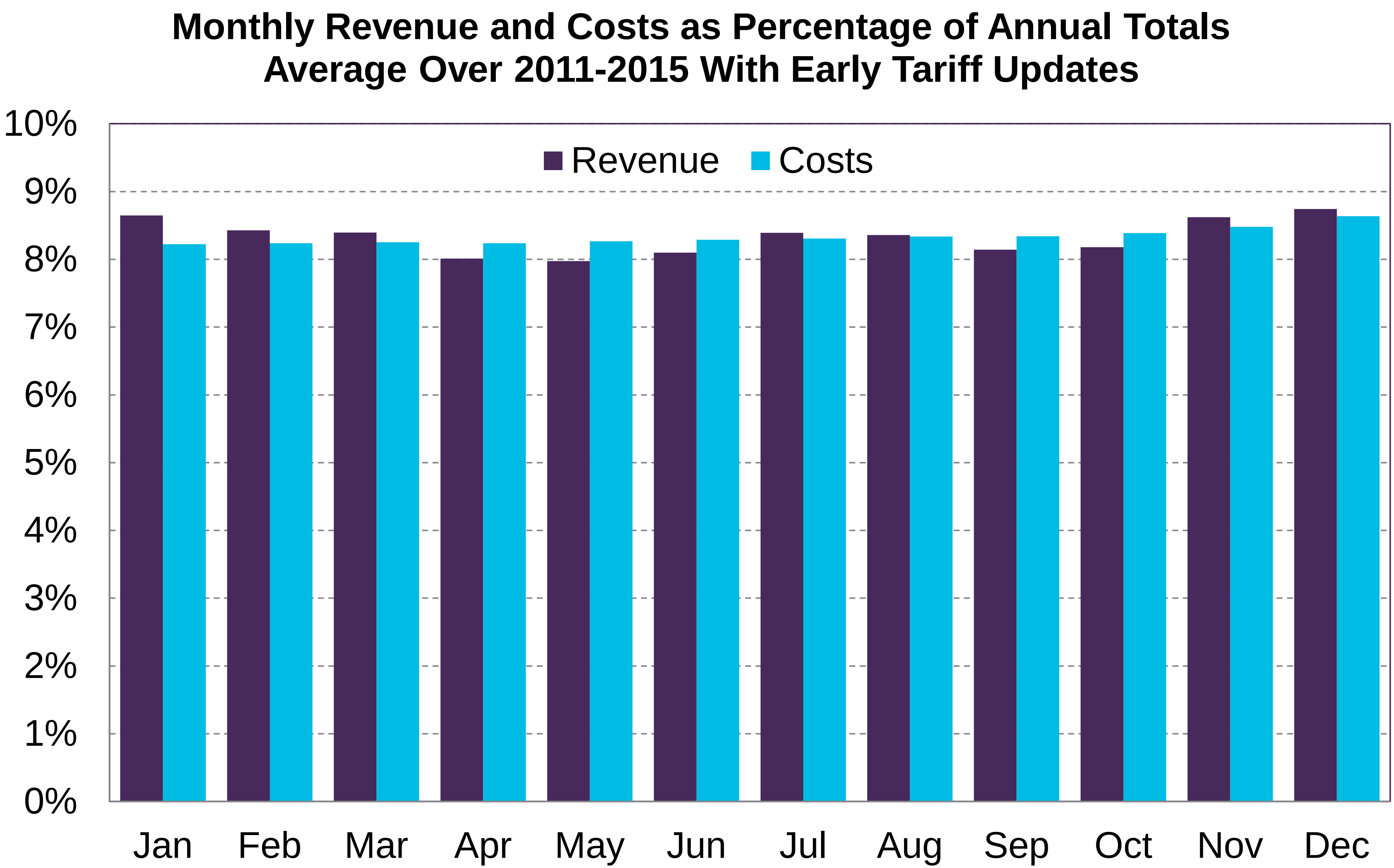
Third consideration

Impact of Changing to Production Year Basis

Monthly revenue exhibits a pattern of winter and summer peaks



Costs do not exhibit the same seasonal pattern



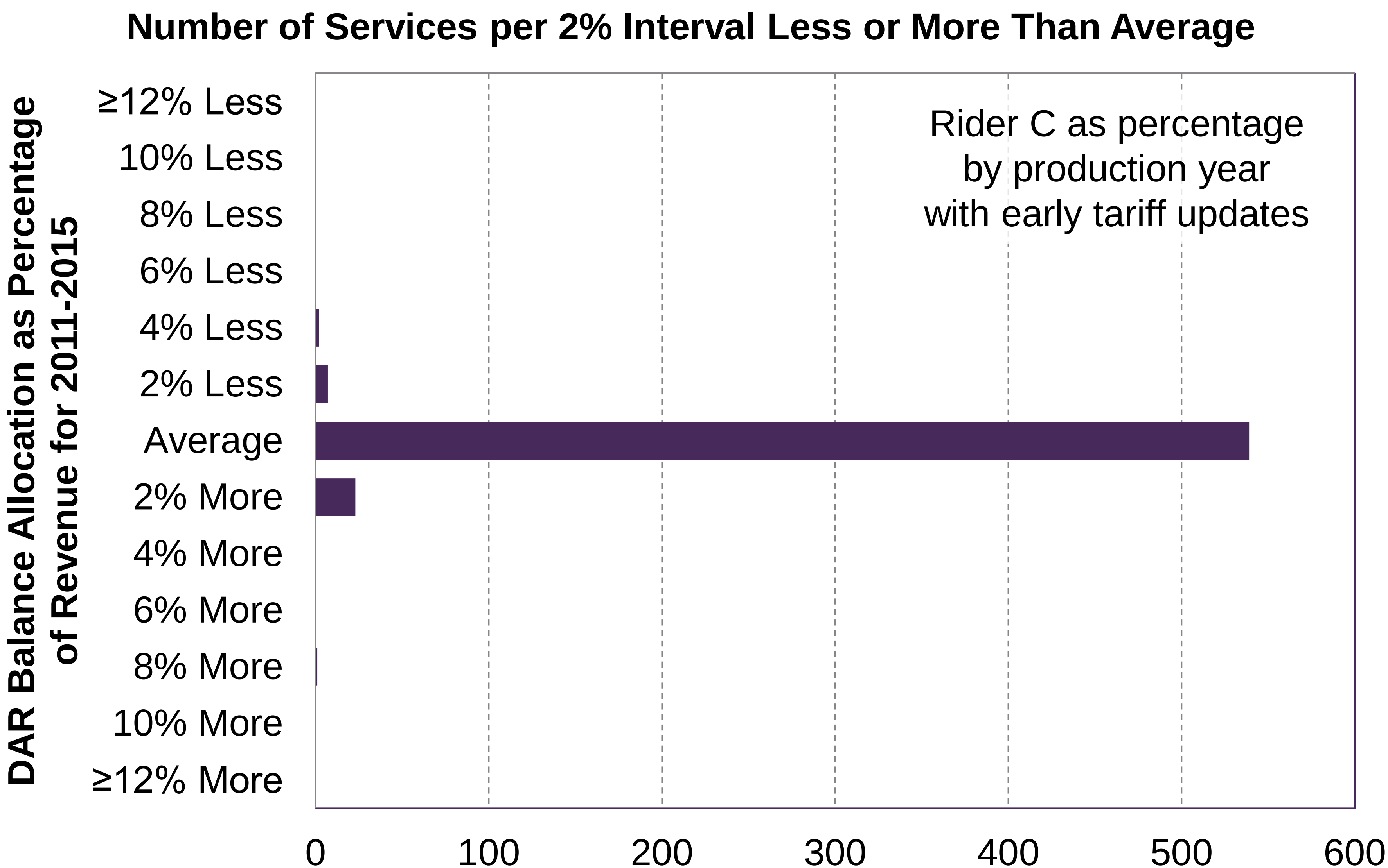
Costs are determined on an annual basis for the AESO's revenue requirement

- Transmission facility owner costs are established on an annual basis
  - Annual amount is simply divided by 12 to get monthly amount
- AESO's own administrative costs are not attributable to specific production months
  - Comprise general and administrative costs, other industry costs, and capital costs of the AESO
  - Are simply attributed to month in which they occur
  - Account for 6% to 9% of the AESO's annual revenue requirements
- Connection charge amount in Rate DTS is calculated on an annual basis in tariff applications and tariff updates

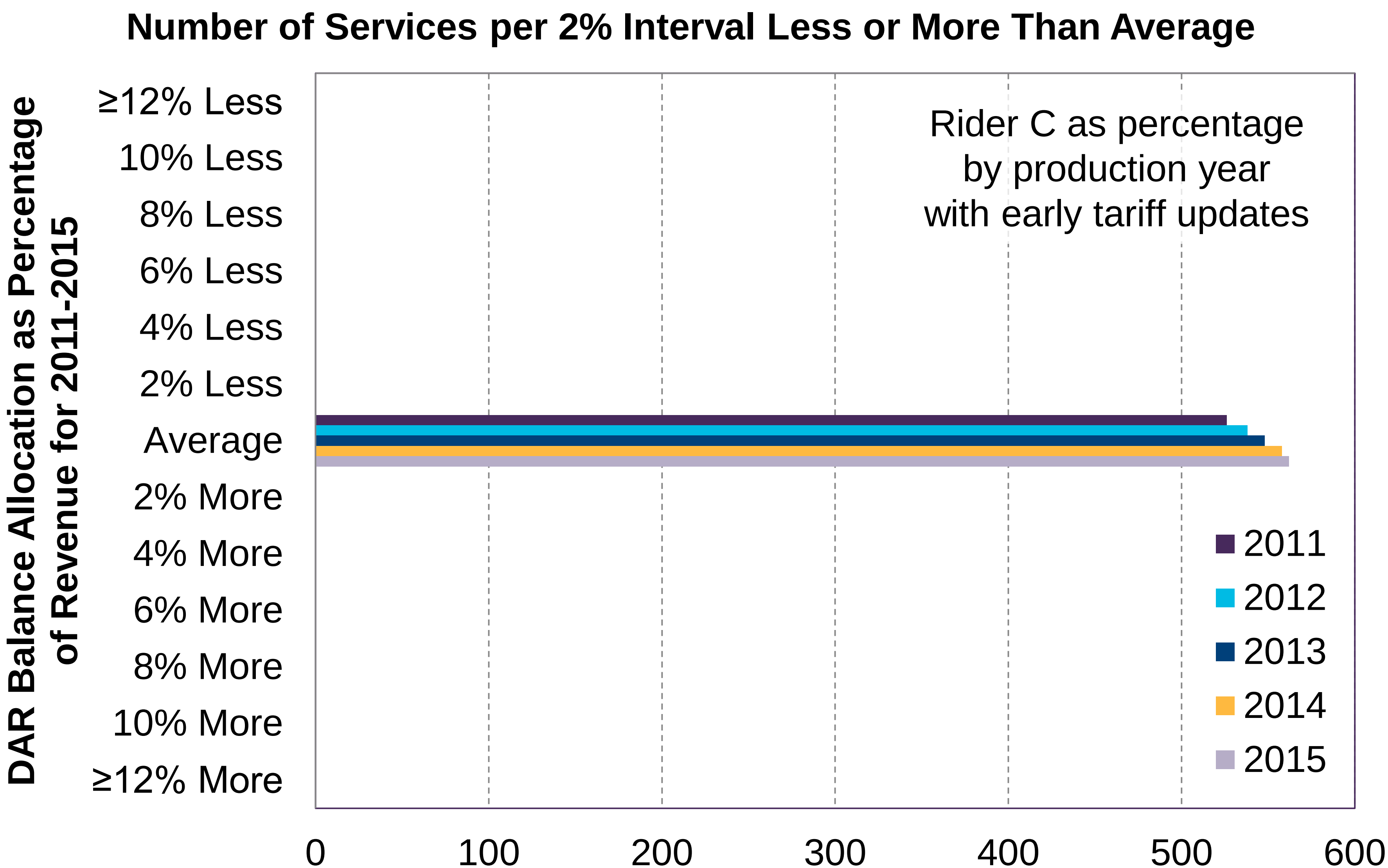
Allocating shortfalls and surpluses by month is inconsistent with rate design approach

- Allocating deferral account balances on a production month basis indirectly establishes a monthly connection charge
  - Lower per-unit charge in winter and summer when volumes are higher
  - Higher per-unit charge in spring and fall when volumes are lower
- Effect is to levelize revenue over all months
  - Inconsistent with cost causation as peak volumes result in lower charges
  - Lowers allocations in peak months compared to off-peak months
- Allocating shortfalls and surpluses on a monthly basis results in different annual allocations between services that have different load patterns between months

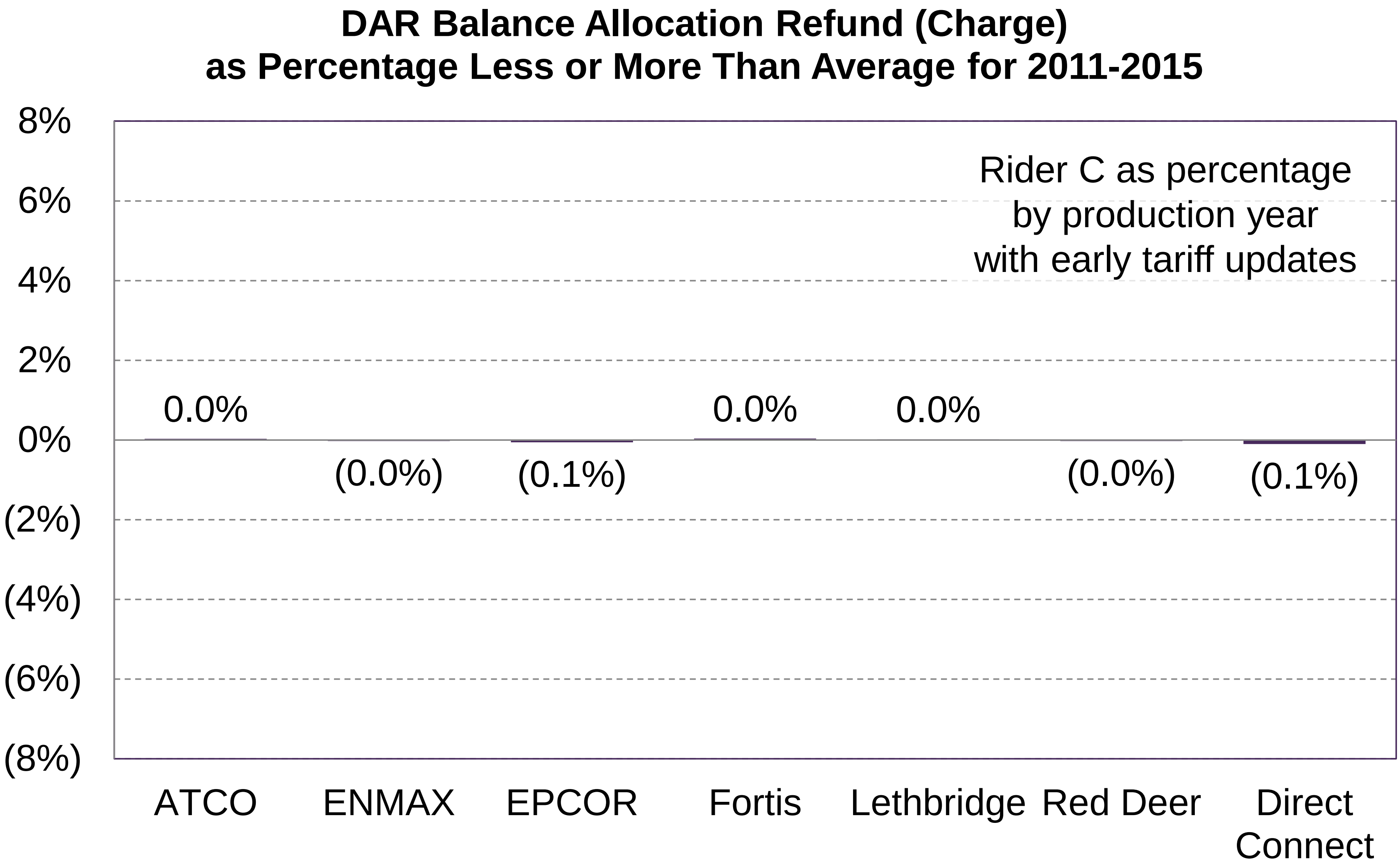
Five-year view obscures impact of Rider C as percentage by production year



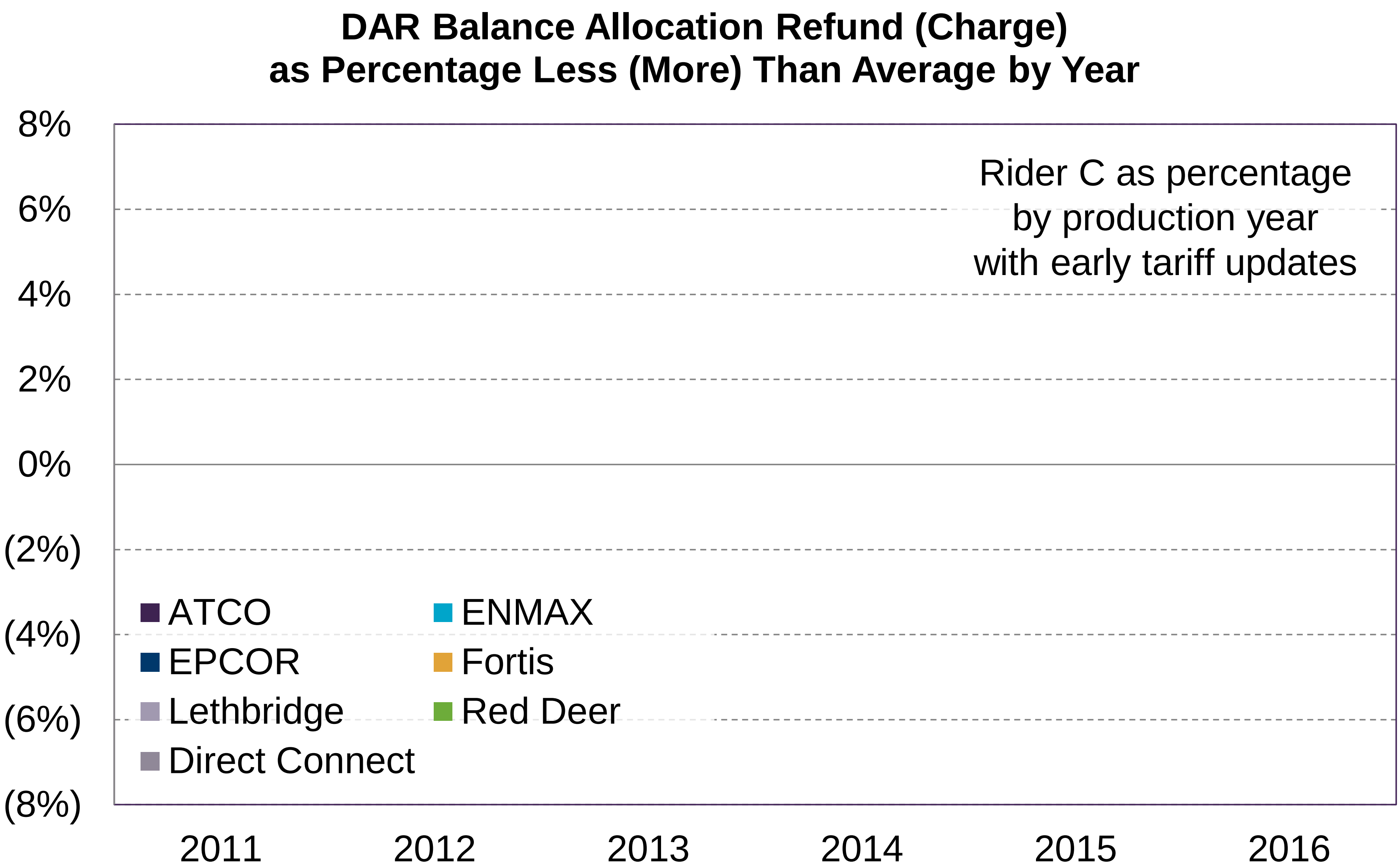
Rider C as percentage by production year eliminates remaining variability



Five-year view also obscures impact by customer



Rider C as percentage by production year eliminates variability between customers



Conclusion: Rider C as percentage by production year eliminates transfers

- Rider C as percentage by production year eliminates transfers between services in a deferral account reconciliation
- In practice there will still be some transfers resulting from timing impacts, such as if an annual cost becomes known partway through year
  - Such costs would be recovered through Rider C in remaining months of year then allocated over full production year in deferral account reconciliation application

break

Additional consideration

Impact of Changing to Net Revenue Allocation Methodology

PS Group has proposed deferral account balances be allocated on net revenue

- Existing methodology allocates deferral account balances on Rate DTS “base rate” revenue only
  - Similar approach for Rate FTS
  - “Base rate” revenue does not include any revenue attributed to the service under other rates and riders, such as Rate PSC, *Primary Service Credit*, or Rate UFLS, *Under Frequency Load Shedding Credits*
- Group of market participants who receive Rate PSC (PS Group) has proposed change in allocation methodology in 2015 deferral account reconciliation application proceeding
- PS Group proposal allocates deferral account balances on Rate DTS “base rate” revenue net of Rate PSC credits
  - Results in smaller allocations to Rate DTS services with Rate PSC and larger allocations to all other Rate DTS services

Matter is being reviewed in 2015 deferral account reconciliation proceeding

- PS Group has submitted evidence
- Oral hearing is currently scheduled for December 13-14, 2016
- PS Group has requested proposed change in methodology be applied to 2008 to 2015 production years
- AESO has submitted any change in methodology should be made on a go-forward basis only
  - For 2017 deferral account year
  - After market participants are made aware of proposed change
  - With review in an ISO tariff application proceeding
- Commission decision on issue expected in mid-March 2017

AESO is considering merits of net revenue methodology on a go-forward basis

- Currently-approved methodology allocates deferral account balance in proportion to Rate DTS revenue for a service

$$\begin{bmatrix} \text{Costs} \\ -\text{ Rate DTS Revenue} \\ -\text{ Other Tariff Revenue} \end{bmatrix} \times \frac{\text{Rate DTS Revenue}_{\text{one service}}}{\text{Sum of Rate DTS Revenue}_{\text{all services}}}$$

- Deferral account balance includes revenue from Rate DTS and from other tariff components, while allocation includes only “base rate” revenue from Rate DTS
- Net revenue allocation methodology would allocate deferral account balance in proportion to Rate DTS netted with other revenue for a service

$$\begin{bmatrix} \text{Costs} \\ -\text{ Rate DTS Revenue} \\ -\text{ Other Tariff Revenue} \end{bmatrix} \times \frac{\text{Net Tariff Revenue}_{\text{one service}}}{\text{Sum of Net Tariff Revenue}_{\text{all services}}}$$

AESO is considering merits of net revenue methodology on a go-forward basis (cont'd)

- Net tariff revenue for a service would include charges and credits related to contracted load service
  - Rate DTS and Rate FTS, *Demand Transmission Service*
  - Rate UFLS, *Demand Underfrequency Load Shedding Credits*
  - Rate PSC, *Primary Service Credit*
  - Riders A1-A4, *Transmission Duplication Avoidance Adjustments*
  - Payments in lieu of notice (PILONs) for reductions or terminations of contract capacity under section 9 of ISO tariff
- Net tariff revenue for a service would not include charges under Rate DOS, *Demand Opportunity Service*
- Net tariff revenue for a load service would not include charges or credits related to non-load service

Net revenue methodology would impact deferral account balance allocations

- Impact primarily on deferral account balance allocated to an individual service rather than on transfers between services in a deferral account reconciliation
  - Deferral account balance is settled through both Rider C during year and deferral account reconciliation after year-end
- Using deferral account reconciliation simulation for 2014-2015, net revenue methodology would impact allocation of $61.8 million deferral account balance
  - Deferral account balance represents about 2% of revenue requirement over 2014-2015

Net revenue methodology would impact deferral account balance allocations (cont'd)

Rate DTS Netted With:	Affected Services	2014-2015 Deferral Account Balance Increase (Decrease)	
Rate UFLS	240	($3.9 million)	(9%)
Rate PSC	43	($0.5 million)	(13%)
Riders A1-A4	3	$0.01 million	1%
PILONs	8	$0.1 million	9%

- Services that include no additional charges or credits would see an increase in deferral account balance allocations, compared to existing methodology
  - Remaining $4.3 million would be allocated over all services
  - All services would see an average 7% increase in deferral account balance allocation
    - Including services with no additional charges or credits

Net revenue methodology would require changes to ISO tariff

- Rates UFLS and PSC, Riders A1-A4, and PILONs would need to indicate they are subject to deferral account adjustment
  - Rider C would need to indicate it applies to amounts under those tariff components, in addition to Rates DTS and FTS
- Consistent with Commission directions in recent decisions, a change in deferral account reconciliation methodology should be reviewed in a comprehensive tariff application

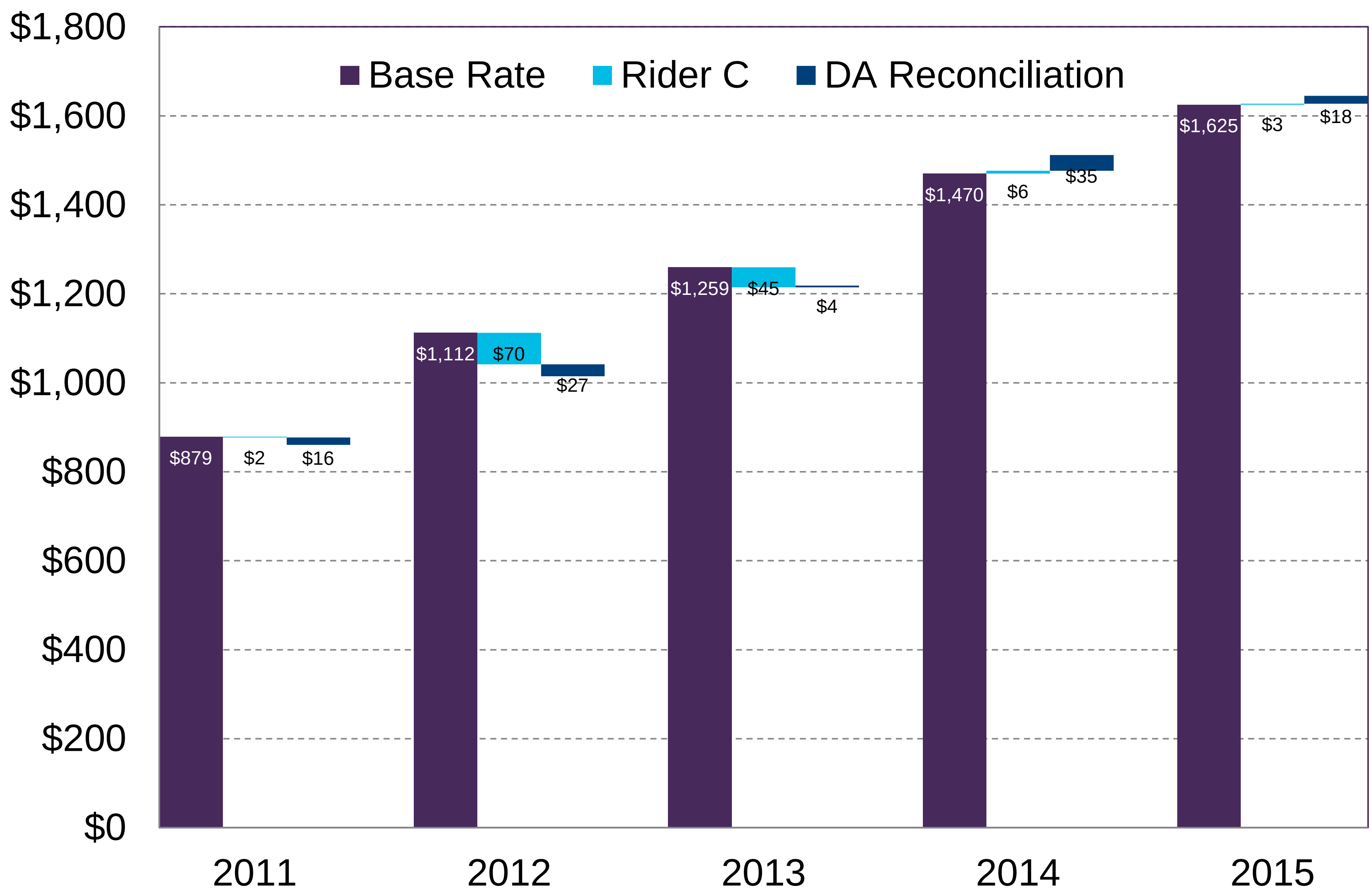
AESO invites stakeholder feedback on net revenue allocation methodology

- AESO is seeking stakeholder comments on net revenue allocation methodology

Future considerations

Possible Future Changes to Rider C

Early tariff updates can significantly reduce Rider C charges and credits



Could Rider C be eliminated?

- Early tariff updates can significantly reduce Rider C charges
- However, simulation included $70 million refund through Rider C in 2012
- Success at maintaining early tariff update process is uncertain
- AESO would likely want to maintain an “emergency” rider of some sort

Could Rider C be converted to a prospective rider?

- Early tariff updates can significantly reduce deferral account balances
- A prospective rider would eliminate deferral account reconciliations
- But prior year adjustments could still be significant
- Impact of “real time” costs incurrence during year is unknown

Conclusion: Maintain use of Rider C and deferral account reconciliations

- AESO suggests maintaining quarterly Rider C and annual deferral account reconciliations for at least a few more years
  - Then evaluate success of early tariff updates and Rider C restructuring

Timing and implementation considerations

Timing and Implementation Options

How should Rider C and reconciliation methodology changes be implemented?

- Commission has directed the AESO to report on tariff updates, deferral account reconciliation processes, and Rider C design in next comprehensive tariff application
  - Would allow comprehensive review with broad stakeholder representation
  - Would allow implementation on a go-forward basis
  - Tariff not expected to be effective until mid-2018
- AESO considers changes to Rider C design should be implemented as soon as practical
  - Expected to nearly eliminate transfers between services in deferral account reconciliation
  - Would require, at a minimum, changes to Rider C in the ISO tariff

What changes should be proposed?

- Early tariff updates already implemented
  – 2018 tariff update planned to be filed in Q3 2017
- Changes to Rider C
    - Will require changes to AESO billing system
  – Convert to percentage of revenue (instead of $/MWh)
  – Target zero deferral account balance at end of year (instead of end of quarter)
  – Potentially apply to net revenue
- Changes to deferral account reconciliation methodology
    - Will require changes to deferral reporting system used for applications
  – Reconcile on production year basis
  – Potentially allocate deferral account balance on net revenue

AESO considers three options are available for Rider C and methodology changes

1. Include Rider C and deferral account reconciliation methodology changes in 2018 tariff application in Q2 2017
   - Aligns with Commission direction in Decision 2014-242
   - Changes likely effective in mid-2018 on go-forward basis
   - Allows comprehensive review with broad representation
2. File separate application in Q1 2017 for Rider C and deferral account reconciliation methodology changes
   - Changes likely effective in late 2017 on go-forward basis
   - Limits review to some extent; representation uncertain
   - Preparing complete separate application may delay completion of tariff application

AESO considers three options are available for Rider C and reconciliation changes (cont'd)

3. File application in Q1 2017 for interim Rider C changes with request to make existing reconciliation methodology interim
   – Full review would occur as part of 2018 tariff proceeding
   – Changes likely effective mid-2017, on interim basis
     • Would need to allow sufficient time for AESO billing system changes
   – Limited review of interim application; comprehensive review in tariff application
   – Minimal impact on 2018 tariff application

• AESO also considered negotiated settlement approach but concluded it had no significant advantages

AESO invites stakeholder feedback on three options for implementation

- Are there other practical options?

Transmission Cost Causation Study Update

Raj Sharma

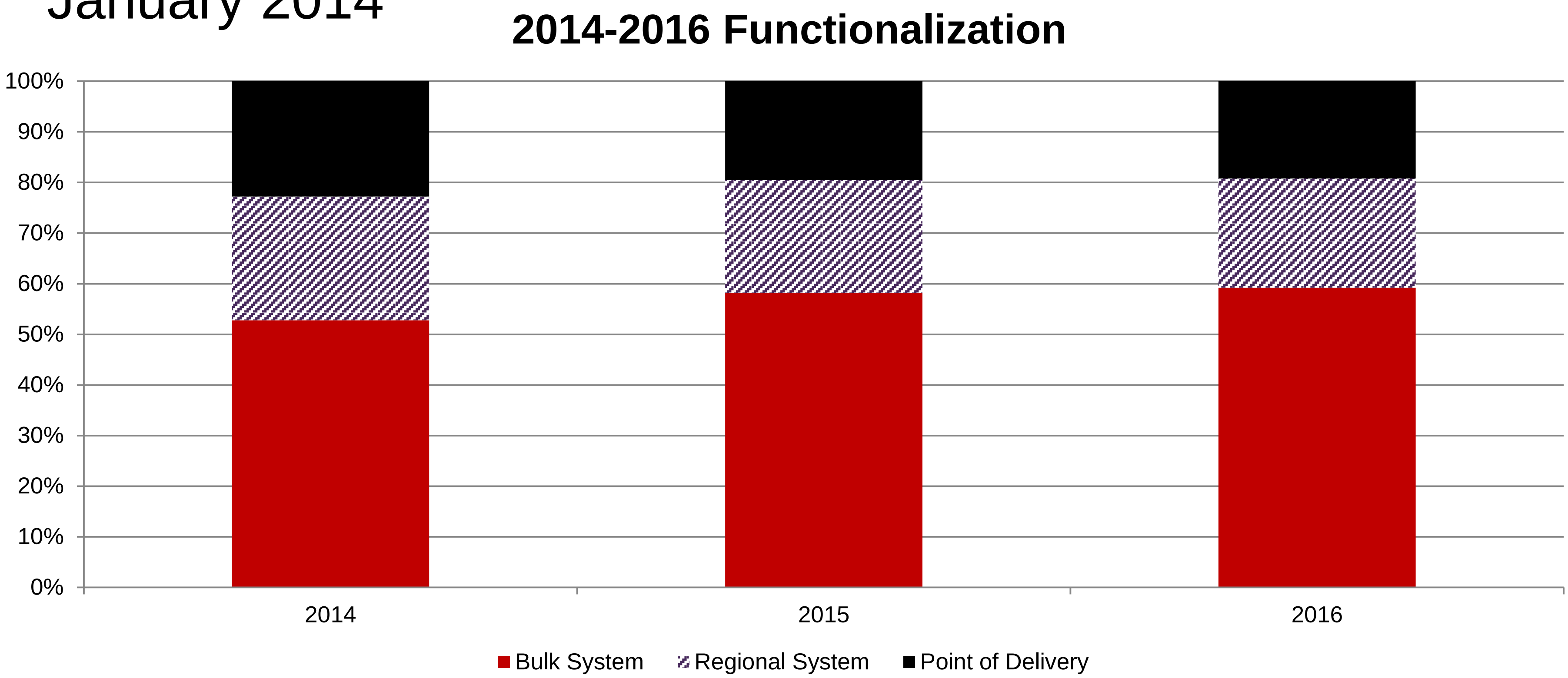
Public

Plan for 2018 – 2020 transmission cost causation study

- The AESO included a 2014-2016 transmission cost causation study prepared by London Economics International (“LEI”) in its 2014 ISO tariff application
  - The study established the inputs and methodology for a comprehensive cost causation study that used both capital cost and operating and maintenance cost data
  - A negotiated settlement process was used with participants and approved by the Commission
- The AESO proposed to update the LEI study itself using identical methodology with functionalization by voltage and classification by minimum system approach (in August 2015)

History of functionalization in transmission cost causation study

- *The 2014-2016 Cost Causation Negotiated Settlement Agreement* was approved as filed November 27, 2013
- In accordance with agreement, an updated study was filed January 2014

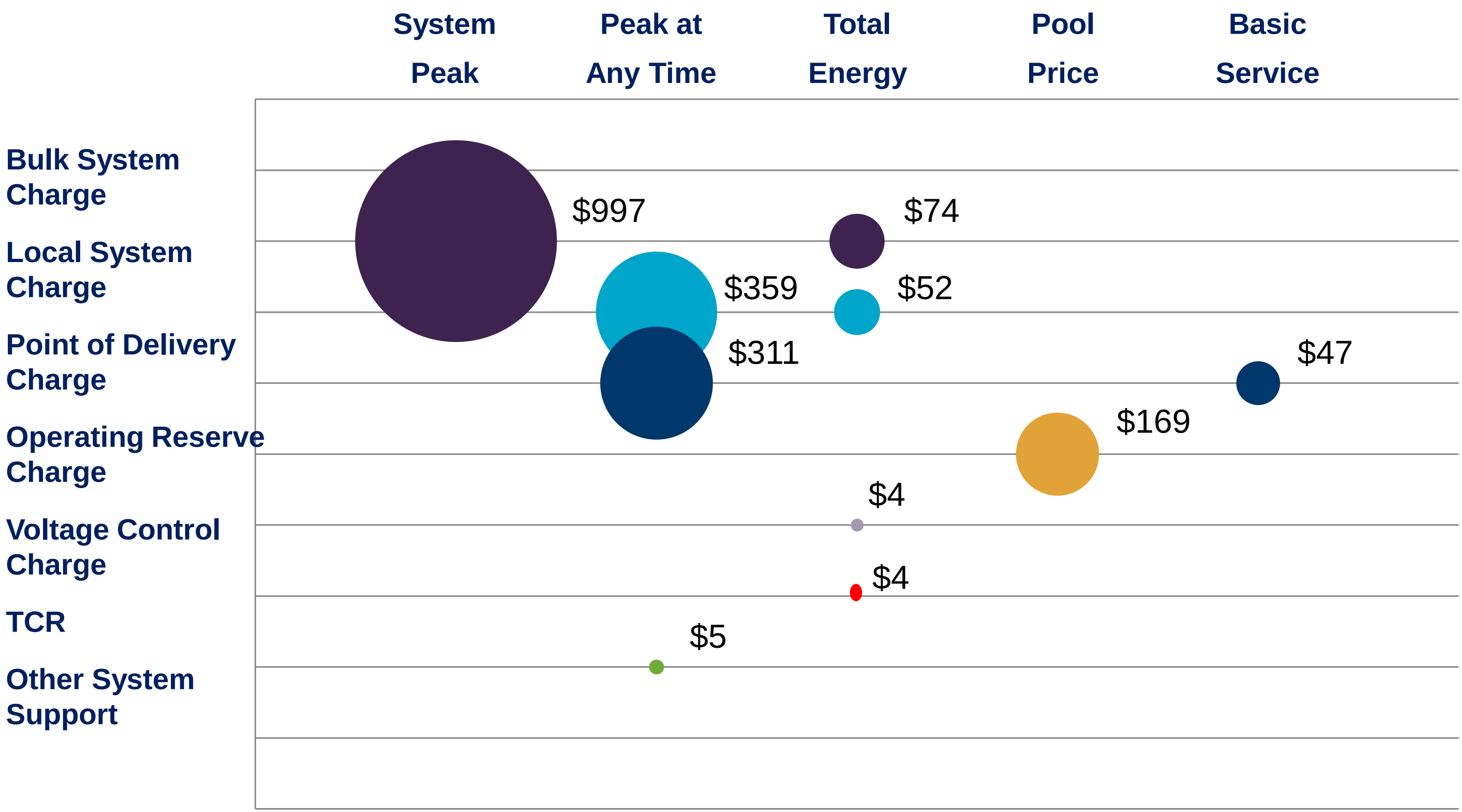


History of classification in transmission cost causation study

2014-2016 cost classification between demand and energy

2014-2016 Classification	Function	
	Bulk	Regional
Demand	93.1%	87.4%
Energy	6.9%	12.6%

Applied for Rate DTS structure in 2017 ISO tariff update application ($ million)



Scope of 2014-2016 transmission cost causation study

Scope included:

- Functionalization of capital costs by voltage methodology (including use of low-side voltage to functionalize substation costs)
- Functionalization of operating and maintenance (O&M) costs by specific allocators for most cost components, and functionalization of non-capitalized general and administration (G&A) costs in proportion to O&M costs
- Weighting of capital and O&M costs over 2014-2016
- Classification of bulk system and regional system costs by minimum system methodology

Scope of 2018-2020 transmission cost causation study

Update of 2014-2016 transmission cost causation study:

- Using identical methodology
- Using same data sources, plus a few additional sources
- For years 2018-2020

Process for 2018-2020 transmission cost causation study

AESO's proposed process:

- update inputs for 2018-2020 transmission cost causation study in Q4 2016
- Present draft results to stakeholders in January 2017
- Include the study in the 2018 ISO tariff application

Point-of-delivery (POD) Cost Function Update

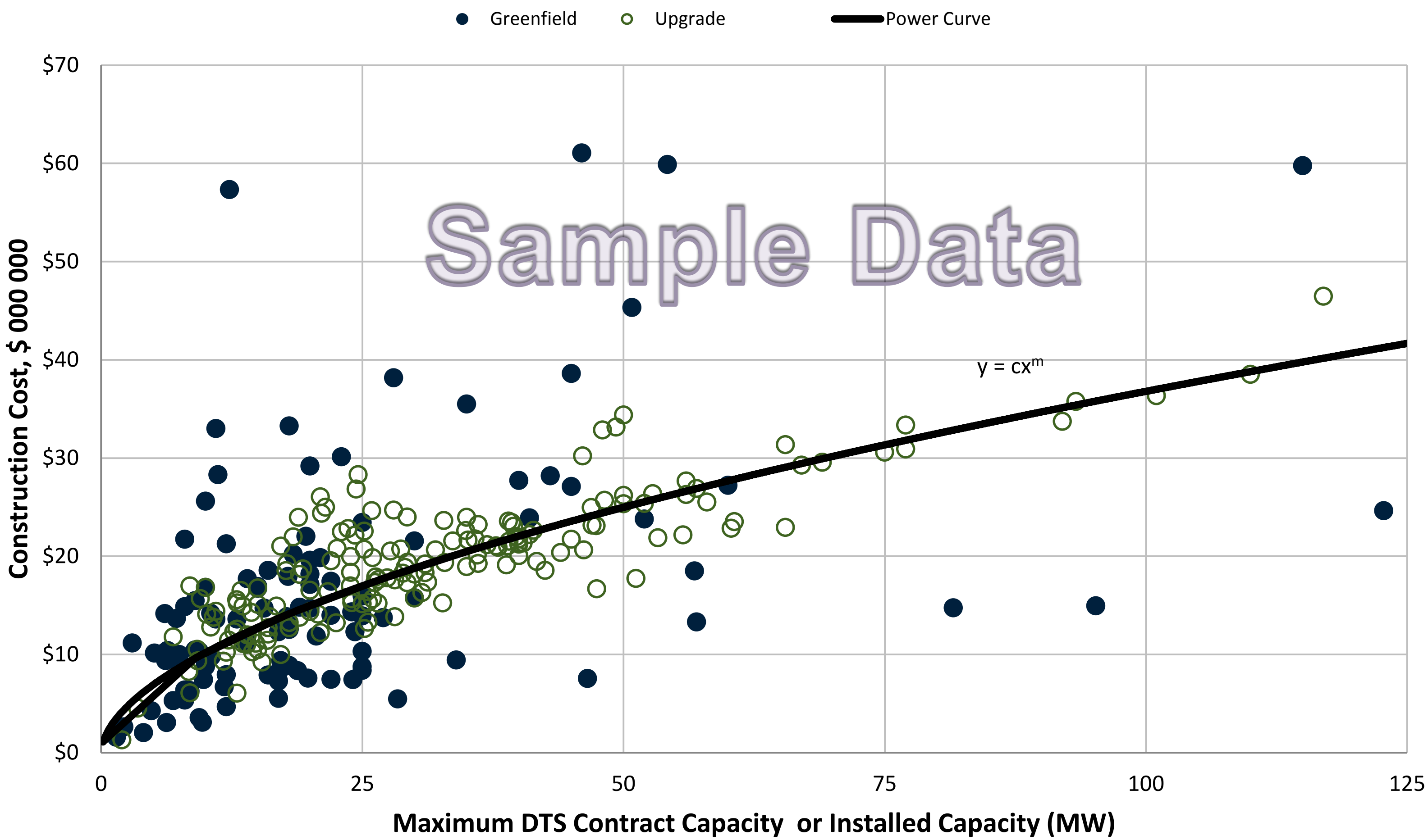
LaRhonda Papworth

Public

POD cost function database input into cost curves

- POD cost function database includes connection project (demand only) attributes: cost data, contract levels, installed capacity, connection type, location, substation number, project type, etc.
- For the 2018 tariff application, AESO will update POD cost function database with projects data since last update in 2014
- After Decision 2014-242 and Decision 3473-D01-2015 from the Commission in regards to project inclusion and criteria, the AESO was directed to “use ‘Greenfield and Update Excluding 0 MW’ until the matter can be <u>thoroughly explored</u>”
  - contract vs installed capacity
  - upgrade projects with 0 MW increase

POD cost function database – cost curves



POD cost function database – cost curves

Cost Curve Options	Greenfield	Upgrade	0 MW Contracts
#1 Pre-2014 Practice	Contract	Contract	Include
#2 Current Interim Practice	Contract	Contract	Remove
#3 As requested in Decision 2014-242	Contract	Installed	By using installed, 0 MW projects are included
#4 Not asked	Installed	Installed	
#5 AESO not considering (Not asked, not debated)	Installed	Contract	?

Potential evaluation criteria for cost curve options

1. Maintaining alignment between POD cost function, maximum investment levels and the POD charge in Rates DTS and PSC
2. Consistency with past practice (post-2007)
3. Maximize number of projects in database
4. Statistical criteria for project exclusion
5. Degree of relationship between installed capacity and contract capacity
6. “Lumpiness” of installed capacity and standard transformer sizes
7. Number of assumptions required to determine the MWs
8. Behavior of market participant’s relationship to MWs
   - encouraging staging to contract appropriately
   - planning signal from contract capacity vs installed capacity
9. Potential to eliminate substation fraction
10. Treatment of split between DTS and STS shared costs
11. Rates reflect true costs per MW
12. Equal services treated equally, unequal services treated unequally
13. Sending the “right” price signal
14. Fairness of treatment of customers with charges based on two different approaches

Application Process, Timeline and Next Steps

LaRhonda Papworth

Public

Checklist for 2018 ISO tariff application

Scope item	Status
Rider C / DAR / Tariff updates	95% complete
POD cost function work	75% complete
Transmission cost causation study	75% complete
Terms and conditions: Sections 4, 5, 8 and 9	75% complete
Clarify tariff for energy storage	100% complete
Updates to Proformas	80% complete
Clarify Rider A-1 – Dow duplication avoidance tariff	75% complete
Address direction from Commission regarding cost recovery from Critical Infrastructure Protection (CIP) work	75% complete
Long-term transmission rate projection model	75% complete

Tariff tentative timeline

Session	Date
1st Technical Session	December 5, 2016
2015 DAR Hearing	December 13 & 14, 2016
Stakeholder comment matrix posted	December 16, 2016
2017 tariff update effective (interim, refundable basis)	January 1, 2017
Stakeholder comments due	mid-January 2017
2nd Technical Session	Tentative: January 30, 2017
3rd Technical Session	February 2017
Application Preview	April 2017
Application writing	Q1 – Q2 2017
Application filing	Q2 2017
2016 DAR Filing	Q3 2017
2018 tariff update application	Q3 2017
Regulatory review process for 2018 tariff application	Q4 2017 - Q1 2018
Compliance filing	Q2 2018

Next steps

- The AESO will invite participants to respond to this presentation through a comment matrix in the next few weeks. To allow transparency, the AESO will post all comments on AESO’s website following the receipt of participants’ input
- For more information:

  LaRhonda Papworth – Manager, Tariff Design
  403-539-2555
  larhonda.papworth@aeso.ca
- All consultation documents can be found on AESO website at www.aeso.ca by following the path:
  Rules, Standards and Tariff ►Stakeholder engagement ►2018 ISO tariff application

Further Discussion? Questions?

Public

Public

Request for Stakeholder Comments on AESO 2018 ISO Tariff Consultation

Background

On December 5, 2016, the AESO and stakeholders participated in a consultation meeting to discuss (1) evaluation of potential changes to deferral account reconciliations and Rider C, *Deferral Account Adjustment Rider*, ("Rider C") (2) transmission cost causation study update, (3) point-of-delivery cost function database update, and (4) application process and next steps. Based on discussion at the meeting, the AESO invites written comments from stakeholders on the information presented at the meeting. The meeting presentation is posted on the AESO website and can be accessed at www.aeso.ca by following the path Tariff ► Stakeholder engagement ► 2018 ISO tariff application.

Please use the comment form below when submitting comments to the AESO on the 2018 ISO tariff consultation. Please ensure that your comments represent all interests within your stakeholder organization with respect to the consultation. Please provide comments or questions no later than **January 20, 2017**, to LaRhonda Papworth at larhonda.papworth@aeso.ca or 403-539-2555.

Consultation and Stakeholder Identification

Date of Request for Comments:	December 20, 2016
Period of Consultation:	November 15, 2016 – January 20, 2017
Comments From:	
Date:	
Contact:	
Phone:	
Email:	

Stakeholder Comments on AESO Information

Stakeholder Comment
(1) Evaluation of Potential Changes to Deferral Account Reconciliations and Rider C (Slides 6 – 61)
A. Impact of Early Tariff Updates (Slides 15 – 21): ***i. Early tariff updates significantly reduce transfers between services in a deferral account reconciliation;*** ***ii. Early tariff updates do not entirely eliminate transfers between services; and*** ***iii. AESO needs to better manage tariff update process.***
Stakeholder Comments:
B. Impact of Changing Rider C Structure (Slides 22 – 30): ***i. Rider C as percentage almost eliminates transfers between services in a deferral account***

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www.aeso.ca www.poweringalberta.com

Stakeholder Comment

reconciliation; and

ii. Some transfers between services still exist but are small.

Stakeholder Comments:

A. Impact of Changing to Production Year Basis (Slides 31 – 40):

- ***i. Rider C as percentage by production year eliminates transfers between services in a deferral account reconciliation;***
- ***ii. In practice there will still be some transfers resulting from timing impacts, such as if an annual cost becomes known partway through the year.***

Stakeholder Comments:

*****AESO notes that the following topic is a matter currently in front of the Commission in the 2015 deferral account reconciliation application, Proceeding 21735*****

B. Impact of Changing to Net Revenue Allocation Methodology (Slides 42 – 50):

- ***i. Consideration of merits to net revenue methodology***
- ***ii. Net tariff revenue for a service would include charges and credits related to contracted load service:***
  - ***a. Rate DTS, Demand Transmission Service, and Rate FTS, Fort Nelson Demand Transmission Service***
  - ***b. Rate UFLS, Demand Underfrequency Load Shedding Credits***
  - ***c. Rate PSC, Primary Service Credit***
  - ***d. Riders A1-A4, Transmission Duplication Avoidance Adjustments***
  - ***e. Payments in lieu of notice (PILONs) for reductions or terminations of contract capacity under section 9 of ISO tariff.***
- ***iii. Net tariff revenue for a service would not include charges under Rate DOS, Demand Opportunity Service.***
- ***iv. Net tariff revenue for a load service would not include charges or credits related to non-load service.***

Stakeholder Comments:

C. Possible Future Changes to Rider C (Slides 51 – 55):

- ***i. AESO suggests maintaining quarterly Rider C and annual deferral account reconciliations for at least a few more years then evaluate success of early tariff updates and Rider C restructuring.***

Stakeholder Comments:

D. Timing and Implementation Options (Slide 56 – 61):

- ***(1) Include Rider C and deferral account reconciliation methodology changes in 2018 tariff application in Q2 2017.***

Stakeholder Comment

(2) ***File separate application in Q1 2017 for Rider C and deferral account reconciliation methodology changes.***

(3) ***File application in Q1 2017 for interim Rider C changes with request to make existing reconciliation methodology interim.***

(4) ***Any other practical options?***

Stakeholder Comments:

(2) Transmission Cost Causation Study Update (Slides 62 – 70)

A. Scope of 2018-2020 transmission cost causation study:

i. Use identical methodology to 2014-2016 transmission cost causation study;

ii. Use same data sources plus additional sources;

iii. For years 2018-2020;

iv. Present draft results to stakeholders in January 2017; and

v. Include study results in the 2018 ISO tariff application.

Stakeholder Comments:

(3) Point-of-delivery (POD) Cost Function Update (Slides 71 – 75)

A. AESO plans to complete POD cost function database using the following capacities in order to present the following cost curve options (Slide 74):

(1) Pre-2014 Practice – Contracted greenfield and contracted upgrade projects, include 0 MW projects;

(2) Current interim practice – Contracted greenfield and contracted upgrade projects, exclude 0 MW projects;

(3) As requested in Decision 2014-242 – Contract greenfield and installed upgrade projects; and

(4) Not requested but will do – Installed greenfield and installed upgrade projects;

Stakeholder Comments:

B. The AESO plans to use criteria to evaluate the different options in Point (3)A above. Please comment on the proposed criteria below or add additional criteria (Slide 75):

(1) Maintaining alignment between POD cost function, maximum investment levels and the POD charge in Rates DTS and PSC;	☐ Support ☐ Oppose ☐ Indifferent
(2) Consistency with past practice (post-2007);	☐ Support ☐ Oppose ☐ Indifferent
(3) Maximize number of projects in database;	☐ Support ☐ Oppose ☐ Indifferent
(4) Statistical criteria for project exclusion	☐ Support ☐ Oppose ☐ Indifferent
(5) Degree of relationship between installed capacity and contract capacity;	☐ Support ☐ Oppose ☐ Indifferent
(6) "Lumpiness" of installed capacity and standard transformer sizes;	☐ Support ☐ Oppose ☐ Indifferent
(7) Number of assumptions required to determine the MWs	☐ Support ☐ Oppose ☐ Indifferent
(8) Behavior of market participants'' relationship to MWs	☐ Support ☐ Oppose ☐ Indifferent
(9) Potential to eliminate substation fraction;	☐ Support ☐ Oppose ☐ Indifferent
(10) Treatment of split between DTS and STS shared costs;	☐ Support ☐ Oppose ☐ Indifferent
(11) Rates reflect true costs per MW;	☐ Support ☐ Oppose ☐ Indifferent
(12) Equal services treated equally, unequal services treated unequally;	☐ Support ☐ Oppose ☐ Indifferent

(13)Sending the "right" price signal;	☐ Support ☐ Oppose ☐ Indifferent	***(14)***
(14)Fairness of treatment of customers with charges based on two different approaches; and	☐ Support ☐ Oppose ☐ Indifferent	***(15)***
(15)Any others?		***(16)***

Stakeholder Comments:

(4) Application Process, Timeline and Next Steps (Slides 76 – 79)

A. AESO presented status on a number of 2018 ISO tariff application scope items (Slide 77) and a tariff tentative timeline.

Stakeholder Comments:

Additional Comments

Please return this form with your comments by **January 20, 2017**, to:

LaRhonda Papworth
Manager, Tariff Design
Email: larhonda.papworth@aeso.ca
Phone: (403) 539-2555

January 18, 2017

AESO Stakeholders
AESO 2018 ISO Tariff Consultation Participants

Dear Stakeholder:

Re: **Invitation to Participate in Consultation on AESO 2018 ISO Tariff Application**

The AESO continues to consult with market participants on the development of its next comprehensive ISO tariff application, which it now refers to as the 2018 ISO tariff application to reflect the year in which the tariff is expected to become effective (in prior stakeholder communications, this application had been referred to as the 2017 ISO tariff application). The AESO will be holding the following consultation session to provide an update on work completed to date and invites you to attend:

Date:	Monday, January 30, 2017
Time:	1 p.m. to 4 p.m.
Place:	Meeting Room 6006, 6th Floor, BP Centre, 240 – 4th Avenue SW, Calgary, Alberta Note that the glass doors on the 6th floor are locked; please knock to have them opened.
Teleconference:	Within Calgary calling area: 403-410-3051, Conference ID 4366631 Outside Calgary calling area: 1-855-453-6957, Conference ID 4366631
RSVP:	By 5 p.m. on **Wednesday, January 25, 2017** to, Tatiana Aparicio-Caris Tatiana.Aparicio-Caris@aeso.ca or 403-539-2664

The AESO plans to discuss the following items during the meeting:

- technical presentation on transmission cost causation study results;
- technical presentation on point of delivery (POD) cost function database results;
- progress on annual tariff updates, deferral account reconciliations, and Rider C matters; and
- planned timeline and next steps for 2018 ISO tariff application.

The AESO plans to present information on these topics to facilitate discussion, and will post a presentation before the meeting. Stakeholders may provide feedback in person during the meeting or through written comments to the AESO after the meeting.

All information relating to the 2018 ISO tariff consultation is available on the AESO website at www.aeso.ca by following the path Rules, Standards and Tariff ► Stakeholder engagement ► 2018 ISO tariff application. As well, new information posted by the AESO on this topic will be mentioned in the AESO stakeholder newsletter, which you can subscribe to at the bottom right of the AESO's home page at www.aeso.ca.

Alberta Electric System Operator, Calgary Place, 2500, 330 – 5th Avenue SW Calgary, AB T2P 0L4
Phone: 403-539-2450 Fax: 403-539-2949 www.aeso.ca @theaeso

If you have any questions on the AESO's 2018 ISO tariff consultation, please contact me at 403-539-2555 in Calgary or by e-mail to larhonda.papworth@aeso.ca.

Yours truly,

LaRhonda Papworth
Manager, Tariff Design

cc: Doyle Sullivan, Director – Market and Tariff Design

AESO 2018 ISO Tariff Consultation

January 30, 2017
AESO Office, Calgary

Public

Agenda

- Introduction and objectives (slide 1-4)
- Transmission cost causation study preliminary results (slide 5-36)
- Point-of-delivery cost function database preliminary results and discussion (slides 37-61)
- Rider C / Deferral Account Reconciliation (DAR) / Rates Update (slide 62-80)
- Summary of comments from previous session (slides 81-82)
- Application process and next steps (slides 83-85)
- Discussion and wrap-up (slide 86)

Please feel free to ask questions during presentation

Stakeholder session objectives

- Enhance understanding of ISO tariff application
- Review technical results of a number of analytical exercises by the AESO
- Share information prior to filing of 2018 ISO tariff application
- Gather feedback to ensure tariff application provides all information stakeholders require
- Review application timeline and next steps

Applications currently in progress

- Directions 5-8 on advancement costs and related provisions
  - Decision 3473-D02-2015 issued on August 26, 2015
  - Process letter issued on October 22, 2015 with additional information on process in the new year *[2016]*
  - Awaiting Commission follow-up
- 2015 Deferral Account Reconciliation application
  - Currently before the Commission in Proceeding 21735
  - Interim settlement was approved and occurred in October 2016
  - Hearing held on December 13 and 14, 2016
  - Decision expected mid-March

Applications currently in progress

- 2017 ISO tariff update
  - Currently before the Commission in Proceeding 22093
  - Interim, refundable approval for January 1, 2017 issued by Commission on December 2, 2016
  - Still some matters before the Commission
  - Final approval expected in 2017

Transmission Cost Causation Study Preliminary Results

Raj Sharma

Public

Plan for 2018–2020 Transmission Cost Causation Study

- The AESO included a 2014-2016 transmission cost causation study prepared by London Economics International (“LEI”) in its 2014 ISO tariff application
  - The study established the inputs and methodology for a comprehensive cost causation study that used both capital cost and operating and maintenance cost data
  - A negotiated settlement process was used with participants and approved by the Commission
- The AESO proposed to update the LEI study itself using identical methodology with functionalization by voltage and classification by minimum system approach (in August 2015)

2014-2016 Transmission Cost Causation Study

- *The 2014-2016 Cost Causation Negotiated Settlement Agreement* was approved as filed November 27, 2013
- In accordance with agreement, an updated study was filed January 21, 2014
- Results of this study set functionalization and classification values for ISO tariff for 2014, 2015, 2016 (and 2017).

Scope of 2014-2016 Transmission Cost Causation Study

Scope included:

- Functionalization of capital costs by voltage methodology (including use of low-side voltage to functionalize substation costs)
- Functionalization of operating and maintenance (O&M) costs by specific allocators for most cost components, and functionalization of non-capitalized general and administration (G&A) costs in proportion to O&M costs
- Weighting of capital and O&M costs over 2014-2016
- Classification of bulk system and regional system costs by minimum system methodology

Capital Functionalization Method in 2014-2016 Transmission Cost Causation Study

- Functionalizing individual line and individual substation facilities:
  - Point of Delivery: radial line and delivery substation
  - Bulk: remaining facilities 240kV and over
  - Regional: remaining facilities below 240kV

Capital Functionalization in 2014-2016 Transmission Cost Causation Study

Year	Function			Total
	Bulk	Regional	POD	
2014	$6.4 billion	$2.2 billion	$1.9 billion	**$10.5 billion**
2015	$9.3 billion	$2.6 billion	$2.1 billion	**$14.0 billion**
2016	$9.9 billion	$2.7 billion	$2.2 billion	**$14.7 billion**

O&M Functionalization Method in 2014-2016 Transmission Cost Causation Study

- Capital related costs: depreciation, return, income tax, structure payments, linear and property taxes and capital related offsets
- Non-capital costs: labour, G&A, fuel and variable O&M for isolated generation and revenue offsets to labour costs
  - Isolated generation cost as regional and POD using capital cost functionalization ratio
  - Control center operations cost based on number of lines and transformers
  - Vegetation management cost based on line brushing allocator
  - Substation cost based on transformers
  - Overhead line and miscellaneous cost based on km of line
  - Net salaries and wages allocated to groups using proportion of full time equivalents (FTEs) and then further to functions

O&M Functionalization in 2014-2016 Transmission Cost Causation Study

Year	Function			Total
	Bulk	Regional	POD	
2014	$35.3 million	$66.6 million	$68 million	$169.9 million

Combined (Capital and O&M) Functionalization in 2014-2016 Transmission Cost Causation Study

Ratio of Non-Capital to Capital Costs			
Type	**2014**	**2015**	**2016**
Non-Capital	19.5%	18.0%	16.3%
Capital	80.5%	82.0%	83.7%

Combined Functionalization			
Year	**Function**		
	Bulk	**Regional**	**POD**
2014	53.2%	24.2%	22.6%
2015	58.4%	22.2%	19.4%
2016	59.4%	21.5%	19.1%

Functionalization in 2014-2016 Transmission Cost Causation Study – Other Items

- Deduct Regulated Generating Unit Connection Charge (RGUCC) revenue from bulk function revenue requirement for the year

Functionalization in 2014-2016 Transmission Cost Causation Study

Year	Function		
	Bulk	Regional	POD
2014	52.8%	24.4%	22.8%
2015	58.2%	22.3%	19.5%
2016	59.2%	21.6%	19.2%

Classification Methodology in 2014-2016 Transmission Cost Causation Study

- Bulk classification:
  - Ratio of per kM cost of 2x795 ACSR and 2x1033 ACSR 240kV conductor
  - Ratio of per kM cost of 3x1590 ACSR and 2x2156 ACSR 500kV conductor
  - Ratio of cost of basic and high efficiency transformer
- Regional classification:
  - Ratio of per kM cost of 1x266 ACSR and 1x477 ACSR 138kV conductor
  - Ratio of cost of basic and high efficiency transformer

Classification in 2014-2016 Transmission Cost Causation Study

Classification	Function	
	Bulk	Regional
Demand	93.1%	87.4%
Energy	6.9%	12.6%

Scope of 2018-2020 Transmission Cost Causation Study

- Update of 2014-2016 transmission cost causation study
- Using identical methodology
- Using same data sources, plus a few additional sources
- For years 2018-2020

Process for 2018-2020 Transmission Cost Causation Study

- Update inputs and conduct 2018-2020 transmission cost causation study in 2016
- Present draft results to stakeholders in January 2017
- Include the study in the 2018 ISO tariff application

Preliminary 2018 Functionalization - Capital

Capital Cost Functionalization			
Function			TOTAL
Bulk	Regional	POD	
$10.6 billion	$4.4 billion	$3.1 billion	**$18.1 billion**

Preliminary 2018 Functionalization – O&M

2014 O&M Cost Functionalization			
Function			Total
Bulk	Regional	POD	
$37.3 million	$64.3 million	$67.1 million	**$168.8 million**

Preliminary 2018 Functionalization – Combined (Capital and O&M)

Ratio of Non-Capital to Capital Costs	
Non-Capital	13.2%
Capital	86.8%

Combined Functionalization		
Function		
Bulk	**Regional**	**POD**
53.5%	26.2%	20.3%

Preliminary 2018 Functionalization – Other Items

- Deduct Regulated Generating Unit Connection Cost (RGUCC) revenue from bulk function revenue requirement for the year

Preliminary 2018 Functionalization

Function		
Bulk	**Regional**	**POD**
53.4%	26.3%	20.3%

Preliminary 2019 Functionalization - Capital

Capital Cost Functionalization			
Function			**TOTAL**
Bulk*	**Regional**	**POD**	
$10.5 billion	$4.5 billion	$3.3 billion	**$18.3 billion**

Preliminary 2019 Functionalization – O&M

2014 O&M Cost Functionalization			
Function			**Total**
Bulk	**Regional**	**POD**	
$37.3 million	$64.3 million	$67.1 million	**$168.8 million**

Preliminary 2019 Functionalization – Combined (Capital and O&M)

Ratio of Non-Capital to Capital Costs	
Non-Capital	12.2%
Capital	87.8%

Combined Functionalization		
Function		
Bulk	**Regional**	**POD**
53.2%	26.1%	20.7%

Preliminary 2019 Functionalization – Other Items

- Deduct Regulated Generating Unit Connection Cost (RGUCC) revenue from bulk function revenue requirement for the year
- Add Fort McMurray West 500kV transmission project ("CP" project) revenue requirement to bulk function revenue requirement for the year

Preliminary 2019 Functionalization

Function		
Bulk	**Regional**	**POD**
55.0%	25.1%	19.9%

Preliminary 2020 Functionalization - Capital

Capital Cost Functionalization			
Function			TOTAL
Bulk*	Regional	POD	
$10.4 billion	$4.8 billion	$3.5 billion	**$18.7 billion**

Preliminary 2020 Functionalization – O&M

O&M Cost Functionalization			
Function			**Total**
Bulk	**Regional**	**POD**	
$37.3 million	$64.3 million	$67.1 million	**$168.8 million**

Preliminary 2020 Functionalization – Combined (Capital and O&M)

Ratio of Non-Capital to Capital Costs	
Non-Capital	11.2%
Capital	88.8%

Combined Functionalization		
Function		
Bulk	**Regional**	**POD**
51.8%	27.2%	20.9%

Preliminary 2020 Functionalization – Other Items

- Deduct Regulated Generating Unit Connection Cost (RGUCC) revenue from bulk function revenue requirement for the year
- Add Fort McMurray West 500kV transmission project (“CP” project) revenue requirement to bulk function revenue requirement

Preliminary 2020 Functionalization

Function		
Bulk	**Regional**	**POD**
53.7%	26.2%	20.1%

Preliminary 2018-2020 Functionalization

Year/Function	Bulk	Regional	POD
2018	53.4%	26.3%	20.3%
2019	55.0%	25.1%	19.9%
2020	53.7%	26.2%	20.1%
Average	**54.0%**	**25.9%**	**20.1%**

Questions and Discussion

Point-of-delivery (POD) Cost Function Preliminary Results and Discussion

LaRhonda Papworth

Public

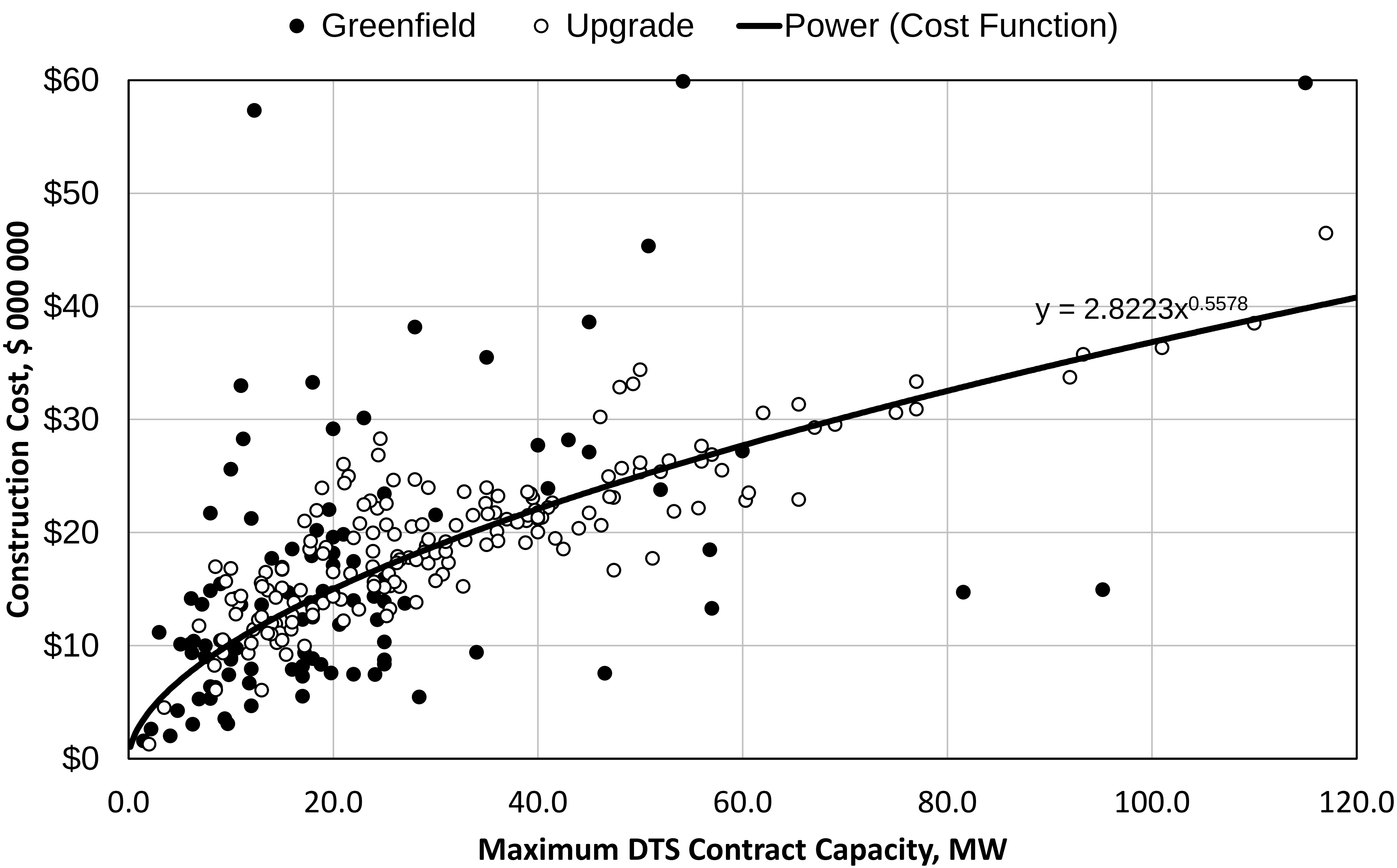
POD cost function database input into cost curves

- POD cost function database includes connection project (demand only) attributes: cost data, contract levels, installed capacity, connection type, location, substation number, project type, etc.
- For the 2018 tariff application, AESO will update POD cost function database with projects data since last update in 2014
- After Decision 2014-242 and Decision 3473-D01-2015 from the Commission in regards to project inclusion and criteria, the AESO was directed to “use ‘Greenfield and Update Excluding 0 MW’ until the matter can be thoroughly explored”
  - contract vs installed capacity
  - upgrade projects with 0 MW increase

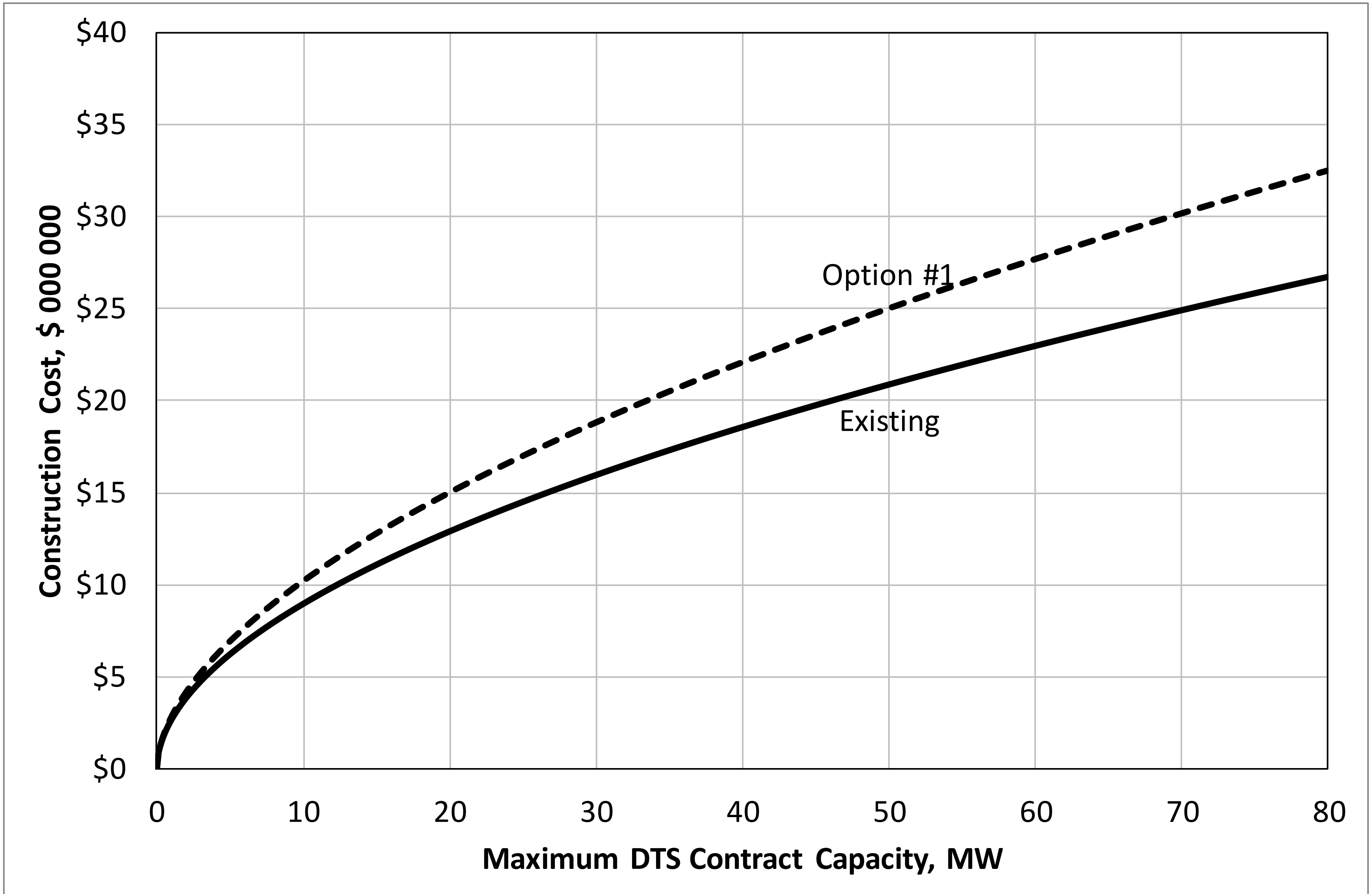
POD cost function database – cost curves

Cost Curve Options	Greenfield	Upgrade	0 MW Contracts
#1 Pre-2014 Practice	Contract	Contract	Include
#2 Current Practice (until thoroughly explored)	Contract	Contract	Remove
#3 As requested in Decision 2014-242	Contract	Installed	By using installed, 0 MW projects <u>are</u> included
#4 Not asked	Installed	Installed	
~~**#5 AESO not considering**~~ ~~(Not asked, not debated)~~	~~Installed~~	~~Contract~~	~~?~~

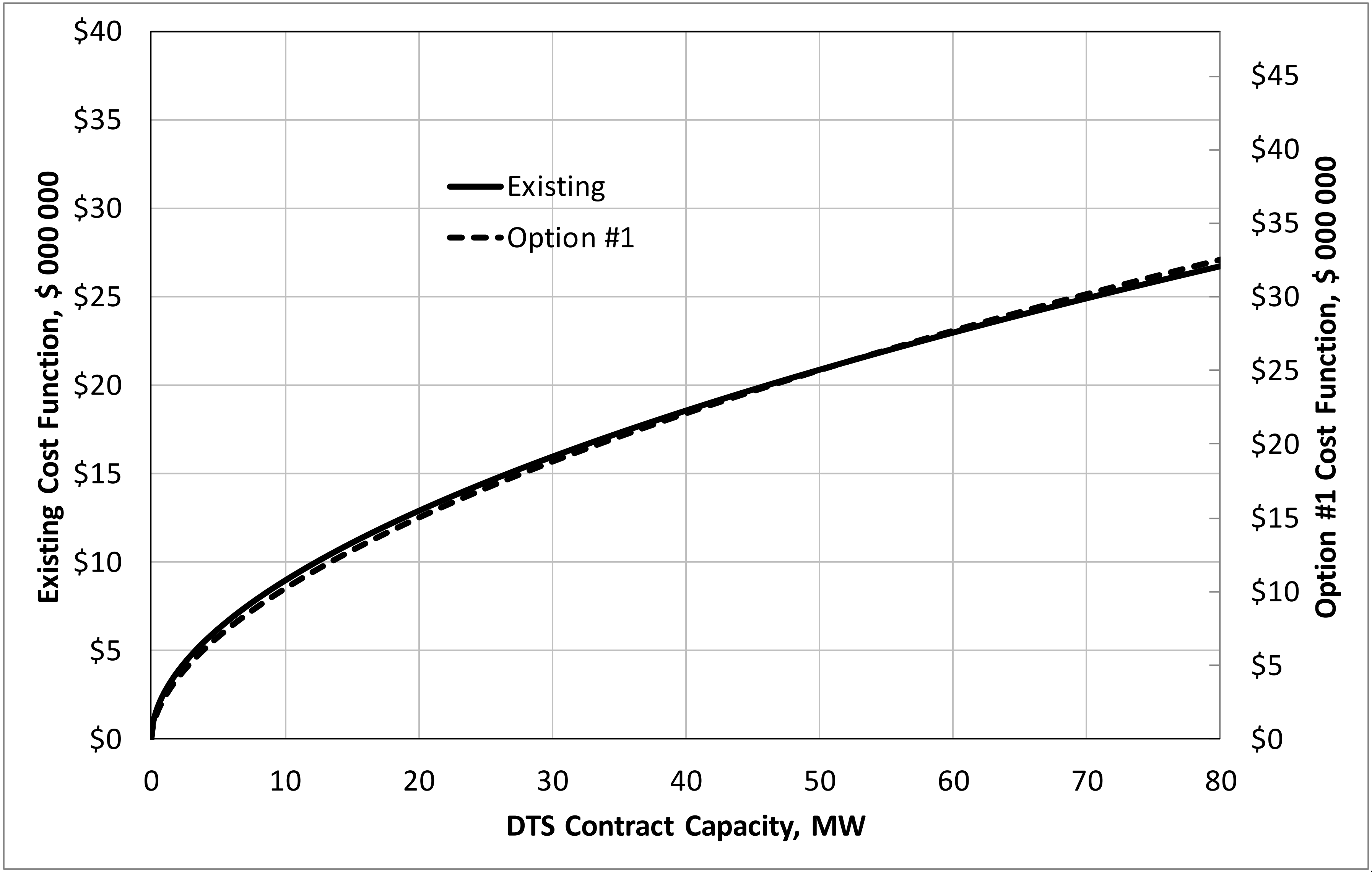
Preliminary POD Cost Function Database
Option #1 – Greenfield & Upgrade Contract, 0 MW Upgrade projects included



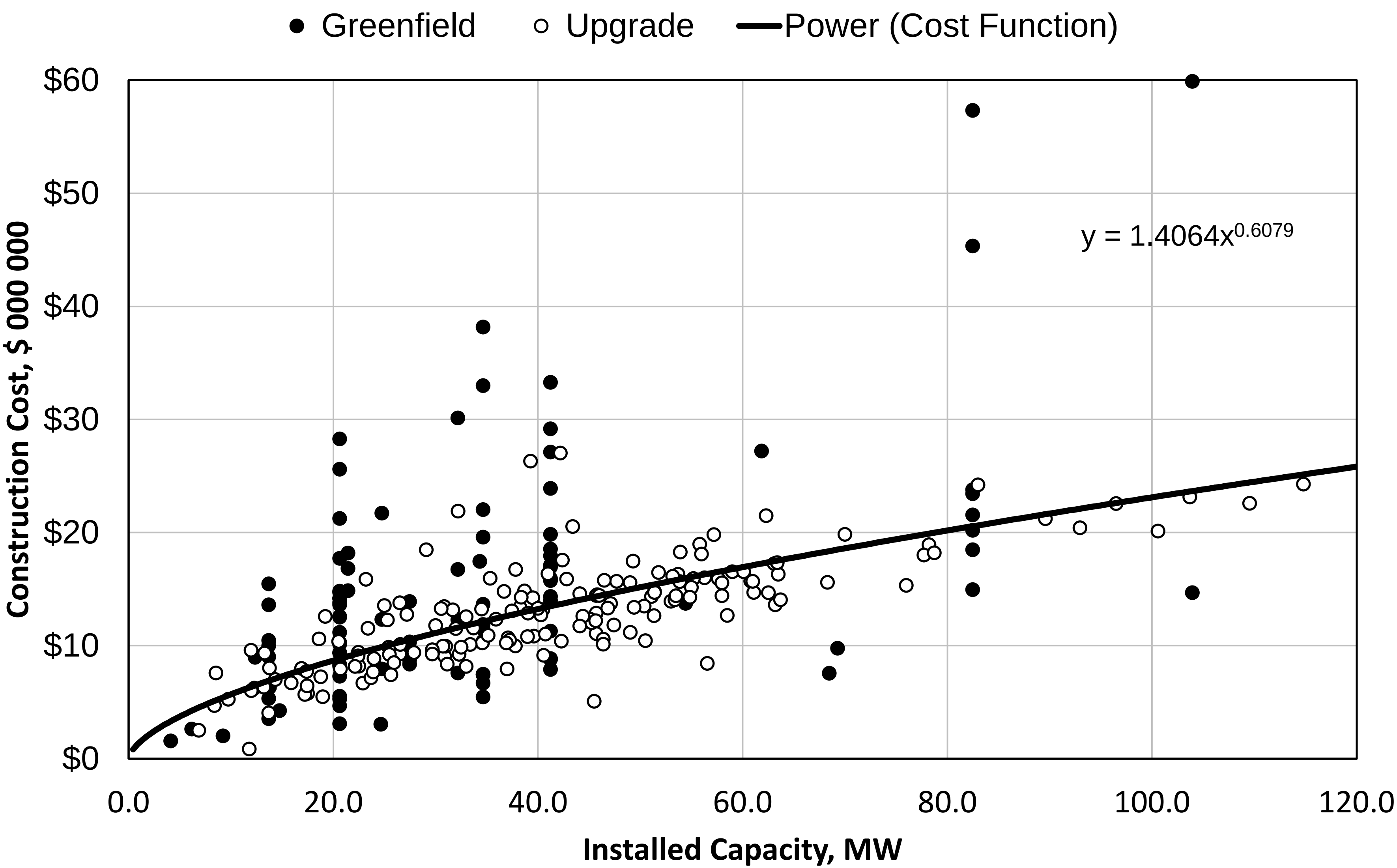
Comparison of Option #1 to Existing (2014 ISO Tariff) Cost Function Curve



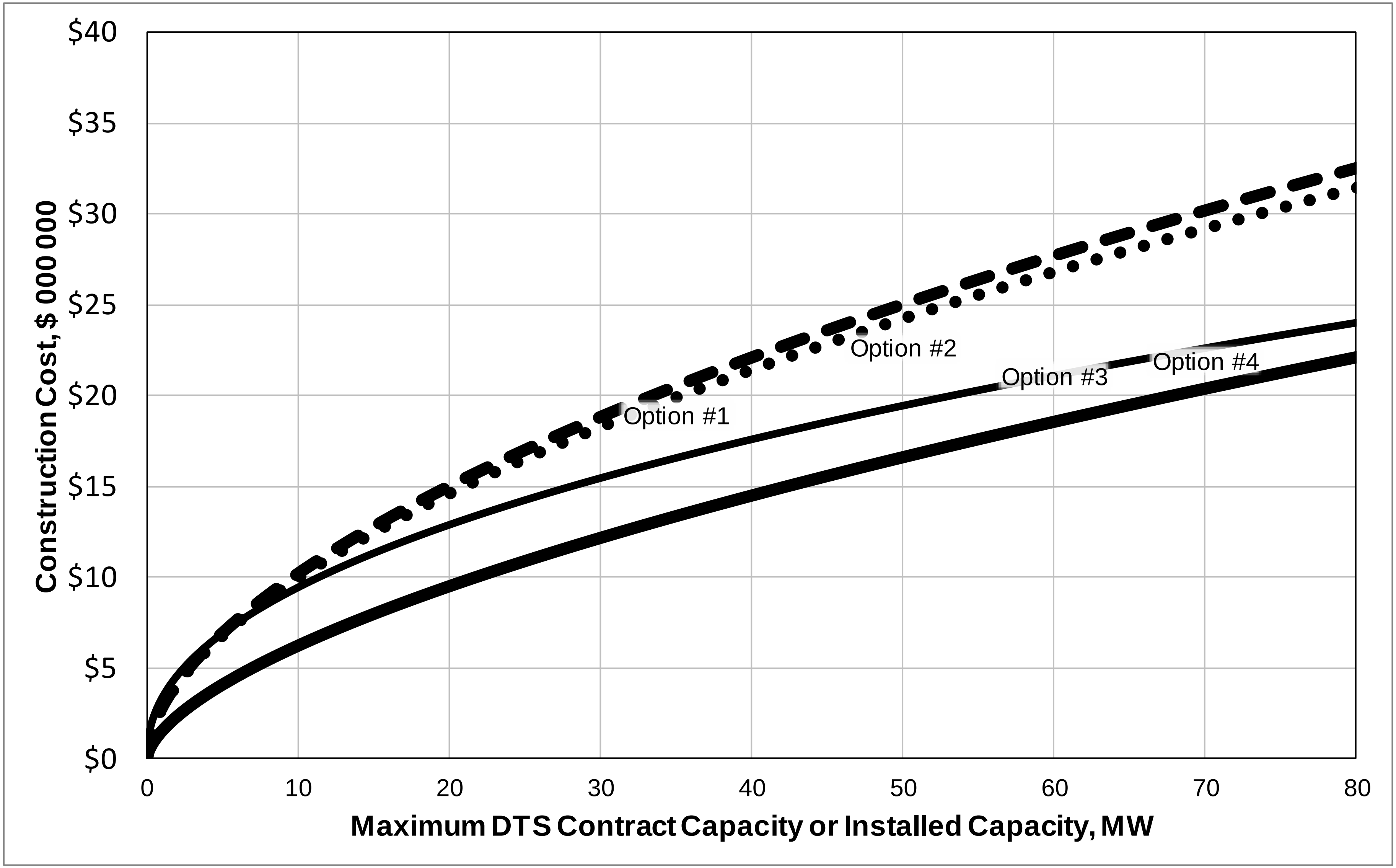
Impact of Update on Shape of Cost Function Curve



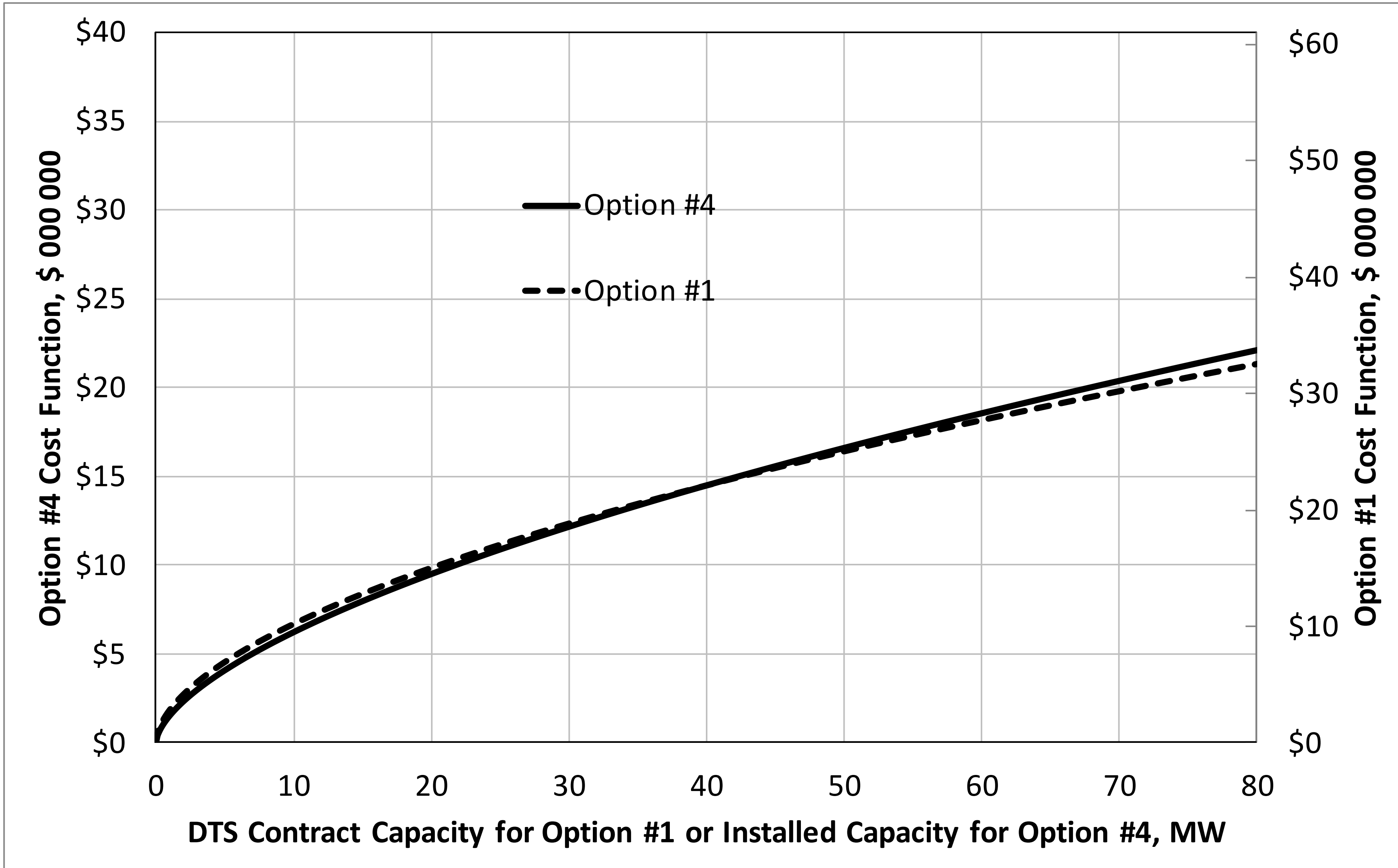
Preliminary POD Cost Function Database
Option #4 – Greenfield & Upgrade Installed Capacity



Impacts of Updates and Options on Cost Function Curves



Impact of Installed Capacity to Shape of Cost Function



Potential evaluation criteria for cost curve options

1. Maintaining alignment between POD cost function, maximum investment levels and the POD charge in Rates DTS and PSC
2. Consistency with past practice (post-2007)
3. Maximize number of projects in database
4. Statistical criteria for project exclusion
5. Degree of relationship between installed capacity and contract capacity
6. “Lumpiness” of installed capacity and standard transformer sizes
7. Number of assumptions required to determine the MWs
8. Behavior of market participant’s relationship to MWs
   - encouraging staging to contract appropriately
   - planning signal from contract capacity vs installed capacity
9. Potential to eliminate substation fraction
10. Treatment of split between DTS and STS shared costs
11. Rates reflect true costs per MW
12. Equal services treated equally, unequal services treated unequally
13. Sending the “right” price signal
14. Fairness of treatment of customers with charges based on two different approaches

Maintaining alignment between POD cost function, maximum investment levels and the POD charge in Rates DTS and PSC

Current ISO Tariff:

- POD cost function determines a relationship between **contract capacity** of a project and the construction cost
- Investment is calculated using investment levels from the POD cost function multiplied by the **contract capacity**
- POD charge in rates is charged based on billing capacity which is the highest of highest-metered demand, 90% of highest metered demand in previous 24-month period or 90% of the **contract capacity**.

Concerns:

Provision of Price Signals Fairness, Objectivity, and Equity

- Moving the POD cost function to relationship between **installed capacity** and the construction cost would require investment levels based on installed capacity and POD charge in rates to installed capacity
- This would result in potentially different determinants for POD charges vs bulk and regional

Consistency with past practice (post-2007)

- Since 2007 investment levels and POD portion have rates has been determined using **contract capacity**

Concerns:

Fairness, Objectivity, and Equity

Stability and Predictability

- Moving to new approach would have to be given some consideration of intergenerational equity
- Potential for unintended consequences

Maximize number of projects in database / statistical criteria for project inclusion

- Currently there are 94 greenfield projects, 18 pre-AESO projects and 285 upgrade projects

Concerns:

Fairness, Objectivity, and Equity

Stability and Predictability

- Removing projects does have an impact on statistical results
- Slippery slope argument for exclusion

Degree of relationship between installed capacity and contract capacity

- Measure the relationship between installed capacity and contract capacity

Concerns:

Provision of Price Signals

- Customer consideration of future expectation of load growth and operation flexibility
- TFO considerations for properly sizing transformers to minimize long-term costs (replace smaller transformer with larger transformer could be larger cost that a larger transformer at the start of a project)
- TFO considerations for standardization and back-up requirements
- Is there a price signal for installed capacity?

“Lumpiness” of installed capacity and standard transformer sizes

- There are efficiencies in the practice of transmission facility owners standardizing transformer sizes

Concerns:

Fairness, Objectivity, and Equity

Provision of Price Signals

- Difficult for a market participant to perfectly match load requirements to standard transformer sizes

Number of assumptions required to determine installed vs contract capacity

- Contract capacity is easily determined and tracked
- Installed capacity requires a number of assumptions along with extremely detailed research between the AESO and DFOs to estimate

Concerns:

Fairness, Objectivity, and Equity

Stability and Predictability

Practicality

- Data could be considered subjective and time-consuming to gather
- Will billing on installed capacity require strong validation?

Behavior of market participant's relationship to installed vs contract capacity

- Market participants "billing" behavior would not change from month to month with a rate based <u>only</u> on installed capacity
- A "billing capacity" calculation including highest-metered demand, past 24-month highest-metered demand and installed capacity would likely maximize to installed capacity

Concerns:

Provision of Price Signals Fairness, Objectivity, and Equity

- No monthly price signal to market participants for POD charge

Encouraging staging to contract appropriately / planning signal from contract capacity vs installed capacity

- Market participant behavior could be to match installed capacity request exactly to standard transformer size
- Potentially less upgrade projects and larger greenfield projects

Concerns:

Provision of Price Signals

- Would installed capacity investment levels and rates encourage behavior of market participants to provide accurate loading levels to allow planning of the transmission system
- Is the price signal for staging strong in tariff today given the present value calculation?

Potential to eliminate substation fraction / Treatment of split between DTS and STS shared costs

- Installed capacity at a substation could potentially remove the requirement to allocate costs and investment by substation fraction

Concerns:

Practicality

- Additional clarity for each market participant at a shared substation
- No substation fractions could result in simpler billing structure and would be easier to understand to new stakeholders

Rates reflect true costs per MW / Sending the “right” price signal

- Are customer connection costs driven by installed capacity or contract capacity

Concerns:

Provision of Price Signals

Fairness, Objectivity, and Equity

- Adding “installed capacity” as a new billing component could introduce conflicting or dampening signal in contrast to existing “billing capacity”

Equal services treated equally, unequal services treated unequally

- For Option #3, for example, a site that contracted for 25 MWs as a greenfield project would be treated differently than a site that contracted for 15 MWs, then upgraded to 25 MWs

Concerns:

Fairness, Objectivity, and Equity

Bridging the “gap” / Fairness of treatment of customers with charges based on two different approaches

- A market participant could have investment based on a contract capacity approach but rates determined by installed capacity

Concerns:

Fairness, Objectivity, and Equity

Criteria Summary

Criteria	Rate Design Principles	Stakeholder Votes
Maintaining alignment between POD cost function, maximum investment levels and the POD charge in Rates DTS and PSC	Fairness, Objectivity, and Equity Provision of Price Signals	Support – 5 Oppose – 0 Indifferent - 1
Degree of relationship between installed capacity and contract capacity	Provision of Price Signals	Support – 4 Oppose – 1 Indifferent – 1
Rates reflect true costs per MW	Fairness, Objectivity, and Equity Provision of Price Signals	Support – 4 Oppose – 1 Indifferent – 1
Treatment of split between DTS and STS shared costs		Support – 3 Oppose – 1 Indifferent - 0
Sending the “right” price signal	Provision of Price Signals	Support – 4 Oppose – 0 Indifferent - 1

Criteria Summary (cont'd)

Criteria	Rate Design Principles	Stakeholder Votes
Maximize the number of projects in database	Fairness, Objectivity, and Equity Stability and Predictability	Support – 3 Oppose – 0 Indifferent – 3
Fairness of treatment of customers with charges based on two different approaches	Fairness, Objectivity, and Equity	Support – 3 Oppose – 0 Indifferent – 1
Consistency with past practice (post-2007)	Fairness, Objectivity, and Equity Stability and Predictability	Support – 1 Oppose – 1 Indifferent – 4
Statistical criteria for project exclusion	Fairness, Objectivity, and Equity	Support – 0 Oppose – 2 Indifferent – 4
Behavior of market participants relationship to MWs	Fairness, Objectivity, and Equity Provision of Price Signals	Support – 2 Oppose – 0 Indifferent - 3

POD Cost Function
Next Steps

- Gather more information from stakeholders in order to develop subjective and objective comparisons of Option #1 and Option #4
- Provide additional analysis to stakeholders on Option #1 and Option #4 to illustrate preliminary rates and investments under each option
- Present AESO’s position at upcoming stakeholder session in March or April

Proposal to Apply for Interim Changes to Rider C and Deferral Account Reconciliations

John Martin, Senior Tariff and Regulatory Advisor

January 30, 2017 – Calgary, Alberta

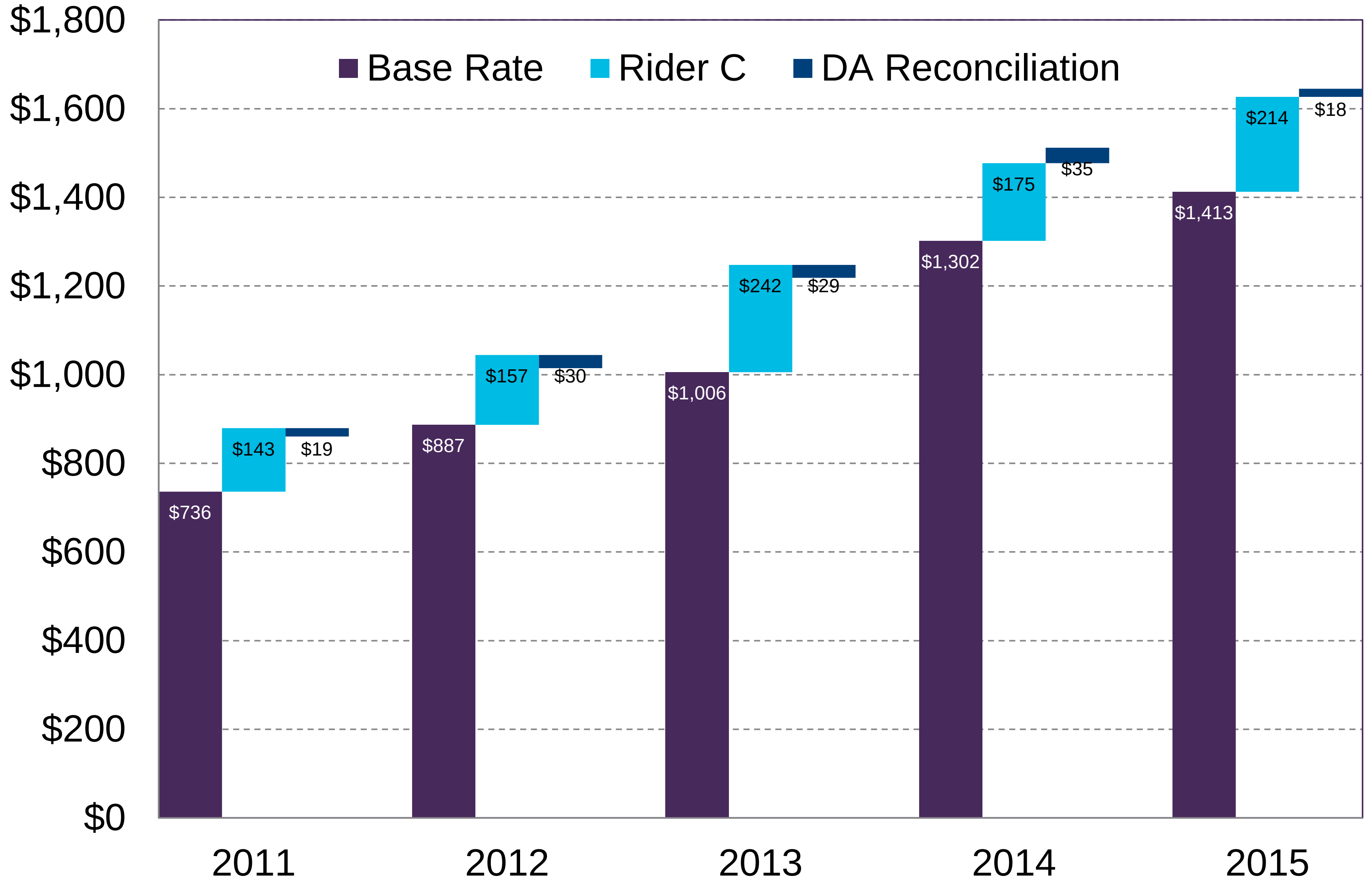
Public

Commission directed AESO to investigate Rider C in Decision 2014-242

- *The Commission acknowledges the view expressed by both the ADC and the DUC that the AESO should be directed to examine further the structure of Rider C with an eye to minimizing imbalances among customers. Therefore, the Commission directs the AESO to discuss the related matters of annual tariff updates, deferral account reconciliation processes and Rider C design with stakeholders prior to filing its next comprehensive GTA, and to provide a report on the outcome of any such discussions, including any recommended changes (if any) within its next comprehensive GTA.*

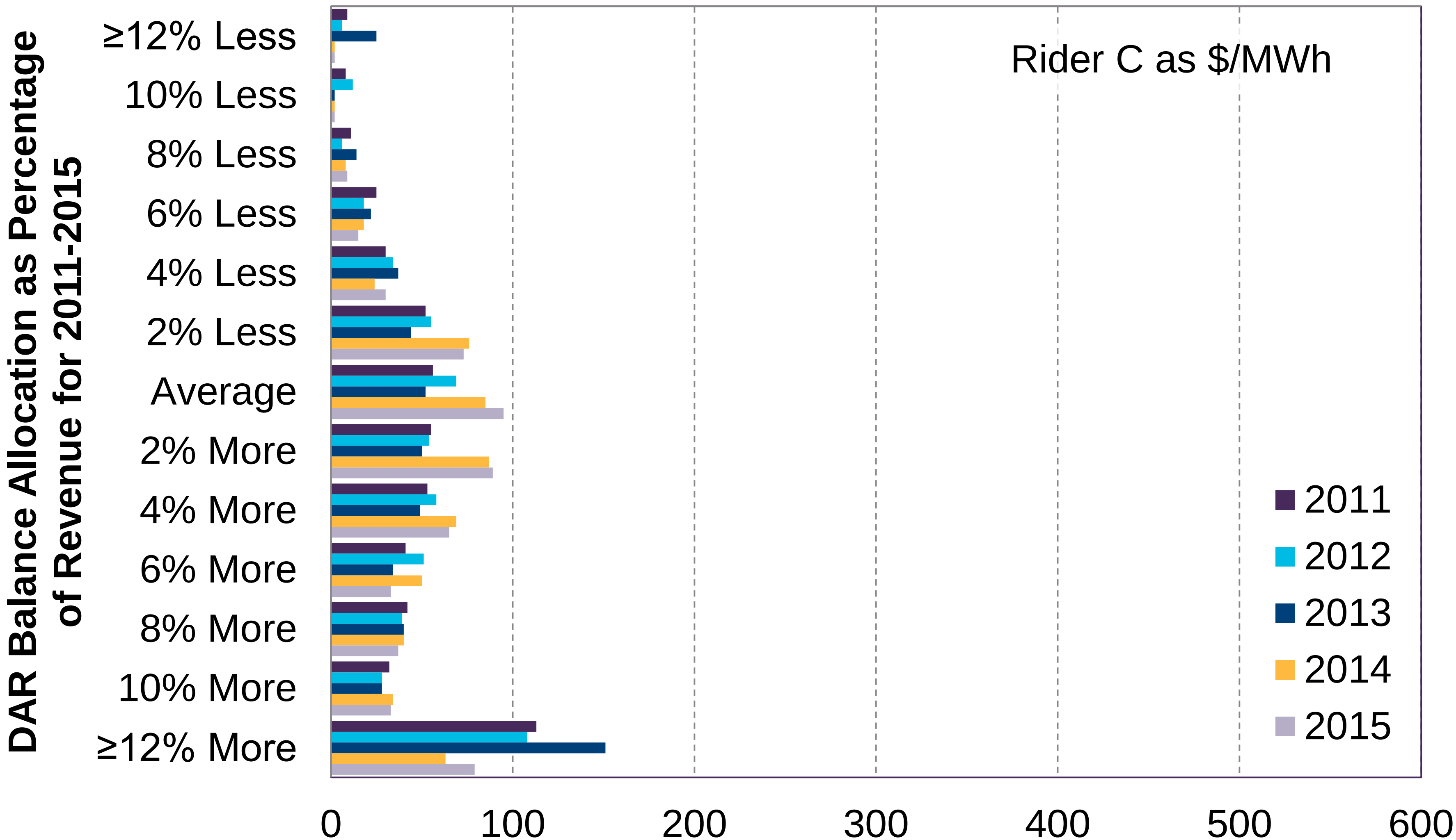
[Decision 2014-242, paragraph 704]

Net amounts allocated through annual reconciliations have been small …



But allocations to individual services have varied over a much wider ±20% range

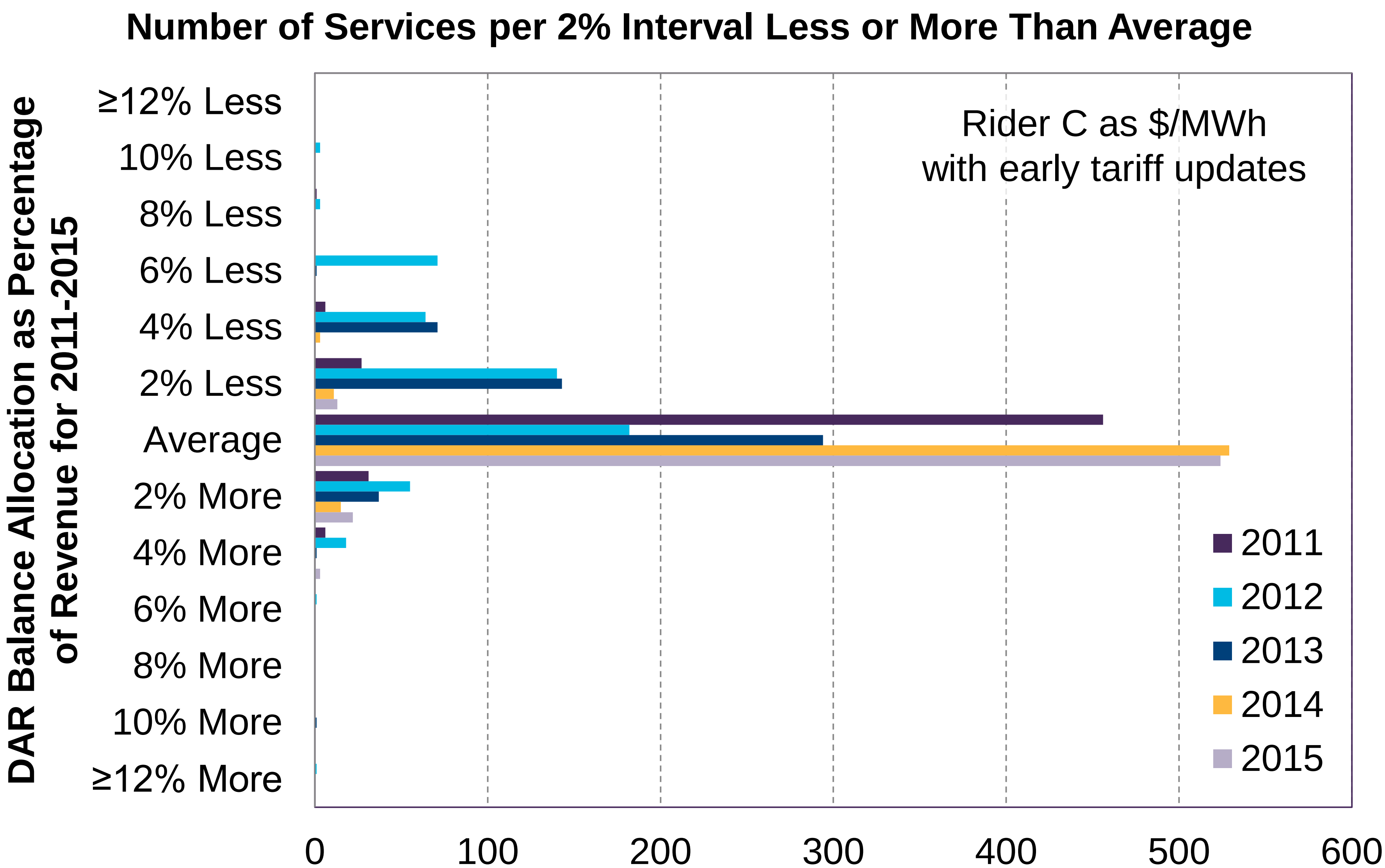
Number of Services per 2% Interval Less or More Than Average



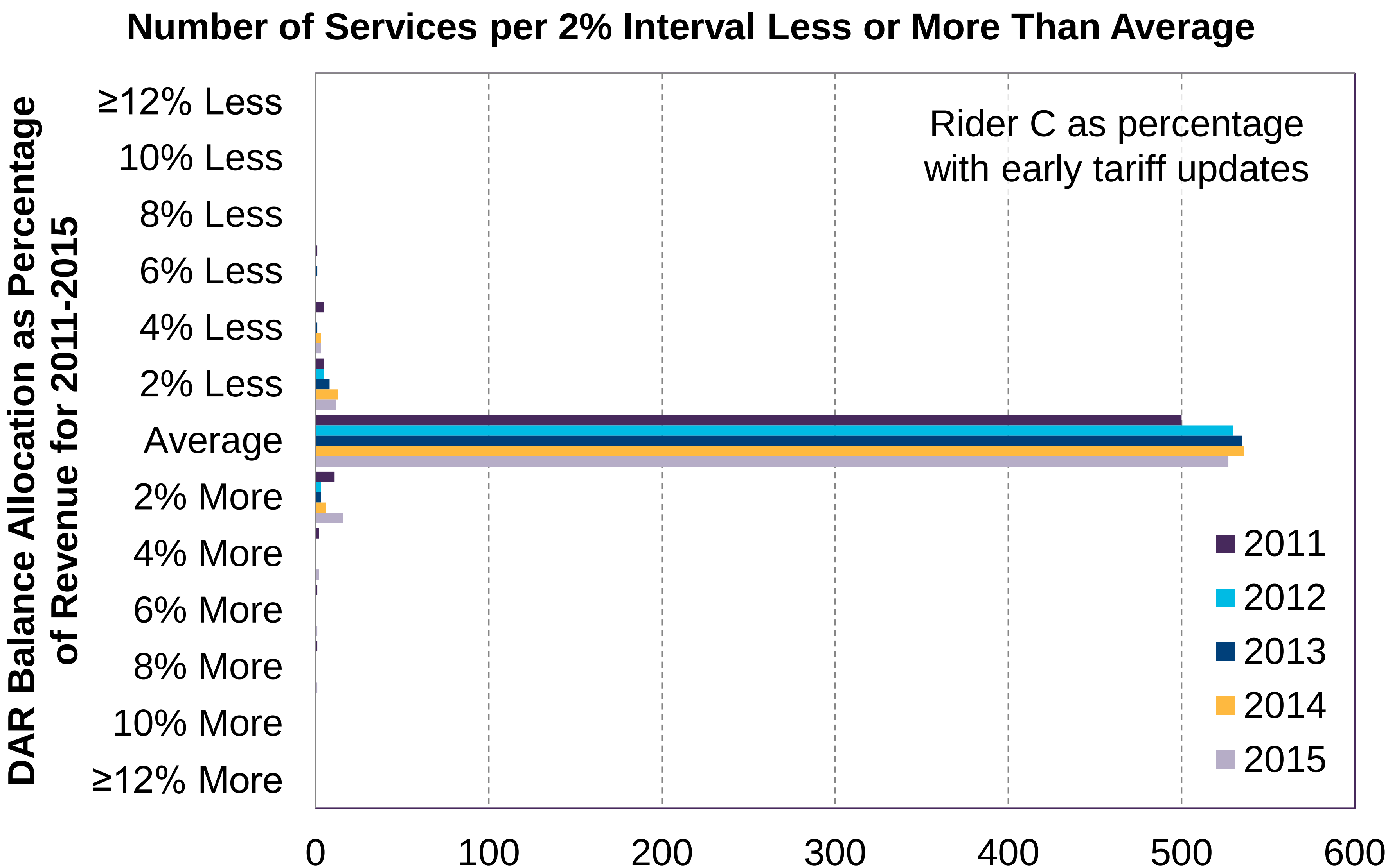
At December consultation meeting, several potential changes were discussed

- To reduce transfers between services in deferral account reconciliation applications:
  - Early tariff updates
  - Rider C as percentage (rather than as $/MWh)
  - Rider C calculated on production year (rather than quarter)
- To address issues raised by Primary Service Group in AESO 2015 deferral account reconciliation proceeding:
  - Allocation of deferral account balances on both Rate DTS and Rate PSC amounts
- AESO proposes to apply for interim approval of these changes to be effective in 2017

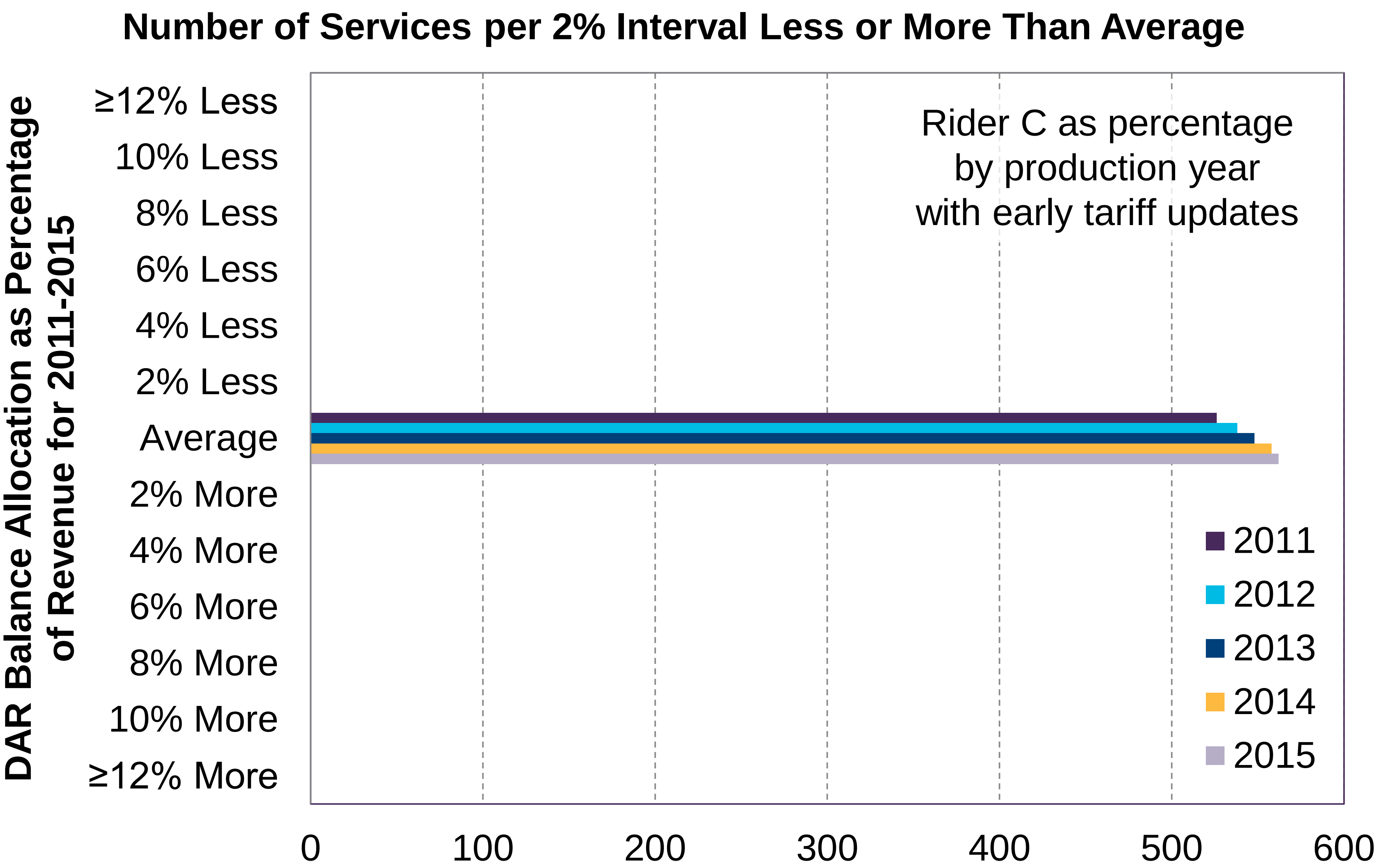
Early tariff updates reduce variability of allocations to individual services



Rider C as percentage further reduces variability of allocations to services



Rider C calculated on production year eliminates remaining variability



Allocating DA balance on Rates DTS and PSC improves alignment with DA balance

- Currently-approved methodology allocates deferral account balance in proportion to Rate DTS revenue for a service

$$\begin{bmatrix} \text{Costs} \\ -\text{Rate DTS Revenue} \\ -\text{Other Tariff Revenue} \end{bmatrix} \times \frac{\text{Rate DTS Revenue}_{\text{one service}}}{\text{Sum of Rate DTS Revenue}_{\text{all services}}}$$

- Deferral account balance includes revenue from Rate DTS, Rate PSC, and other tariff components, while allocation currently includes only “base rate” revenue from Rate DTS
- Allocating deferral account balance in proportion to Rates DTS and PSC would result in allocation being more closely aligned with deferral account balance

$$\begin{bmatrix} \text{Costs} \\ -\text{Rate DTS Revenue} \\ -\text{Other Tariff Revenue} \end{bmatrix} \times \frac{\text{Rates DTS and PSC Revenue}_{\text{one service}}}{\text{Sum of Rates DTS and PSC Revenue}_{\text{all services}}}$$

AESO considered three alternatives for applying for approval of proposed changes

- Include changes in 2018 tariff application in Q2 2017
  – Changes likely effective in mid-2018 on go-forward basis
- File separate application in Q1 2017 for changes
  – Changes likely effective in late 2017 on go-forward basis
  – Potentially limited review and potential conflict with Commission direction to report in comprehensive tariff application
- File application in Q1 2017 for interim changes
  – Changes likely effective mid-2017, on interim basis
  – Changes would be comprehensively reviewed as part of 2018 tariff application

Stakeholders supported moving forward with proposed changes on timely basis

- Almost all stakeholders who commented supported early tariff updates, Rider C as percentage, and Rider C calculated on production year
  - One party suggested Rider C be determined separately for bulk system, regional system, and point of delivery rate components
    - Costs are not recorded by those components and separate deferral account balances cannot be determined
  - One party asked for more information on Rider C changes
    - The AESO will include some additional information in interim application, but information was essentially summarized in December consultation meeting

Stakeholders supported moving forward with proposed changes on timely basis (cont'd)

- Support was more limited for allocation of deferral account balances on both Rate DTS and Rate PSC amounts
  – Some parties will await decision on allocation issue in AESO 2015 deferral account reconciliation proceeding
    - AESO acknowledges that the decision may affect proposal
- Stakeholders generally supported an application for changes to be effective in 2017 on an interim basis
  – One party requested timing be coordinated with the quarterly deferral account riders of distribution system owners
    - AESO will try to maintain publishing Rider C 30 days before start of quarter

AESO currently proposing application at end of February for approval of interim changes

- Early tariff updates already implemented
- Proposed application would request interim approval of three changes
  - Rider C as percentage (rather than as $/MWh)
  - Rider C calculated on production year (rather than quarter)
  - Allocation of deferral account balances on both Rate DTS and Rate PSC amounts
- Application would be filed at end of February
  - Decision on AESO 2015 deferral account reconciliation proceeding is expected in mid-March
- Interim approval would be requested by end of May
- Interim changes to Rider C would be effective July 1, 2017

Preliminary proposed changes to Rider C

- 1 Rider C applies to system access service provided under … <u>(c) Rate PSC, *Primary Service Credit*</u>.
- 2(2) The ISO must determine Rider C for each calendar quarter as an <u>additional percentage charge or credit</u> ….
  - Currently: additional $/MWh charge or credit
- 2(4) The ISO must calculate the Rider C charge or credit as the sum of amounts … required to restore the deferral account balance to zero (0) <u>at the end of the calendar year</u> … in each of the following rate components: <u>(a) connection charge and primary service credit</u> ….
  - Currently: over the following calendar quarter … (a) connection charge
  - Will also affect 2017 deferral account reconciliation process

Preliminary proposed changes to Rate PSC

- 3(3) The ISO must apply Rider C, *Deferral Account Adjustment Rider*, to system access service provided under this rate.
  - Will also affect 2017 deferral account reconciliation process

Is interim approval by end of May practical?

- Interim approval seems best approach to accomplish early implementation
- Three-month proceeding for approval is tight
  - Application will included limited information
  - Full report will be filed with 2018 ISO tariff application
- Interim approval is subject to change or reversal, and does not establish precedent
  - Rider C charges themselves are effectively interim and subject to change in deferral account reconciliations
  - 2017 deferral account reconciliation application will not be filed until Q2 of 2018 at the earliest, and much of 2018 ISO tariff proceeding will be completed by then

Is interim approval by end of May practical? (cont'd)

- Stakeholder opposition will put end-of-May approval at risk
  - Substantial information requests or raising of tangentially-related issues may be viewed as opposition
  - Assigning AESO resources to respond to information requests or prepare substantial argument and reply could delay filing of 2018 ISO tariff application
- Delaying effective date for Rider C changes to October 1, 2017 would eliminate much of the benefit of interim approval
- AESO will request stakeholder feedback on practicality of request for interim approval by end of May

Request for final approval of changes will be included in 2018 ISO tariff application

- AESO plans to include full report on tariff updates, deferral account reconciliation processes, and Rider C design in 2018 ISO tariff application
  - Responds to Commission direction in Decision 2014-242
  - Report would address whether net revenue allocation should include other tariff components like Rate UFLS, Riders A1-A4, and payments in lieu of notice (PILON)
- Full review of proposed changes would occur in that proceeding
  - Would also reflect outcome of 2015 deferral account reconciliation proceeding
- Changes would be expected to be confirmed as final or otherwise modified in mid-2018

Further discussion?

- Comments or questions

Application Process, Timeline and Next Steps

LaRhonda Papworth

Public

December 5, 2016 Session – Stakeholder Comments Review

- Generally keep deferral account reconciliation filings and tariff updates on schedule with communication to stakeholders on timing
- Concern on keeping 2018 ISO tariff application on schedule
- Updates on some scope items that haven't been discussed yet in a stakeholder technical session . AESO will discuss in relation to schedule on upcoming slides
- Transmission rate projection <u>model</u> will be filed with the 2018 ISO tariff application
- AESO tariff treatment of energy storage continued concerns raised

Checklist for 2018 ISO tariff application

Scope item	Status
Rider C / DAR / Tariff updates	100% complete
POD cost function work	90% complete
Transmission cost causation study	95% complete
Terms and conditions: Sections 4, 5, 8 and 9	50% complete
Clarify tariff for energy storage	100% complete
Updates to Proformas	90% complete
Clarify Rider A-1 – Dow duplication avoidance tariff	80% complete
Address direction from Commission regarding cost recovery from Critical Infrastructure Protection (CIP) work	75% complete
Long-term transmission rate projection model	75% complete

Tariff tentative timeline

Session	Date
2nd Technical Session	January 30, 2017
Stakeholder comment matrix posted	February 3, 2017
Stakeholder comments due	February 17, 2017
3rd Technical Session	**Tentative: March 1, 2017**
4th Technical/Information Session	March/April 2017
Application Preview Session	April/May 2017
Application writing	Q1 – Q2 2017
Application filing	Q2 2017
2016 DAR Filing	Q3 2017
2018 tariff update application	Q3 2017
Regulatory review process for 2018 tariff application	Q4 2017 – Q1 2018
Compliance filing	Q2 2018

Next steps

- The AESO will invite participants to respond to this presentation through a comment matrix in the next few weeks. To allow transparency, the AESO will post all comments on AESO's website following the receipt of participants' input
- For more information:

  LaRhonda Papworth – Manager, Tariff Design
  403-539-2555
  larhonda.papworth@aeso.ca
- All consultation documents can be found on AESO website at www.aeso.ca by following the path:
  Rules, Standards and Tariff ►Stakeholder engagement ►2018 ISO tariff application

Further Discussion? Questions?

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Request for Stakeholder Comments on AESO 2018 ISO Tariff Consultation

Background

On January 30, 2017, the AESO and stakeholders participated in a consultation meeting to discuss (1) technical presentation on transmission cost causation study results; (2) technical presentation on point of delivery (POD) cost function database results and discussion on criteria; (3) progress on annual tariff updates, deferral account reconciliations, and Rider C, *Deferral Account Adjustment Rider* ("Rider C") matters; and (4) application process and next steps. Based on discussion at the meeting, the AESO invites written comments from stakeholders on the information presented at the meeting. The meeting presentation is posted on the AESO website and can be accessed at www.aeso.ca by following the path Tariff ► Stakeholder engagement ► 2018 ISO tariff application.

Please use the comment form below when submitting comments to the AESO on the 2018 ISO tariff consultation. Please ensure that your comments represent all interests within your stakeholder organization with respect to the consultation. Please provide comments or questions no later than **February 17, 2017**, to LaRhonda Papworth at larhonda.papworth@aeso.ca or 403-539-2555.

Consultation and Stakeholder Identification

Date of Request for Comments:	February 6, 2017
Period of Consultation:	November 15, 2016 – February 3, 2017
Comments From:	
Date:	
Contact:	
Phone:	
Email:	

Stakeholder Comments on AESO Information

Stakeholder Comment
(1) Transmission Cost Causation Study – Preliminary Results (Slides 6 – 36)
A. Scope of 2018-2020 Transmission Cost Causation Study (Slide 18): ***1. Update of 2014-2016 transmission cost causation study;*** ***2. Using identical methodology*** ***3. Using same data sources, plus a few additional sources; and*** ***4. For years 2018-2020.***
Stakeholder Comments:

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Stakeholder Comment

B. Process for 2018-2020 Transmission Cost Causation Study (Slide 19):

i. Update inputs and conduct 2018-2020 transmission cost causation study in 2016

ii. Present draft results to stakeholders in January 2017; and

iii. Include the study in the 2018 ISO tariff application.

Stakeholder Comments:

C. Preliminary Functionalization - 2018 (Slides 20 – 24):

Bulk	***Regional***	***POD***
53.4%	***26.3%***	***20.3%***

Stakeholder Comments:

D. Preliminary Functionalization - 2019 (Slides 25 – 29):

Bulk	***Regional***	***POD***
55.0%	***25.1%***	***19.9***

Stakeholder Comments:

E. Preliminary Functionalization - 2020 (Slides 30 – 34):

Bulk	***Regional***	***POD***
53.7%	***26.2%***	***20.1%***

Stakeholder Comments:

F. Preliminary Functionalization – 2018-2020 3-year Average (Slide 35):

Bulk	***Regional***	***POD***
54.0%	***25.9%***	***20.1%***

Stakeholder Comments:

(2) Point-of-delivery ("POD") Cost Function – Preliminary Results and Discussion (Slides 38 – 61)

A. Background and POD Cost Function Cost Curve Options (Slides 38 - 39):

Cost Curve Options	Greenfield	Upgrade	0 MW Contracts
#1 – Pre-2014 practice	***Contract***	***Contract***	***Include***
#2 Current practice (until thoroughly explored)	***Contract***	***Contract***	***Remove***
#3 As requested in Decision 2014-242	***Contract***	***Installed***	***By using installed, 0 MW projects are included***
#4 Not asked for	***Installed***	***Installed***	
~~***#5 AESO not considering (not asked, not debated)***~~	~~***Installed***~~	~~***Contract***~~	~~***?***~~

Stakeholder Comments:

B. POD Cost Database and Cost Curves - Preliminary (Slides 40 – 45):

- ***i. Option #1 Cost Curve;***
- ***ii. Option #1 Cost Curve comparison to existing tariff;***
- ***iii. Option #4 Cost Curve;***
- ***iv. Options #1, #2, #3 and #4 Cost Curves comparison; and***
- ***v. Impact on curve from Option #1 and Option #4***

Stakeholder Comments:

C. Potential evaluation criteria for cost curve options (Slides 46 – 58):

- ***i. Maintaining alignment between POD cost function, maximum investment levels and the POD charge in Rates DTS and PSC;***
- ***ii. Consistency with past practice (post-2007);***
- ***iii. Maximize number of projects in database / statistical criteria for project inclusion;***
- ***iv. Degree of relationship between installed capacity and contract capacity;***
- ***v. "Lumpiness" of installed capacity and standard transformer sizes;***
- ***vi. Number of assumptions required to determine installed vs contract capacity;***
- ***vii. Behavior of market participant's relationship to installed vs contract capacity;***
- ***viii. Encouraging staging to contract appropriately / planned signal from contract capacity vs installed capacity;***
- ***ix. Potential to eliminate substation fraction / treatment of split between DTS and STS shared costs;***
- ***x. Rates reflect true costs per MW / sending the "right" price signal;***
- ***xi. Equal services treated equally, unequal services treated unequally; and***
- ***xii. Bridging the "gap" / fairness of treatment of customers with charges based on two different approaches.***

Stakeholder Comments:

D. Criteria Summary / Ranking (Slides 59 – 60):

Rank	Criteria	Rate Design Principles
1	***Maintaining alignment between POD cost function, maximum investment levels and the POD charge in Rates DTS and PSC***	***Fairness, Objectivity, and Equity*** ***Provision of Price Signals***
2	***Degree of relationship between installed capacity and contract capacity***	***Provision of Price Signals***
3	***Rates reflect true costs per MW***	***Fairness, Objectivity, and Equity*** ***Provision of Price Signals***
4	***Treatment of split between DTS and STS shared costs***	
5	***Sending the "right" price signal***	***Provision of Price Signals***
6	***Maximize the number of projects in database / statistical criteria for project exclusion***	***Fairness, Objectivity, and Equity***
7	***Fairness of treatment of customers with charges based on two different approaches, consistency with past practice (post-2007)***	***Fairness, Objectivity, and Equity*** ***Stability and Predictability***
8	***Behavior of market participants relationship to MWs***	***Fairness, Objectivity, and Equity*** ***Provision of Price Signals***
9	***Number of assumptions required to determine installed vs contract capacity***	***Fairness, Objectivity, and Equity*** ***Stability and Predictability*** ***Practicality***

Stakeholder Comments:

E. POD Cost Function Next Steps (Slide 61):

i. Gather more information from stakeholders in order to develop subjective and objective comparisons of Option #1 and Option #4;

ii. Provide additional analysis to stakeholders on Option #1 and Option #4 to illustrate preliminary rates and investments under each option; and

iii. Present the AESO's position at upcoming stakeholder session in March or April.

Stakeholder Comments:

(3) Proposal to Apply for Interim Changes to Rider C and Deferral Account Reconciliations (Slides 63 – 80)

A. The AESO anticipates filing an application before the end of February for interim approval of changes to address the following issues (Slide 66):

i. To reduce transfers between services in deferral account reconciliation applications:

1. Determine Rider C as percentage (rather than as $/MWh);

2. Determine Rider C based on production year (rather than quarter); and

ii. To address issues raised by Primary Service Group in the 2015 deferral account reconciliation proceeding:

1. Allocate deferral account balances on both Rate DTS and Rate PSC amounts.

Stakeholder Comments Regarding Included Issues:

B. The AESO does not plan to address in its interim application the following matters raised in stakeholder comments (Slides 72-73):

i. To determine Rider C separately for bulk system, regional system, and point of delivery rate components;

ii. To provide more extensive information beyond the analysis presented to stakeholders;

iii. To address the allocation of deferral account balances for years prior to 2017 (which is under consideration in the 2015 deferral account reconciliation proceeding;

iv. To allocate deferral account balances on amounts other than Rates DTS and PSC (such as Rate UFLS, Riders A1-A4, or payment in lieu of notice amounts); or

v. To modify the timing of publishing Rider C quarterly charges or credits.

Stakeholder Comments Regarding Excluded Issues, Including Identification of Any Issues Stakeholder Considers Should Be Included:

C. Application timing (Slides 74 and 79):

i. Application would be filed at end of February;

ii. Interim approval would be requested by end of May;

iii. Interim changes to Rider C would be effective July 1, 2017; and

iv. Request for final approval of changes will be included in 2018 ISO tariff application.

Do you support the AESO's plan to apply for interim changes to Rider C and deferral account reconciliations?

☐ Support

☐ Oppose

☐ Indifferent

Stakeholder Reasons for Position:

(4) Application Process, Timeline and Next Steps (Slides 82 – 85)

A. The AESO discussed the status of a number of 2018 ISO tariff application scope items (Slide 83) and a 2018 ISO tariff tentative timeline.

Stakeholder Comments:

Additional Comments

Please return this form with your comments by **February 17, 2017**, to:

LaRhonda Papworth
Manager, Tariff Design
Email: larhonda.papworth@aeso.ca
Phone: (403) 539-2555

Consolidated Stakeholder Comments on AESO 2018 ISO Tariff Consultation Session – December 5, 2016

Background

On December 5, 2016, the AESO and stakeholders participated in a consultation meeting to discuss (1) evaluation of potential changes to deferral account reconciliations and Rider C, *Deferral Account Adjustment Rider*, ("Rider C"); (2) transmission cost causation study update; (3) point-of-delivery cost function database update; and (4) application process and next steps. Based on discussion at the meeting, the AESO invited written comments from stakeholders on the information presented at the meeting. The written comments from stakeholders are consolidated below.

The meeting presentation is posted on the AESO website and can be accessed at www.aeso.ca by following the path Tariff ► Stakeholder engagement ► 2018 ISO tariff application.

Stakeholder Comments on AESO Information

Stakeholder Comment
(1) Evaluation of Potential Changes to Deferral Account Reconciliations and Rider C (Slides 6 – 61)
A. Impact of Early Tariff Updates (Slides 15 – 21): ***i. Early tariff updates significantly reduce transfers between services in a deferral account reconciliation;*** ***ii. Early tariff updates do not entirely eliminate transfers between services; and*** ***iii. AESO needs to better manage tariff update process.***
Alberta Direct Connect Consumers Association ("ADC"): ADC supports the AESO's efforts in completing an annual tariff update to be effective January 1st to help minimize deferral accounts.
The Alberta Storage Alliance: No comment.
Capital Power: Capital Power supports the AESO's efforts to pursue early tariff updates and regulatory efficiency to reduce and/or eliminate deferral account balances and Rider C imbalances among customers
Depal Consulting Limited: No comment.
Dual Use Customers ("DUC"): i. DUC is of the view that timely and accurate annual updates will help AESO customers better manage their electricity costs by paying the required revenue requirement closer to "real time". ii. Timely updates will not eliminate deferral account balances; however, a better matching of revenue and costs will help reduce DAR balances iii. The AESO does need to a better job of filing annual updates by the end of Q3 each year for the following year; esp. during periods like the past 5 + years where revenue requirements have been increasing significantly.

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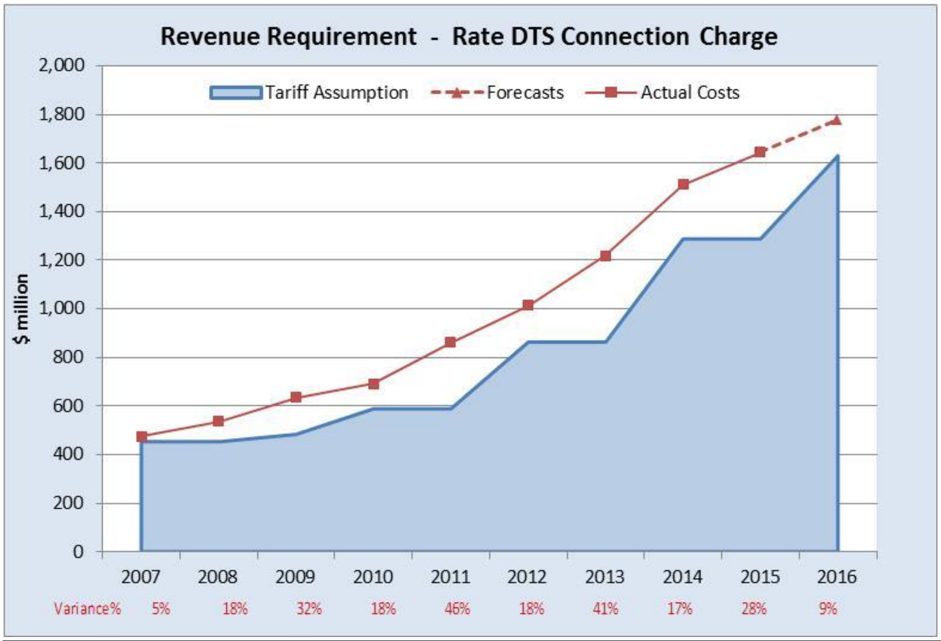
Stakeholder Comment
EPCOR Distribution and Transmission Inc. ("EDTI"): EDTI supports early tariff updates.
Industrial Power Consumers Association of Alberta ("IPCAA"): IPCAA supports a move to early tariff updates. Regulatory lag is a real concern for customers. IPCAA concurs that the AESO needs to better manage the tariff update process – and be as transparent as possible regarding the filing schedule.
NRStor Inc.: No comment.
On Power Systems: No comment.
Primary Service Group ("PS Group"): 1) The PS Group supports the AESO filing tariff rate updates in a timely basis. To be most effective in reducing the use of Rider C or the retrospective DAR true-up process for allocating under-forecasted costs, tariff applications should be based on an accurate forecast of the calendar year revenue requirement, especially for Wires costs. 2) In the past decade, the Connection Charge forecasts used to prepare tariff rates have been materially lower than actual costs, in some years by more than 40%. The approved rates were accordingly too low and the AESO relied materially on collecting monies using Rider C (temporarily) and material billing adjustments using the retrospective DAR true-up process (permanently). (See chart below.) 3) Material reliance on Rider C and retrospective DAR true-ups should be avoided. 4) Tariff updates should include amendments to the terms and conditions when needed to improve clarity or to avoid ambiguities, if necessary. 5) The PS Group registers its disappointment that the AESO did not use the 2017 ISO Tariff Update application as an opportunity to adjust its processes to prevent the shifting of substation related charges to DTS customers that did not cause the AESO to incur substation related costs by way of after-the fact bill adjustments using the retrospective DAR true-up process. This process should not be used to effect cost shifting.



Rocky Mountain Power (2006) Inc.:

No comment.

B. Impact of Changing Rider C Structure (Slides 22 – 30):

i. Rider C as percentage almost eliminates transfers between services in a deferral account reconciliation; and

ii. Some transfers between services still exist but are small.

Alberta Direct Connect Consumers Association ("ADC"):

ADC supports the AESO's efforts in modifying Rider C to a percentage in order to minimize transfers between customers.

The Alberta Storage Alliance:

No comment.

Capital Power:

No comment.

Depal Consulting Limited:

No comment.

Dual Use Customers ("DUC"):

The DUC directionally supports moving from a $/MWh Rider C charge to a percentage of revenue charge as quickly as possible. The DUC suggests that a percentage of revenue charge could be derived for each major tariff component; for example, x% for bulk charges, y% for regional, etc. to better match where costs and revenues are not aligned.

EPCOR Distribution and Transmission Inc. ("EDTI"):

EDTI supports changes which reduce the size of deferral account reconciliations however is unsure how

Stakeholder Comment
Rider C structure impacts deferral accounts amounts and transfers. More information is required.
Industrial Power Consumers Association of Alberta ("IPCAA"): IPCAA supports a move to charging Rider C as a percentage.
NRStor Inc: No comment.
On Power Systems: No comment.
Primary Service Group ("PS Group"): 1) Rider C and the retrospective DAR true-up adjustments should be applied consistent with the cost causation principle and rate design used when calculating the tariff published rates. They should not promote cost shifting between customers, especially in the case of the retrospective DAR true-up process, when bills are adjustment after the fact to eliminate a the AESO's revenue shortfall/surplus. 2) Using the customer's percentage of actual revenue collected as a means of allocating the deferral account balances (revenue shortfall/surplus) is mathematically consistent with adjusting the original rates by the percentage change sufficient to eliminate a deferral account balance; on the condition that the "revenue collected" matches the charges and credits arising from tariff published rates that are directly established from the respective revenue requirement cost component. 3) As a result, to align Rider C with the original rate design for tariff rates and the retrospective DAR true-up adjustments, Rider C should be designed as a percentage increase to the tariff published rates. 4) The PS Group therefore generally supports a Rider C that is based on percentage changes to the tariff approved rates, subject to Rider C being applied to Rate PSC. 5) Rate PSC is a tariff published rate that is based on the Connection Charge revenue requirement forecast. It represents the substation related charges otherwise due under Rate DTS. If, when preparing the tariff published rates, the Connection Charge revenue requirement is increased, the Rate DTS rates and Rate PSC credits both increase correspondingly. Making billing adjustments when applying Rider C should lead to the same result as if the AESO had known in the first instance that the Connection Charge revenue requirement was to increase. Only then will Rider C adjustments uphold the cost causation and rate design principle that DTS customers that do not cause the AESO to incur substation costs are not liable to pay substation related charges. Rider C should not lead to cost shifting.
Rocky Mountain Power (2006) Inc.: No comment.
A. Impact of Changing to Production Year Basis (Slides 31 – 40): ***i. Rider C as percentage by production year eliminates transfers between services in a deferral account reconciliation;*** ***ii. In practice there will still be some transfers resulting from timing impacts, such as if an annual cost becomes known partway through the year.***
Alberta Direct Connect Consumers Association ("ADC"): ADC supports this change.
The Alberta Storage Alliance: No comment.

Stakeholder Comment
Capital Power: No comment.
Depal Consulting Limited: No comment.
Dual Use Customers (“DUC”): The DUC directionally supports Rider C as percentage by production year to match the DAR by production year.
EPCOR Distribution and Transmission Inc. (“EDTI”): EDTI supports changes which reduce the size of deferral account reconciliations however is unsure how Rider C structure impacts deferral accounts amounts and transfers. More information is required.
Industrial Power Consumers Association of Alberta (“IPCAA”): IPCAA supports charging Rider C as a percentage by production year.
NRStor Inc.: No comment.
On Power Systems: No comment.
Primary Service Group: No comments at this time.
Rocky Mountain Power (2006) Inc.: No comment.

AESO notes that the following topic is a matter currently in front of the Commission in the 2015 deferral account reconciliation application, Proceeding 21735

B. Impact of Changing to Net Revenue Allocation Methodology (Slides 42 – 50):

- ***i. Consideration of merits to net revenue methodology***
- ***ii. Net tariff revenue for a service would include charges and credits related to contracted load service:***
  - ***a. Rate DTS, Demand Transmission Service, and Rate FTS, Fort Nelson Demand Transmission Service***
  - ***b. Rate UFLS, Demand Underfrequency Load Shedding Credits***
  - ***c. Rate PSC, Primary Service Credit***
  - ***d. Riders A1-A4, Transmission Duplication Avoidance Adjustments***
  - ***e. Payments in lieu of notice (PILONs) for reductions or terminations of contract capacity under section 9 of ISO tariff.***
- ***iii. Net tariff revenue for a service would not include charges under Rate DOS, Demand Opportunity Service.***
- ***iv. Net tariff revenue for a load service would not include charges or credits related to non-load service.***

Stakeholder Comment
Alberta Direct Connect Consumers Association (“ADC”): ADC awaits the Commission decision on this item.
The Alberta Storage Alliance: No comment.
Capital Power: No comment.
Depal Consulting Limited: No comment.
Dual Use Customers (“DUC”): The DUC directionally supports net tariff services for direct wires related charges under rates DTS and PSC. The DUC suggests that additional review of the application of net tariff services is required for the DAT riders and UFLS as it may not be appropriate to apply Rider C to these tariff charges.
EPCOR Distribution and Transmission Inc. (“EDTI”): EDTI supports changes which reduce the size of deferral account reconciliations however is unsure how allocation methods impact deferral accounts amounts and transfers. More information is required.
Industrial Power Consumers Association of Alberta (“IPCAA”): IPCAA supports appropriate cost causation – and awaits the decision from the AUC on Proceeding 21735.
NRStor Inc.: No comment.
On Power Systems: No comment.
Primary Service Group: If, when preparing the tariff published rates, the Connection Charge revenue requirement is increased, the Rate DTS rates and Rate PSC credits will both increase correspondingly; the rates under Rate UFLS or Riders A1 to A4 will not change. The retrospective DAR true-up process should lead to a consistent result. Only then will the DAR process uphold the cost causation and rate design principles used to calculate the tariff published rates. The “net revenue” methodology should therefore be based only the “revenue” corresponding to the rates that are a derived directly from the amount of Connection Charge costs, such as Rate DTS rates and Rate PSC credits. Revenue based rates that are not directly based on the level of the Connection Charge costs should be excluded, such a Rate UFLS and Rider A1 to A4. Additionally, revenue associated with opportunity rates should be excluded because they are based on a “value of service” design not “cost of service” design. Accordingly, only Rate DTS and Rate PSC should be included in the “net revenue” used to allocate the Connection Charge deferral account balances. To demonstrate these points in detail consider that using past “revenue collected” to allocate unforeseen new costs is mathematically consistent with adjusting the original rate by a percentage change sufficient to eliminate the revenue shortfall. For example, “revenue collected” (r) from a customer might equal the approved rate (P) times the customer specific billing units (q). Original Revenue Collected (r)= q*P=qP

Stakeholder Comment

If, after the fact, costs are higher than forecasted and more revenue needs to be collected from customers, then bills will be adjusted to collected the revenue shortfall, i.e. the deferral account balance (D). Using each customer "revenue" as a percentage of total revenue collected (R) to allocate the deferral account balance "D" can be represented as follows:

Final Revenue Collected $(fr)=r+[r/R]D$

And, by simple substitution of variables, this equation can be re-written as:

Final Revenue Collected $(fr)=qP^*((R+D)/R)$

Assuming, for example, a 10% revenue shortfall, this equation then becomes:

Final Revenue Collected $(fr)=qP^*(110\%)$

Therefore, allocating deferral account balances using a customer's percentage of total revenue is mathematically consistent with adjusting the original rate (P) by a percentage change sufficient to eliminate the revenue shortfall. In this example, by 10%. The same revenue would have been collected from customers if the original rates where 10% higher when preparing the tariff published rates in the first instance.

Connection Charge Costs

The above illustration can be extended in detail to account for the three Rate DTS Connection Charge sub-rates (Bulk (P_B), Regional (P_R) and POD (P_P)) and the Rate PSC credit $(0.79P_P)$, whose purpose is to eliminate the substation related charges for DTS customers that did not cause such costs.

For example, the "revenue collected" can be shown as:

$$fr= [(q_B P_B+q_R P_R+q_P P_P)-(q_P\, 0.79P_P)] + [((q_B P_B+q_R P_R+q_P P_P)-(q_P\, 0.79P_P))/R]^*D$$

Again, by simple substitution of variables, this equation can be re-written as:

$$fr=q_B P_B ((R+D)/R)+q_R P_R ((R+D)/R)+q_P P_P ((R+D)/R)-q_P (0.79P_P)((R+D)/R)$$

And, assuming a 10% revenue shortfall, this equation becomes:

$$fr=q_B P_B (110\%)+q_R P_R (110\%)+q_P P_P (110\%)-q_P (0.79P_P)(110\%)$$

By using a "net revenue" methodology that accounts for Rate PSC credits, the resulting after-the-fact adjustment of bills will result in the same amount of charges to customers as if the AESO had known in the first instance that its costs were going to be higher; in this instance, by 10%. Such an outcome upholds the cost causation principle underling the tariff published rates (i.e. DTS customers that do not cause substation related costs are not liable to pay substation-related charges) and rate design that set the substation related charges at a prescribed ratio of POD rate (79% for the first four tiers and 100% for the final tier).

The AESO proposed a "net revenue" that includes Rates DTS and PSC and other aspects of the ISO tariff including Rate UFLS and DAT Riders A1 to A4. Doing so would convert the above equation to the following:

$$fr=q_B P_B (110\%)+q_R P_R (110\%)+q_P P_P (110\%)-(q_P\, 0.79P_P)(110\%)-q_U P_U (110\%) +q_A P_A (110\%)$$

adjusted charges: Bulk Regional POD PSC UFLS Rider A1

This amounts to proposing an after-the-fact adjustment to credits and charges associated with Rate UFLS and Riders A1 to A4. There is no principled cost causation or rate design reason for this to occur. If the AESO knew beforehand that its revenue requirement should be 10% higher, it would not change the "rates" for Rate UFLS or Rider A1 to A4 because these are based on calculation methodologies that are completely unrelated to the level of the Connection Charge costs (e.g. Wires or AESO G&A).

The onus rests with the AESO to demonstrate why the retrospective DAR true-up process for the Connection Charge cost components should cause bills to be adjusted in a manner that is consistent with

Stakeholder Comment
changing the rates after the fact, outside of Rate DTS and Rate PSC, to eliminate a Connection Charge revenue shortfall. Would the approved rates have been different if the AESO used a forecast for the Connection Charge revenue requirement that was 10% greater in the first instance?
Rocky Mountain Power (2006) Inc.: No comment.
C. Possible Future Changes to Rider C (Slides 51 – 55): ***i. AESO suggests maintaining quarterly Rider C and annual deferral account reconciliations for at least a few more years then evaluate success of early tariff updates and Rider C restructuring.***
Alberta Direct Connect Consumers Association (“ADC”): ADC considers this a reasonable approach.
The Alberta Storage Alliance: No comment.
Capital Power: Capital Power does not object to the AESO’s proposal.
Depal Consulting Limited: No comment.
Dual Use Customers (“DUC”): The DUC submits that the current Rider C energy charges should be replaced with a tariff design that better tracks costs. A percentage of revenue charge appears be superior to an energy change, esp. for DUC members who can incur large bulk demand charges with minimal energy consumed from the grid. Early updates will help; however, the AESO cannot be compelled to filing annual updates and the DUC is seeking tariff solutions that are more robust.
EPCOR Distribution and Transmission Inc. (“EDTI”): No comment.
Industrial Power Consumers Association of Alberta (“IPCAA”): IPCAA supports keeping the quarterly Rider C and annual deferral account reconciliations in place for now. If there are problems or delays with the restructuring, it will be needed.
NRStor Inc.: No comment.
On Power Systems: No comment.
Primary Service Group (“PS Group”): 1) The PS Group supports the AESO preparing tariff applications using more accurate revenue requirement forecasts, especially in respect of the Wires costs (i.e. no longer discounting the future Wires costs by using only 72% if the incremental TFO revenue requirement requests). 2) While this is expected to materially reduce the reliance on Rider C and the retrospective DAR true-up billing adjustments, the PS Group supports the continued use of Rider C to recover under-forecasted

Stakeholder Comment

costs and an annual retrospective DAR true-up process, subject to both procedures allocating costs consistently with the cost causation principles as approved for the calculation of rates published in the tariff.

3) This means Rider C and the retrospective DAR methodology should be applied to the revenue collected from DTS customers for the Connection Charge costs, being the sum of the amounts from Rate DTS and Rate PSC for the DTS customers that did not cause substation related costs.

4) The PS Group is opposed to using Rider C or the retrospective DAR methodology to shift costs on to customers that did not cause those costs, especially substation related charges being shifted to DTS customers that did not cause the AESO to incur substation related costs.

Rocky Mountain Power (2006) Inc.:

No comment.

D. Timing and Implementation Options (Slide 56 – 61):

- ***(1) Include Rider C and deferral account reconciliation methodology changes in 2018 tariff application in Q2 2017.***
- ***(2) File separate application in Q1 2017 for Rider C and deferral account reconciliation methodology changes.***
- ***(3) File application in Q1 2017 for interim Rider C changes with request to make existing reconciliation methodology interim.***
- ***(4) Any other practical options?***

Alberta Direct Connect Consumers Association ("ADC"):

ADC supports the option that will result in the timely implementation of the change. Option 2 or 3 is preferred. The ADC also requests the AESO complete the 2016 deferral account reconciliation as soon as reasonably practical.

The Alberta Storage Alliance:

No comment.

Capital Power:

Capital Power does not object to the AESO's proposal.

Depal Consulting Limited:

No comment.

Dual Use Customers ("DUC"):

The DUC requests that the Rider C and deferral account reconciliation methodology changes, including moving Rider C to a percentage of revenue and the inclusion of PSC in the DAR allocation methodology, be implemented as soon as practical and in a way that will include the entire 2017 calendar year, upon AUC approval. Option 3 could achieve these objectives, or the AESO could amend its application in Proceeding 22093 to ask for the requested changes to be applied to the 2017 production year.

EPCOR Distribution and Transmission Inc. ("EDTI"):

EDTI supports changes which reduces the magnitude or eliminates the need for Rider C. Any changes to Rider C timing needs to be coordinated with timing requirements of the DFO's quarterly transmission access charge deferral account rider process (Decision 2012-304).

Industrial Power Consumers Association of Alberta ("IPCAA"):

Stakeholder Comment
IPCAA supports Option #3. This will allow changes to be made effective (on an interim basis) in mid-2017.
NRStor Inc.: No comment.
On Power Systems: No comment.
Primary Service Group ("PS Group"): 1) The PS Group requests that the Rider C and deferral account reconciliation methodology changes, including moving Rider C to a percentage of revenue and the inclusion of PSC in the DAR allocation methodology, be implemented as soon as practical and in a way that will include the entire 2017 calendar year, upon AUC approval. Option 3 could achieve these objectives. Preferably, the AESO could amend its application in Proceeding 22093 (2017 ISO Tariff Update) to seek approval of these changes so they can be applied to the 2017 production year. 2) The PS Group suggests the simplest means of maintaining the cost causation and rate design principles is to physically merge the terms and conditions of Rate PSC within Rate DTS. Alternatively, Rate PSC should be identified as an intrinsic extension of Rate DTS and directly netted from the DTS charges on the AESO invoices (i.e. use a single line item billing approach).
Rocky Mountain Power (2006) Inc.: No comment.
(2) Transmission Cost Causation Study Update (Slides 62 – 70)
A. Scope of 2018-2020 transmission cost causation study: ***i. Use identical methodology to 2014-2016 transmission cost causation study;*** ***ii. Use same data sources plus additional sources;*** ***iii. For years 2018-2020;*** ***iv. Present draft results to stakeholders in January 2017; and*** ***v. Include study results in the 2018 ISO tariff application.***
Alberta Direct Connect Consumers Association ("ADC"): ADC supports this methodology.
The Alberta Storage Alliance: No comment.
Capital Power: No comment.
Depal Consulting Limited: Agree with the strategy and use of internal resources.
Dual Use Customers ("DUC"): The DUC supports this approach. The DUC would be pleased to work with the AESO to review the Transmission Cost Causation Study Update prior to the GTA filing.

Stakeholder Comment
EPCOR Distribution and Transmission Inc. ("EDTI"): EDTI supports updating the existing cost causation study.
Industrial Power Consumers Association of Alberta ("IPCAA"): When will this be presented to stakeholders in January? IPCAA would appreciate the opportunity to work with the AESO to review the Transmission Cost Causation Study Update prior to the GTA filing.
NRStor Inc.: No comment.
On Power Systems: No comment.
Primary Service Group: No comment.
Rocky Mountain Power (2006) Inc.: No comment.
(3) Point-of-delivery (POD) Cost Function Update (Slides 71 – 75)
A. AESO plans to complete POD cost function database using the following capacities in order to present the following cost curve options (Slide 74): ***(1) Pre-2014 Practice – Contracted greenfield and contracted upgrade projects, include 0 MW projects;*** ***(2) Current interim practice – Contracted greenfield and contracted upgrade projects, exclude 0 MW projects;*** ***(3) As requested in Decision 2014-242 – Contract greenfield and installed upgrade projects; and*** ***(4) Not requested but will do – Installed greenfield and installed upgrade projects;***
Alberta Direct Connect Consumers Association ("ADC"): ADC supports the AESO preparing the 4 cost curve options for purposes of comparison.
The Alberta Storage Alliance: No comment.
Capital Power: No comment.
Depal Consulting Limited: Agree.
Dual Use Customers ("DUC"): The DUC submits that the development of the POD cost function could benefit from additional stakeholder consultation prior to the filing of the 2018 GTA. Installed costs should be aligned with increased capacity, not contract capacity, as the DUC argued in the last GTA. The DUC recommends that the AESO work with its customers to develop principles, objectives and work scope on how best to improve the POD cost function.

Stakeholder Comment
EPCOR Distribution and Transmission Inc. ("EDTI"): No comment.
Industrial Power Consumers Association of Alberta ("IPCAA"): Will the results of this update be presented to stakeholders? The AESO would benefit from working with customers to review and improve the POD cost function.
NRStor Inc.: No comment.
On Power Systems: No comment.
Primary Service Group ("PSG"): No comment.
Rocky Mountain Power (2006) Inc.: No comment.

B. The AESO plans to use criteria to evaluate the different options in Point (3)A above. Please comment on the proposed criteria below or add additional criteria (Slide 75):

(1) Maintaining alignment between POD cost function, maximum investment levels and the POD charge in Rates DTS and PSC;	Support - 5 Oppose - 0 Indifferent - 1
(2) Consistency with past practice (post-2007);	Support - 1 Oppose - 1 Indifferent – 4
(3) Maximize number of projects in database;	Support - 3 Oppose - 0 Indifferent – 3
(4) Statistical criteria for project exclusion	Support - 0 Oppose - 2 Indifferent – 4
(5) Degree of relationship between installed capacity and contract capacity;	Support - 4 Oppose - 1 Indifferent – 1
(6) "Lumpiness" of installed capacity and standard transformer sizes;	Support - 1 Oppose - 0 Indifferent – 3
(7) Number of assumptions required to determine the MWs	Support - 0 Oppose - 0 Indifferent – 4
(8) Behavior of market participants'' relationship to MWs	Support - 2 Oppose - 0 Indifferent – 3
(9) Potential to eliminate substation fraction;	Support - 0 Oppose - 0 Indifferent – 5
(10)Treatment of split between DTS and STS shared costs;	Support - 3 Oppose - 1 Indifferent – 0
(11)Rates reflect true costs per MW;	Support - 4 Oppose - 1 Indifferent – 1
(12)Equal services treated equally, unequal services treated unequally;	Support - 1 Oppose - 0 Indifferent - 3

(13)Sending the "right" price signal;	Support - 4 Oppose - 0 Indifferent – 1	***(14)***
(14)Fairness of treatment of customers with charges based on two different approaches; and	Support - 3 Oppose - 0 Indifferent – 1	***(15)***
(15)Any others?	None	***(16)***

Alberta Direct Connect Consumers Association ("ADC"):

ADC requires further discussion on the topic to understand the full cost consequences of the different approaches and merit of one versus another.

The Alberta Storage Alliance:

No comment.

Capital Power:

Capital Power opposes any changes to item 10 (based upon Decision 2013-421) that could potentially shift more costs to STS contracts.

Depal Consulting Limited:

I have left items blank since I am not sure what you mean by the short description. Generally support the method that shows a strong relationship between costs and rates with a fair level of investment (compared to historical levels). Also, moving from the existing method must only occur if a new method displays a significant improvement. Finally, the impact of moving methods and the price signal that could be sent must also be considered. AESO should hold open the discussion on the multiplier level required for investment following this analysis.

Dual Use Customers ("DUC"):

The DUC is not able to respond to many of the 15 criteria as we are not sure of what is meant or being proposed. The DUC suggests that additional discussion is required to better understand the meaning and impact of these options. The DUC would be pleased to work with the AESO to review these options prior to the GTA filing.

EPCOR Distribution and Transmission Inc. ("EDTI"):

No comment.

Industrial Power Consumers Association of Alberta ("IPCAA"):

Please note that "Indifferent" selections also reflect the fact that the criteria are unclear. The AESO should consider presenting this information to interested stakeholders, to solicit better responses.

NRStor Inc.:

No comment.

On Power Systems:

No comment.

Primary Service Group:

No comment.

Rocky Mountain Power (2006) Inc.:

No comment.

(4) Application Process, Timeline and Next Steps (Slides 76 – 79)

A. AESO presented status on a number of 2018 ISO tariff application scope items (Slide 77) and a tariff tentative timeline.

Alberta Direct Connect Consumers Association ("ADC"):

The ADC supports the timeline and encourages the AESO to keep this initiative a priority in light of the other 2018 AESO initiatives.

The Alberta Storage Alliance:

No comment.

Capital Power:

Does the AESO foresee any impacts to the scope and/or timelines of its 2018 General Tariff Application in light of the announced AESO-led capacity market transition and DOE-led transmission policy review?

Depal Consulting Limited:

The AESO stated that it might provide the rate impact model update in a year. The detailed model is required sooner to support the operating budgets for participants and to enable the evaluation of generation opportunities. The update recently provided is of little help since many underlying assumptions are not present. It would be beneficial to the market for the AESO to prepare the update in a timelier manner such as with the 2018 tariff filing.

Dual Use Customers ("DUC"):

The tentative time lime appears to be reasonable.

EPCOR Distribution and Transmission Inc. ("EDTI"):

EDTI requests that the 2016 DAR application be filed prior to July 1st to allow the DFO's to comply with the AUC direction to include the AESO DAR amounts in their respective annual transmission access deferral account applications (Decision 2012-304, paragraphs 69 and 77). The DFOs have been directed to file their annual transmission access deferral account applications between July 1 and August 10 each year (Decision 3334-D01-2015, paragraph 86). EDTI notes that the DFOs typically file their respective SAS rates on September 10th of each year as part of their annual PBR rate adjustment filings for the upcoming year (Decision 2012-237). EDTI requests that, to the extent possible, the AESO file its tariff update prior to September 10th of each year to allow the DFOs to reflect the AESOs tariff update in their respective annual rate adjustment filings.

Industrial Power Consumers Association of Alberta ("IPCAA"):

As mentioned above, IPCAA members are concerned with regulatory lag, as such, the AESO should be cautious of slippage from the proposed timeline

NRStor Inc.:

No comment.

On Power Systems:

No comment.

Primary Service Group ("PS Group"):

1) The PS Group requests the AESO expedite the changes to Rider C and the DAR true-up process to

ensure that substation related costs are no longer unfairly shifted to customers that did not cause the AESO to incur substation costs through after-the-fact charges imposed using the DAR true-up process.

2) The PS Group suggests the simplest means of maintaining the cost causation and rate design principles is to physically merge the terms and condition of Rate PSC within Rate DTS. Alternatively, Rate PSC should be identified as an intrinsic extension of Rate DTS and directly netted from the DTS charges on the AESO invoices (i.e. use a single line item billing approach).

Rocky Mountain Power (2006) Inc.:

No comment.

Additional Comments

Alberta Direct Connect Consumers Association ("ADC"):

ADC appreciates the efforts on improving the Rider C methodology as well as the opportunity to provider input in advance of the filing.

The Alberta Storage Alliance:

The Alberta Storage Alliance (ASA) is an industry group aiming to educate stakeholders on the benefits that energy storage technology can bring to the Alberta electricity system. Our membership includes a variety of key stakeholders in the Alberta market including utilities, technology manufacturers, developers, independent power producers, engineering firms, etc. The ASA is advocating a technology neutral approach and believes smart regulations can unlock the growth of a new energy storage industry in the province while providing improved flexibility and resiliency to the electricity grid.

The ASA believes changes to the rate structure should be considered in order to ensure that energy storage technologies are being valued on their unique merits rather than being penalized for their fundamental operational differences relative to incumbent technologies. Energy storage technologies perform fundamentally differently from traditional energy assets governed by current rate structures. Energy storage technologies are highly flexible assets, acting as both dispatchable load and generation with unique operational characteristics that can serve to benefit the Alberta market.

The ASA notes that on page 77 of the "AESO 2018 Tariff Consultation" the issue of the application of the DTS rate to energy storage is characterized as being 100% complete. ("Clarify tariff for energy storage - 100% complete".) Respectfully, the ASA disagrees with this characterization. The AESO has decided to apply the existing STS and DTS tariff structure to energy storage with no clarification as to why these rate structures apply to a system that is not equivalent to a load and a generator due to the nature of its operation.

The AESO's decision to apply STS and DTS to energy storage ignores and prevents the realization of the benefits that energy storage can provide to the AIES including grid reliability, grid stability, integration of renewables and reductions in the overall cost of electricity to Albertan consumers. The ASA does believe that rationale exists to support the application of rates similar to import and export opportunity service rates or some modified tariff for energy storage transmission service. However, the AESO has not given due consideration to the similarities between energy storage and imports/exports or the differences between energy storage and load customers.

The ASA is keen to work collaboratively with the AESO to resolve these issues; the ASA and its members have made numerous attempts to embark on discussions with the AESO regarding a host of issues surrounding the integration of energy storage into the AIES, including the application of the DTS and STS service rates. We remain committed to continued open dialogue on all issues in order to find an effective solution. We implore the AESO to engage in further dialogue considering alternative energy storage rate structures to DTS and STS. While the ASA would prefer to address the issue in collaboration with the AESO, the AESO has stated that the only means of recourse is to intervene in the 2017 GTA. This is unfortunate for both storage proponents and the remainder of the Alberta market, as intervention adds time and expense to the GTA process.

Capital Power:

Compliance with Directions 5 through 8

Capital Power submitted comments to the AESO on September 1, 2016 regarding the Scope of AESO 2017 ISO Tariff Consultation. Contained in those comments were several clarification questions posed to the AESO which have not been addressed. Capital Power is specifically interested in the AESO's response to questions concerning changes to the ISO tariff's terms and conditions to align with the Commission's Decision 3473-D02-2015 (Compliance with Directions 5 through 8). Please provide an update on the AESO's work to date on complying with the Commission's Directions 5 through 8 and any discussions with the AUC concerning integration with Proceeding 20922 and procedural correctness.

Capital Power reiterates its request that the AESO provide stakeholders with a preliminary list of its positions as they relate to the various topics outlined by the Commission in AUC Bulletin 2015-15 and elaborated in Section 6 of Decision 3473-D02-2015, and how the AESO plans to integrate these positions into its Tariff via changes to the terms and conditions.

Capital Power reiterates that it does not support re-opening the issue of applying system project advancement costs to generators in the 2017 GTA.

CIP Standards Generator Cost Recovery

Please provide an update on the AESO's work to date to address direction from the Commission regarding cost recovery from Critical Infrastructure ("CIP"). Capital Power requests that the AESO provide stakeholders with a preliminary list of its positions as they relate to CIP cost recovery; in this respect a stakeholder session may be helpful.

Dual Use Customers ("DUC"):

The DUC appreciates the opportunity to submit comments and looks forward to working with the AESO and other customers.

Industrial Power Consumers Association of Alberta ("IPCAA"):

Thank you for the opportunity to comment.

NRStor Inc.:

NRStor Inc. (NRStor) is a member of the Alberta Storage Alliance (ASA) – an industry group aiming to educate stakeholders on the benefits that energy storage technology can bring to the Alberta electricity system. The ASA's membership includes a variety of key stakeholders in the Alberta market including utilities, technology manufacturers, developers, independent power producers, engineering firms, etc. NRStor is supportive of the ASA's technology neutral approach and believes smart regulations can unlock the growth of a new energy storage industry in the province while providing improved flexibility and resiliency to the electricity grid.

NRStor believes changes to the rate structure should be considered in order to ensure that energy storage technologies are being valued on their unique merits rather than being penalized for their fundamental operational differences relative to incumbent technologies. Energy storage technologies perform fundamentally differently from traditional energy assets governed by current rate structures. Energy storage technologies are highly flexible assets, acting as both load and generation with unique operational characteristics that can serve to benefit the Alberta market.

NRStor notes that on page 77 of the “AESO 2018 Tariff Consultation” the issue of the application of the DTS rate to energy storage is characterized as being 100% complete. (“Clarify tariff for energy storage - 100% complete”.) Respectfully, NRStor disagrees with this characterization. The AESO has decided to apply the existing STS and DTS tariff structure to energy storage with no clarification as to why these rate structures apply to a system that is not equivalent to a load and a generator due to the nature of its operation.

The AESO’s decision to apply STS and DTS to energy storage ignores and prevents the realization of the benefits that energy storage can provide to the AIES including grid reliability, grid stability, integration of renewables and reductions in the overall cost of electricity to Albertan consumers. NRStor does believe that rationale exists to support the application of rates similar to import and export opportunity service rates or some modified tariff for energy storage transmission service. However, the AESO has not given due consideration to the similarities between energy storage and imports/exports or the differences between energy storage and load customers.

NRStor is keen to work collaboratively with the AESO to resolve these issues; NRStor, alongside the ASA and its members, has made numerous attempts to embark on discussions with the AESO regarding a host of issues surrounding the integration of energy storage into the AIES, including the application of the DTS and STS service rates. We remain committed to continued open dialogue on all issues in order to find an effective solution. We implore the AESO to engage in further dialogue considering alternative energy storage rate structures to DTS and STS. While NRStor and the ASA would prefer to address the issue in collaboration with the AESO, the AESO has stated that the only means of recourse is to intervene in the 2017 GTA. This is unfortunate for both storage proponents and the remainder of the Alberta market, as intervention adds time and expense to the GTA process.

On Power Systems:

On Power Systems, as a market participant focused on power quality in Alberta and throughout North America, supports the view that energy storage assets within the Alberta Electric System can offer several benefits to reliability, power quality, and renewables integration, in addition to supporting Alberta's Greenhouse Gas reduction objective. Some energy storage technologies also have unique advantages in their ability to perform ancillary services such as frequency regulation.

However, the tariff rules in place today, whereby storage assets are obliged to pay transmission / distribution fees when absorbing energy, act as an unfair disincentive to implementing grid energy storage in Alberta.

We assert that grid-connected energy storage assets, when managed to charge from the grid during off-peak times, should not be burdened with transmission & distribution tariffs.

Further, we support the use of energy storage, as a recognized asset class by the AESO, to provide ancillary services such as frequency regulation to the Alberta market.

We recommend re-assessment of tariffs affecting energy storage assets, in the spirit of encouraging 'best use' of energy storage technologies within the Alberta Electric system. On Power Systems is eager to work with regulators to achieve this goal. As a reference, it may be instructive to refer to tariff treatments used by other ISO's such as in PJM, Hawaii, California.

Rocky Mountain Power (2006) Inc.:

Rocky Mountain Power (RMP) respectfully submits comments in response to AESO 2018 ISO Tariff Consultation specifically regarding notes that on page 77 of the “AESO 2018 Tariff Consultation” that the issue of the application of the DTS rate to energy storage is characterized as being 100% complete. (“Clarify tariff for energy storage - 100% complete”.) Respectfully, RMP disagrees with this characterization. The AESO has decided to apply the existing STS and DTS tariff structure to energy storage with no clarification as to why these rate structures apply to a system that is not equivalent to a load and a generator due to the nature of its operation.

RMP suggests that the AESO take note of the Federal Energy Regulatory Commission (FERC) Notice of Proposed Rulemaking (NOPR) dated Nov. 17, 2016 recommendation for the application that proposed "to require each RTO and ISO to revise its tariff to (1) establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, accommodates their participation in the organized wholesale electric markets". RMP additionally agrees with comments filed by Schulte Associates LLC to FERC AD20-16-000 on May 23, 2016 that "A MW of dispatchable load that a storage facility can add to the system on command (e.g., in a time period when renewable resources are over-generating) has more value than a MW of customer load that just happens randomly due to customer behavior" and that if energy storage developers "cannot monetize the benefits, they cannot invest in storage, and the storage does not happen."

RMP believes changes to the rate structure should be considered in order to ensure that energy storage technologies are being valued on their unique merits rather than being penalized for their fundamental operational differences relative to incumbent technologies. Energy storage technologies perform fundamentally differently from traditional energy assets governed by current rate structures. Energy storage technologies are highly flexible assets, acting as both dispatchable load and generation with unique operational characteristics that can serve to benefit the Alberta market.

The AESO's decision to apply STS and DTS to energy storage ignores and prevents the realization of the benefits that energy storage can provide to the AIES including grid reliability, grid stability, integration of renewables and reductions in the overall cost of electricity to Albertan consumers. RMP does believe that rationale exists to support the application of rates similar to import and export opportunity service rates or some modified tariff for energy storage transmission service. However, the AESO has not given due consideration to the similarities between energy storage and imports/exports or the differences between energy storage and load customers.

RMP is a member of the Alberta Storage Alliance (ASA) and through the ASA is keen to work collaboratively with the AESO to resolve these issues; the ASA and RMP have made numerous attempts to embark on discussions with the AESO regarding a host of issues surrounding the integration of energy storage into the AIES, including the application of the DTS and STS service rates. RMP remains committed to continued open dialogue on all issues in order to find an effective solution. RMP implores the AESO to engage in further dialogue considering alternative energy storage rate structures to DTS and STS. While RMP would prefer to address the issue in collaboration with the AESO and ASA, the AESO has stated that the only means of recourse is to intervene in the 2017 GTA. This is unfortunate for both storage proponents and the remainder of the Alberta market, as intervention adds time and expense to the GTA process.

February 14, 2017

AESO Stakeholders
AESO 2018 ISO Tariff Consultation Participants

Dear Stakeholder:

Re: **Invitation to Participate in Consultation on AESO 2018 ISO Tariff Application**

The AESO continues to consult with market participants on the development of its next comprehensive ISO tariff application, which it now refers to as the 2018 ISO tariff application to reflect the year in which the tariff is expected to become effective (in prior stakeholder communications, this application had been referred to as the 2017 ISO tariff application). The AESO will be holding the following consultation session to provide an update on work completed to date and invites you to attend:

Date:	Wednesday, March 1, 2017
Time:	1 pm to 4 pm
Place:	Meeting Room 6006, 6th Floor, BP Centre, 240 – 4th Avenue SW, Calgary, Alberta Note that the glass doors on the 6th floor are locked; please knock to have them opened.
Teleconference:	Within Calgary calling area: 403-410-3051, Conference ID 4366631 Outside Calgary calling area: 1-855-453-6957, Conference ID 4366631
RSVP:	By 5 pm on **Friday, February 24, 2017** to, Tatiana Aparicio-Caris Tatiana.Aparicio-Caris@aeso.ca or 403-539-2664

The AESO plans to discuss the following items during the meeting:

- potential proposed changes to the ISO Tariff's Terms and Conditions;
- cost responsibility for compliance with the Critical Infrastructure Protection ("CIP") Alberta reliability standards;
- potential proposed changes to Rider A-1 – *Transmission Duplication Avoidance Adjustment Dow Chemical Canada Inc. / Dow Hydrocarbons / ASU2*;
- continued work on the AESO's point of delivery (POD) cost function database results and analysis; and
- planned timeline and next steps for the 2018 ISO tariff application.

The AESO plans to present information on these topics to facilitate discussion, and will post a presentation before the meeting. Stakeholders may provide feedback in person during the meeting or through written comments to the AESO after the meeting.

All information relating to the 2018 ISO tariff consultation is available on the AESO website at www.aeso.ca by following the path Rules, Standards and Tariff ► Stakeholder engagement ► 2018 ISO tariff application. As well, new information posted by the AESO on this topic will be mentioned in the

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Phone: 403-539-2450 Fax: 403-539-2949 www.aeso.ca @theaeso

AESO stakeholder newsletter, which you can subscribe to at the bottom right of the AESO's home page at www.aeso.ca.

If you have any questions on the AESO's 2018 ISO tariff consultation, please contact me at 403-539-2555 in Calgary or by e-mail to larhonda.papworth@aeso.ca.

Yours truly,

LaRhonda Papworth
Manager, Tariff Design

cc: Doyle Sullivan, Director – Market and Tariff Design

AESO 2018 ISO Tariff Consultation

March 1, 2017
AESO Office, Calgary

Public

Agenda

- Introduction and objectives (slide 1-5)
- ISO Tariff Terms and Conditions Proposals(slides 6-30)
- Rider A1 – proposed changes(slide 31-33)
- Summary of comments from previous session (slides 34-35)
- Application process and next steps (slides 36-38)
- Discussion and wrap-up (slide 39)

Please feel free to ask questions during presentation

Stakeholder session objectives

- Enhance understanding of ISO tariff application
- Review technical results of a number of analytical exercises by the AESO
- Share information prior to filing of 2018 ISO tariff application
- Gather feedback to ensure tariff application provides all information stakeholders require
- Review application timeline and next steps

Applications currently in progress

- Directions 5-8 on advancement costs and related provisions
  - Decision 3473-D02-2015 issued on August 26, 2015
  - Process letter issued on October 22, 2015 with additional information on process in the new year *[2016]*
  - AESO will proceed with addressing matters in the 2018 ISO tariff application unless Commission provides further guidance
- 2015 Deferral Account Reconciliation application
  - Currently before the Commission in Proceeding 21735
  - Interim settlement was approved and occurred in October 2016
  - Hearing held on December 13 and 14, 2016
  - Decision expected mid-March

Applications currently in progress

- 2017 ISO tariff update
  - Currently before the Commission in Proceeding 22093
  - Interim, refundable approval for January 1, 2017 issued by Commission on December 2, 2016
  - Commission considered close of record for this proceeding to be February 15, 2017
  - Commission final decision expected on or before April 11, 2017
- Upcoming Rider C Amendment application
  - Amending Rider C to apply to Rate PSC, *Primary Service Credit*, change to percentage charge or credit and restore deferral account balance to zero at the end of the calendar year
  - AESO now planning to file Rider C Amendment application in early March 2017

ISO Tariff Terms and Conditions Proposals

Lee Ann Kerr

Public

Matters for consideration in Commission-initiated proceeding

#	Matter
6.1	Price signals and system transmission project advancement costs
6.2	Effect of *Transmission Regulation* sections 15(1)(e) and (f) on classification of advancement costs
6.3	AESO discretion and need to develop clear criteria when applying advancement costs in respect of system transmission projects
6.4	Materiality threshold for applying advancement cost provisions to system projects
6.5	Application of advancement cost provisions to non-radial system transmission projects
6.6	Application of advancement cost provisions to upgrades/enhancements of existing system transmission facilities
6.7	Application of system project advancement costs to generator
6.8	Application system project advancement costs to distribution utilities
6.9	Time limitations on participant-related classification of system project advancement
6.10	Impact of system transmission project advancement cost provisions on transmission system planning and project execution
6.11	Adequacy of market participant accountability mechanisms in tariff
6.12	Application of Good Electric Industry Practice to staged loads

Other Commission Decisions

Decision	Summary
2005-096	“The underlying purpose of the contribution policy is to send price signals (reflective of the AESO’s economics) to market participants when they are considering siting alternatives for their facilities.”
2005-096	“With respect to the request of AE that the Board should provide clear directions respecting the classification of system and customer costs, the Board considers that the AESO should approach any situation in which there may be “shades of grey” in this designation exercise, with the position that a debatable interconnection project cost should be presumed initially to be customer-related unless clearly demonstrated otherwise.”
2005-096	“The Board, however, considers that a general stance that system enhancement costs are customer costs unless demonstrated otherwise is consistent with the expectation that the AESO adopt a more proactive stance in respect of its overall system planning and transmission system upgrade responsibilities, as detailed in the *Transmission Regulation*.”

Other Commission Decisions(cont'd)

Decision	Summary
2010-606	"The Commission considers that Article 9.3(c)(ii) of the current T&Cs provides a reasonable balance between the attribution of incremental costs caused by a connecting customer and the designation of costs as system costs where the AESO was already contemplating a system planning driven expenditure prior to the connection request. Article 9.3(c)(iii) already provides broad discretion to designate costs that would otherwise be classified as customer costs to be classified as system costs.“
3473-D02-2015	"…the Commission intended that the AESO would develop tariff provisions that would induce the market participant on the critical path to either consent to a shifting of the requested in-service date or absorb relevant incremental costs that would arise from a decision not to shift the requested in-service date."

Principles for Load Customers

- Provide a price signal
  - Unconstrained alternative selection
  - ISDs for system transmission projects should be moved if they can't be met without incurring significant increases to project costs (or the market participant can pay)
  - Where the <u>construction</u> of system transmission facilities are triggered, the market participant needs to provide some form of commitment
- System transmission facilities aren't built as the result of a connection(s) not proceeding
  - We need sufficient certainty that projects will "show up"
  - Don't construct system transmission facilities if market participants don't show up
- General high-level alignment with Decision 3473-D02-2015

Alternative Selection for Load Connections

Alternatives to connect to transmission system

a) most load connection projects will be radial facilities to existing transmission facilities with capacity

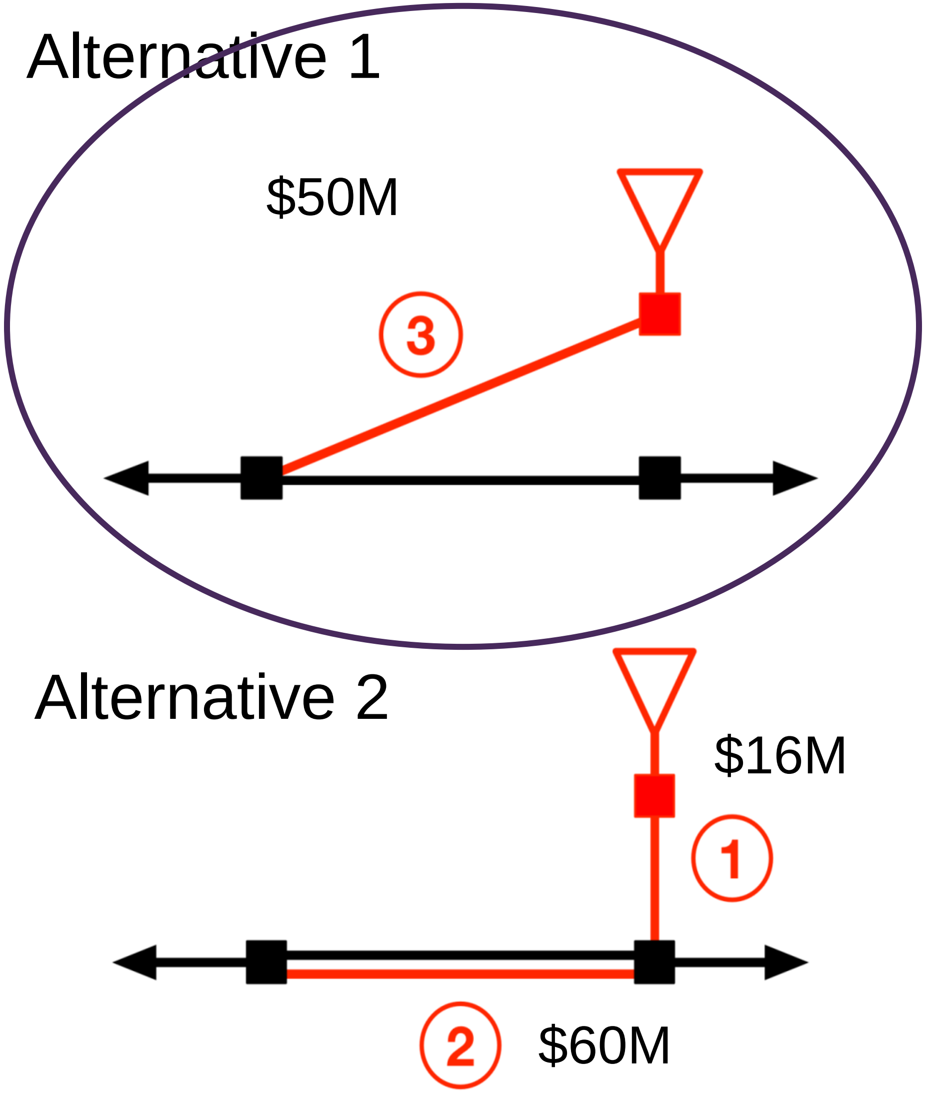
b) in some cases load connection projects may require an enhancement of existing system facilities or creation of looped facilities

- Load connection alternative must be unconstrained

and

- Alternative selected will be lowest overall costs

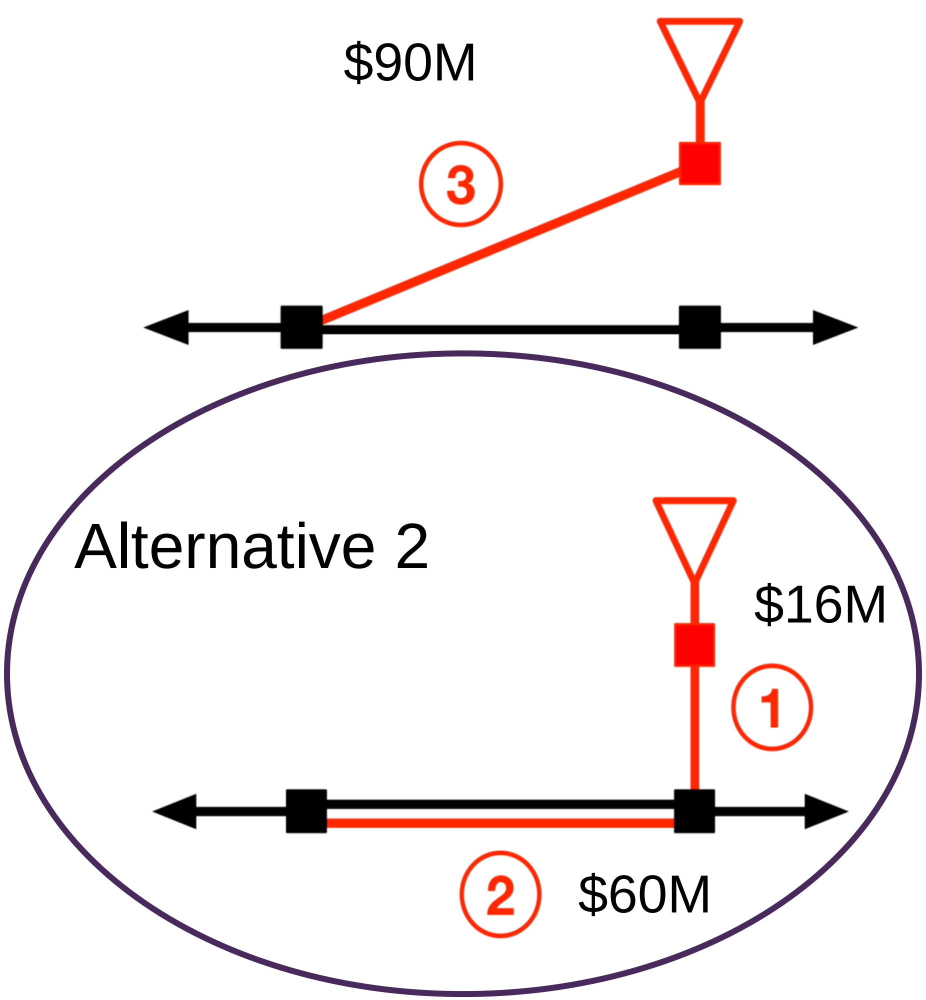
Alternative Selection - “Lowest Overall Costs”



- Both Alternative 1 and 2 are unconstrained
- Alternative 1 is a radial connection to a strong source
- Alternative 2 is a radial to a weaker source ① with a required system upgrade ②
- Alternative selection would result in Alternative 1 as it is the lowest overall costs (system upgrade required)

Alternative Selection - “Lowest Overall Costs”

Alternative 1



- Both Alternative 1 and 2 are unconstrained
- Alternative 1 is a radial connection to a strong source
- Alternative 2 is a radial to a weaker source ① with a required system upgrade ②
- Alternative selection would result in Alternative 2 as it is the lowest overall costs (with system upgrade required)

System Transmission Facilities Required for a Load Connection

Connection Alternative Selection

Majority of projects

- Radial connection to a strong source
- 100% participant-related costs

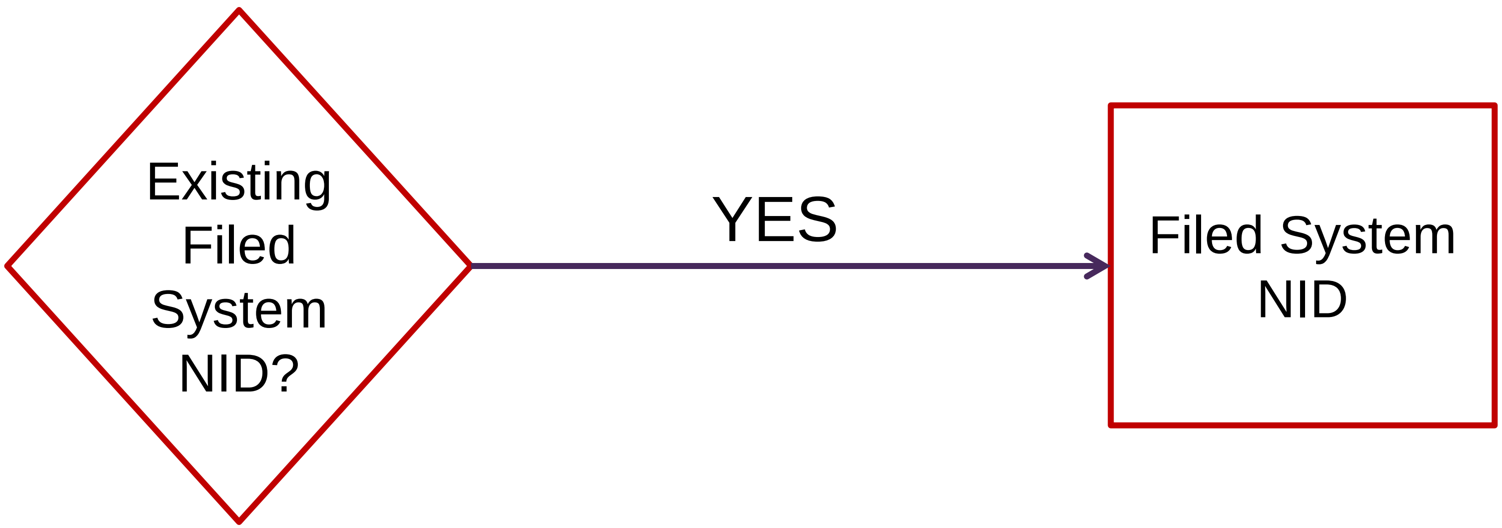
Few projects

- Lowest overall costs include looped facilities (system transmission facilities)
- System-related cost component

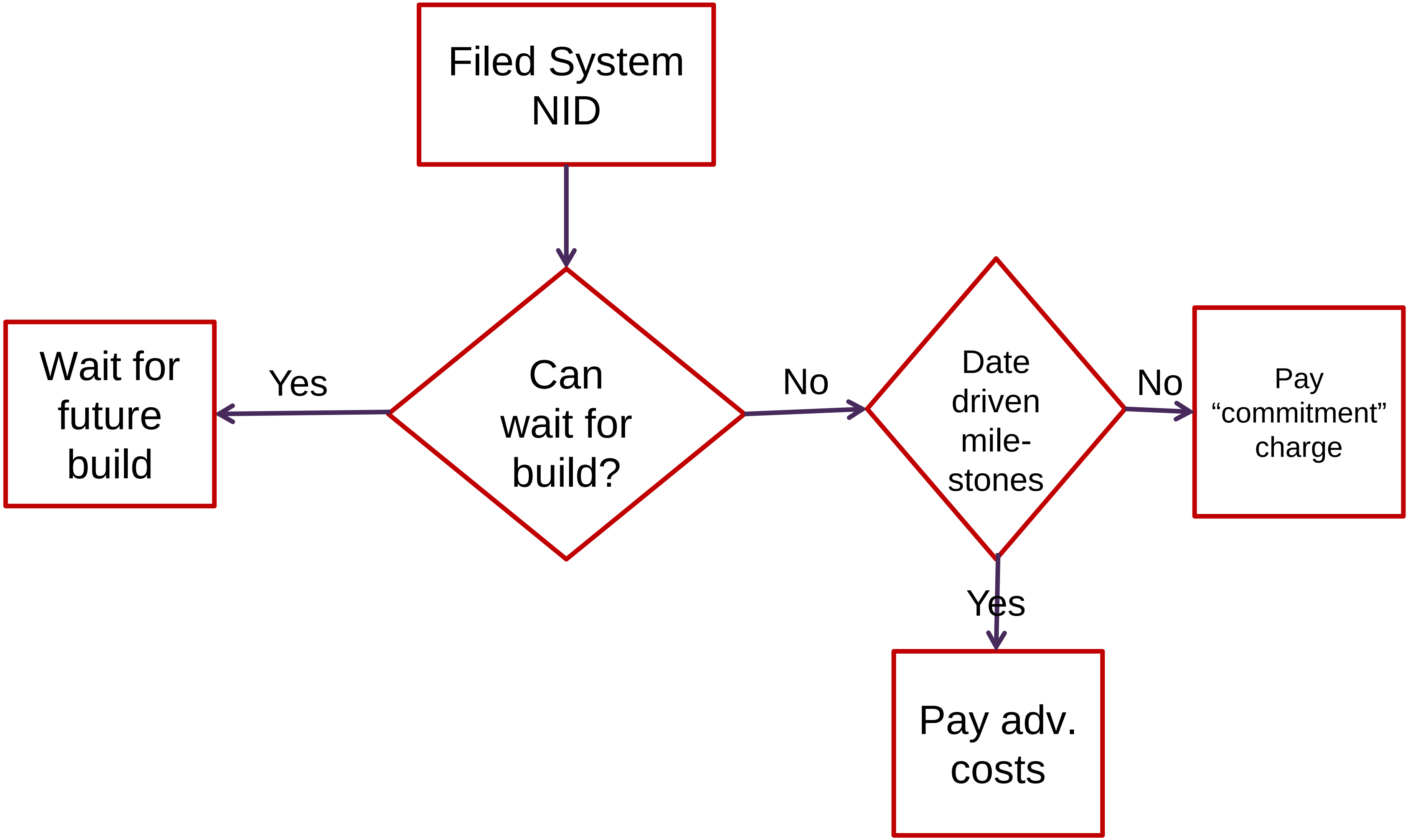
System Transmission Facilities Required for a Load Connection

- Current tariff refers to long term plan and “as reasonably expected” by the AESO
- “While the AESO’s intention to complete a loop of a new radial transmission line within five years can point to various types of documents, the Commission is unaware of any mechanism to ensure that planned loops are actually completed in accordance with the above noted planning documents. The Commission considers a five-year planning horizon to be arbitrary.”

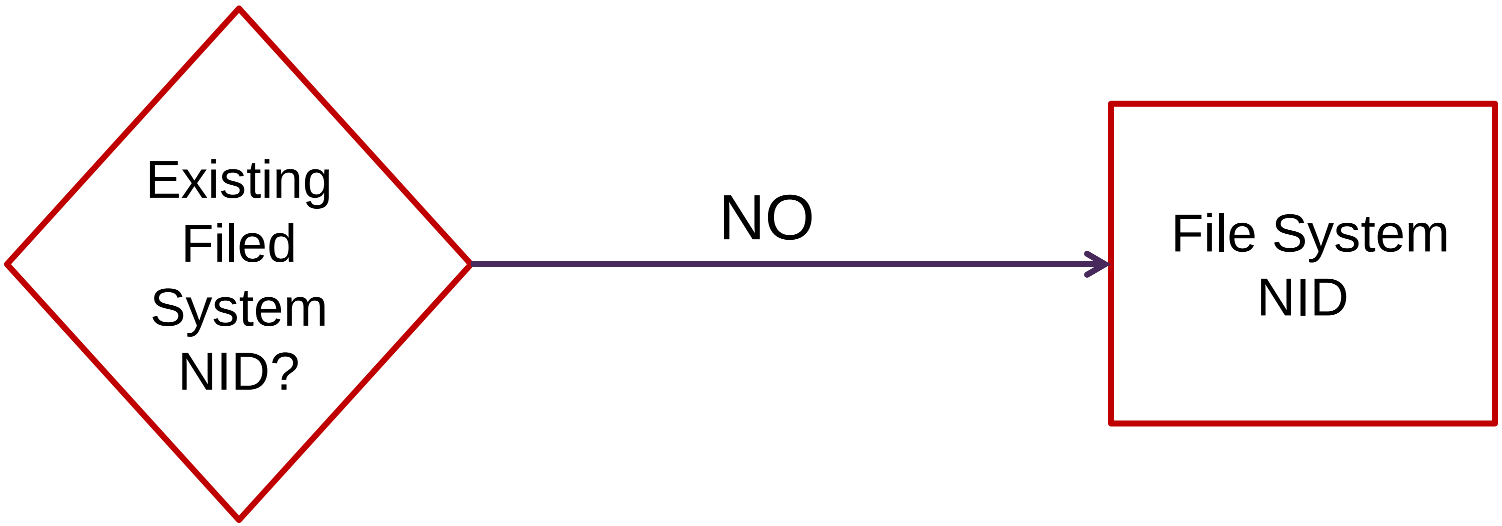
System Transmission Facilities Required for a Load Connection



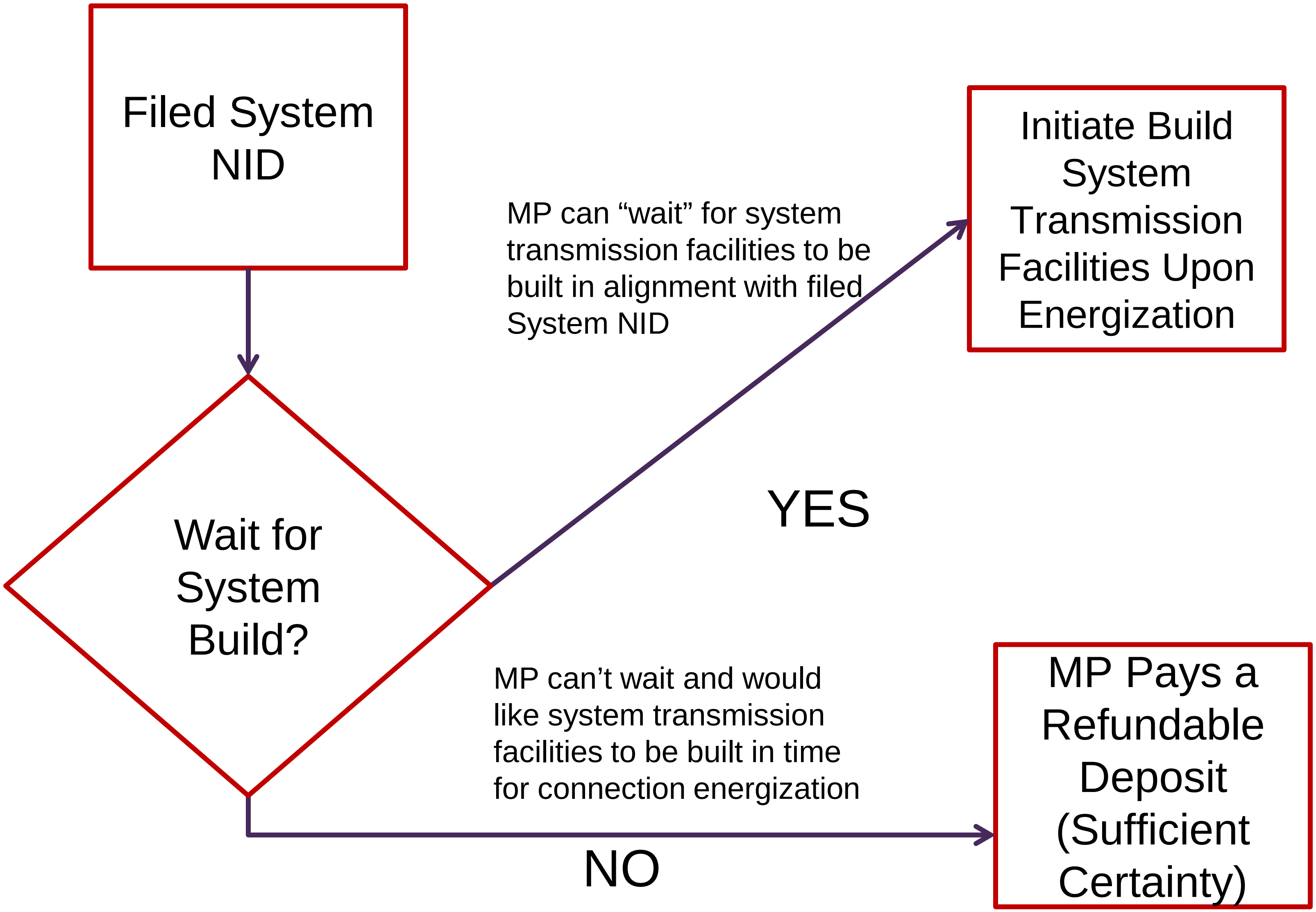
System Transmission Facilities Required for a Load Connection



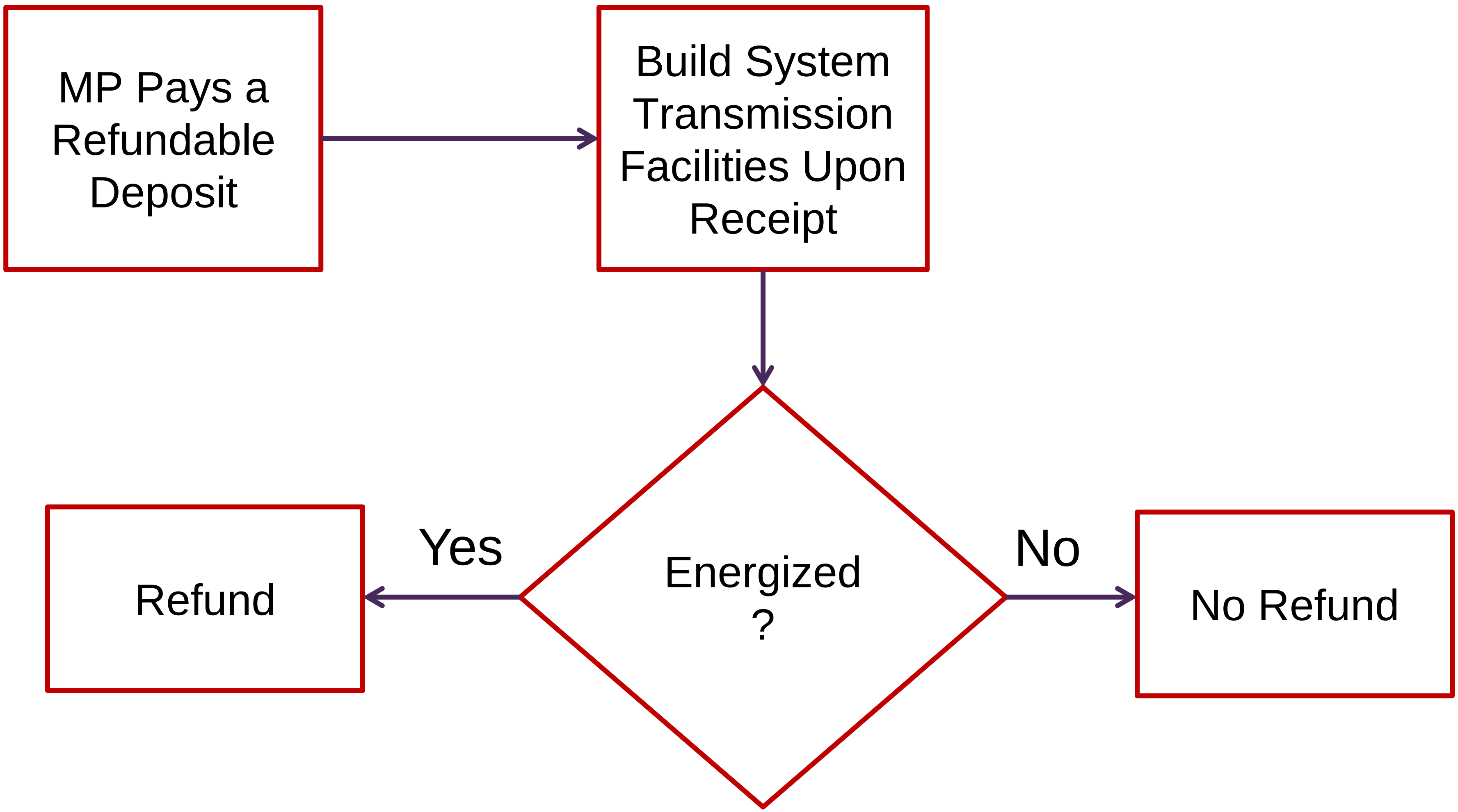
System Transmission Facilities Required for a Load Connection



System Transmission Facilities Required for a Load Connection – Concept 1 -“Refundable Deposit”



System Transmission Facilities Required for a Load Connection – Concept 1 – Refundable Deposit



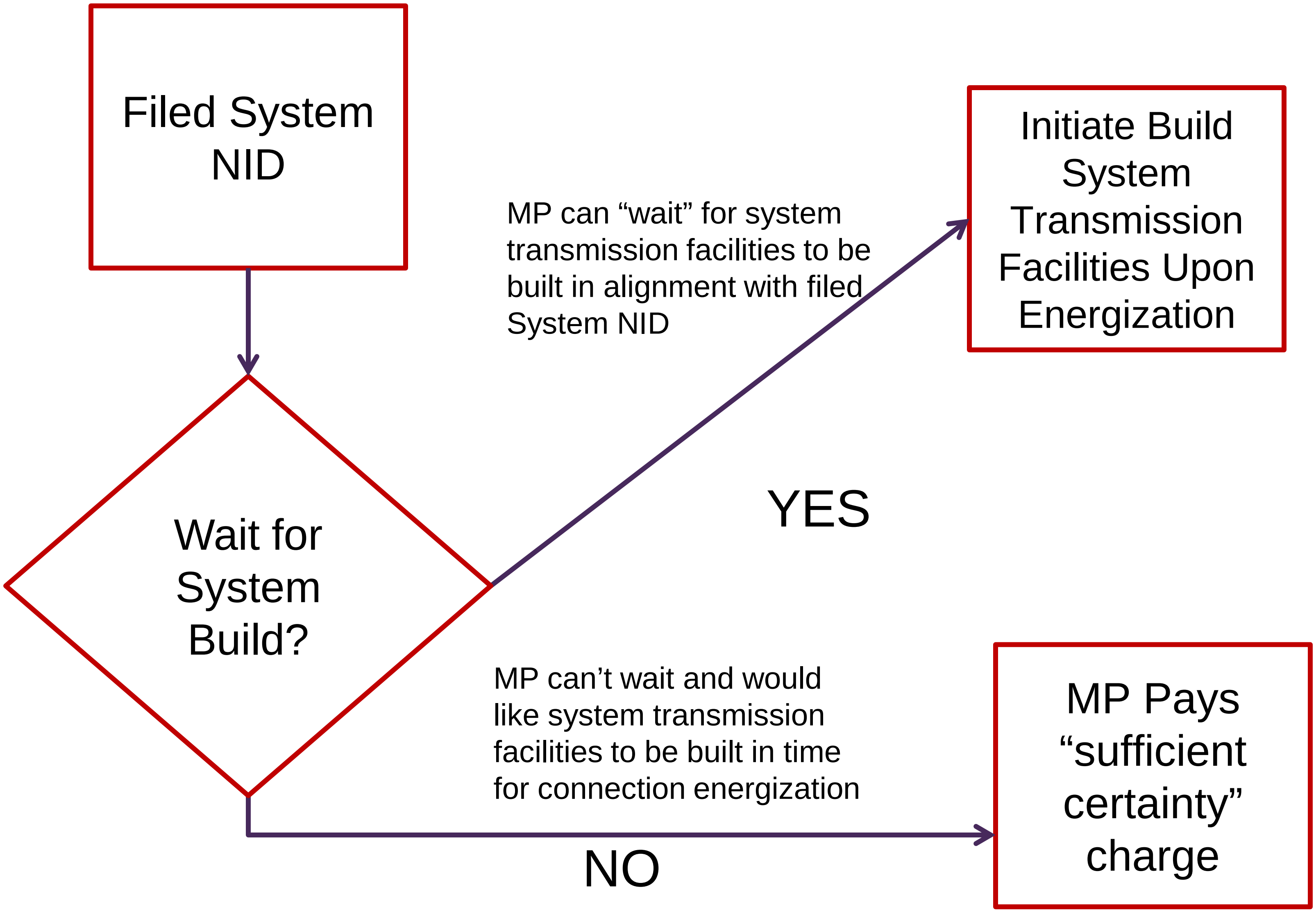
“Refundable Deposit” – What does it provide for the AESO?

- Provides the AESO with sufficient certainty that the connection project will energize
- Not building system transmission assets that will not be used
- Provides a price signal where there is limited capacity
- Only applies when the MP can’t “wait” for system transmission facilities

Pros and Cons – Concept 1 – Refundable Deposit

- Pros
  - Strong price signal (if you can't wait)
  - Aligns with GUOC incentives ("performance" = "energization")
  - Encourages timely energization (the AESO is holding a large deposit)
  - The MP can choose to "wait", stage their contract to accommodate current system capacity and construction will begin after energization
- Cons
  - System transmission facility costs might be prohibitively high
  - Delay in cost estimates (creation of system NID)

System Transmission Facilities Required for a Load Connection – Concept 2 – "Pay a Share"



System Transmission Facilities Required for a Load Connection – Concept 2 – “Pay A Share”

MP Pays an “sufficient certainty” charge → Build System Transmission Facilities Upon Receipt

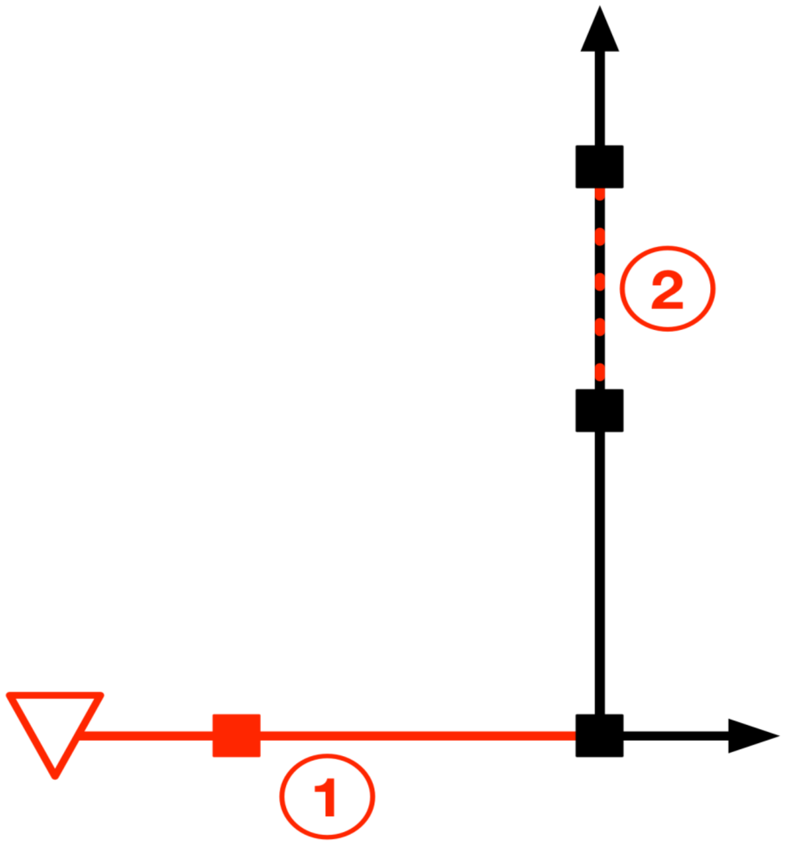
“Pay A Share” – What does it provide for the AESO?

- Restores a reasonable balance between certainty and price signals
- Provides the AESO with sufficient certainty that the connection project will energize
- May calculate in accordance with the current tariff provisions
- Provides a price signal where there is limited capacity
- Only applies when the market participant can’t “wait” for system transmission facilities
- Intended to address system build required that is not anticipated or planned in the AESO near term planning horizon (5 years)

Pros and Cons – Concept 2 – “Pay A Share”

- Pros
  - Market participant pays a share of the system transmission facilities for causing advancement of unplanned facilities
  - Strong price signal (if you can’t wait)
  - The MP can choose to “wait”, stage their contract to accommodate current system capacity (considering forecast growth) and initiation of the system transmission facility project will begin after energization
- Cons
  - “Commitment” cost charge might be high

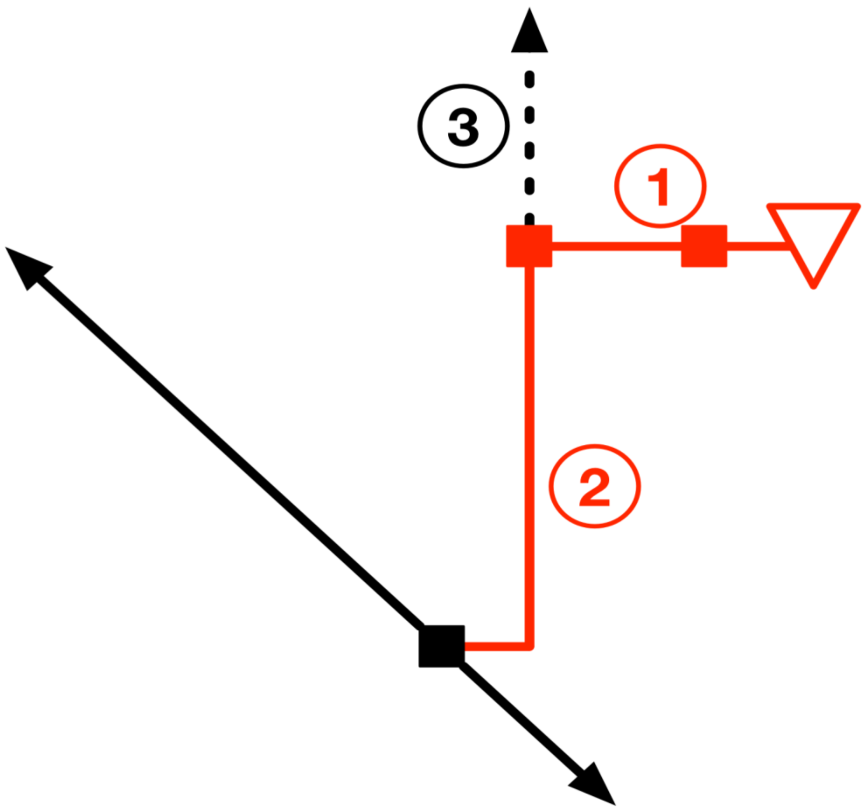
Example – Wait or Pay



Tariff Alignment

- Advancement costs apply to all system transmission facilities required for a load connection, not solely radial facilities planned to be looped (section 8 subsection 3(3)(b))
- “Accelerated Construction Costs” as contemplated in Decision 3473-D01-2015
- Filed system NID (with MW milestones) required, current tariff refers to the long term plan, or as ISO reasonably expects will be required in the future
- Differentiation between generation and load connections
- “Shared with system” cost provisions

Examples – Initially Radial then "Shared"



Next Steps

- Allow stakeholders to review presentation and concepts
- Gather stakeholder feedback and incorporate in to further work
- Follow up in next stakeholder session
- Work towards recommended approach for application

Rider A1 – Dow Chemical Canada Inc. / Dow Hydrocarbons / ASU2 Changes

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Rider A1 - Dow Duplication Avoidance Tariff (DAT) Issues

- Rider A1 inconsistent with other Rider A's with language and detail
- Forecast benefit table ends in 2021 – what happens after 2021?
  - 25 year business case assumption in original application does not reflect the expectation of asset life for a transmission line
- What is required in the ISO tariff to provide clarity on future duplication avoidance sites?

Rider A1 - Dow Duplication Avoidance Tariff (DAT) Next Steps

1. The AESO plans to update Rider A1 to authoritative language
2. High-level test of some criteria considered in original AEUB decision U98125 (available capacity, credible bypass threat, service life of transmission facilities)
3. Consideration of Rider A1 continuing to a reasonably expected transmission life period with recovery of O&M and losses annual/monthly payments from Dow
4. Add “expiry” or “term” to clarify what happens after a certain date, i.e. re-application for duplication avoidance tariff

Application Process, Timeline and Next Steps

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January 30, 2017 Session – Stakeholder Comments Review

- Clarification of transmission cost causation study results, specifically around regional assets costs – next session
- POD cost function work – next session
  - POD cost function translated to rates and investment
  - Concerns around installed capacity assumptions
  - One preference for Option #4 – installed capacity basis
  - Stakeholders request to see more data and results before deciding on preferred approach
- Request for transmission rate projection model on a timely basis – to be filed with application in Q2 2017

Checklist for 2018 ISO tariff application

Scope item	Status
Rider C / DAR / Tariff updates	100% complete
POD cost function work	90% complete
Transmission cost causation study	95% complete
Terms and conditions: Sections 4, 5, 8 and 9	65% complete
Clarify tariff for energy storage	100% complete
Updates to Proformas	90% complete
Clarify Rider A-1 – Dow duplication avoidance tariff	80% complete
Address direction from Commission regarding cost recovery from Critical Infrastructure Protection (CIP) work	75% complete
Long-term transmission rate projection model	75% complete

Tariff tentative timeline

Session	Date
3rd Technical Session	March 1, 2017
Stakeholder comment matrix posted	March 6, 2017
Stakeholder comments due	March 20, 2017
4th Technical/Information Session	late March/ early April 2017
Application Preview Session	April/May 2017
Application writing	Q1 – Q2 2017
Application filing	Q2 2017
2016 DAR Filing	Q3 2017
2018 tariff <u>update</u> application	Q3 2017
Regulatory review process for 2018 tariff application	Q4 2017 – Q1 2018
Compliance filing	Q2 2018

Next steps

- The AESO will invite participants to respond to this presentation through a comment matrix in the next few weeks. To allow transparency, the AESO will post all comments on AESO's website following the receipt of participants' input
- For more information:

  LaRhonda Papworth – Manager, Tariff Design
  403-539-2555
  larhonda.papworth@aeso.ca
- All consultation documents can be found on AESO website at www.aeso.ca by following the path:
  Rules, Standards and Tariff ►Stakeholder engagement ►2018 ISO tariff application

Further Discussion? Questions?

Public

Public

Request for Stakeholder Comments on AESO 2018 ISO Tariff Consultation

Background

On March 1, 2017, the AESO and stakeholders participated in a consultation meeting to discuss (1) potential changes to the ISO tariff's terms and conditions; (2) potential changes/amendments to Rider A1 – *Transmission Duplication Avoidance Adjustment Dow Chemical Canada Inc. / Dow Hydrocarbons / ASU2*; and (3) application process and next steps. Based on discussion at the meeting, the AESO invites written comments from stakeholders on the information presented. The meeting presentation is posted on the AESO website and can be accessed at www.aeso.ca by following the path Rules, Standards and Tariff ► Stakeholder engagement ► 2018 ISO Tariff Application.

Please use the comment form below when submitting comments to the AESO on the 2018 ISO tariff consultation. Please ensure that your comments represent all interests within your stakeholder organization with respect to the consultation. Please provide comments or questions no later than **March 17, 2017**, to LaRhonda Papworth at larhonda.papworth@aeso.ca or 403-539-2555.

Consultation and Stakeholder Identification

Date of Request for Comments:	March 7, 2017
Period of Consultation:	November 15, 2016 – March 7, 2017
Comments From:	
Date:	
Contact:	
Phone:	
Email:	

Stakeholder Comments on AESO Information

Stakeholder Comment
(1) ISO Tariff Terms and Conditions Proposals (Slides 6 – 30)
A. Principles for Load Customers (Slide 10): • ***Provide a price signal;*** • ***System transmission facilities are not built as the result of a connection(s) not proceeding; and*** • ***General high-level alignment with Decision 3473-D02-2015.***
Stakeholder Comments:
B. Alternative Selection for Load Connections (Slides 11-13):

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Stakeholder Comment
• ***Load connection alternative must be <u>unconstrained</u>; and*** • ***Alternative selected will be <u>lowest overall costs</u> alternative.***
Stakeholder Comments:
C. System Transmission Facilities Required for a Load Connection – "Filed System NID" (Slides 14 – 16): • ***AESO is proposing to change language in the ISO tariff terms and conditions to add clarity regarding "long term transmission system plan" and "as the ISO reasonable expects will be required in the future" (section 8, subsection 3(3)(b)).***
Stakeholder Comments:
D. System Transmission Facilities Required for a Load Connection – <u>with</u> a Filed System NID (Slide 17): • ***Market participant can wait for build?*** • ***If not, a System NID with date driven milestones – customer would pay advancement costs calculated in accordance with current ISO tariff provisions*** • ***If not, and a System NID <u>without</u> date driven milestones – customer would pay "commitment" charge***
Stakeholder Comments:
E. Concept 1: System Transmission Facilities Required for a Load Connection – <u>without</u> a Filed System NID (Slides 18 - 21): • ***Market participant can wait for build?*** • ***If market participant <u>can</u> wait for system development (with milestones), the system transmission development will be initiated upon market participant's energization;*** • ***If market participant <u>cannot</u> wait for system development (with milestones), market participant pays a refundable deposit in order to provide "sufficient certainty" of project going ahead.*** ○ ***Market participant will be refunded deposit upon connection project energization***
Stakeholder Comments:
F. Concept 1: Refundable Deposit – What does it provide for the AESO? (Slide 21): • ***Provides "sufficient certainty" that connection project will energize;*** • ***Will not build system transmission assets that will not be used;*** • ***Provides a price signal where there is limited capacity; and*** • ***Only applies when the market participant cannot wait for system transmission facilities.***
Stakeholder Comments:

Stakeholder Comment

G. Concept 1: Refundable Deposit – Pros and Cons (Slide 22):

Pros:

- ***Strong price signal if market participant cannot wait;***
- ***Aligns with Generator Unit Owner's Contribution ("GUOC") incentives, (i.e. "performance" = "energization");***
- ***Encourages timely energization as the AESO is holding a large deposit;***
- ***The market participant can choose to wait or stage their contract to accommodate current system capacity and system facilities construction will begin after connection project energization.***

Cons:

- ***System transmission facility costs might be prohibitively high;***
- ***Delay in cost estimates (may not occur until the creation of the system NID).***

Stakeholder Comments:

H. Concept 2: System Transmission Facilities Required for a Load Connection – <u>without</u> a Filed System NID (Slides 23 - 24):

- ***Market participant can wait for build?***
- ***If market participant <u>can</u> wait for system development (with milestones), the system transmission development will be initiated upon market participant's energization;***
- ***If market participant <u>cannot</u> wait for system development (with milestones), market participant pays a "sufficient certainty charge" in order to provide "sufficient certainty" of project going ahead.***
  - ***System transmission facilities will be initiated upon receipt of the "sufficient certainty charge".***

Stakeholder Comments:

I. Concept 2: Sufficient Certainty Charge – What does it provide for the AESO? (Slide 25):

- ***Restores a reasonable balance between certainty and price signals;***
- ***Provides the AESO with sufficient certainty that the connection project will energize;***
- ***May calculate in accordance with the current tariff provisions;***
- ***Provides a price signal where there is limited capacity;***
- ***Only applies when the market participant cannot wait for system transmission facilities; and***
- ***Intended to address system build required that is not anticipated or planned in the AESO near-term planning horizon (5 years).***

Stakeholder Comments:

J. Concept 2: Sufficient Certainty Charge – Pros and Cons (Slide 26):

Pros:

- ***Market participant pays a share of the system transmission facilities for causing***

Stakeholder Comment

advancement of unplanned facilities;

- ***Strong price signal if market participant cannot wait;***
- ***The market participant can choose to wait or stage their contract to accommodate current system capacity (considering forecast growth) and system facilities construction will begin after connection project energization.***

Cons:

- ***"Sufficient certainty charge" cost might be high.***

Stakeholder Comments:

K. Tariff Alignment – Other items (Slides 28 - 29):

1. ***Advancement costs apply to ally system transmission facilities required for a load connection, not solely radial facilities planned to be looped (section 8, subsection 3(3)(b));***
2. ***"Accelerated construction costs" as contemplated in Decision 3473-D02-2015;***
3. ***Filed system NID (with MW milestones) required, current tariff refers to the long-term plan, or as ISO reasonable expects will be required in the future;***
4. ***Differentiation between generation and load connections; and***
5. ***"Shared with system" cost provisions.***

Stakeholder Comments:

L. Next Steps (Slide 30)

- ***Allow stakeholders to review presentation and concepts;***
- ***Gather stakeholder feedback and incorporate in to further work;***
- ***Follow up in next stakeholder session; and***
- ***Work towards recommended approach for application.***

Stakeholder Comments:

(2) Rider A1 – Dow Chemical Canada Inc. / Dow Hydrocarbons / ASU2 Changes (Slides 31 – 33)

A. Rider A1 – Dow Duplication Avoidance Tariff (DAT) Issues (Slide 32):

- ***Rider A1 is inconsistent with other Rider A's with language and detail;***
- ***Forecast benefit table ends in 2021 – what happens after 2021; and***
    - ***25-year (approx.) business case assumption in original application does not reflect the expectation of asset life for a transmission line.***
- ***What is required in the ISO tariff to provide clarity on future duplication avoidance sites' treatment.***

Stakeholder Comments:

B. Rider A1- Dow Duplication Avoidance Tariff (DAT) – Next Steps (Slide 33):

Stakeholder Comment
1. The AESO plans to update Rider A1 to authoritative language; ***2. High-level test of some criteria considered in original AEUB decision U98125 (available capacity, credible bypass threat, and service life of transmission facilities);*** ***3. Consideration of Rider A1 continuing to a reasonable expected transmission life period with recovery of O&M and losses annual/monthly payments from Dow; and*** ***4. Add "expiry" or "term" to clarify what happens after a certain date, i.e. re-application for duplication avoidance tariff? Other?***
Stakeholder Comments:
(3) Application Process, Timeline and Next Steps (Slides 34 – 39)
A. The AESO discussed the status of a number of 2018 ISO tariff application scope items (Slide 36) and a 2018 ISO tariff tentative timeline.
Stakeholder Comments:
Additional Comments

Please return this form with your comments by **March 17, 2017**, to:

LaRhonda Papworth
Manager, Tariff Design
Email: larhonda.papworth@aeso.ca
Phone: (403) 539-2555

Consolidated Stakeholder Comments on AESO 2018 ISO Tariff Consultation Session – January 30, 2017

Background

On January 30, 2017, the AESO and stakeholders participated in a consultation meeting to discuss (1) a technical presentation on transmission cost causation study results; (2) a technical presentation on point of delivery (POD) cost function database results; (3) progress on annual tariff updates, deferral account reconciliations, and Rider C, *Deferral Account Adjustment Rider*, matters; and (4) the process and next steps for the 2018 ISO tariff application. The AESO invited written comments from stakeholders on the information presented at the meeting. The written comments received from stakeholders are consolidated below.

A copy of the presentation provided by the AESO at the January 30, 2017 meeting is posted on the AESO website and can be accessed at www.aeso.ca by following the path Tariff ► Stakeholder engagement ► 2018 ISO tariff application.

Stakeholder Comments on AESO Information

Stakeholder Comment
(1) Transmission Cost Causation Study – Preliminary Results (Slides 6 – 36)
A. Scope of 2018-2020 Transmission Cost Causation Study (Slide 18): ***i. Update of 2014-2016 transmission cost causation study;*** ***ii. Using identical methodology*** ***iii. Using same data sources, plus a few additional sources; and*** ***iv. For years 2018-2020.***
Alberta Direct Connect Consumers Association ("ADC"): ADC supports this approach.
ATCO Electric: While ATCO Electric understands that the AESO's 2018 Transmission Cost Causation Study methodology is similar to the Cost Study methodology approved in the AESO's 2014 ISO Tariff application, ATCO Electric will require more time to review and understand the updated Cost Study as well as associated Rate Design implications once the AESO submits its 2018 application.
Dual Use Customers ("DUC"): DUC supports the proposed methodology to update the transmission cost causation study.
EPCOR Distribution & Transmission Inc. ("EDTI"): EDTI is supportive and has no concerns at this time.
ENMAX Power Corporation ("EPC"): No comment.
FortisAlberta Inc.: No comment.

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www.aeso.ca www.poweringalberta.com

Stakeholder Comment
Industrial Power Consumers Association of Alberta ("IPCAA"): IPCAA supports the use of identical methodology to update the transmission cost causation study.
Primary Service Group ("PSG"): No comment.
B. Process for 2018-2020 Transmission Cost Causation Study (Slide 19): ***i. Update inputs and conduct 2018-2020 transmission cost causation study in 2016*** ***ii. Present draft results to stakeholders in January 2017; and*** ***iii. Include the study in the 2018 ISO tariff application.***
Alberta Direct Connect Consumers Association ("ADC"): ADC Supports this approach.
ATCO Electric: No comment.
Dual Use Customers ("DUC"): No comment.
EPCOR Distribution & Transmission Inc. ("EDTI"): EDTI is supportive and has no concerns at this time.
ENMAX Power Corporation ("EPC"): No comment.
FortisAlberta Inc.: No comment.
Industrial Power Consumers Association of Alberta ("IPCAA"): IPCAA supports the AESO's proposed process.
Primary Service Group ("PSG"): No comment.
C. Preliminary Functionalization - 2018 (Slides 20 – 24):

Bulk	***Regional***	***POD***
53.4%	***26.3%***	***20.3%***

| | |---|
| Alberta Direct Connect Consumers Association ("ADC"):
Slide 21 indicates that there has been an increase of regional assets in the order of $1.7B since 2016. Can the AESO provide a list of the key projects that are included in the total? |
| ATCO Electric:
No comment. |
| Dual Use Customers ("DUC"):
We are surprised with the Regional cost increases. The DUC looks forward to the opportunity to review |

Stakeholder Comment

the proposed COS models.

EPCOR Distribution & Transmission Inc. (“EDTI”):

EDTI has no concerns at this time.

ENMAX Power Corporation (“EPC”):

No comment.

FortisAlberta Inc.:

No comment.

Industrial Power Consumers Association of Alberta (IPCAA):

These results seem reasonable. However, the presentation raises the following question:

Slide 21 indicates that the 2018 Regional Costs are $4.4 Billion. Slide 11 indicates that 2016 Regional Costs were $2.7 B. Can the AESO provide a list of the regional projects that make up this increase of $1.7 B over the 2-year timeframe?

Primary Service Group (“PSG”):

No comment.

D. Preliminary Functionalization - 2019 (Slides 25 – 29):

Bulk	***Regional***	***POD***
55.0%	***25.1%***	***19.9***

Alberta Direct Connect Consumers Association (“ADC”):

No comment.

ATCO Electric:

No comment.

Dual Use Customers (“DUC”):

No comment.

EPCOR Distribution & Transmission Inc. (“EDTI”):

EDTI has no concerns at this time.

ENMAX Power Corporation (“EPC”):

No comment.

FortisAlberta Inc.:

No comment.

Industrial Power Consumers Association of Alberta (IPCAA):

These results seem reasonable

Primary Service Group (“PSG”):

No comment.

E. Preliminary Functionalization - 2020 (Slides 30 – 34):

Stakeholder Comment		
Bulk	***Regional***	***POD***
53.7%	***26.2%***	***20.1%***

Alberta Direct Connect Consumers Association ("ADC"):
No comment.

ATCO Electric:
No comment.

Dual Use Customers ("DUC"):
No comment.

EPCOR Distribution & Transmission Inc. ("EDTI"):
EDTI has no concerns at this time.

ENMAX Power Corporation ("EPC"):
No comment.

FortisAlberta Inc.:
No comment.

Industrial Power Consumers Association of Alberta (IPCAA):
These results seem reasonable.

Primary Service Group ("PSG"):
No comment.

F. Preliminary Functionalization – 2018-2020 3-year Average (Slide 35):

Bulk	***Regional***	***POD***
54.0%	***25.9%***	***20.1%***

Alberta Direct Connect Consumers Association ("ADC"):
No comment.

ATCO Electric:
No comment.

Dual Use Customers ("DUC"):
No comment.

EPCOR Distribution & Transmission Inc. ("EDTI"):
EDTI has no concerns at this time.

ENMAX Power Corporation ("EPC"):
No comment.

FortisAlberta Inc.:
No comment.

Stakeholder Comment

Industrial Power Consumers Association of Alberta (IPCAA):

These results seem reasonable.

Primary Service Group ("PSG"):

No comment.

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(2) Point-of-delivery ("POD") Cost Function – Preliminary Results and Discussion (Slides 38 – 61)

A. Background and POD Cost Function Cost Curve Options (Slides 38 - 39):

Cost Curve Options	Greenfield	Upgrade	0 MW Contracts
#1 – Pre-2014 practice	***Contract***	***Contract***	***Include***
#2 Current practice (until thoroughly explored)	***Contract***	***Contract***	***Remove***
#3 As requested in Decision 2014-242	***Contract***	***Installed***	***By using installed, 0 MW projects are included***
#4 Not asked for	***Installed***	***Installed***	
~~***#5 AESO not considering (not asked, not debated)***~~	~~***Installed***~~	~~***Contract***~~	~~***?***~~

Alberta Direct Connect Consumers Association ("ADC"):

Valid to examine the various approaches.

ATCO Electric:

No comment.

Dual Use Customers ("DUC"):

The DUC supports Option 4 as installed capacity (e.g. mid-transformer size) is much better aligned to cost causation than contract capacity. As our evidence in the last proceeding clearly showed, some market participants do not have the proper incentives to contract for capacity upgrades. Upgrade projects with 0 MW contract capacity increase are a clear indication that contract capacity is not appropriate for the development of the POD cost function.

EPCOR Distribution & Transmission Inc. ("EDTI"):

EDTI has no concerns at this time.

ENMAX Power Corporation ("EPC"):

No comment.

FortisAlberta Inc.:

No comment.

Industrial Power Consumers Association of Alberta (IPCAA):

IPCAA has two main concerns: (1) the intergenerational equity issues associated with changing the POD function cost curve at this point; and (2) the AESO's ability to assemble accurate installed capacity data, in order to create an accurate curve. These issues should be examined thoroughly.

Stakeholder Comment
Primary Service Group ("PSG"): No comment.
B. POD Cost Database and Cost Curves - Preliminary (Slides 40 – 45): ***i. Option #1 Cost Curve;*** ***ii. Option #1 Cost Curve comparison to existing tariff;*** ***iii. Option #4 Cost Curve;*** ***iv. Options #1, #2, #3 and #4 Cost Curves comparison; and*** ***v. Impact on curve from Option #1 and Option #4***
Alberta Direct Connect Consumers Association ("ADC"): It would be helpful to see how the curves translate into the POD tariff.
ATCO Electric: No comment.
Dual Use Customers ("DUC"): The DUC supports Option #4. The DUC suggests the AESO consider the following: • Develop a cost curve that correlates capital costs and installed capacity • Develop a correlation between installed capacity and contract capacity (IC/CC ratio) using all AESO PODs (with potentially excluding those services where market participants do not the incentive to fully contract for capacity) • Use the IC/CC ratio to determine which slopes of the cost curve line are used to develop the POD rates. For example, instead of using the slope between 7.5 MW and 17 MW on a capital cost vs. contract capacity curve, use 9 MW to 20 MW from the Option #4 capital cost vs. installed capacity curve, where the 9 MW and 20 MW values are derived using the IC/CC ratio. The DUC submits that using the IC/CC ratio will introduce less inaccuracy to the development of the POD cost function than using Options #1 to #3 with contract capacities. • Only use projects from the past 5 years – older project data is likely not as accurate and influenced by the accuracy of cost escalators. A valid sample set should be obtainable from using project cost data from the past ~5 years.
EPCOR Distribution & Transmission Inc. ("EDTI"): EDTI has no concerns at this time.
ENMAX Power Corporation ("EPC"): No comment.
FortisAlberta Inc.: No comment.
Industrial Power Consumers Association of Alberta (IPCAA): Can the AESO provide additional information on how the curves translate into the POD portion of the tariff?
Primary Service Group ("PSG"): No comment.

Stakeholder Comment
C. Potential evaluation criteria for cost curve options (Slides 46 – 58): ***i. Maintaining alignment between POD cost function, maximum investment levels and the POD charge in Rates DTS and PSC;*** ***ii. Consistency with past practice (post-2007);*** ***iii. Maximize number of projects in database / statistical criteria for project inclusion;*** ***iv. Degree of relationship between installed capacity and contract capacity;*** ***v. "Lumpiness" of installed capacity and standard transformer sizes;*** ***vi. Number of assumptions required to determine installed vs contract capacity;*** ***vii. Behavior of market participant's relationship to installed vs contract capacity;*** ***viii. Encouraging staging to contract appropriately / planned signal from contract capacity vs installed capacity;*** ***ix. Potential to eliminate substation fraction / treatment of split between DTS and STS shared costs;*** ***x. Rates reflect true costs per MW / sending the "right" price signal;*** ***xi. Equal services treated equally, unequal services treated unequally; and*** ***xii. Bridging the "gap" / fairness of treatment of customers with charges based on two different approaches.***
Alberta Direct Connect Consumers Association ("ADC"): Does the AESO have an estimate of the difference between installed capacity and contract capacity in the provinces POD facilities? Has there been a great number of POD upgrades where the contract capacity hasn't increased?
ATCO Electric: No comment.
Dual Use Customers ("DUC"): DUC submits that response to B. above best meets these criteria.
EPCOR Distribution & Transmission Inc. ("EDTI"): No comment.
ENMAX Power Corporation ("EPC"): No comment.
FortisAlberta Inc.: No comment.
Industrial Power Consumers Association of Alberta (IPCAA): The AESO has listed some fair concerns.
Primary Service Group ("PSG"): No comment.
D. Criteria Summary / Ranking (Slides 59 – 60):

Rank	***Criteria***	***Rate Design Principles***

Stakeholder Comment		
1	***Maintaining alignment between POD cost function, maximum investment levels and the POD charge in Rates DTS and PSC***	***Fairness, Objectivity, and Equity*** ***Provision of Price Signals***
2	***Degree of relationship between installed capacity and contract capacity***	***Provision of Price Signals***
3	***Rates reflect true costs per MW***	***Fairness, Objectivity, and Equity*** ***Provision of Price Signals***
4	***Treatment of split between DTS and STS shared costs***	
5	***Sending the "right" price signal***	***Provision of Price Signals***
6	***Maximize the number of projects in database / statistical criteria for project exclusion***	***Fairness, Objectivity, and Equity***
7	***Fairness of treatment of customers with charges based on two different approaches, consistency with past practice (post-2007)***	***Fairness, Objectivity, and Equity*** ***Stability and Predictability***
8	***Behavior of market participants relationship to MWs***	***Fairness, Objectivity, and Equity*** ***Provision of Price Signals***
9	***Number of assumptions required to determine installed vs contract capacity***	***Fairness, Objectivity, and Equity*** ***Stability and Predictability*** ***Practicality***

Alberta Direct Connect Consumers Association ("ADC"):

Criteria seems reasonable.

ATCO Electric:

No comment.

Dual Use Customers ("DUC"):

DUC submits that response to B. above best meets these criteria.

EPCOR Distribution & Transmission Inc. ("EDTI"):

EDTI has no concerns at this time.

ENMAX Power Corporation ("EPC"):

No comment.

FortisAlberta Inc.:

No comment.

Industrial Power Consumers Association of Alberta (IPCAA):

These Rate Design Principles have been stated fairly.

Stakeholder Comment
Primary Service Group ("PSG"): No comment.
E. POD Cost Function Next Steps (Slide 61): ***(1) Gather more information from stakeholders in order to develop subjective and objective comparisons of Option #1 and Option #4;*** ***(2) Provide additional analysis to stakeholders on Option #1 and Option #4 to illustrate preliminary rates and investments under each option; and*** ***(3) Present the AESO's position at upcoming stakeholder session in March or April.***
Alberta Direct Connect Consumers Association ("ADC"): ADC agrees that further analysis is required before deciding on a preferred option.
ATCO Electric: No comment.
Dual Use Customers ("DUC"): DUC supports these next steps. The DUC asks the AESO to consider our response to B. above.
EPCOR Distribution & Transmission Inc. ("EDTI"): No comment.
ENMAX Power Corporation ("EPC"): No comment.
FortisAlberta Inc.: No comment.
Industrial Power Consumers Association of Alberta (IPCAA): IPCAA supports the proposed next steps.
Primary Service Group ("PSG"): No comment.
(3) Proposal to Apply for Interim Changes to Rider C and Deferral Account Reconciliations (Slides 63 – 80)
A. The AESO anticipates filing an application before the end of February for interim approval of changes to address the following issues (Slide 66): ***i. To reduce transfers between services in deferral account reconciliation applications:*** ***a. Determine Rider C as percentage (rather than as $/MWh);*** ***b. Determine Rider C based on production year (rather than quarter); and*** ***ii. To address issues raised by Primary Service Group in the 2015 deferral account reconciliation proceeding:*** ***a. Allocate deferral account balances on both Rate DTS and Rate PSC amounts.***
Alberta Direct Connect Consumers Association ("ADC"): ADC supports the timely filing of the Rider C changes by the end of February and will lend its support in

Stakeholder Comment
the AUC process.
ATCO Electric: ATCO Electric is supportive of the AESO's approach and timing towards making changes with respect to its Rider C.
Dual Use Customers ("DUC"): DUC supports the AESO's proposal.
EPCOR Distribution & Transmission Inc. ("EDTI"): It is not clear to EDTI whether the calculation of Rider C as a percentage will be on total DTS charges or DTS charges net of pool price impacted charges such as operating reserve. EDTI is concerned that if Rider C is calculated as a percentage of total DTS charges including operating reserve, a spike in actual pool price may cause Rider C revenues to grossly exceed the forecast amounts. To avoid this potential problem, the proposal to calculate Rider C as a percentage should specify calculation based on DTS charges net of pool price impacted charges. EDTI supports this proposal subject to resolution of this concern.
ENMAX Power Corporation ("EPC"): EPC supports changes which reduce the magnitude for Rider C.
FortisAlberta Inc.: FortisAlberta supports calculating Rider C as a percentage of revenue rather than as $/MWh. FortisAlberta supports interim changes to the Rider C as long as the timing of the approval and the changes to the Rider C provides FortisAlberta with sufficient time to update, file and receive its approval from the Commission with regard to the standardized Quarterly AESO DTS Deferral Account Rider templates to accommodate the changes to Rider C. In addition to the approval of the standardized templates, as per Decision 2012-304, FortisAlberta is directed to file its Quarterly AESO DTS Deferral Account Rider Application within 3 business days of the AESO's Rider C publication. FortisAlberta would like to ensure that any interim approvals requested by the AESO considers FortisAlberta and the other utilities' quarterly applications filing deadlines.
Industrial Power Consumers Association of Alberta (IPCAA): IPCAA supports the AESO's proposal.
Primary Service Group ("PSG"): The Primary Service Group supports the AESO promptly filing an application for interim approval to address the issues identified.
B. The AESO does not plan to address in its interim application the following matters raised in stakeholder comments (Slides 72-73): ***i. To determine Rider C separately for bulk system, regional system, and point of delivery rate components;*** ***ii. To provide more extensive information beyond the analysis presented to stakeholders;*** ***iii. To address the allocation of deferral account balances for years prior to 2017 (which is under consideration in the 2015 deferral account reconciliation proceeding;***

Stakeholder Comment
iv. To allocate deferral account balances on amounts other than Rates DTS and PSC (such as Rate UFLS, Riders A1-A4, or payment in lieu of notice amounts); or ***v. To modify the timing of publishing Rider C quarterly charges or credits.***
Alberta Direct Connect Consumers Association ("ADC"): ADC agrees that the interim tariff should be limited in scope.
ATCO Electric: ATCO Electric is supportive of the AESO's plan to exclude the above noted items as part of its Rider C process.
Dual Use Customers ("DUC"): The DUC agrees that these issues are more appropriately dealt with in the upcoming GTA proceeding.
EPCOR Distribution & Transmission Inc. ("EDTI"): See EDTI's response to part A. EDTI requires more information regarding the calculation of Rider C as a percentage, specifically whether the calculation will be net of pool price related charges.
ENMAX Power Corporation ("EPC"): No comment.
FortisAlberta Inc.: No comment.
Industrial Power Consumers Association of Alberta (IPCAA): IPCAA has no concerns with this approach.
Primary Service Group ("PSG"): The Primary Service Group supports the AESO proposal to exclude the above issues from the interim application.
C. Application timing (Slides 74 and 79): ***i. Application would be filed at end of February;*** ***ii. Interim approval would be requested by end of May;*** ***iii. Interim changes to Rider C would be effective July 1, 2017; and*** ***iv. Request for final approval of changes will be included in 2018 ISO tariff application.***
Do you support the AESO's plan to apply for interim changes to Rider C and deferral account reconciliations? Support / Oppose / Indifferent
Alberta Direct Connect Consumers Association ("ADC"): **Support** All high load factor loads incur a real cost (both in lost use of capital and foregone interest) with the current Rider C methodology. The timely change of methodology will result in a fair allocation of deferral amounts for all DTS customers.
ATCO Electric: **Support** ATCO Electric is supportive of the AESO's plan with respect to interim changes to Rider C and deferral account reconciliations. ATCO Electric is of the view that the AESO's proposal to change Rider C

Stakeholder Comment
recovery from a $/MWh to a Percentage basis should help reduce true-up balances amongst market participants. ATCO Electric considers, however, that it will need to review the AESO's proposal to understand the mechanics of the new Rider C calculation as it pertains to billing Transmission Direct Customers. As well, ATCO Electric will need to coordinate and be consistent with the other DFOs to make any necessary changes to the DFO's Quarterly Rider process for flowing through AESO costs.
Dual Use Customers ("DUC"): **Support** A quick, interim solution to the Rider C issues is required. Rider C is becoming more of an issue for some DUC members. Rider C as a percentage of revenue is likely a much better way to allocate additional base rate charges / credits.
EPCOR Distribution & Transmission Inc. ("EDTI"): **Oppose** At this time EDTI opposes the proposed interim changes to Rider C due to the concerns described in the responses to parts A and B of this section. If these concerns can be resolved to the satisfaction of EDTI then EDTI will support the AESO's plan to apply for interim changes to Rider C and deferral account reconciliations.
ENMAX Power Corporation ("EPC"): **Support** EPC supports interim changes to Rider C effective July 1, 2107 on the assumption that the DFOs can incorporate the changes necessary to the TAC Deferral Account Reconciliation Applications to accommodate the change in Rider C from a $/MWh to a percentage
FortisAlberta Inc.: **Support** FortisAlberta supports the AESO's plan to apply for interim changes to Rider C as long as consideration is made for filing deadlines of FortisAlberta's Quarterly AESO DTS Deferral Account Reconciliation
Industrial Power Consumers Association of Alberta (IPCAA): **Support** This is the fastest way to implement the proposed changes, so the AESO should move forward with this approach.
Primary Service Group ("PSG"): **Support** The Primary Service Group supports the prompt resolution of these issues. The Group requests the AESO consider all opportunities to advance the effective date before July 1, 2017.
(4) Application Process, Timeline and Next Steps (Slides 82 – 85)
A. The AESO discussed the status of a number of 2018 ISO tariff application scope items (Slide 83) and a 2018 ISO tariff tentative timeline.
Alberta Direct Connect Consumers Association ("ADC"): ADC supports the scope and timeline.
ATCO Electric: ATCO Electric is supportive of the AESO's Application Process, Timeline, and Next Steps.
Dual Use Customers ("DUC"): If possible, the DUC would like the opportunity to review the COS and rate projection models prior to the GTA filing.
EPCOR Distribution & Transmission Inc. ("EDTI"): i. Timing of changes to calculation of Rider C - Any changes to Rider C timing needs to be

Stakeholder Comment
coordinated with timing requirements of the DFO's quarterly transmission access charge deferral account rider process (Decision 2012-304). A change to Rider C from $/MWhr basis to a percentage basis will likely require AUC approval of corresponding changes to the DFO's quarterly transmission access charge deferral account rider process (approved in Decision 2012-304). Accordingly, a change to the calculation of Rider C with an effective date of July 1, 2017 will require approval by the AUC of any corresponding changes to the quarterly rider process prior to June 1, 2017. The AESO should inquire whether the AUC would contemplate approving changes to the quarterly rider template as part of the proceeding to decide the AESO's application for interim approval of the Rider C changes. ii. Timing of DAR Applications - EDTI requests that the 2016 DAR application be filed prior to July 1st to allow the DFO's to comply with the AUC direction to include the AESO DAR amounts in their respective annual transmission access deferral account applications (Decision 2012-304, paragraphs 69 and 77). The DFOs have been directed to file their annual transmission access deferral account applications between July 1 and August 10 each year (Decision 3334-D01-2015, paragraph 86). iii. Timing of AESO Tariff Updates and Tariff Applications - EDTI notes that the DFOs typically file their respective SAS rates on September 10th of each year as part of their annual PBR rate adjustment filings for the upcoming year (Decision 2012-237). EDTI requests that, to the extent possible, the AESO file its tariff update or applications for interim approval of proposed rates prior to September 10th of each year to allow the DFOs to reflect the AESOs tariff update in their respective annual rate adjustment filings.
ENMAX Power Corporation ("EPC"): No comment.
FortisAlberta Inc.: No comment.
Industrial Power Consumers Association of Alberta (IPCAA): Support When the AESO states: "Transmission rate projection model will be filed with the 2018 ISO tariff application" does this mean an update of the previous "TRIP model" (last updated in June 2014 and recently removed from the AESO's website) or the less robust "TRP" (introduced in 2016)? IPCAA members support the publication of a robust transmission rate forecast.
Primary Service Group ("PSG"): No comment.
Additional Comments
Alberta Direct Connect Consumers Association ("ADC"): ADC appreciates the timely publishing of the Transmission rate projection model.

March 27, 2017

AESO Stakeholders
AESO 2018 ISO Tariff Consultation Participants

Dear Stakeholder:

Re: **<u>Invitation to Participate in Consultation on AESO 2018 ISO Tariff Application</u>**

The AESO continues to consult with market participants on the development of its next comprehensive ISO tariff application, which it now refers to as the 2018 ISO tariff application to reflect the year in which the tariff is expected to become effective (in prior stakeholder communications, this application had been referred to as the 2017 ISO tariff application). The AESO will be holding the following consultation session to provide an update on work completed to date and invites you to attend:

Date:	Monday, April 10, 2017
Time:	1:00 pm to 4:00 pm
Place:	Meeting Room 6006, 6th Floor, BP Centre, 240 – 4th Avenue SW, Calgary, Alberta. Note that the glass doors on the 6th floor are locked; please knock to have them opened.
Teleconference:	Within Calgary calling area: 403-410-3051, Conference ID 4366631 Outside Calgary calling area: 1-855-453-6957, Conference ID 4366631
RSVP:	By 5 pm on **April 3, 2017** to, Tatiana Aparicio-Caris Tatiana.Aparicio-Caris@aeso.ca or 403-539-2664.

The AESO plans to discuss the following items during the meeting:

- proposed changes to the ISO Tariff's Terms and Conditions;
- cost responsibility for compliance with the Critical Infrastructure Protection ("CIP") Alberta reliability standards;
- results on the AESO's point of delivery (POD) cost function database results and analysis; and
- planned timeline and next steps for the 2018 ISO tariff application.

The AESO plans to present information on these topics to facilitate discussion and will post a presentation before the meeting. Stakeholders may provide feedback in person during the meeting or through written comments to the AESO after the meeting.

All information relating to the 2018 ISO tariff consultation is available on the AESO website at www.aeso.ca by following the path Rules, Standards and Tariff ► Stakeholder engagement ► 2018 ISO tariff application. As well, new information posted by the AESO on this topic will be mentioned in the AESO stakeholder newsletter, which you can subscribe to at the bottom right of the AESO's home page at www.aeso.ca.

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Phone: 403-539-2450 Fax: 403-539-2949 www.aeso.ca @theaeso

If you have any questions on the AESO's 2018 ISO tariff consultation, please contact me at 403-539-2555 in Calgary or by email to larhonda.papworth@aeso.ca.

Yours truly,

LaRhonda Papworth
Manager, Tariff Design

cc: Doyle Sullivan, Director – Market and Tariff Design

Consolidated Stakeholder Comments on AESO 2018 ISO Tariff Consultation Session – March 1, 2017

Background

On March 1, 2017, the AESO and stakeholders participated in a consultation meeting to discuss (1) potential changes to the ISO tariff's terms and conditions; (2) potential changes/amendments to Rider A1 – *Transmission Duplication Avoidance Adjustment Dow Chemical Canada Inc. / Dow Hydrocarbons / ASU2*; and (3) application process and next steps. The AESO invited written comments from stakeholders on the information presented at the meeting. The written comments received from stakeholders are consolidated below.

A copy of the presentation provided by the AESO at the March 1, 2017 meeting is posted on the AESO website and can be accessed at www.aeso.ca by following the path Tariff ► Stakeholder engagement ► 2018 ISO tariff application.

Stakeholder Comments on AESO Information

Stakeholder Comment
(1) ISO Tariff Terms and Conditions Proposals (Slides 6 – 30)
A. Principles for Load Customers (Slide 10): • ***Provide a price signal;*** • ***System transmission facilities are not built as the result of a connection(s) not proceeding; and*** • ***General high-level alignment with Decision 3473-D02-2015.***
Alberta Direct Connect Consumers Association ("ADC"): ADC supports the principles.
AltaLink Management Ltd. ("AML"): AltaLink agrees that load customers should have some form of a price signal that ties their commitment for connection to the system, if their connection project drives transmission system development. The price signal should not be punitive to the customer as load customers drive economic growth in the province.
Capital Power Corporation: Capital Power has no comments at this time.
Dual Use Customers ("DUC"): Agreed. The AESO should ensure that system transmission facilities are built in time to meet customer requirements.
EPCOR Distribution & Transmission Inc. ("EDTI"): No comments.
Industrial Power Consumers Association of Alberta ("IPCAA"): IPCAA agrees with the principles listed here..

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Stakeholder Comment
TransCanada Energy Ltd. ("TCE"): No comments.

B. Alternative Selection for Load Connections (Slides 11-13):

- ***Load connection alternative must be <u>unconstrained</u>; and***
- ***Alternative selected will be <u>lowest overall costs</u> alternative.***

Alberta Direct Connect Consumers Association ("ADC"):

Agree.

AltaLink Management Ltd. ("AML"):

AltaLink generally agrees that the load connection alternative must be unconstrained and will be based on the lowest overall cost. However, in determining the overall lowest cost solution, the AESO needs to consider the benefits provided to the system and therefore other customers when system related investments are part of an alternative being considered. In Alternative 2, slide 12, the $60M represented by "2" provides benefits to customers connected to both the right and left of the connection, as the investment is a networked system asset. The benefits to the network, the region and to the customers in the region should all be considered in the selection process. AltaLink does not agree with the view that in Alternative 2 the customer being connected receives the only benefit.

Capital Power Corporation:

Capital Power wishes to better understand the AESO's proposal for connection alternative selection as presented on Slides 11-13, particularly in respect to whether or not the proposal is consistent with previous determinations of the Commission regarding transmission rights in Alberta. Capital Power requests more details from the AESO regarding its proposal and the rationale behind the proposed change.

Dual Use Customers ("DUC"):

Appears to align with T-reg..

EPCOR Distribution & Transmission Inc. ("EDTI"):

The AESO clarified at the meeting that cost is not the only factor it considers when selecting a preferred alternative. Other factors include environmental and social impacts. Also, when considering locations of new transmission facilities or enhancements of existing facilities, section 15.1(2)(b) of the *Transmission Regulation* require the ISO to consider maximizing the efficient use of right of ways, corridors or other routes that already contain or provide for utility or energy infrastructure. A more accurate statement than "Alternative selected will be lowest overall costs alternative" would be "The total project cost, including both participant-related and system-related component costs, will be used for the purpose of cost comparisons."

Industrial Power Consumers Association of Alberta ("IPCAA"):

IPCAA has no major concerns with this..

TransCanada Energy Ltd. ("TCE"):

.

C. System Transmission Facilities Required for a Load Connection – "Filed System NID" (Slides 14 – 16):

- ***AESO is proposing to change language in the ISO tariff terms and conditions to add***

Stakeholder Comment
clarity regarding "long term transmission system plan" and "as the ISO reasonably expects will be required in the future" (section 8, subsection 3(3)(b)).
Alberta Direct Connect Consumers Association ("ADC"): No comment.
AltaLink Management Ltd. ("AML"): The AESO has the responsibility to forecast the future requirements for the transmission system. The long term plan is the forecast of that future and there is uncertainty around this forecast. A connecting customer should not be penalized for any inaccuracy in the AESO's forecast. In other words, the connecting customer should not bear the cost of uncertainty in the AESO's forecast. As the demand in a region grows there will be a requirement for transmission infrastructure which should be reflected in the AESO's long term plan. If a customer wants to be connected and their load requirements have been generally incorporated into the AESO's long term transmission plan from a load growth forecast or through ongoing discussions with the AESO that the customer's load is specifically included in the AESO's load growth forecast, the AESO should accommodate the customer without any additional costs to the customer other than their own connection costs. If the customer's load has not been incorporated into the AESO's long term plan then there should be a cost to the customer for advancing the transmission system infrastructure.
Capital Power Corporation: Capital Power has no comments at this time.
Dual Use Customers ("DUC"): The DUC is uncomfortable with tariff terms like "reasonably expects". What requirements exist for the AESO to initiate a system NID?
EPCOR Distribution & Transmission Inc. ("EDTI"): No comments.
Industrial Power Consumers Association of Alberta ("IPCAA"): Does the AESO plan on elaborating on what "reasonably expects" means? Are there any quantifiable metrics associated with this term?
TransCanada Energy Ltd. ("TCE"): TCE supports the AESO's proposal to provide additional clarity and looks forward to reviewing the AESO's proposed language.
D. System Transmission Facilities Required for a Load Connection – <u>with</u> a Filed System NID (Slide 17): ***a. Market participant can wait for build?*** ***b. If not, a System NID with date driven milestones – customer would pay advancement costs calculated in accordance with current ISO tariff provisions*** ***c. If not, and a System NID <u>without</u> date driven milestones – customer would pay "commitment" charge***
Alberta Direct Connect Consumers Association ("ADC"): No comment.

Stakeholder Comment
AltaLink Management Ltd. ("AML"): AltaLink agrees that if the customer's load was not included in the AESO's long term planning process, the customer should pay for advancing an already identified system project with a NID in service date or planned milestone driven in service date in order to meet the customer's earlier project ISD. The commitment charge must be refundable once their project has been energized. See AML's comments to C above. The AESO should consider updating its plan on an annual basis for ISDs which would set a reasonable expectation for connecting customers.
Capital Power Corporation: Capital Power has no comments at this time.
Dual Use Customers ("DUC"): Unlike generation customers, load customers typically can't wait for service. One bad experience should not cause an overreaction. Perhaps the AESO should review project management practices to ensure that system facilities are not built in advance of need. The DUC does not object to having connecting customers pay deposits for advancing system projects, within commercially reasonable parameters.
EPCOR Distribution & Transmission Inc. ("EDTI"): No comments..
Industrial Power Consumers Association of Alberta ("IPCAA"): Is the AESO concerned that this new process will encourage customers to be more aggressive about their in-service dates in order to avoid advancement costs and commitment charges? IPCAA agrees that customers should be accountable for building what they say they will build. Particularly when other ratepayers are taking on system costs on their behalf..
TransCanada Energy Ltd. ("TCE"): TCE is of the view that the AESO should provide the necessary information to market participants that would allow them to make an informed decision whether they should wait for a system build or not. The necessary information would include both the cost to advance or accelerate a project and the time that a market participant may have to wait for the system facilities to be built. In those cases where an existing NID does not have date-driven milestones, TCE understands that the NID will have MW-driven milestones. In this circumstance, TCE submits that the AESO should provide a forecast as to when it expects the MW-driven milestones to be met. TCE will be able to provide further comments once the AESO provides clarity as to the details of the "commitment charge".

E. Concept 1: System Transmission Facilities Required for a Load Connection – without a Filed System NID (Slides 18 - 21):

- ***a. Market participant can wait for build?***
- ***b. If market participant can wait for system development (with milestones), the system transmission development will be initiated upon market participant's energization;***
- ***c. If market participant cannot wait for system development (with milestones), market participant pays a refundable deposit in order to provide "sufficient certainty" of project going ahead.***

Stakeholder Comment
i. Market participant will be refunded deposit upon connection project energization
Alberta Direct Connect Consumers Association ("ADC"): No comment, might be valuable to test the concept with a load that is looking to build or has recently built and can identify how this may have been viewed for their project..
AltaLink Management Ltd. ("AML"): AltaLink generally agrees with customer costs being tied to the NID being filed by the AESO and supports a fully refundable deposit (including carrying costs). If a deposit is required, the deposit should be determined based on a percentage of the amount of the forecast incremental system project costs due to advancing the system project, not the entire system project costs, and should be refundable upon the customer signing a DTS contract. The AESO should consider staging the deposit to align with the actual incurrence of incremental project costs, not a lump sum at the start. AltaLink's support of these principles relies upon the AESO initiating timely need project applications to meet the forecast planning of the transmission system per their long term plans.
Capital Power Corporation: Capital Power has no comments at this time.
Dual Use Customers ("DUC"): The DUC is not comfortable with the "Filed System NID" test / concept. The DUC prefers Concept 2 over Concept 1 at this time.
EPCOR Distribution & Transmission Inc. ("EDTI"): In situations where system development is required to meet a customer's load connection, but there is no system NID currently filed, all options appear to have the AESO create a system NID separate from the customer connection NID (slides 18-26). An additional option would be for the system component to be included in the customer connection NID and include a portion of the system component cost in the financial security currently required by the market participant as per Section 5 of the existing T&Cs. This would achieve the same objectives as the two concepts proposed at the session, but require fewer changes to the existing approved T&Cs.
Industrial Power Consumers Association of Alberta ("IPCAA"): This is an interesting test to apply. What happens when the customer project has been in the works for a while, and perhaps should have triggered a system NID, but the AESO did not consider the project "real" enough to warrant a system NID being filed? What level of refundable deposit would this be? Does the AESO have an estimate or range available for discussion purposes?
TransCanada Energy Ltd. ("TCE"): Please define "sufficient certainty". TCE will be able to provide more comments regarding Concept 1 once the AESO provides clarity as to the terms of the proposed refundable deposit and of the refund. With respect to the deposit, TCE is interested in knowing what the AESO is proposing in terms of the magnitude, timing and form of payment that would be required. With respect to the refund, TCE is interested in knowing the proposed timing of the refund and, in the case where the market participant's project does not energize, whether the AESO would propose that the market participant receive a refund (or partial refund) if the system facilities

Stakeholder Comment

become needed at some future point in time.

F. Concept 1: Refundable Deposit – What does it provide for the AESO? (Slide 21):

- ***a. Provides "sufficient certainty" that connection project will energize;***
- ***b. Will not build system transmission assets that will not be used;***
- ***c. Provides a price signal where there is limited capacity; and***
- ***d. Only applies when the market participant cannot wait for system transmission facilities.***

Alberta Direct Connect Consumers Association ("ADC"):

No comment.

AltaLink Management Ltd. ("AML"):

AltaLink agrees that if the customer is required to pay any advancement costs, they should be 100% refundable upon the customer signing a DTS contract.

Capital Power Corporation:

Capital Power has no comments at this time.

Dual Use Customers ("DUC"):

Please see response to E. above.

EPCOR Distribution & Transmission Inc. ("EDTI"):

See comments to E.

Industrial Power Consumers Association of Alberta ("IPCAA"):

See comments above.

TransCanada Energy Ltd. ("TCE"):

No comments.

G. Concept 1: Refundable Deposit – Pros and Cons (Slide 22):

Pros:

- ***a. Strong price signal if market participant cannot wait;***
- ***b. Aligns with Generator Unit Owner's Contribution ("GUOC") incentives, (i.e. "performance" = "energization");***
- ***c. Encourages timely energization as the AESO is holding a large deposit;***
- ***d. The market participant can choose to wait or stage their contract to accommodate current system capacity and system facilities construction will begin after connection project energization.***

Cons:

- ***e. System transmission facility costs might be prohibitively high;***
- ***f. Delay in cost estimates (may not occur until the creation of the system NID).***

Alberta Direct Connect Consumers Association ("ADC"):

No comment.

AltaLink Management Ltd. ("AML"):

Stakeholder Comment
See AltaLink's comments in F.
Capital Power Corporation: Capital Power has no comments at this time.
Dual Use Customers ("DUC"): Please see response to E. above.
EPCOR Distribution & Transmission Inc. ("EDTI"): See comments to E.
Industrial Power Consumers Association of Alberta ("IPCAA"): See comments above.
TransCanada Energy Ltd. ("TCE"): When the AESO states "[e]ncourages timely energization as the AESO is holding a large deposit", is the AESO referring to the timely energization of the market participant's project or the system project? If the latter, please explain the rationale for the statement.

H. Concept 2: System Transmission Facilities Required for a Load Connection – <u>without</u> a Filed System NID (Slides 23 - 24):

- ***a. Market participant can wait for build?***
- ***b. If market participant <u>can</u> wait for system development (with milestones), the system transmission development will be initiated upon market participant's energization;***
- ***c. If market participant <u>cannot</u> wait for system development (with milestones), market participant pays a "sufficient certainty charge" in order to provide "sufficient certainty" of project going ahead.***
    - ***i. System transmission facilities will be initiated upon receipt of the "sufficient certainty charge".***

Alberta Direct Connect Consumers Association ("ADC"): This method seems to strike the right balance of protecting customers from projects that are not advanced, while not being a barrier for new load to grow in the province..
AltaLink Management Ltd. ("AML"): AltaLink does not support any concept where the customer pays an amount for certainty that is not refundable. Additionally, it would be very difficult for the AESO to determine the amount of a fair "sufficiency charge" given the high degree of uncertainty of the overall cost and timeline to build the system (filing of applications, approvals and construction) without a filed System NID. AltaLink would be very concerned with the punitive price signals that this may send to load customers and the disincentive this will create in Alberta for economic growth from connecting load customers. Please see AltaLink's response to C above.
Capital Power Corporation: Capital Power has no comments at this time.
Dual Use Customers ("DUC"): Please see response to E. above.

Stakeholder Comment
EPCOR Distribution & Transmission Inc. (“EDTI”): See comments to E.
Industrial Power Consumers Association of Alberta (“IPCAA”): What level of sufficient certainty charge would this be? Does the AESO have an estimate or range available for discussion purposes?
TransCanada Energy Ltd. (“TCE”): TCE will be able to provide more comments regarding Concept 2 once the AESO provides clarity as to the terms of the proposed sufficient certainty charge. TCE is interested in knowing what the AESO is proposing in terms of the magnitude, timing and form of payment that would be required.

I. Concept 2: Sufficient Certainty Charge – What does it provide for the AESO? (Slide 25):

a. Restores a reasonable balance between certainty and price signals;

b. Provides the AESO with sufficient certainty that the connection project will energize;

c. May calculate in accordance with the current tariff provisions;

d. Provides a price signal where there is limited capacity;

e. Only applies when the market participant cannot wait for system transmission facilities; and

f. Intended to address system build required that is not anticipated or planned in the AESO near-term planning horizon (5 years).

Alberta Direct Connect Consumers Association (“ADC”): No comment.
AltaLink Management Ltd. (“AML”): See AltaLink’s response to H above.
Capital Power Corporation: Capital Power has no comments at this time.
Dual Use Customers (“DUC”): Please see response to E. above.
EPCOR Distribution & Transmission Inc. (“EDTI”): See comments to E.
Industrial Power Consumers Association of Alberta (“IPCAA”): See comments above.
TransCanada Energy Ltd. (“TCE”): No comments.

J. Concept 2: Sufficient Certainty Charge – Pros and Cons (Slide 26):

Pros:

a. Market participant pays a share of the system transmission facilities for causing advancement of unplanned facilities;

b. Strong price signal if market participant cannot wait;

Stakeholder Comment
c. ***The market participant can choose to wait or stage their contract to accommodate current system capacity (considering forecast growth) and system facilities construction will begin after connection project energization.*** ***Cons:*** *d.* ***"Sufficient certainty charge" cost might be high.***
Alberta Direct Connect Consumers Association ("ADC"): No comment.
AltaLink Management Ltd. ("AML"): See AltaLink's response to H above.
Capital Power Corporation: Capital Power has no comments at this time.
Dual Use Customers ("DUC"): Please see response to E. above.
EPCOR Distribution & Transmission Inc. ("EDTI"): See comments to E.
Industrial Power Consumers Association of Alberta ("IPCAA"): See comments above.
TransCanada Energy Ltd. ("TCE"): No comments.
K. Tariff Alignment – Other items (Slides 28 - 29): ***1. Advancement costs apply to ally system transmission facilities required for a load connection, not solely radial facilities planned to be looped (section 8, subsection 3(3)(b));*** ***2. "Accelerated construction costs" as contemplated in Decision 3473-D02-2015;*** ***3. Filed system NID (with MW milestones) required, current tariff refers to the long-term plan, or as ISO reasonable expects will be required in the future;*** ***4. Differentiation between generation and load connections; and*** ***5. "Shared with system" cost provisions.***
Alberta Direct Connect Consumers Association ("ADC"): No comment.
AltaLink Management Ltd. ("AML"): AltaLink is unclear of what the AESO is requesting as it relates to these Other Items and therefore has no specific additional comments.
Capital Power Corporation: Differentiation between load and generation connections must prevail.
Dual Use Customers ("DUC"): No comment at this time.

Stakeholder Comment
EPCOR Distribution & Transmission Inc. ("EDTI"): No comments.
Industrial Power Consumers Association of Alberta ("IPCAA"): IPCAA has no comments at this time.
TransCanada Energy Ltd. ("TCE"): The AESO has presented two concepts to address accelerating system projects. TCE recommends that the AESO include both options in its tariff. The financial positions and circumstances of AESO's load customers vary significantly. Including both options in the tariff may allow a market participant to accelerate a system project, whereas limiting the tariff to only one of the options may unnecessarily preclude this.
L. Next Steps (Slide 30) • ***Allow stakeholders to review presentation and concepts;*** • ***Gather stakeholder feedback and incorporate in to further work;*** • ***Follow up in next stakeholder session; and*** • ***Work towards recommended approach for application.***
Alberta Direct Connect Consumers Association ("ADC"): ADC will review the concepts at our next Board meeting and provide any further thoughts at the next stakeholder session..
AltaLink Management Ltd. ("AML"): AltaLink recommends that the AESO incorporate stakeholder feedback into a recommended approach and provide an explanation for those stakeholder suggestions not adopted. This should then enable a future effective stakeholder session prior to finalizing its decision on this matter.
Capital Power Corporation: Capital Power notes verbal indication from the AESO at the March 1, 2017 stakeholder session that the AESO generally agrees with the views of the Commission presented in Section 6.7 of Decision 3473-D02-2015 concerning the application of advancement costs to generators, specifically that system project advancement costs should not be applied to generators. For clarity, Capital Power requests that the AESO confirm its position on the application of system advancement costs to generators at its next stakeholder session and include discussion of the item in its written presentation materials. Capital Power considers the issue of applying system project advancement costs to generators closed and does not support re-opening the issue in the 2018 GTA.
Dual Use Customers ("DUC"): We look forward to reviewing additional material on this topic.
EPCOR Distribution & Transmission Inc. ("EDTI"): No comments.
Industrial Power Consumers Association of Alberta ("IPCAA"): IPCAA would be happy to invite the AESO to present at a Board meeting to run these concepts by members directly. It would be beneficial to have estimates of potential deposits and charges for customers to consider.

Stakeholder Comment

TransCanada Energy Ltd. ("TCE"):

No comments.

(2) Rider A1 – Dow Chemical Canada Inc. / Dow Hydrocarbons / ASU2 Changes (Slides 31 – 33)

A. Rider A1 – Dow Duplication Avoidance Tariff (DAT) Issues (Slide 32):

- ***Rider A1 is inconsistent with other Rider A's with language and detail;***
- ***Forecast benefit table ends in 2021 – what happens after 2021; and***
  - ***25-year (approx.) business case assumption in original application does not reflect the expectation of asset life for a transmission line.***
- ***What is required in the ISO tariff to provide clarity on future duplication avoidance sites' treatment.***

Alberta Direct Connect Consumers Association ("ADC"):

ADC submits that the circumstances that arose to justify this treatment still exist and that the table should be updated to reflect the life of the assets.

AltaLink Management Ltd. ("AML"):

AltaLink has not had time to consider this issue fully and will provide the AESO comments in the future should we have any.

Capital Power Corporation:

Capital Power has no comments at this time.

Dual Use Customers ("DUC"):

The DUC submits that a Rider A should result in tariff treatment as if the transmission substation and/or line was built and remains in service. Under no circumstances should net metering/totalization cease at the end of a Rider A term. If the Rider A transmission facilities are equivalent to "customer owned" assets, then the customers should be responsible for maintenance and losses costs. If equivalent to "system" assets, then all AESO customers should be responsible for maintenance and losses costs. The DUC submits that it may be appropriate to re-evaluate maintenance costs and losses costs at the end of a Rider A term, and set for another term, e.g. 20 years.

EPCOR Distribution & Transmission Inc. ("EDTI"):

No comments.

Industrial Power Consumers Association of Alberta ("IPCAA"):

IPCAA has no comments at this time.

TransCanada Energy Ltd. ("TCE"):

No comments.

B. Rider A1- Dow Duplication Avoidance Tariff (DAT) – Next Steps (Slide 33):

1. ***The AESO plans to update Rider A1 to authoritative language;***
2. ***High-level test of some criteria considered in original AEUB decision U98125 (available capacity, credible bypass threat, and service life of transmission facilities);***
3. ***Consideration of Rider A1 continuing to a reasonable expected transmission life period***

Stakeholder Comment
with recovery of O&M and losses annual/monthly payments from Dow; and ***4. Add "expiry" or "term" to clarify what happens after a certain date, i.e. re-application for duplication avoidance tariff? Other?***
Alberta Direct Connect Consumers Association ("ADC"): While the transmission service is in place, it should retain the same treatment without need to reapply..
AltaLink Management Ltd. ("AML"): See comments above.
Capital Power Corporation: Capital Power has no comments at this time.
Dual Use Customers ("DUC"): 1. No issues with updating language, if intent is not altered. 2. The "test" was performed when the Rider was approved. A "re-test" concept is inappropriate and would meet with highest level of objection from the DUC. Retroactive rate making should not be considered. 3. See comments to under A. above 4. See comments to under A. above. The DUC would object to any tariff terms that would result in loss of net metering/totalization and at any time prior to the customer's facilities being removed from transmission service.
EPCOR Distribution & Transmission Inc. ("EDTI"): No comments.
Industrial Power Consumers Association of Alberta ("IPCAA"): IPCAA has no comments at this time.
TransCanada Energy Ltd. ("TCE"): No comments.
(3) Application Process, Timeline and Next Steps (Slides 34 – 39)
A. The AESO discussed the status of a number of 2018 ISO tariff application scope items (Slide 36) and a 2018 ISO tariff tentative timeline.
Alberta Direct Connect Consumers Association ("ADC"): ADC is supportive of the timeline and scope items..
AltaLink Management Ltd. ("AML"): No comments.
Capital Power Corporation: Capital Power understands that the AESO will be holding a future stakeholder session to review its work to date addressing direction from Commission regarding cost recovery from Critical Infrastructure Protection (CIP) and looks forward to participating.
Dual Use Customers ("DUC"):

Stakeholder Comment
No comments.
EPCOR Distribution & Transmission Inc. ("EDTI"): It is difficult to provide fulsome comments on proposed changes to the Terms and Conditions without reviewing a draft of the proposed changes. Additional consultation will likely be needed once revised T&Cs have been drafted.
Industrial Power Consumers Association of Alberta ("IPCAA"): Thank you for the update.
TransCanada Energy Ltd. ("TCE"): No comments.
Additional Comments
Capital Power Corporation: Capital Power has no additional comments at this time.
Industrial Power Consumers Association of Alberta ("IPCAA"): None at this time.

AESO 2018 ISO Tariff Consultation

April 10, 2017
AESO Office, Calgary

Public

Agenda

- Introduction and objectives(slides 1-5)
- ISO Tariff Terms and Conditions Proposals(slides 6-29)
  - Certainty Charge Workshop(slides 30-36)
- POD Cost Function Database(slides 37-46)
- Transmission Cost Causation Study follow-up(slides 47-53)
- Critical Infrastructure Protection ("CIP") Alberta reliability standards cost responsibility(slides 54-56)
- Application process and next steps (slides 57-63)
- Discussion and wrap-up (slide 64)

Please feel free to ask questions during presentation

Stakeholder session objectives

- Enhance understanding of ISO tariff application
- Review technical results of a number of analytical exercises by the AESO
- Share information prior to filing of 2018 ISO tariff application
- Gather feedback to ensure tariff application provides all information stakeholders require
- Review application timeline and next steps

Applications currently in progress

- Directions 5-8 on advancement costs and related provisions
  - Decision 3473-D02-2015 issued on August 26, 2015
  - AUC letter issued March 29 “Issues list and closure of Proceeding 20922”
  - “…*the Commission has determined that matters anticipated to be addressed within proceeding 20922 should instead be considered as part of a comprehensive tariff application*”
- 2015 Deferral Account Reconciliation application
  - Hearing held on December 13 and 14, 2016
  - Decision 21735-D02-2017 issued on March 14, 2017, ordered that the application is approved as filed.
  - “ . . .*the Commission directs the AESO to address whether changes to the deferral account allocation methodology and to Rider C are warranted given the concerns raised by the PS Group, as part of its next ISO tariff application*”

Applications currently in progress

- 2017 ISO tariff update
  - Interim, refundable approval for January 1, 2017 issued by Commission on December 2, 2016
  - Commission final decision 22093-D02-2017 issued on April 4, 2017 approving 2017 rates and investment levels as filed
- Upcoming Rider C Amendment application
  - Amending Rider C to apply to Rate PSC, *Primary Service Credit*, change to percentage charge or credit and restore deferral account balance to zero at the end of the calendar year
  - AESO now planning to file Rider C Amendment application in April 2017
  - The AESO will request an effective date of July 1, 2017 but given the delay in filing, the AESO will be able to handle a mid-quarter change to Rider C methodology, i.e. August 1, 2017

ISO Tariff Terms and Conditions Proposals

Lee Ann Kerr

Public

Proceeding 20922 Closure March 29, 2017 Commission "Issues List"

#	Issue
Issue 1	Legislative framework
Issue 2	Advanced system-related classification of radial transmission projects
Issue 3	Load forecasting

Commission "Issues List"
Issue 1 - Legislative framework

- The Commission suggests that one way to interpret the legislation is that there is a distinction between the construction of transmission to serve generation and to serve forecast load
- The planning restrictions affect the ability of the AESO to set and alter in-service dates, affecting the cost of achieving its congestion and planning mandates

Commission "Issues List"
Issue 2 – advanced system-related classification of radial transmission projects

- The "in-advance system-related classification" can affect the magnitude and timing of entry into the transmission system by load customers
- A market participant may have an incentive to overstate its long-term requirements as it is not responsible for system-related costs
- The AESO should balance between the preferences for certainty among market participants and the desire to minimize the costs of transmission development

Commission "Issues List"
Issue 3 - Load forecasting

- "Because the information used by the AESO for transmission system planning and development decisions currently relies on information provided by the large industrial customer group, the forecast inaccuracy identified by interveners could be related to the incentives built-in to the provision of information to the AESO"
- There is no financial reason for the market participant to be accurate or conservative when providing forecast information
- Establish a target rate of load growth? Load connections who want to connect more quickly can do so only if there is no net cost to other market participants

Other Commission Decisions

Decision	Summary
2005-096	“The underlying purpose of the contribution policy is to send price signals (reflective of the AESO’s economics) to market participants when they are considering siting alternatives for their facilities.”
2005-096	“With respect to the request of AE that the Board should provide clear directions respecting the classification of system and customer costs, the Board considers that the AESO should approach any situation in which there may be “shades of grey” in this designation exercise, with the position that a debatable interconnection project cost should be presumed initially to be customer-related unless clearly demonstrated otherwise.”
2005-096	“The Board, however, considers that a general stance that system enhancement costs are customer costs unless demonstrated otherwise is consistent with the expectation that the AESO adopt a more proactive stance in respect of its overall system planning and transmission system upgrade responsibilities, as detailed in the *Transmission Regulation*.”

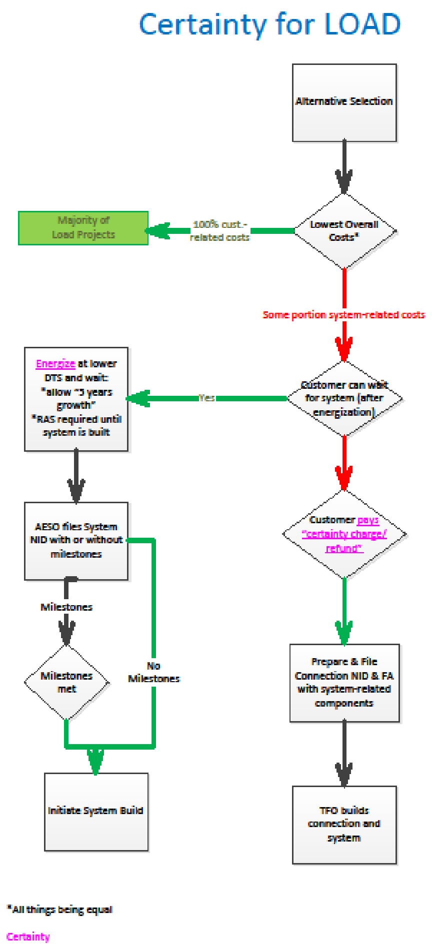
Other Commission Decisions(cont'd)

Decision	Summary
2010-606	"The Commission considers that Article 9.3(c)(ii) of the current T&Cs provides a reasonable balance between the attribution of incremental costs caused by a connecting customer and the designation of costs as system costs where the AESO was already contemplating a system planning driven expenditure prior to the connection request. Article 9.3(c)(iii) already provides broad discretion to designate costs that would otherwise be classified as customer costs to be classified as system costs."
3473-D02-2015	"…the Commission intended that the AESO would develop tariff provisions that would induce the market participant on the critical path to either consent to a shifting of the requested in-service date or absorb relevant incremental costs that would arise from a decision not to shift the requested in-service date."

Principles for Load Customers

- Provide a price signal
  - Unconstrained alternative selection
  - ISDs for system transmission projects should be moved if they can't be met without incurring significant increases to project costs (or the market participant can pay)
  - Where the <u>construction</u> of system transmission facilities are triggered, the market participant needs to provide some form of commitment
- System transmission facilities aren't built as the result of a connection(s) not proceeding
  - We need sufficient certainty that projects will "show up"
  - Don't construct system transmission facilities if market participants don't show up
- Alignment with Commission's issue list (Proceeding 20922)

System Transmission Facilities Required for a Load Connection



See pdf file "Certainty for Load" for larger image

Alternative Selection for Load Connections

Alternatives to connect to transmission system

a) most load connection projects will be radial facilities to existing transmission facilities with capacity

b) in some cases load connection projects may require an enhancement of existing system facilities or creation of looped facilities

- Load connection alternative must be <u>unconstrained</u>

and

- Alternative selected will be <u>lowest overall costs</u>

Market participant can wait for system or pay certainty charge/refund

If lowest overall costs alternative requires some portion system-related costs, customer has a choice

1. Energize at lower DTS and wait for system to be built
   – Will require market participant to lower DTS request and allow “5 years of growth” in the area (planning horizon), energize and upon energization AESO can plan system development
   – RAS will be required on the market participant until system is built

or

2. Customer pays a certainty charge/refund to ensure that at their energization, there are no constraints on the transmission system

“Refundable Deposit” – What does it provide for the AESO?

- Provides the AESO with sufficient certainty that the connection project will energize
- Not building system transmission assets that will not be used
  - If market participant does not show – no refund
  - If market participant only partially shows up (lower DTS), only partial refund
- Provides a price signal where there is limited capacity
- Only applies when the MP can’t “wait” for system transmission facilities

Pros and Cons – Refundable Deposit

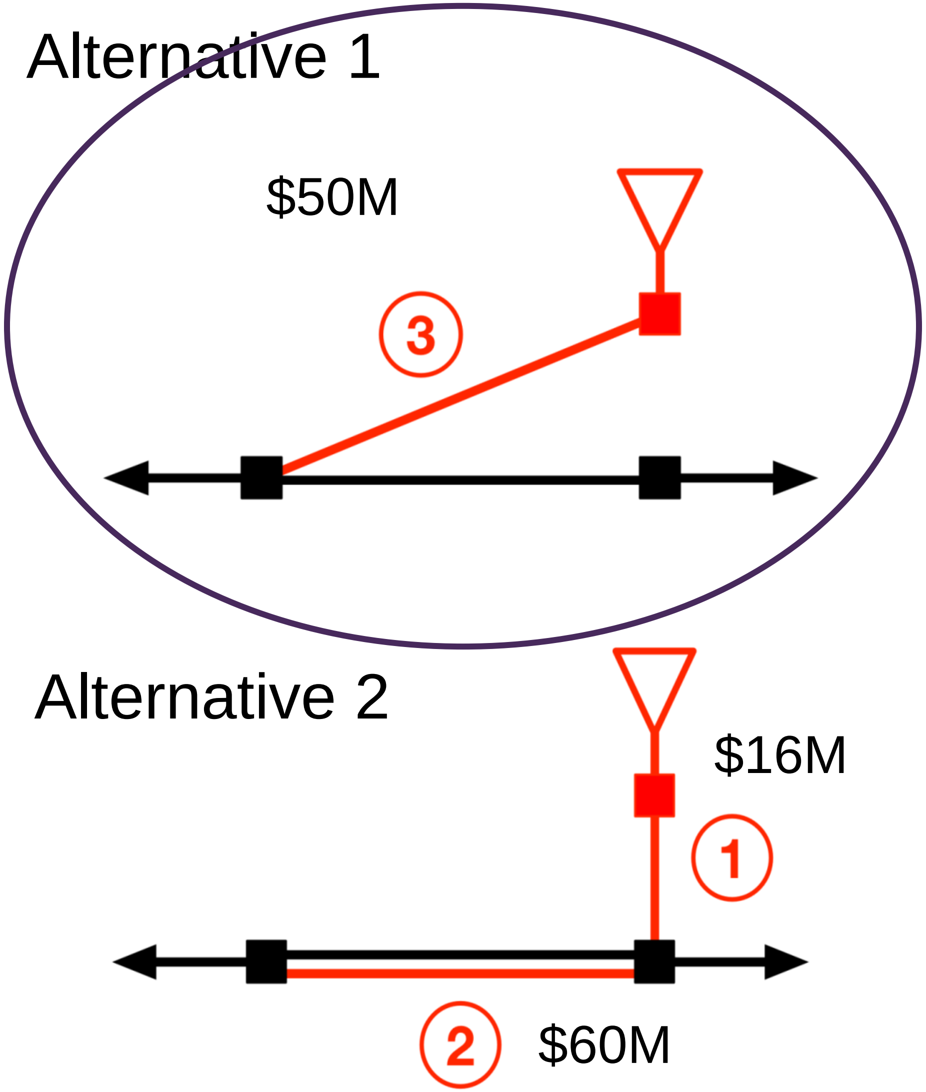
- Pros
  - Strong price signal (if you can’t wait)
  - Aligns with GUOC incentives (“performance” = “energization”)
  - Encourages timely energization (the AESO is holding a large deposit)
  - The MP can choose to “wait”, stage their contract to accommodate current system capacity and construction will begin after energization
- Cons
  - System transmission facility costs might be prohibitively high
  - Delay in cost estimates (creation of system NID)

System Transmission Facilities Required for a Load Connection

Option	Pros	Cons	Overall Score
Charge $/MW	-Easy to understand -Avoids “true” advancement cost calculation	- Facilities may be built and not used - Cliff between waiting and not - MP “pay’s” for system facilities - Sunk costs, MP might “sit”	
Charge Adv. Cost	- Aligns with existing provision - 5 years aligns PILON/planning horizon - Very strong price locational signal (drives economic efficient outcome) - Difficult to determine “actual” adv. Costs - Perception that they are paying for system_in advance	- Facilities may be built and no used - Cliff between waiting and not - MP “pays” for system facilities - Sunk costs, MP might “sit” - Based on O&M cost estimate (+50/-50)- consultant prepared?	
Refund Full System	- No system facilities build that won’t be used/paid for - somewhat strong locational price signal - Avoids MP contributions to system facilities cost - encourages timely energization - Avoids “true” adv. costs calculation	- Delay in cost estimates in order to determine refundable charge - Who holds the $	
Refund $/MW	-Like GUOC - Easy to understand - Avoids MP contributions to system facilities cost - Encourages timely energization - Avoids “true” advancement cost calculation	- Facilities may be built and not used	
Refund Adv. Cost	- Somewhat aligns with existing provision - 5 years aligns with PILON/planning horizon - Avoids MP contributions to system facilities cost - Encourages timely energization	- Facilities may be built and not used	

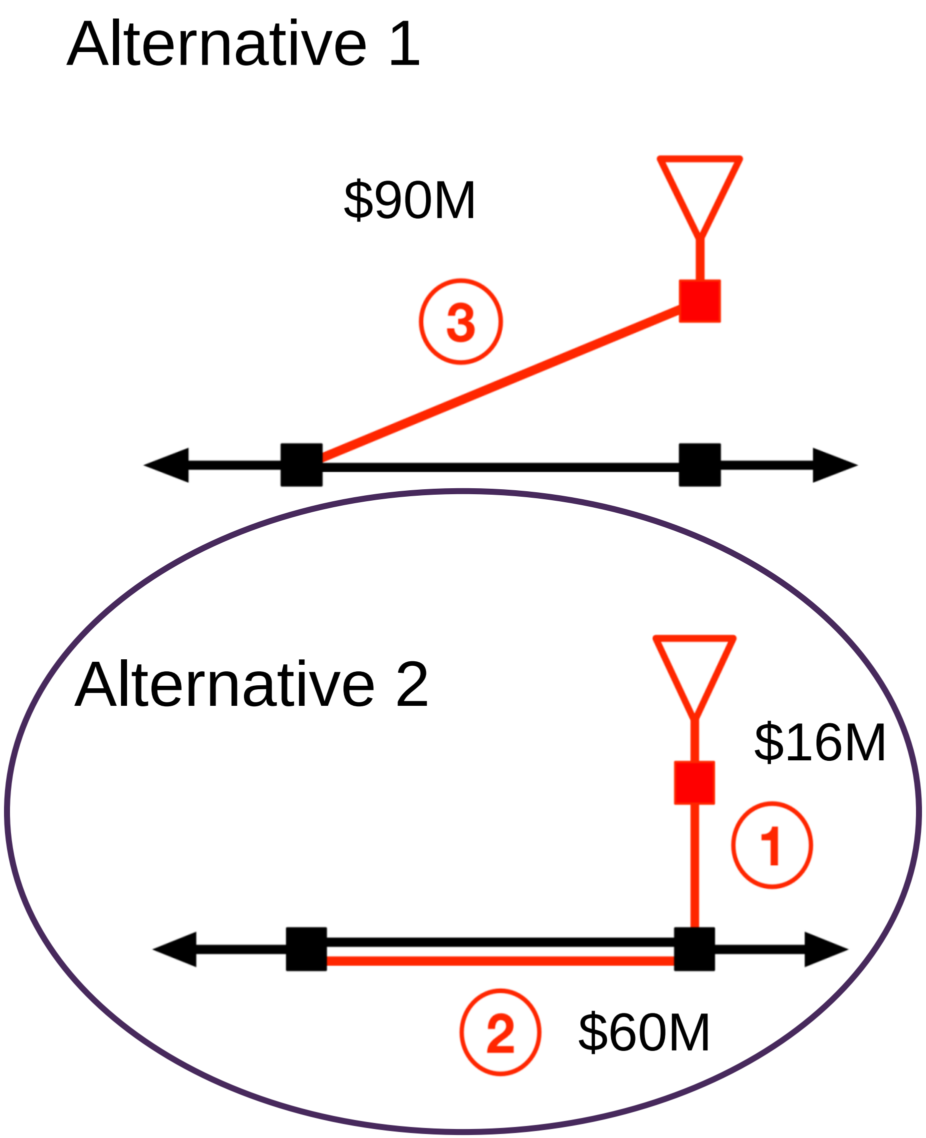
Increasing shade is higher score

Alternative Selection - “Lowest Overall Costs”



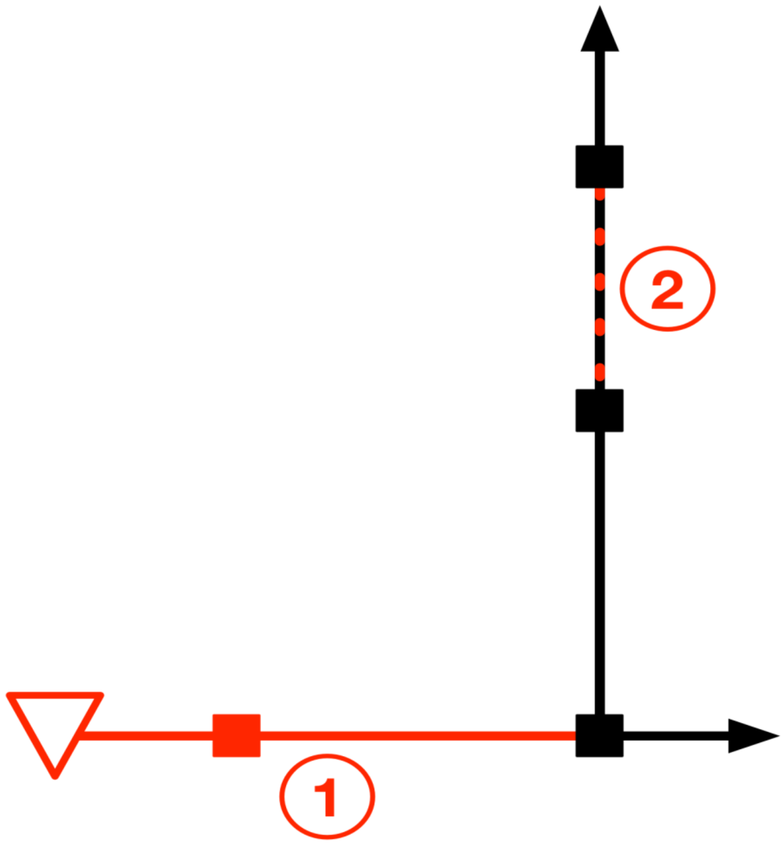
- Both Alternative 1 and 2 are unconstrained
- Alternative 1 is a radial connection to a strong source
- Alternative 2 is a radial to a weaker source ① with a required system upgrade ②
- Alternative selection would result in Alternative 1 as it is the lowest overall costs (system upgrade required)

Alternative Selection - “Lowest Overall Costs”

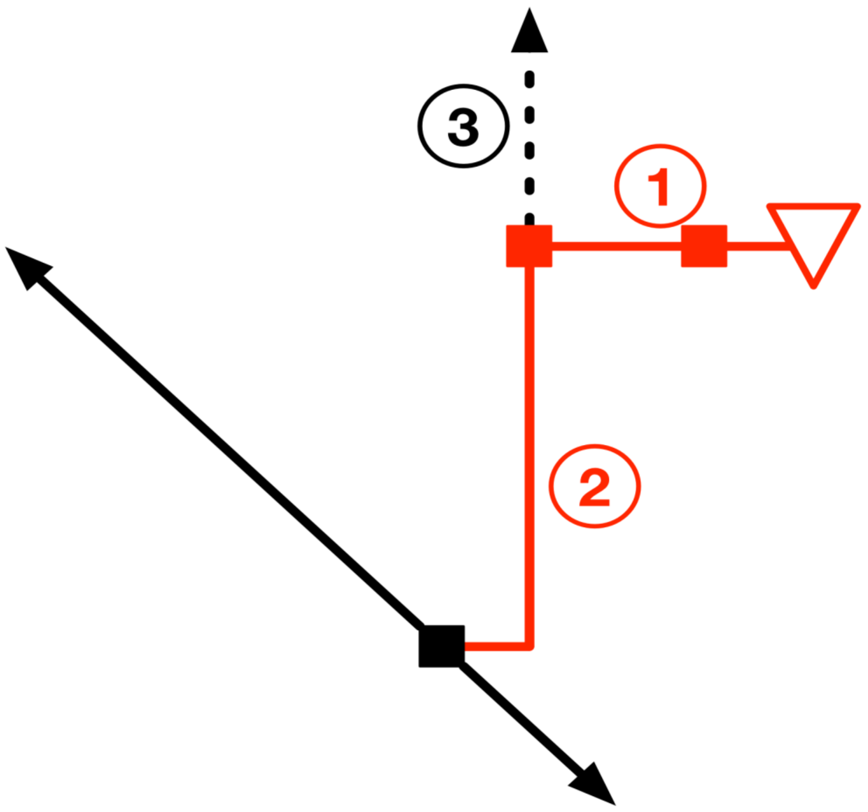


- Both Alternative 1 and 2 are unconstrained
- Alternative 1 is a radial connection to a strong source
- Alternative 2 is a radial to a weaker source ① with a required system upgrade ②
- Alternative selection would result in Alternative 2 as it is the lowest overall costs (with system upgrade required)

Example – Wait or Pay



Examples – Initially Radial then "Shared"



Changes to Sections 4, 5, 8 & 9: What are we proposing to add?

- New provisions that identify how the AESO will determine the preferred alternative
  – Constraint/congestion free
- Revised practices for system access (to replace the AESO's "Practices for System Access Service")
- Defining and enforcing critical requirements for a SASR
  – MWs, in-service date, location
- Identify when connection projects give us "sufficient certainty" that they will materialize
  – Example: GUOC payment, REP award, energization, "load certainty charge"
- New provisions around advancement costs and "accelerated construction" charges

Changes to Sections 4, 5, 8 & 9: What are we proposing to add? (cont'd)

- Differentiation between generation and load
  - New provisions for dual use customers?
- "Shared with system" cost provisions
- Connection that are initially radial are 100% participant-related costs, to be "shared" if loop is closed

Changes to Sections 4, 5, 8 & 9: What are we proposing to revise/remove?

- Remove any provisions that are duplicative of the legislation, Rules, Reliability Standards
- Language in Section 8 referring to a “contiguous” connection project
- Remove provision referring to “planned to be looped” as system-related cost
  – Advancement costs will apply to all system transmission facilities required for a load connection
- Remove connection process references
- Revisit the “Good Electric Industry Practice” to reflect the AESO’s minimum requirements

Other Terms and Conditions Proposals

- Section 1 - Applicability and Interpretation of ISO Tariff
  - Legal review
  - Ensure no duplication of legislation, rules, reliability standards
- Section 2 - Provision of and Limitations to System Access Service (may merge Sections 2 - 4)
  - Make distinction between load and generation
  - Add t-tap expectation of service
  - Remove outage provisions (covered in ISO Rules)
- Section 3 - System Access Service Connection Requirements (may merge Sections 2 - 4)
  - Remove technical requirements (covered in ISO Rules)
  - Move compliance requirements to section 2

Other Terms and Conditions Proposals (cont'd)

- Section 5 - Financial Obligations for Connection Projects
  - Legal Review
  - Ensure no duplication of other authoritative documents
- Section 6 - Metering
  - Remove altogether (covered in ISO Rules)
- Section 7 - Provision of Information by Market Participants
  - Review for duplication of ADs and legislation
- Section 10 - Generating Unit Owners Contribution
  - Add GUOC rates to the tariff

Other Terms and Conditions Proposals (cont'd)

- Section 11 - Ancillary Services
  - No changes proposed
- Section 12 - Demand Opportunity Service
  - No changes proposed
- Section 13 - Financial Security, Settlement and Payment Terms
  - Duplication with ISO Rules?
- Section 14 Peak Metered Demand Waivers
  - No changes proposed
- Section 15 Miscellaneous
  - Confirm with legal

Workshop

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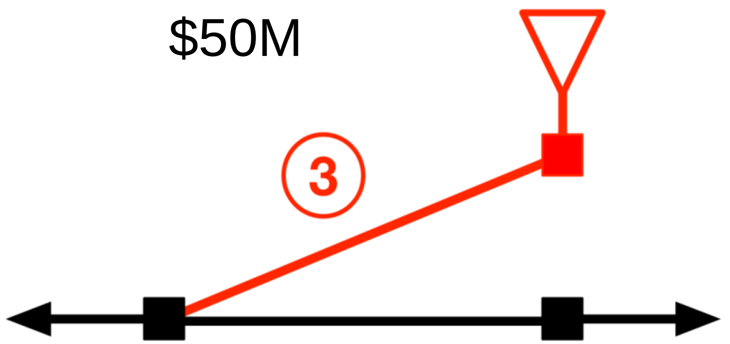
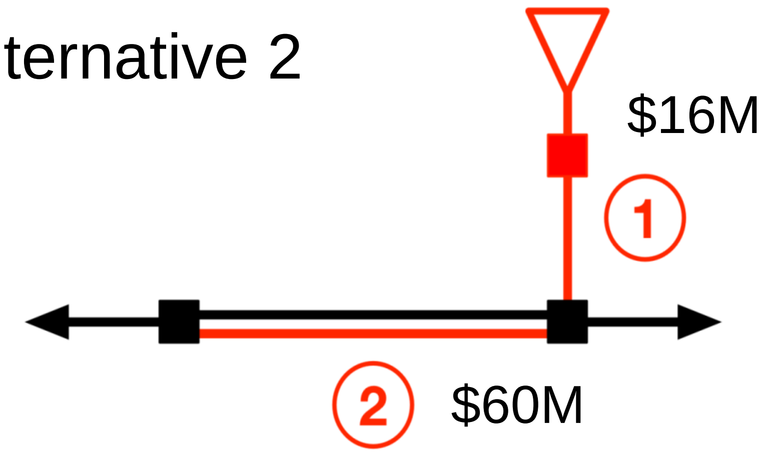
Workshop – Example 1

Alternative 1

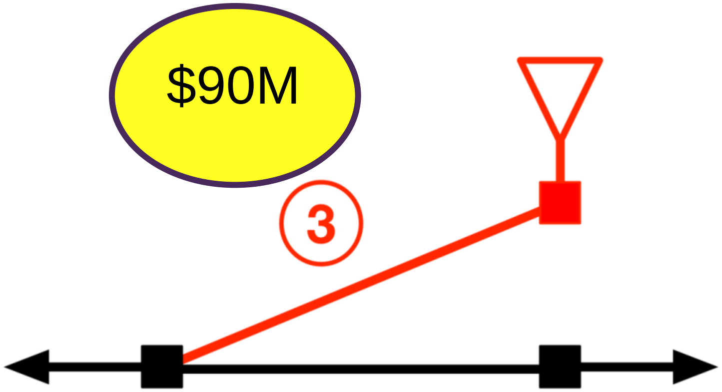


Alternative 2

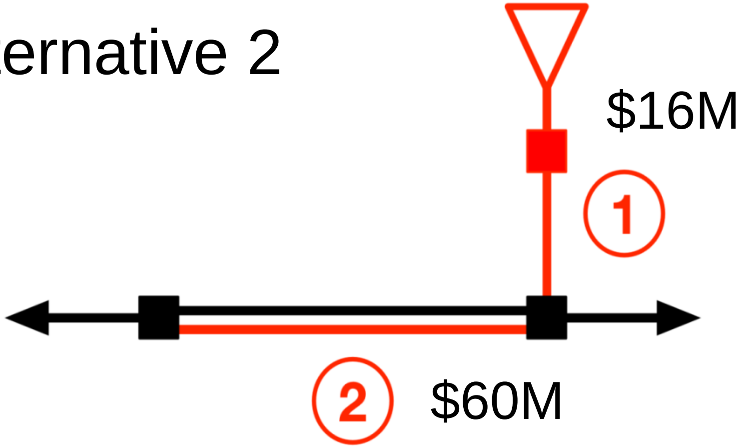


Workshop – Example 1a

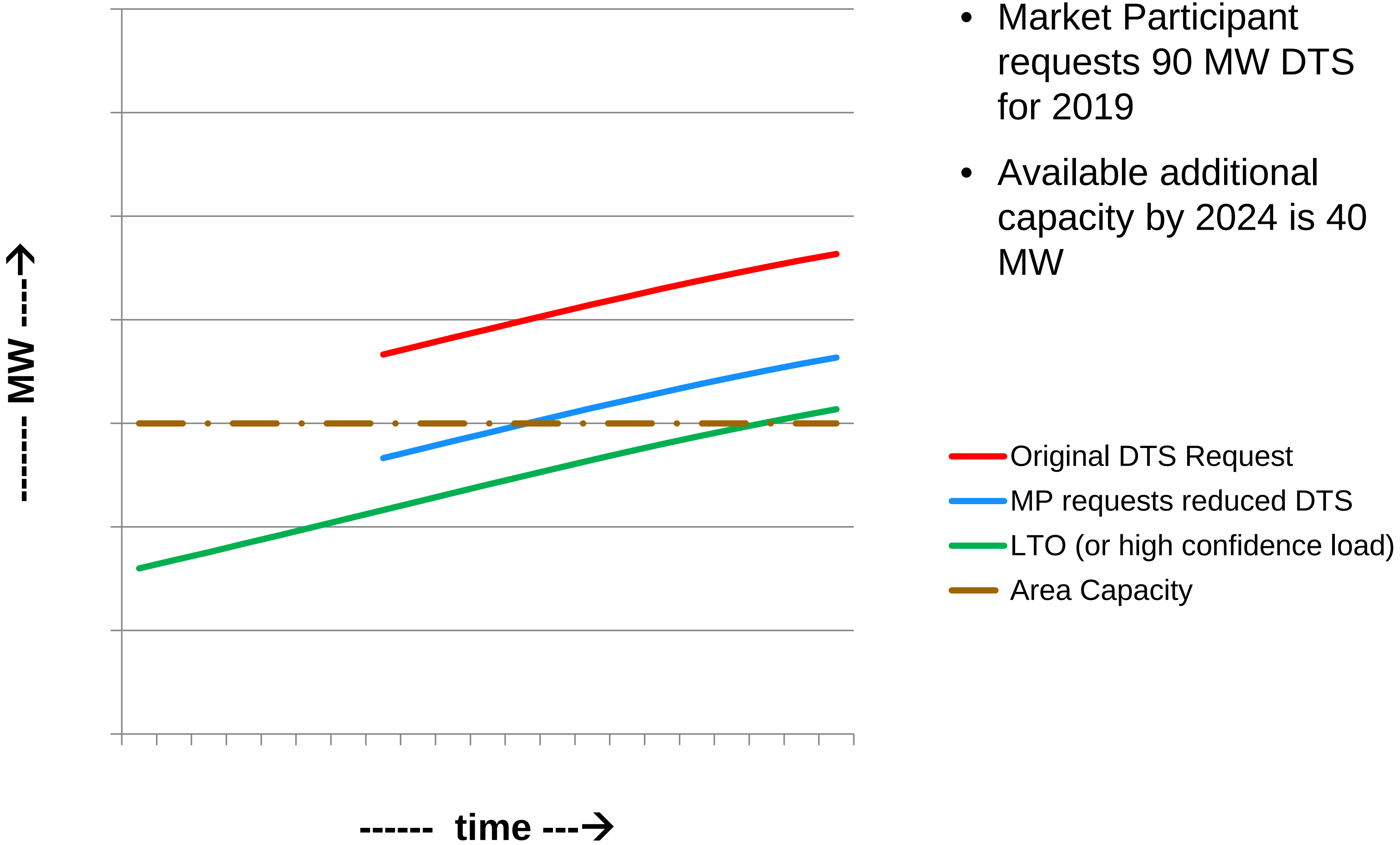
Alternative 1a



Alternative 2

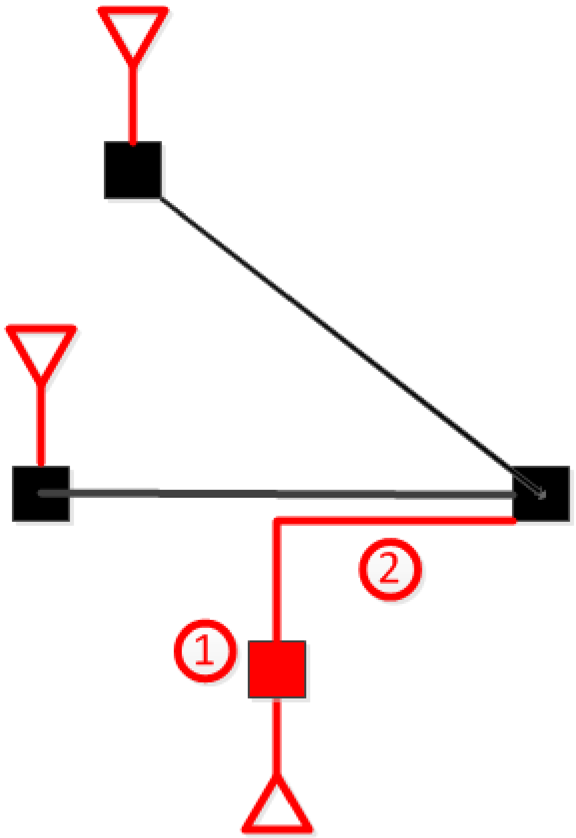


Example 1 (cont'd)



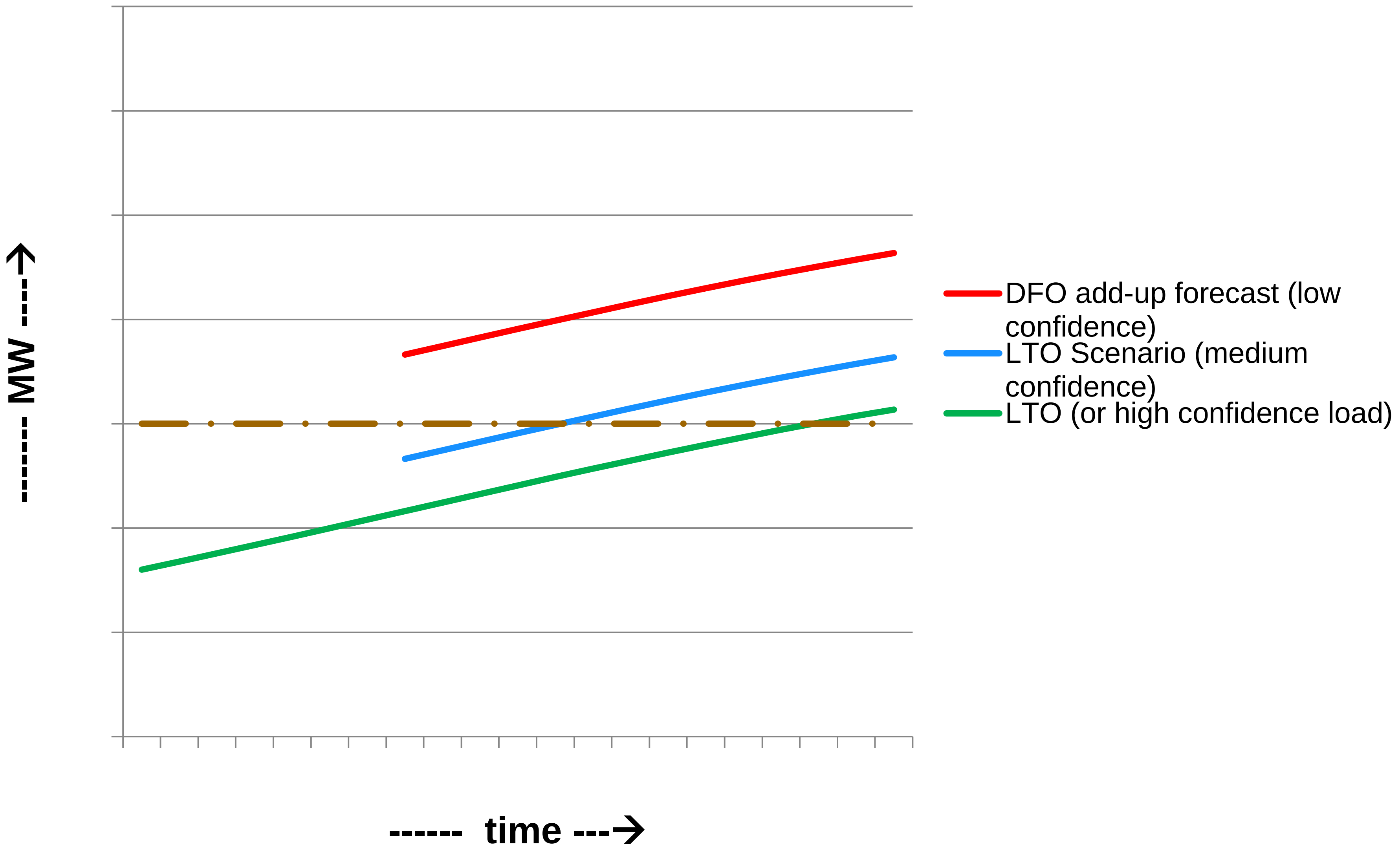
- Market Participant requests 90 MW DTS for 2019
- Available additional capacity by 2024 is 40 MW

Workshop – Example 2



- If all 3 projects energize, system component ② is required.
- If only 2 projects energize and 1 project cancels, system component ② is <u>not</u> required.

Example 2 (cont'd)



Next Steps

- Allow stakeholders to review presentation and concepts and provide feedback
- Prepare application with revised terms and conditions

POD Cost Function Database

LaRhonda Papworth

Public

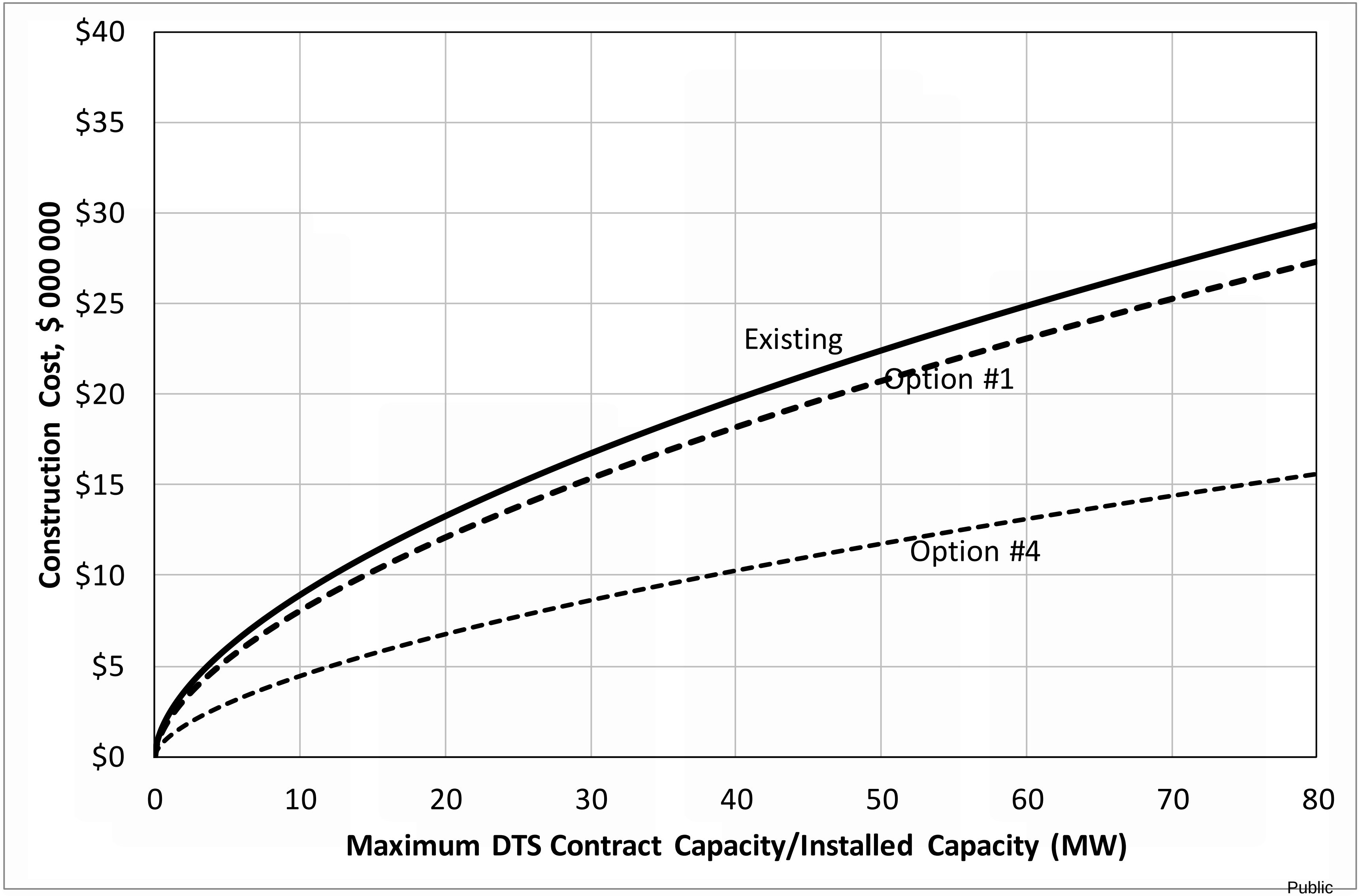
POD cost function database input into cost curves

- POD cost function database includes connection project (demand only) attributes: cost data, contract levels, installed capacity, connection type, location, substation number, project type, etc.
- For the 2018 tariff application, AESO will update POD cost function database with projects data since last update in 2014
- After Decision 2014-242 and Decision 3473-D01-2015 from the Commission in regards to project inclusion and criteria, the AESO was directed to "use 'Greenfield and Update Excluding 0 MW' until the matter can be <u>thoroughly explored</u>"
  - contract vs installed capacity
  - upgrade projects with 0 MW increase

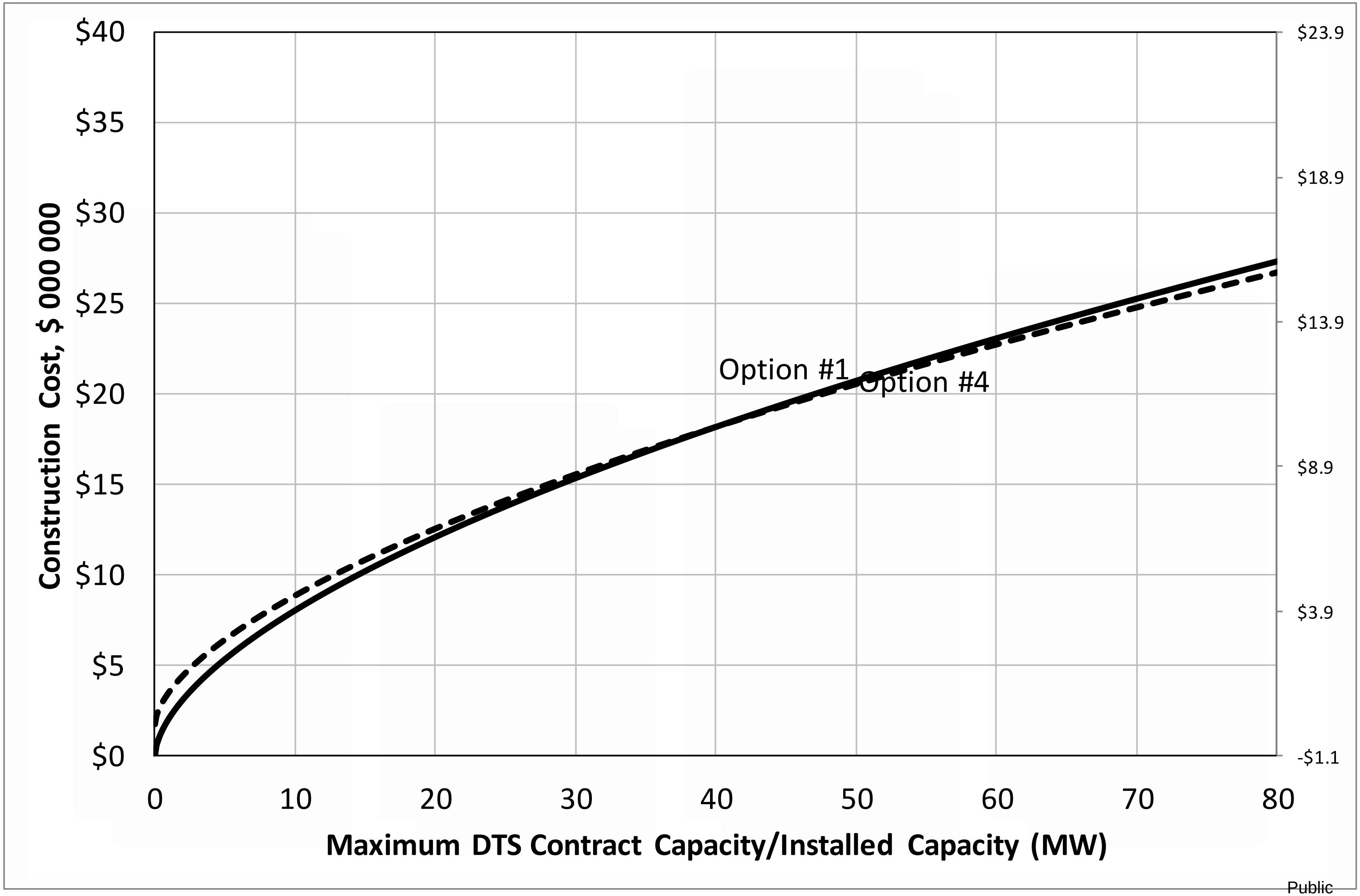
POD cost function database – cost curves

Cost Curve Options	Greenfield	Upgrade	0 MW Contracts
#1 Pre-2014 Practice	Contract	Contract	Include
#2 Current Practice (until thoroughly explored)	Contract	Contract	Remove
#3 As requested in Decision 2014-242	Contract	Installed	By using installed, 0 MW projects are included
#4 Not asked	Installed	Installed	
~~**#5 AESO not considering**~~ ~~(Not asked, not debated)~~	~~Installed~~	~~Contract~~	~~?~~

Comparison of Options to Existing (2014 ISO Tariff) Cost Function Curve



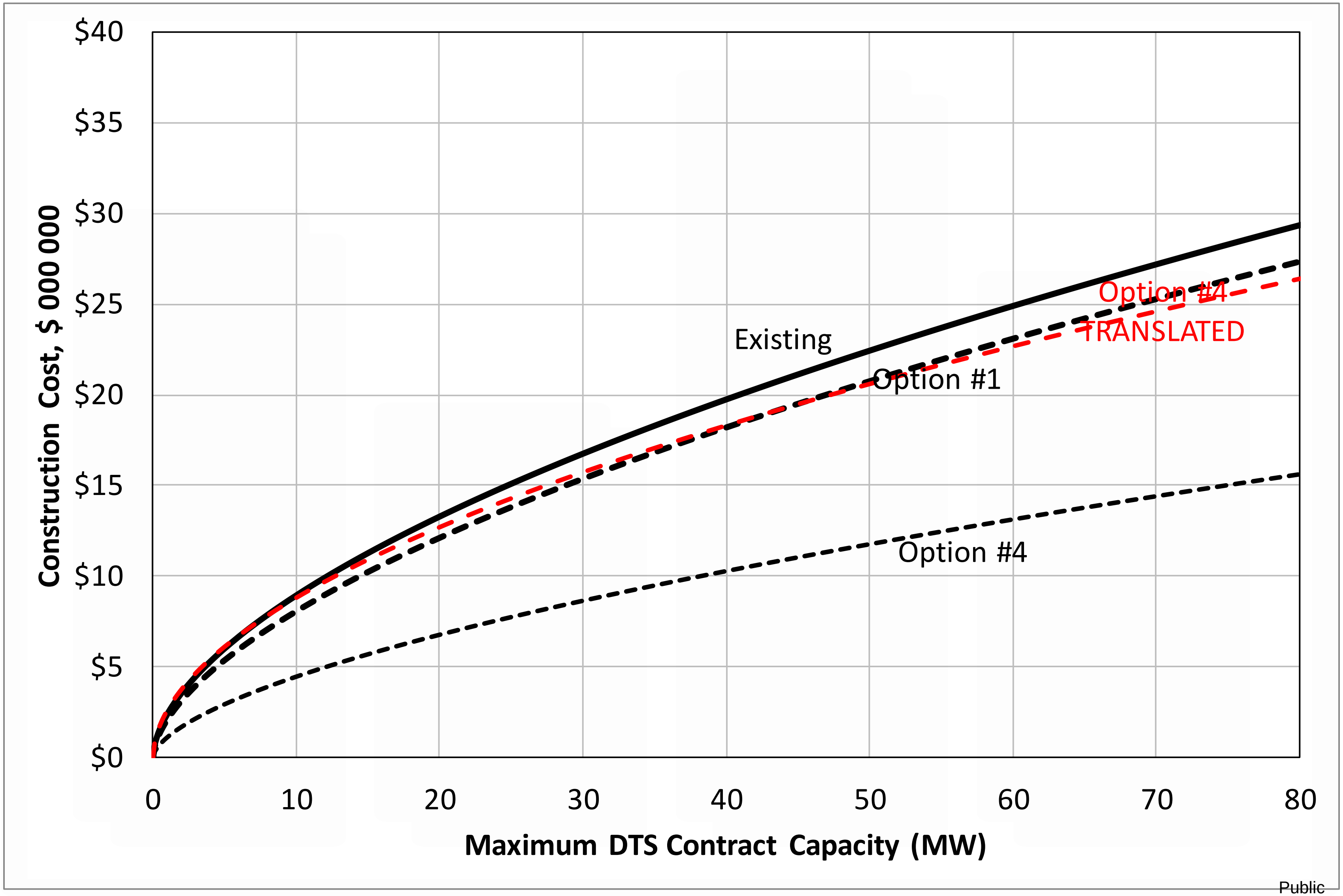
Comparison of Options - Shape



Translated Installed Capacity to Contract Capacity – X axis

- In order to continue to bill based on contract capacity, the cost curve x-axis for installed capacity must be “translated” to contract capacity
- In other words, create the exact same shape and dimensions as previous graph Option #4 which can be graphed against Option #1 without altering the secondary vertical axis

Comparison of Options to Existing (2014 ISO Tariff) Cost Function Curve



Criteria Summary

Criteria	Option #1	Option #4
Variability of relationship between installed capacity and contract capacity		
Number of assumptions and reasonableness of assumptions		
Fairness of treatment of customers with charges based on two different approaches (intergenerational equity)		
Reflect actual cost drivers of projects	$R2 = 0.35$	$R2 = 0.37$

Increasing shade is more positive

Impact on POD Rates

POD Charge	2017 ISO Tariff	Option #1 – est.*	Option #4 – est.*
Customer X SF	$8,789/month	$8,353/month	$10,986/month
<= 7.5 MW	$3,559/MW	$3,616/MW	$3,687/MW
>7.5 to <=17 MW	$2,229/MW	$2,306/MW	$2,196/MW
>17 to <=40 MW	$1,555/MW	$1,633/MW	$1,476/MW
>40 MW	$1,007/MW	$1,070/MW	$914/MW

* Estimated using proposed transmission cost study results for 2018 and 2017 wires costs and 2017 billing determinants

POD Cost Function
Next Steps

- Proceed with rates calculations based on Option #1
- Continue to work on translation of Installed Capacity cost curve to a Contract Capacity cost curve to provide analysis to Commission in application in order to thoroughly explore the matter
- Application will include analysis of all 4 options:
  – Option #1 – Contract capacity for both greenfield and upgrade projects, including 0 MW upgrade projects
  – Option #2 – Contract capacity for both greenfield and upgrade projects, excluding MW upgrade projects
  – Option #3 – Contract capacity for greenfield and installed capacity for upgrade projects
  – Option #4 – Installed capacity for both greenfield and installed capacity for upgrade projects

Transmission Cost Causation Study Follow-up

Raj Sharma

Preliminary 2018-2020 Functionalization

Year/Function	Bulk	Regional	POD
2016	59.2%	21.6%	19.2%
2018	53.4%	26.3%	20.3%
2019	55.0%	25.1%	19.9%
2020	53.7%	26.2%	20.1%

Regional System Additions in 2020

- Downtown Calgary (P1456) – about $145 million
- Grande Prairie (P1784, P1785) – about $75 million
- Central East (PENV, P1781) – about $280 million potentially moving to post 2020

Classification by Minimum System Approach

- Demand related cost as ratio of minimum system cost and optimal system cost
- 138kV: minimum system is 1x266 ACSR and optimal system is 1x477 ACSR
- 240kV: minimum system is 2x795 ACSR and optimal system is 2x1033 ACSR
- 500kV: minimum system is 2x2156 ACSR and optimal system is 3x1590 ACSR

Classification Calculations

- Normalize cost to single circuit for 138kV
- Normalize cost to double circuit for 240kV
- Escalate cost to common test year*

Regional System Classification

Conductor	1x266 ACSR	1x477 ACSR
2019 $ per kM	487,202	537,349

Class	Demand	Energy
2014-2016	87.4%	12.6%
2018-2020	93.3%	6.7%

Bulk System Classification

Conductor	2x795 ACSR	2x1033 ACSR
2019 $ per kM	1,764,083	2,306,910

Class	Demand	Energy
2014-2016	93.1%	6.9%
2018-2020	78.2%	21.8%

Critical Infrastructure Protections (“CIPs”) Cost Recovery

LaRhonda Papworth

Public

Background to CIPs Cost Recovery Issue

- Alberta reliability standard – *Cyber Security – BES Cyber System Categorization CIP-002-AB-5.1* is planned to be come effective on October 1, 2017
- TransAlta's Sundance Facility (units 1-6) would be the only aggregated generating facility classified with a Medium Impact Rating and would be then subject to additional expenditures
- In Proceeding 3443, the Commission directed the AESO to:

  "Address as part of its next general tariff application, the issue of cost responsibility for compliance with the CIP Alberta reliability standards. The AESO's application must either state that the AESO is including any such costs in its proposed tariff as recoverable under the AESO's tariff pursuant to section 30(2)(iv) of the *Electric Utilities Act*, or that the AESO does not propose that some or all of such costs are recoverable through its proposed tariff."

AESO's Proposed Position in Upcoming Application

- Not recoverable under tariff; generators should be individually responsible for the costs of complying with Alberta Reliability Standards, including CIPs
  - Based on AESO's internal FEOC assessment (costs that are directly assigned to the market participant are more efficient than if they are socialized)
  - Consistent with the treatment of other Alberta reliability standards that provide a benefit to the AIES and all market participants
- AESO's rationale included in application, may include evaluation of tariff, cost causation and FEOC principles

Application Process, Timeline and Next Steps

LaRhonda Papworth

Public

Commission Letter from March 29, 2017

- "In order to present a manageable set of issues, the Commission considers it may be helpful to parties if certain scope issues are communicated to market participants in advance of the submission of the ISO's tariff application. The scope issues include consideration of issues that arose out of Proceeding 20922 and also incorporate issues that were raised in subsequent proceedings, since Proceeding 20922 was initiated. However, parties are not limited or constrained in any way from submitting evidence on the issues identified below or on any other issues of significance to the operation and construction of the ISO tariff."

Other issues raised by stakeholders

To be investigated after 2018 ISO Tariff Application

- Capacity market cost recovery
- Coincident metered demand as billing determinant for bulk recovery charges
- Export rates

Will be addressed in application but with no proposed changes in rates or terms and conditions in 2018 ISO Tariff Application

- Energy storage tariff
- Isolated generation connections

March 1, 2017 Session – Stakeholder Comments Review

- Rider A1 – Dow - General agreement to approach the AESO is proposing to include in application
  - – Revise Rider A1 in ISO Tariff to add clarity regarding the life of the duplication avoidance tariff (DAT) and include a high-level assessment of the continued applicability of the DAT
  - – Extend forecast benefit to reflect life of the assets so that O&M and losses payments (only) continue in an extended payment table
- Application preview session will be an opportunity for the AESO to share the complete scope of changes proposed to the ISO tariff
  - – Due to the amount time required for legal and language review, the exact provisions will only be provided in the application to the Commission, not in the application preview

Checklist for 2018 ISO tariff application

Scope item	Status
Rider C / DAR / Tariff updates	100% complete
POD cost function work	100% complete
Transmission cost causation study	100% complete
Terms and conditions including Sections 4, 5, 8 and 9	80% complete
Clarify tariff for energy storage	100% complete
Updates to Proformas	100% complete
Clarify Rider A-1 – Dow duplication avoidance tariff	100% complete
Address direction from Commission regarding cost recovery from Critical Infrastructure Protection (CIP) work	100% complete
Long-term transmission rate projection model	75% complete

Tariff tentative timeline

Session	Date
Application Preview Session	June 2017
Application writing	Q2 2017
Application filing	Q2 2017
2016 DAR Filing	Q3 2017
2018 tariff <u>update</u> application	Q3 2017
Regulatory review process for 2018 tariff application	Q4 2017 – Q1 2018
Compliance filing	Q2 2018

Next steps

- The AESO will invite participants to respond to this presentation through a comment matrix in the next few weeks. To allow transparency, the AESO will post all comments on AESO's website following the receipt of participants' input
- For more information:

  LaRhonda Papworth – Manager, Tariff Design
  403-539-2555
  larhonda.papworth@aeso.ca
- All consultation documents can be found on AESO website at www.aeso.ca by following the path:
  Rules, Standards and Tariff ►Stakeholder engagement ►2018 ISO tariff application

Further Discussion? Questions?

Request for Stakeholder Comments on AESO 2018 ISO Tariff Consultation

Background

On April 10, 2017, the AESO and stakeholders participated in a consultation meeting to discuss (1) proposed changes to the ISO tariff's terms and conditions; (2) cost responsibility for compliance with the Critical Infrastructure Protection ("CIP") Alberta reliability standards; (3) results on the AESO's point of delivery ("POD") cost function database results and analysis; and (4) application process and next steps. Based on discussion at the meeting, the AESO invites written comments from stakeholders on the information presented. The meeting presentation is posted on the AESO website and can be accessed at www.aeso.ca by following the path: Rules, Standards and Tariff ► Stakeholder engagement ► 2018 ISO Tariff Application.

Please use the comment form below when submitting comments to the AESO on the 2018 ISO tariff consultation. Please ensure that your comments represent all interests within your stakeholder organization with respect to the consultation. Please provide comments or questions no later than **May 2, 2017**, to LaRhonda Papworth at larhonda.papworth@aeso.ca or 403-539-2555.

Consultation and Stakeholder Identification

Date of Request for Comments:	April 18, 2017
Period of Consultation:	November 15, 2016 – April 18, 2017
Comments From:	
Date:	
Contact:	
Phone:	
Email:	

Stakeholder Comments on AESO Information

Stakeholder Comment
(1) ISO Tariff Terms and Conditions - Proposals (Slides 6 – 36)
A. Proceeding 20922 Closure Letter, March 29, 2017 (Slides 7-10): • ***Issue 1: Legislative framework;*** • ***Issue 2: Advanced system-related classification of radial transmission projects; and*** • ***Issue 3: Load forecasting***
Stakeholder Comments:
B. Other Commission Decisions (Slides 11-12)

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Stakeholder Comment

Stakeholder Comments:

C. Principles for Load Customers (Slide 13):

- ***Provide a price signal;***
- ***System transmission facilities are not built as the result of a connection(s) not proceeding; and***
- ***Alignment with Commission's issue list (Proceeding 20922).***

Stakeholder Comments:

D. System transmission facilities required for a load connection (Slides 14-19):

- ***Alternative selection for load connections (Slide 15);***
- ***Market participant can wait for system or pay certainty charge/refund (Slide 16);***
- ***"Refundable deposit" – What does it provide for the AESO? (Slide 17);***
- ***Pros and cons – "refundable deposit" (Slide 18); and***
- ***Options (Slide 19)***

Stakeholder Comments:

E. Alternative selection example 1 – "lowest overall costs" (Slides 20-23):

- ***Diagram - Alternative 1 is "lowest overall costs" (Slide 20);***
- ***Diagram - Alternative 2 is "lowest overall costs" (Slide 21); and***
- ***Diagrams - Other examples (not discussed) (Slides 22-23).***

Stakeholder Comments:

F. Changes to Sections 4, 5, 8 & 9: What are we proposing to add? (Slides 24-25):

- ***New provisions that identify how the AESO will determine the preferred alternative;***
- ***Revised practices for system access (to replace the AESO's "Practices for System Access Service");***
- ***Defining and enforcing critical requirements for a SASR;***
- ***Identify when connection projects give us "sufficient certainty" that they will materialize;***
- ***New provisions around advancement costs and "accelerated construction" charges;***
- ***Differentiation between generation and load;***
- ***"Shared with system" cost provisions; and***
- ***Connections that are initially radial are 100% participant-related costs, to be "shared" if loop is closed.***

Stakeholder Comments:

G. Changes to Sections 4, 5, 8 & 9: What are proposing to revise/remove? (Slide 26):

Stakeholder Comment

- ***Remove any provisions that are duplicative of the legislation, rules, & reliability standards;***
- ***Remove "contiguous" in Section 8 referring to a "contiguous" connection project;***
- ***Remove provision referring to "planned to be looped" as system-related cost;***
- ***Remove connection process references; and***
- ***Revisit the "Good Electric Industry Practice" to reflect the AESO's minimum requirements.***

Stakeholder Comments:

H. Other terms and conditions proposals (Slides 27-29):

- ***Section 1 – Applicability and interpretation of ISO Tariff;***
  - ***Legal Review***
  - ***Ensure no duplication of legislation, rules, or reliability standards***
- ***Section 2 – Provision of and Limitations to System Access Service (may merge Sections 2 – 4);***
  - ***Make distinction between load and generation***
  - ***Add t-tap expectation of service***
  - ***Remove outage provisions (covered in ISO rules)***
- ***Section 3 – System Access Service Connection Requirements (may merge Sections 2-4);***
  - ***Remove technical requirements (covered in ISO rules)***
  - ***Move compliance requirements to Section 2***
- ***Section 5 – Financial Obligations for Connection Projects;***
  - ***Legal review***
  - ***Ensure no duplication of other authoritative documents***
- ***Section 6 – Metering;***
  - ***Remove altogether, covered in ISO rules***
- ***Section 7 – Provision of Information;***
  - ***Review for duplication of authoritative documents and legislation***
- ***Section 10 – Generating Unit Owners Contribution;***
  - ***Add GUOC rates to the ISO tariff***
- ***Section 11 – Ancillary Services;***
  - ***No changes proposed***
- ***Section 12 – Demand Opportunity Service;***
  - ***No changes proposed***
- ***Section 13 – Financial Security, Settlement and Payment Terms;***
  - ***Duplication with ISO rules?***
- ***Section 14 – Peak Metered Demand Waivers; and***
  - ***No changes proposed***
- ***Section 15 - Miscellaneous;***
  - ***Confirm with legal review.***

Stakeholder Comment

Stakeholder Comments:

I. Workshop Slides (Slides 30-36):

- ***Repeated from Slides 20-21 (Slides 31-32);***
- ***Example 1 background, area load, and area load forecasts (Slide 33);***
- ***Example 2 diagram and background (Slide 34); and***
- ***Example 2 area load and area load forecasts (Slide 35).***

Stakeholder Comments:

J. Terms and Conditions' Changes – Next Steps (Slide 36):

- ***Allow stakeholders to review presentation and concepts, and provide feedback;***
- ***Prepare application with revised terms and conditions.***

Stakeholder Comments:

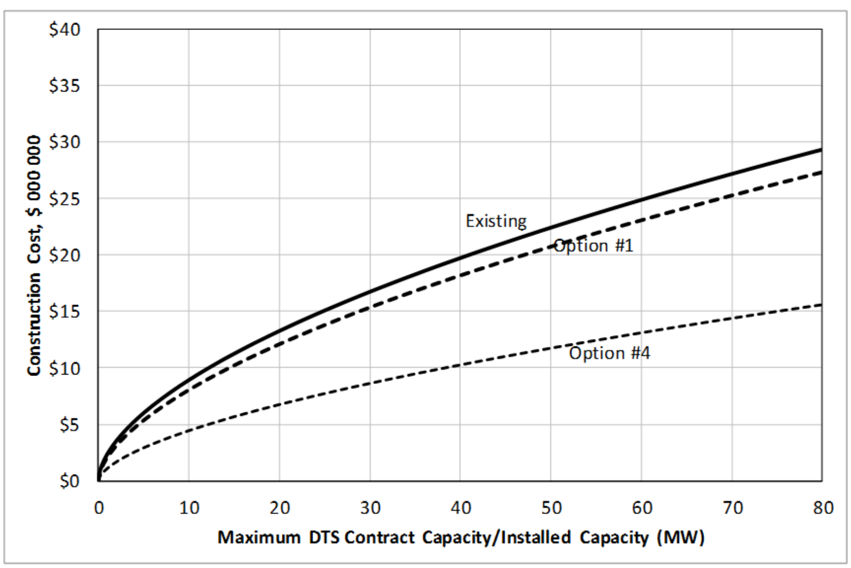
(2) POD Cost Function Database (Slides 37 – 46)

A. POD cost function database input into cost curves and options (Slides 38-39):

- ***AESO was directed to "use 'Greenfield and Update Excluding 0 MW' until the matter can be thoroughly explored" (Slide 38);***
- ***AESO thoroughly exploring four options (Slide 39).***

Stakeholder Comments:

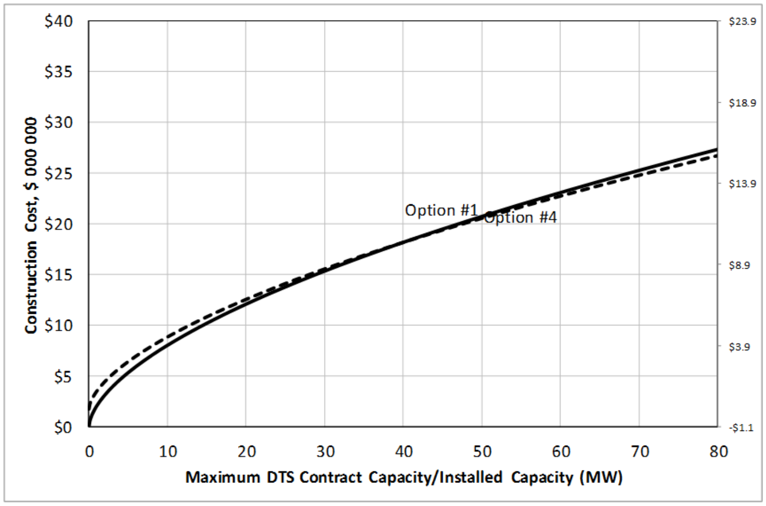
B. Comparison of options to existing (2014 ISO Tariff) Cost Function Curve (Slide 40):



Stakeholder Comment

Stakeholder Comments:

C. Comparison of options shape (Slide 41):



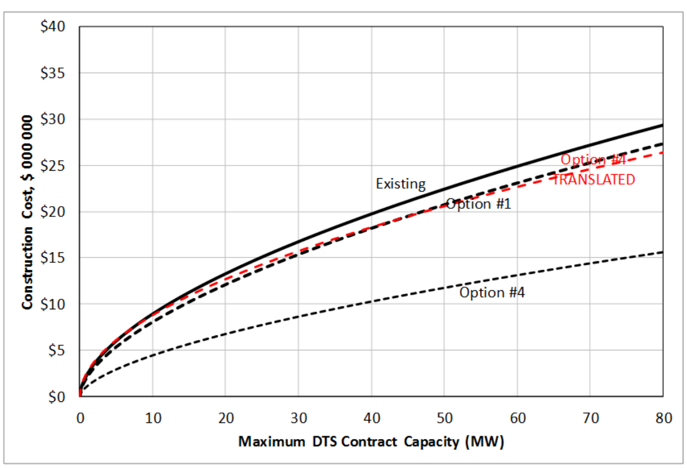
Stakeholder Comments:

D. Translated installed capacity to contract capacity – X axis (Slide 42):

- ***In order to continue to bill based on contract capacity, the cost curve x-axis for installed capacity must be "translated" to contract capacity;***
- ***In other words, create the exact same shape and dimensions as previous graph Option #4 which can be graphed against Option #1 without altering the secondary vertical axis.***

Stakeholder Comments:

E. Comparisons of options to existing (2014 ISO Tariff) cost function curve (Slide 43):



Stakeholder Comment

Stakeholder Comments:

F. Criteria summary (Slide 44):

Criteria	Option #1	Option #4
Variability of relationship between installed capacity and contract capacity		
Number of assumptions and reasonableness of assumptions		
Fairness of treatment of customers with charges based on two different approaches (intergenerational equity)		
Reflect actual cost drivers of projects	R2 = 0.35	R2 = 0.37

Stakeholder Comments:

G. Impact on POD rates (Slide 45)

POD Charge	2017 ISO Tariff	Option #1 – est.*	Option #4 – est.*
Customer X SF	$8,789/month	$8,353/month	$10,986/month
<= 7.5 MW	$3,559/MW	$3,616/MW	$3,687/MW
>7.5 to <=17 MW	$2,229/MW	$2,306/MW	$2,196/MW
>17 to <=40 MW	$1,555/MW	$1,633/MW	$1,476/MW
>40 MW	$1,007/MW	$1,070/MW	$914/MW

Stakeholder Comments:

H. POD cost function – next steps (Slide 46):

- ***Proceed with rates calculations based on Option #1 – pre-2014 practice;***
- ***Continue to work on translation of "Installed Capacity" cost curve to a "Contract Capacity" cost curve to provide analysis to Commission in application, in order to thoroughly explore the matter; and***
- ***Application will include analysis of all four options.***

Stakeholder Comments:

(3) Transmission Cost Causation Study Follow-up (Slides 47 – 53)

A. Preliminary 2018-2020 Functionalization (Slide 48):

Stakeholder Comment			
Year/Function	Bulk	Regional	POD
2016	59.2%	21.6%	19.2%
2018	53.4%	26.3%	20.3%
2019	55.0%	25.1%	19.9%
2020	53.7%	26.2%	20.1%

Stakeholder Comments:

B. Regional system additions in 2020 (Slide 49):

- ***Downtown Calgary (P1456) – about $145 million***
- ***Grande Prairie (P1784, P1785) – about $75 million***
- ***Central East (PENV, P1781) – about $280 million, potentially moving to post-2020***

Stakeholder Comments:

C. Classification by minimum system approach (Slides 50-51):

- ***Demand related cost as ration of minimum system cost and optimal system cost (Slide 50)***
  - ***138kV: minimum system is 1x266 ACSR and optimal system is 1x477 ACSR***
  - ***240kV: minimum system is 2x795 ACSR and optimal system is 2x1033 ACSR***
  - ***500kV: minimum system is 2x2156 ACSR and optimal system is 3x1590***
- ***Classification calculations (Slide 51):***
  - ***Normalize cost to single circuit for 138kV;***
  - ***Normalize cost to double circuit for 240kV; and***
  - ***Escalate cost to common test year (new improvement for this study).***

Stakeholder Comments:

D. Regional system classification (Slide 52):

Conductor	1x266 ACSR	1x477 ACSR
2019 $ per kM	487,202	537,349

Class	Demand	Energy
2014-2016	87.4%	12.6%
2018-2020	93.3%	6.7%

Stakeholder Comments:

Stakeholder Comment

E. Bulk system classification (Slide 53):

Conductor	2x795 ACSR	2x1033 ACSR
2019 $ per kM	1,764,083	2,306,910

Class	Demand	Energy
2014-2016	93.1%	6.9%
2018-2020	78.2%	21.8%

Stakeholder Comments:

(4) Critical Infrastructure Protections ("CIPs") Cost Recovery (Slides 54-56)

A. Background to CIPS Cost Recover Issue (Slide 55)

- ***Alberta reliability standard – Cyber Security – BES Cyber System Categorization CIP-002-AB-5.1 is planned to be effective on October 1, 2017***
- ***TransAlta's Sundance Facility (units 1-6) would be the only aggregated generating facility classified with a Medium Impact Rating subject to additional expenditures***
- ***In Proceeding 3443, the Commission directed the AESO state if these costs would recoverable under the ISO tariff or not***

Stakeholder Comments:

B. AESO's proposed position in upcoming application (Slide 56)

- ***Not recoverable under the tariff; generators should be individually responsible for the costs of complying with Alberta Reliability Standards, including CIPs***
  - ***Based on AESO's internal FEOC assessment (costs that are directly assigned to the market participant are more efficient that if they are socialized);***
  - ***Consistent with the treatment of other Alberta reliability standards that provide a benefit to the AIES and all market participants.***
- ***AESO's rationale will be included in the ISO tariff application and may include evaluation of tariff, cost causation and FEOC principles.***

Stakeholder Comments:

(5) Application Process, Timeline and Next Steps (Slides 57 – 62)

C. The AESO discussed the status of a number of 2018 ISO tariff application scope items (Slide 36) and a 2018 ISO tariff tentative timeline.

Stakeholder Comments:

Stakeholder Comment
Additional Comments

Please return this form with your comments by **May 2, 2017**, to:

LaRhonda Papworth
Manager, Tariff Design
Email: larhonda.papworth@aeso.ca
Phone: (403) 539-2555

Consolidated Stakeholder Comments on AESO 2018 ISO Tariff Consultation Session – April 10, 2017

Background

On April 10, 2017, the AESO and stakeholders participated in a consultation meeting to discuss (1) proposed changes to the ISO tariff's terms and conditions; (2) cost responsibility for compliance with the Critical Infrastructure Protection ("CIP") Alberta reliability standards; (3) results on the AESO's point of delivery ("POD") cost function database results and analysis; and (4) application process and next steps. The AESO invited written comments from stakeholders on the information presented at the meeting. The written comments received from stakeholders are consolidated below.

A copy of the presentation provided by the AESO at the April 10, 2017 meeting is posted on the AESO website and can be accessed at www.aeso.ca by following the path Tariff ► Stakeholder engagement ► 2018 ISO tariff application.

Stakeholder Comments on AESO Information

Stakeholder Comment
(1) ISO Tariff Terms and Conditions - Proposals (Slides 6 – 36)
A. Proceeding 20922 Closure Letter, March 29, 2017 (Slides 7-10): • ***Issue 1: Legislative framework;*** • ***Issue 2: Advanced system-related classification of radial transmission projects; and*** • ***Issue 3: Load forecasting***
Alberta Direct Connect Consumers Association ("ADC"): ADC supports the AESO working closely with new customers to have confidence in project scope and timing in order to advance new facilities while not incurring unnecessary costs.
AltaLink Management Ltd. ("AltaLink"): AltaLink is generally concerned with the direction being proposed related to advancement costs for load customers, as the proposals appear to be quite punitive to new load customers connecting to our system and will create an additional barrier to economic development within Alberta. AltaLink is concerned that Alberta will become an outlier jurisdiction sending punitive price signals to new customer growth at a time when our economy needs to be welcoming economic development of all kinds. Reasonable and balanced price signals should be considered, for the rare situation that an un-forecast load addition drives the need for earlier than planned system expansion. It must be recognized that long term transmission planning and load forecasting will always be inaccurate to actual results, it is a forecasting process after all. It is unrealistic and inappropriate to place the risk of the AESO's long term forecast inaccuracy on a single load customer that is helping to drive the economy in Alberta. Forecasts are a prediction of the future, and by their very nature cannot be accurate especially over long time frames of 10-20 years. It is unreasonable to expect otherwise. The use of scenarios is important to establish commonalities and triggers in the planning of transmission system reinforcements, and we support the AESO in continuing to refine this approach. It may be beneficial for the AESO to re-explain the planning process to the industry. AltaLink's understanding is that

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Stakeholder Comment
the AESO's LTP is based on a long term forecast and scenarios. This does not drive specific transmission development. The AESO brings forward specifically a NID for a specific project with the specific updated local forecast to support the development at that time. It is therefore a low probability that development will occur that much before needed. AltaLink would request the AESO bring forward in its application an analysis that confirms the magnitude of the risk trying to be addressed with the advancement cost proposal. To address the Commission's concern of load customers being incented to overstate their load requirements (size and timing), the AESO should include over the last 5-10 years, the number of load addition projects, the % of load addition projects that resulted in the need for transmission system projects, the % of load addition projects that resulted in advancing from the AESO's plans the timing of the energization of transmission system projects, and the % of advanced transmission system projects where the last customer in driving the need did not proceed. AltaLink is quite concerned with creating a punitive price signal to all future load customers in order to address a very low probability event or even worse, an outcome that has yet to materialize.
ATCO Electric Ltd. ("ATCO Electric"): ATCO Electric is concerned that more projects in the AESO connection queue will be delayed significantly if the AESO elects to cancel projects and have them restart at Stage 0 to be re-studied even for the smallest of load forecast differences. ATCO Electric is of the view that a more streamlined process is required to reduce churn otherwise created.
Capital Power Corporation ("Capital Power"): Capital Power notes and understands that the focus of the presentation, and potential tariff revisions being considered by the AESO for the 2018 GTA, relates to the treatment and allocation of costs relevant to load, and that the potential revisions described are not intended to affect generator costs or those associated with supply transmission service ("STS") contract holders. In this key respect, Capital Power notes and supports the finding of the AUC noted on slide 8 that there is a distinction between load serving transmission projects and generation serving transmission projects Capital Power further notes the AESO's continued and ongoing obligation to plan for and maintain a congestion free system [Transmission Regulation section15(1)(e)(i)] and the AUC's previous findings that ""there are no explicit or implicit transmission 'rights' but that the obligation imposed on the AESO is to provide market participants with a reasonable opportunity to access the AIES." – Decision 2013-135 at para 96. (slide 8) Any proposed tariff amendments considered by the AESO must be consistent with these principles and directives.
Dual Use Customers: No comments.
Industrial Power Consumers Association of Alberta ("IPCAA"): IPCAA welcomes the AESO's acceptance of the view that they should adopt a more proactive stance with respect to its overall system planning and transmission upgrade responsibilities for both load and generation.
TransCanada Energy Ltd.: No comments.

B. Other Commission Decisions (Slides 11-12)

Alberta Direct Connect Consumers Association ("ADC"):

ADC supports that an economic signal be sent to ensure robust planning and that facilities built will be efficiently utilized. There should be some latitude for market participants to stage their DTS contract levels or accept an interruptible service until full system build is completed or pay advancement costs if in service dates are firm.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta ("IPCAA"):

While the AUC indicates that to reduce costs a market participant could either shift its in-service date or absorb incremental costs, IPCAA believes that the market participant should have the opportunity as well to stage its market access, with options such as RAS schemes. This is a fundamental difference from the AESO's view that it is an all or nothing approach of completely unconstrained access.

TransCanada Energy Ltd.:

No comments.

C. Principles for Load Customers (Slide 13):

- ***Provide a price signal;***
- ***System transmission facilities are not built as the result of a connection(s) not proceeding; and***
- ***Alignment with Commission's issue list (Proceeding 20922).***

Alberta Direct Connect Consumers Association ("ADC"):

Principles are fine, however the degree of price signal needs to be established such that it doesn't discourage new load from locating in Alberta.

AltaLink Management Ltd. ("AltaLink"):

AltaLink is concerned with the implications of adding incremental up front cost to new load connecting customers as this will be an additional barrier to economic development in Alberta. Load connecting customers already make significant upfront capital investments for their own plant or growth project, for the costs of interconnecting to the grid and now may be required to provide additional upfront capital to fund a transmission system development. Transmission system development fundamentally benefits all customers in the region, generation and load, new and existing, and as such it is unfair to place the entire development cost on one customer, the "last in". AltaLink is not aware of any other jurisdictions in Canada or North America that require a single load customer to fund transmission system developments.

AltaLink is concerned with the "last in pays" concept being proposed. Transmission system development is driven by all types of customers: generation, gradual load growth of existing customers, new small load customers, and new larger load customers. System development goes through a process of long term planning, through to need application, permitting, construction and energization. There are regulatory reviews at the first three stages to reaffirm timing of proceeding to construction and energization. The AESO's role is to plan the system for forecast load and generation as transmission development takes many years. Not having the transmission system in place for actual load customer needs is not the customers issue, it is a forecast inaccuracy in the transmission planning process. Requiring new load customers to pay large upfront "last in pays" contributions to advance transmission system development to meet their needs because the forecasting process did not, is punitive to the customer.

AltaLink would request the AESO bring forward in its application an analysis that confirms the magnitude of the risk trying to be addressed with the advancement cost proposal. This analysis should include over the last 5-10 years, the number of load addition projects, the % of load addition projects that resulted in the need for transmission system projects, the % of load addition projects that resulted in advancing from the AESO's plans the timing of the energization of transmission system projects, and the % of advanced transmission system projects where the last customer in driving the need did not proceed. AltaLink is quite concerned with creating a punitive price signal to all future load customers in order to address a very low probability event or even worse, an outcome that has yet to materialize.

Although AltaLink is concerned with the proposed approach, should the AESO and the AUC determine some price signal is warranted, AltaLink would recommend and support the AESO seeking from the Commission a more principles based approach that the AESO can apply to the rare situation being considered, versus a tariff based approach that is inflexible to changing customer needs or government policy. This is because AltaLink believes the situation will be very rare. The discretionary approach should follow these key principles:

1) Advancement costs should not be considered if the system development was in the latest AESO LTP and the in-service date was within 5 years of the now needed in-service date. This addresses the inherent forecast accuracy of the LTP process.

2) Should advancement costs be applicable, the following principles should be considered:

- the pricing signal must be 100% refundable
- should be related to a % of the carrying costs of the advanced transmission system development, to a maximum of 5 years (as all customers in the region are driving the need not just one)
- should not be the full cost of the advanced transmission system development
- should be paid based on the progression of costs incurred and not all upfront
- should be refunded at the earliest stage of customer commitment such as when its interconnection project begins construction or when a DTS contract is signed
- should the customer ultimately not proceed, the customer should be refunded all of its deposit less the costs actually incurred for the system development

ATCO Electric Ltd.:

No comment.

Capital Power Corporation:

No comments.

Dual Use Customers ("DUC"):

No comments.

Industrial Power Consumers Association of Alberta ("IPCAA"):

IPCAA disagrees with the AESO's concept of only offering an unconstrained alternative selection. While load may have the desire for full access, some load may examine other alternatives such as constrained access using a RAS schema. Considering the implementation of both a capacity market and a carbon market, load may at times have incentives to construct some behind-the-fence generation or demand response capabilities.

IPCAA agrees that like generation, some form of financial commitment should be made if construction of system transmission facilities is triggered.

TransCanada Energy Ltd.:

No comments.

D. System transmission facilities required for a load connection (Slides 14-19):

- ***Alternative selection for load connections (Slide 15);***
- ***Market participant can wait for system or pay certainty charge/refund (Slide 16);***
- ***"Refundable deposit" – What does it provide for the AESO? (Slide 17);***
- ***Pros and cons – "refundable deposit" (Slide 18); and***
- ***Options (Slide 19)***

Alberta Direct Connect Consumers Association ("ADC"):

For points D-G: A new load, once they have entered into a DTS contract has an ongoing obligation to pay for the transmission system through the DTS tariff. Appropriate contract timing may reduce the concern for loads advancing system before they are ready to take service as they would start paying effective the contract date. Any treatment of new load connections should not be more onerous than a new generator connection.

AltaLink Management Ltd. ("AltaLink"):

Fundamentally, AltaLink supports enabling customer load as economic development on the grid. New load growth is good for existing customers and the economy in Alberta. AltaLink has provided its principles in C above. AltaLink supports a fully refundable deposit (including carrying costs) and as AltaLink has stated in its last comments to the AESO, the AESO should consider staging the deposits to align with the actual incurrence of incremental project costs. AltaLink does not support a lump sum approach. AltaLink supports a longer term view of least cost in developing the transmission system. The AESO should be looking at long term forecasts in the region when a new customer wishes to connect and should plan the system for the long term accordingly, seeking the least cost solution to interconnect the new customer. AltaLink is concerned with what appears to be a new planning approach that all new load customers will be radially connected as this can be suboptimal development in the region. AltaLink would expect the AESO has the expertise and capabilities to effectively assess what is the best long term development in the region to connect a new customer and justify if any of that development is system based. The AESO should be given deference as the independent system operator in its transmission development plans, for connecting new loads and for long term system development, they have the expertise and it is their role in the industry, not any other agency or entity.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta ("IPCAA"):

IPCAA disagrees with the AESO that load connection alternatives must be unconstrained. By unconstrained, we interpret this to mean that at all times the load has complete access. Since typically transmission constraints are the result of rare events, such as transmission outages etc. at most times significantly more transmission capacity may be available than the AESO's worst case assumptions. It would be useful for the load to assess the costs of full transmission access versus costs it may incur from having to reduce its consumption.

IPCAA is concerned with the AESO's view that the alternative selected will be the lowest overall cost. IPCAA would like to better understand this term. For example, does the AESO consider a probabilistic assessment of alternatives.

IPCAA agrees that any deposit provided by the load to ensure energization should be fully refundable. If the load does energize within the specified window and the deposit is NOT refundable, there is reduced incentive for the load to meet its commitment.

There should be a reasonableness test to a load only partially showing up (i.e. with a lower DTS capacity). For example, if a load with a 20 MW commitment shows up with 18 MW is not unreasonable. It would be worthwhile understanding the AESO's view on reasonableness.

The concern IPCAA has is that the deposit for the system cost could be prohibitive and load may ultimately decide not to invest. Unlike GUOC in which the generation owner pays a contribution towards a system build, between $10,000/MW and $50,000/MW, would the load would be on the hook for the whole system build? Can the AESO explain the difference between a system build for a load versus a generator?

TransCanada Energy Ltd.:

The process diagram on slide 14 has changed from the process diagrams on slides 14-24 from the March 1, 2017 consultation session. In the circumstance in which the customer cannot wait for the system build, the earlier slides contemplated a certainty charge/refundable deposit or an advancement cost depending on whether a system NID had been filed and on the form of the milestones. The April 10, 2017 presentation appears to replace the advancement costs associated with advancing a system project for which a NID has already been filed with a refundable deposit. In this case, the magnitude of the refundable deposit should not be for the full system project, but should be commensurate with what the advancement costs would otherwise have been (i.e., the deposit should be relative to the incremental costs associated with advancing the system project). Alternatively, if the deposit is for the full cost of the system project and the customer does not connect, the customer must be refunded all of the deposit less the incremental advancement costs.

E. Alternative selection example 1 – "lowest overall costs" (Slides 20-23):

- ***Diagram - Alternative 1 is "lowest overall costs" (Slide 20);***
- ***Diagram - Alternative 2 is "lowest overall costs" (Slide 21); and***
- ***Diagrams - Other examples (not discussed) (Slides 22-23).***

Alberta Direct Connect Consumers Association:

No comments.

AltaLink Management Ltd. ("AltaLink"):

Based on the discussions at the April 10 stakeholder meeting, it was noted by the AESO that if there was near future benefits in Alternative 2, the AESO would choose Alternative 2 and charge the customer $50M, the same amount as the AESO would have charged the customer in Alternative 1. AltaLink supports this approach as the AESO should have the long term planning perspective for the region and system development benefits all customers in the region.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta ("IPCAA"):

Slide 20: IPCAA believes that Alternative 2 with the option of a RAS schema for the load may be the cheapest solution until the system build becomes inevitable. Alternative 1 ($50M of radial connection) may saddle the load with costs that may make the load project uneconomic. Load should be able to assess its options for a constrained versus unconstrained option.

Slide 21: It would be useful understanding what a generators obligation would be under alternative 2 for GUOC versus a load's obligation. Alternative 2 is certainly more attractive for the load in ultimately only having a financial obligation for element 1 with element 2 socialized across all load.

Slide 23: Can the AESO please expand on the radial then shared component in terms of recovery of costs associated with the radial connection? If 3 is a generator instead of a load would it also share costs?

TransCanada Energy Ltd.:

The determination of lowest overall costs for alternative selections should consider the long-term overall costs by taking into consideration projects already contemplated in the long-term plan. For example, consider the scenario presented on slide 20 in which Alternative 1 ($50M cost for a radial connection) is deemed to be of lower overall cost than Alternative 2 ($16M cost for radial connection and $60M for system upgrade). If the $60M system upgrade is already in the long-term plan or a NID has been filed, this fact should be taken into consideration. If the incremental advancement cost for this system upgrade is only $10M, then the $10M incremental cost should be applied to Alternative 2 rather than the $60M total cost resulting in the selection of Alternative 2.

F. Changes to Sections 4, 5, 8 & 9: What are we proposing to add? (Slides 24-25):

- ***New provisions that identify how the AESO will determine the preferred alternative;***
- ***Revised practices for system access (to replace the AESO's "Practices for System Access Service");***
- ***Defining and enforcing critical requirements for a SASR;***
- ***Identify when connection projects give us "sufficient certainty" that they will materialize;***
- ***New provisions around advancement costs and "accelerated construction" charges;***
- ***Differentiation between generation and load;***
- ***"Shared with system" cost provisions; and***
- ***Connections that are initially radial are 100% participant-related costs, to be "shared" if loop is closed.***

Alberta Direct Connect Consumers Association ("ADC"):

No comment.

AltaLink Management Ltd. ("AltaLink"):

AltaLink would recommend that sufficient certainty occurs when the customer's interconnection project moves to the construction stage following permit. At this stage the customer will need to commit sufficient funding for the customer contribution payments for the interconnection, and most customer interconnections now require millions in contributions. Other options would be when they sign a DTS contract or upon energization of their interconnection project, whichever is sooner. The customer should be refunded all costs provided with carrying costs to keep the customer whole.

ATCO Electric Ltd.:

No comment.

Capital Power Corporation:

Section 4: Capital Power agrees with preserving the current distinction between load and generation. Capital Power submits it is not necessary to establish a tariff classification for dual-use customers. The current supply transmission service ("STS") and demand transmission service ("DTS") structure appropriately addresses the supply and demand requirements for dual-use customers. A level playing field must be preserved, and is preserved, by having distinct DTS and STS classifications governing the fundamental distinction between whether a site is drawing power from the grid, or delivering power to the grid. Consequently, service connections for dual-use customers (i.e. storage) are properly achieved with STS and DTS contracts like generators and load respectively (slide 25).

Dual Use Customers ("DUC"):

No comments.

Industrial Power Consumers Association of Alberta ("IPCAA"):

IPCAA submits that ultimately dual use customers should not be viewed as both generation and load and be forced to cover costs of both components. Typically, dual use is attractive to electricity consumers as a whole, as these entities shave peak costs for both energy and ancillary services. Considering the capacity market evolution, more discussion should take place with respect to dual use entities.

How are radial costs shared if a loop is "closed"? Can the AESO explain the anticipated cost-sharing mechanism?

TransCanada Energy Ltd.:

With respect to "Defining and enforcing critical requirements for a SASR", the AESO should strive to develop flexible requirements such that any such enforcements are only implemented if necessary to avoid unnecessary costs being imposed upon customers.

G. Changes to Sections 4, 5, 8 & 9: What are proposing to revise/remove? (Slide 26):

- ***Remove any provisions that are duplicative of the legislation, rules, & reliability standards;***
- ***Remove "contiguous" in Section 8 referring to a "contiguous" connection project;***
- ***Remove provision referring to "planned to be looped" as system-related cost;***
- ***Remove connection process references; and***
- ***Revisit the "Good Electric Industry Practice" to reflect the AESO's minimum requirements.***

Alberta Direct Connect Consumers Association ("ADC"):

No comments.

AltaLink Management Ltd. ("AltaLink"):

AltaLink considers any change to "Good Electric Industry Practice" to be a material change to the tariff and as such, the AESO should consult on the specific reasons why the AESO believes the definition needs to change and provide a draft of the changes to enable a stakeholders an opportunity to provide comments on the definition.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta ("IPCAA"):

Clearer language and intent is always welcome.

IPCAA is concerned with the statement "advancement costs will apply to all transmission facilities for a load connection." Do the same rules apply to generators? If not, what is the rational for difference between the two groups?

TransCanada Energy Ltd.:

No comments.

H. Other terms and conditions proposals (Slides 27-29):

- ***Section 1 – Applicability and interpretation of ISO Tariff;***
  - ***Legal Review***
  - ***Ensure no duplication of legislation, rules, or reliability standards***
- ***Section 2 – Provision of and Limitations to System Access Service (may merge Sections 2 – 4);***
  - ***Make distinction between load and generation***
  - ***Add t-tap expectation of service***
  - ***Remove outage provisions (covered in ISO rules)***
- ***Section 3 – System Access Service Connection Requirements (may merge Sections 2-4);***
  - ***Remove technical requirements (covered in ISO rules)***
  - ***Move compliance requirements to Section 2***
- ***Section 5 – Financial Obligations for Connection Projects;***
  - ***Legal review***
  - ***Ensure no duplication of other authoritative documents***
- ***Section 6 – Metering;***
  - ***Remove altogether, covered in ISO rules***
- ***Section 7 – Provision of Information;***
  - ***Review for duplication of authoritative documents and legislation***
- ***Section 10 – Generating Unit Owners Contribution;***
  - ***Add GUOC rates to the ISO tariff***
- ***Section 11 – Ancillary Services;***
  - ***No changes proposed***
- ***Section 12 – Demand Opportunity Service;***
  - ***No changes proposed***
- ***Section 13 – Financial Security, Settlement and Payment Terms;***
  - ***Duplication with ISO rules?***

- ***Section 14 – Peak Metered Demand Waivers; and***
    - ***No changes proposed***
- ***Section 15 - Miscellaneous;***
    - ***Confirm with legal review.***

Alberta Direct Connect Consumers Association:

No Comments at this time.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd. ("ATCO Electric"):

ATCO Electric notes that the AESO has not addressed the current challenge associated with connection projects that are not eligible for local investment and are required to provide cash security up to Stage 4 of the AESO connection process. ATCO Electric is seeking clarity whether other financial mechanisms can be used that will still provide the AESO will certainty on the level of the commitment required from Market Participants.

Capital Power Corporation ("Capital Power"):

Capital Power has comments for Section 14 only at this time.

Amendments to Section 14 should be made to accommodate peak metered demand exception requests for generators. The Peak Metered Demand Waiver ("PMDW") currently addresses load customer events only; for example, the transfer of load between substations in distribution networks without increasing substation DTS contracts. However, there are no provisions in Section 14 that consider a generator's need to seek PMDW relief due to events that may be beyond their control that may result in exceedances of their peak metered demand. These include forced outages (trips) involving individual or co-located generating units – caused by system events beyond the operator's control – when the generator(s) are returned to service under abnormal conditions.

Capital Power has experienced such events where rare, unlikely, and unanticipated transmission system events have occurred coincident with a co-located unit's planned outage and tripped the operating units. No self-supply option was available to return the blacked-out units to service and consequently the tripped units were returned to service with DTS support under abnormal start-up conditions. In those circumstances, and under the current tariff, Capital Power pursued resolution of the issue under the AESO's dispute resolution processes. However, Capital Power believes it would be beneficial to provide greater clarity with respect to when and how PMDW applies to generators, and provides the following proposed amendments to Section 14 2(1)(c).

Causes Eligible for Peak Metered Demand Waivers

2(1) The **ISO** may waive peak **metered demand** for a **market participant** for the purpose of calculating **billing capacity** when the peak **metered demand** was caused by one of the following:

(a) **commissioning**;

(b) activities required to repair and maintain **transmission facilities**;

(c) ~~load~~ service restoration activities that:

(i) for load that follow a **forced outage**, **planned outage** or **unplanned outage** of **transmission facilities** or facilities that are part of an **electric distribution system**; or

(ii) for load that are caused by an **emergency** on the **transmission system**; or

(iii) for generators that follow the trip of a **generating unit** or trip of co-located **generating units**, beyond the control of the generator, that results in abnormal **demand** during service restoration that exceeds the DTS contract amount.

(A) when the AIES is importing from any of the tie lines; and

(B) absent the conditions in (d) and (e) below.

(d) compliance with a **directive** the **ISO** issues during an **emergency**; or

(e) an event of **force majeure** that impacts the **ISO**.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta:

Section 2: Please make it clear what the AESO's intent is for a distinction between load and generation.

Section 10: Since the AESO is adding GUOC to the tariff, can it ensure symmetry between generators and loads in terms of connections and financial responsibilities? Can that be provided as a comparison table?

TransCanada Energy Ltd.:

No comments.

I. Workshop Slides (Slides 30-36):

- ***Repeated from Slides 20-21 (Slides 31-32);***
- ***Example 1 background, area load, and area load forecasts (Slide 33);***
- ***Example 2 diagram and background (Slide 34); and***
- ***Example 2 area load and area load forecasts (Slide 35).***

Alberta Direct Connect Consumers Association:

No comments.

AltaLink Management Ltd. ("AltaLink"):

The transmission planning process is based on long term forecasts and scenarios to test the robustness of the long term transmission plans. In the rare case that a large new customer, for example a new petrochemical plant of 90 MW comes along as a complete surprise to the AESO plans and was not included in the latest LTP, which occurs every two years, the AESO should accommodate the new customer as new customers drive the economy in Alberta. There should be no punitive charges to the customer for the enablement of transmission to supply its load. Load customers should be uncongested on the transmission system. For the example of the new petrochemical plant, possibly supported by government policy, charging the new customer an additional $100M up front to provide sufficient regional transmission system capacity to supply this new load may make the project uneconomic.

AltaLink is concerned with any distinction between "natural load growth" and single customer load growth.

Load growth is load growth. It is unfair to be punitive to one large load by charging major advancement costs while other customers do not need to pay for these advancement costs when they trigger the need. As such, AltaLink reemphasizes its principles in C above around any decision to apply advancement costs on single load customers that may require system developments.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta (“IPCAA”):

Slide 32: Because the AESO is only offering unconstrained solutions, the option of the radial connection with a cost of $16M and a RAS schema is not available to the load.

Slide 33: While the original request was for 90 MW, it is not clear why a load would not be offered the alternative of the full capacity requested with a RAS scheme until the full system capacity was available.

TransCanada Energy Ltd.:

No comments.

J. Terms and Conditions’ Changes – Next Steps (Slide 36):

- ***Allow stakeholders to review presentation and concepts, and provide feedback;***
- ***Prepare application with revised terms and conditions.***

Alberta Direct Connect Consumers Association:

No comments.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta:

No comments.

TransCanada Energy Ltd.:

No comments.

(2) *POD Cost Function Database*
(Slides 37 – 46)

A. POD cost function database input into cost curves and options (Slides 38-39):

- ***AESO was directed to "use 'Greenfield and Update Excluding 0 MW' until the matter can be thoroughly explored" (Slide 38);***
- ***AESO thoroughly exploring four options (Slide 39).***

Alberta Direct Connect Consumers Association:

No comments.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

DUC submits that the AESO was directed to use installed capacities. The POD cost function should be derived using escalated capital costs (to 2018 $) and installed capacities.

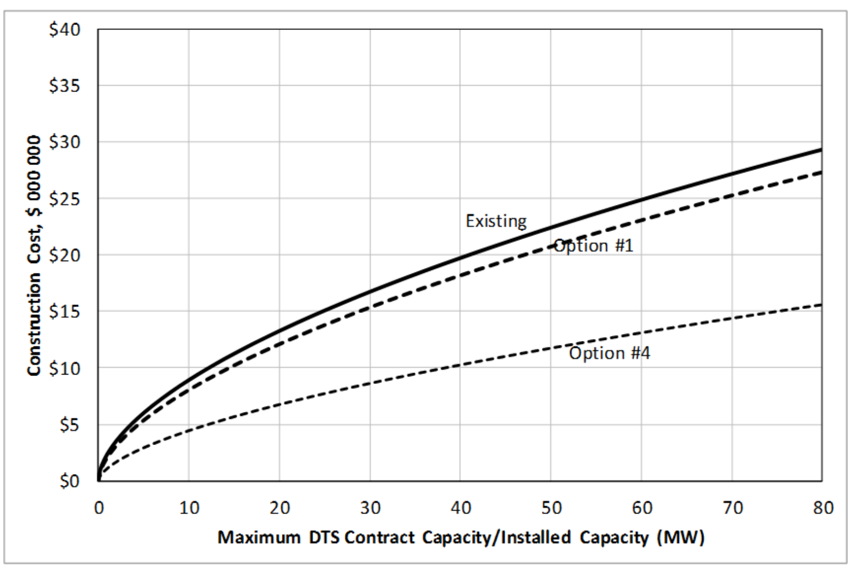
Industrial Power Consumers Association of Alberta:

No comments.

TransCanada Energy Ltd.:

No comments.

B. Comparison of options to existing (2014 ISO Tariff) Cost Function Curve (Slide 40):



Alberta Direct Connect Consumers Association:

From our understanding of the Options, it seems that Option 4 better reflects actual cost drivers of projects.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

The DUC does not support Option 1 or Option 4.

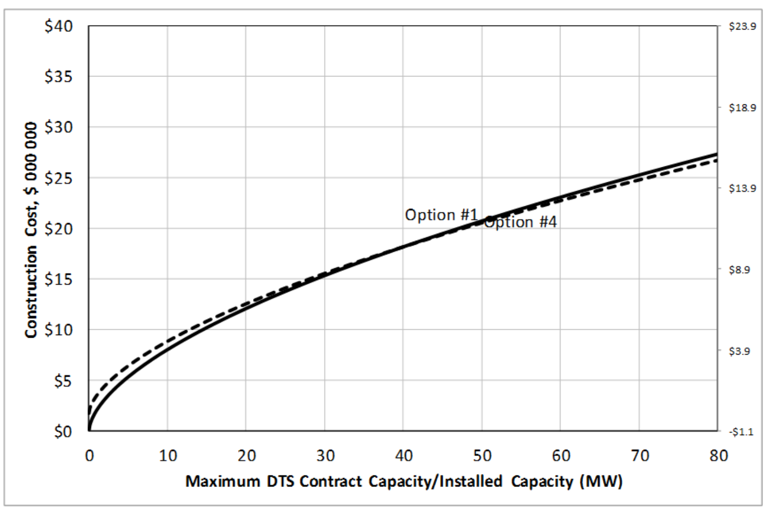
Industrial Power Consumers Association of Alberta ("IPCAA"):

IPCAA submits that capital cost versus installed capacity should be used to develop the pod cost function and then an adjustment should be made to correlate to billing capacity in the rate design. As it presently stands Option #4 better reflects actual cost drivers of projects.

TransCanada Energy Ltd.:

No comments.

C. Comparison of options shape (Slide 41):



Alberta Direct Connect Consumers Association:

No comments.

AltaLink Management Ltd. ("AltaLink"):

No comments.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta:

No Comments.

TransCanada Energy Ltd.:

No comments.

D. Translated installed capacity to contract capacity – X axis (Slide 42):

- ***In order to continue to bill based on contract capacity, the cost curve x-axis for installed capacity must be "translated" to contract capacity;***
- ***In other words, create the exact same shape and dimensions as previous graph Option #4 which can be graphed against Option #1 without altering the secondary vertical axis.***

Alberta Direct Connect Consumers Association:

Agree that if Option 4 is preferred that it needs to be translated to billing capacity.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd.:

No comment.

Capital Power Corporation:

No comments.

Dual Use Customers ("DUC"):

The DUC submits that the capital cost / installed capacity POD cost function should be used, and the conversation to Billing Capacity billing determinants should be used in rate design by adjusting POD rate levels by the average billing capacity to installed capacity ratio for all PODs.

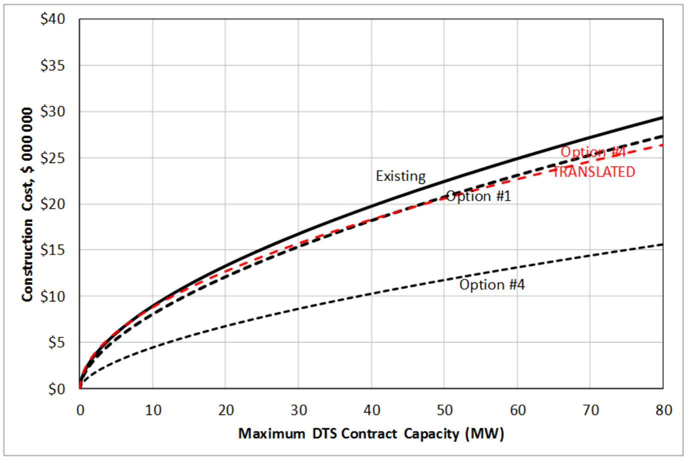
Industrial Power Consumers Association of Alberta:

No comments.

TransCanada Energy Ltd.:

No comments.

E. Comparisons of options to existing (2014 ISO Tariff) cost function curve (Slide 43):



Alberta Direct Connect Consumers Association:

No comments.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta:

No comments.

TransCanada Energy Ltd.:

No comments.

F. Criteria summary (Slide 44):

Criteria	Option #1	Option #4
Variability of relationship between installed capacity and contract capacity		
Number of assumptions and reasonableness of assumptions		
Fairness of treatment of customers with charges based on two different approaches (intergenerational equity)		
Reflect actual cost drivers of projects	R2 = 0.35	R2 = 0.37

Alberta Direct Connect Consumers Association:

No comments.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta:

Option #4 better reflects actual cost drivers of projects.

TransCanada Energy Ltd.:

No comments.

G. Impact on POD rates (Slide 45)

POD Charge	2017 ISO Tariff	Option #1 – est.*	Option #4 – est.*
Customer X SF	$8,789/month	$8,353/month	$10,986/month
<= 7.5 MW	$3,559/MW	$3,616/MW	$3,687/MW
>7.5 to <=17 MW	$2,229/MW	$2,306/MW	$2,196/MW
>17 to <=40 MW	$1,555/MW	$1,633/MW	$1,476/MW
>40 MW	$1,007/MW	$1,070/MW	$914/MW

Alberta Direct Connect Consumers Association:

Option 4 is a better reflection of actual costs.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd. (“ATCO Electric”):

ATCO Electric supports Option #1 - pre-2014 practice.

Capital Power Corporation:

No comments.

Dual Use Customers (“DUC”):

See DUC comments above.

Industrial Power Consumers Association of Alberta:

No comments.

TransCanada Energy Ltd.:

No comments.

H. POD cost function – next steps (Slide 46):

- ***Proceed with rates calculations based on Option #1 – pre-2014 practice;***
- ***Continue to work on translation of "Installed Capacity" cost curve to a "Contract Capacity" cost curve to provide analysis to Commission in application, in order to thoroughly explore the matter; and***
- ***Application will include analysis of all four options.***

Alberta Direct Connect Consumers Association ("ADC"):

ADC appreciates a thorough analysis of all the options.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd. ("ATCO Electric"):

ATCO Electric supports Option #1 - pre-2014 practice.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta ("IPCAA"):

IPCAA supports including the analysis of all four options as part of the application.

TransCanada Energy Ltd.:

No comments.

(3) Transmission Cost Causation Study Follow-up (Slides 47 – 53)

A. Preliminary 2018-2020 Functionalization (Slide 48):

Year/Function	Bulk	Regional	POD
2016	59.2%	21.6%	19.2%
2018	53.4%	26.3%	20.3%
2019	55.0%	25.1%	19.9%
2020	53.7%	26.2%	20.1%

Alberta Direct Connect Consumers Association:

No comments.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd. ("ATCO Electric"):

ATCO Electric will need more time to review and understand the AESO's Transmission Cost Causation Study, but generally does not have significant issues with the proposed 2018-2020 functionalization of costs at this time. ATCO Electric notes that ratepayers in ATCO Electric's service area continue to pay more for transmission chargers than customers in other service areas, which ATCO Electric may consider exploring further in the AESO's upcoming tariff application..

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta:

No comments.

TransCanada Energy Ltd.:

No comments.

B. Regional system additions in 2020 (Slide 49):

- ***Downtown Calgary (P1456) – about $145 million***
- ***Grande Prairie (P1784, P1785) – about $75 million***
- ***Central East (PENV, P1781) – about $280 million, potentially moving to post-2020***

Alberta Direct Connect Consumers Association:

No comments.

AltaLink Management Ltd. ("AltaLink"):

These planned system additions are an example of the dichotomy being considered for advancement costs. These system additions are based on forecasts. If the projects are built and the load does not materialize on the forecasted time, should the AESO charge the City of Calgary or the City of Grande Prairie an upfront advancement payment for the entirety of the project until it is needed?

AltaLink believes the AESO should not, it is the forecasting accuracy that should be borne by the AESO and all the customers in Alberta. The same principle should be considered for individual customers..

ATCO Electric Ltd.:

No comments.

Capital Power Corporation ("Capital Power"):

Capital Power is concerned with the proposal to delay system transmission projects in the Central region, particularly the deferral of PENV and P1781 to post 2020; currently scheduled for end Q1-2021. Capital Power recognizes the first renewable energy procurement ("REP1") auction will procure 400MW while future auction capacities and timing have yet to be determined. Currently, there are 17 projects, totaling ≈2,275MW with in-service-dates ranging from October 25, 2017 to December 31, 2019 in the Central planning areas (32, 35, 36, 37 39, 42) as reproduced from the AESO Connection Project list below.

Proj N	Project Name	Phase	Queue Type	Planning	Gen MW	Load MW	MW Type	Stage	Planned ISD	Received
635	Suncor Hand Hills Wind Energy Project	1	Connection	42	80.0	0.0	Wind	5	Dec 31, 2018	Oct 6, 2006
678	BluEarth Hand Hills Wind Project	1	Connection	42	80.0	1.0	Wind	5	Dec 31, 2018	Jan 15, 2007
937	Irma Wainwright Wind	1	Connection	32	90.0	3.0	Wind	3	Sep 30, 2018	Jun 11, 2009
1567	Sharp Hills Wind Farm New Facility Generator Capacity	1	Connection	42	300.0	0.0	Wind	3	Apr 8, 2019	Jun 4, 2014
1704	Paintearth Wind Farm	1	Connection	42	150.0	1.0	Wind	3	Jul 1, 2019	Oct 8, 2015
1710	Capital Power Halkirk 2 Wind	1	Connection	36	150.0	1.8	Wind	3	Jan 15, 2019	Oct 22, 2015
1752	Suncor Braconnier Wind Project New POS	1	Connection	42	80.0	0.3	Wind	2	Oct 31, 2019	Feb 23, 2016
1753	Suncor Huxley Wind Project New POS	1	Connection	42	50.0	0.3	Wind	2	Oct 31, 2019	Feb 23, 2016
1761	EDF EN Hand Hills WAGF	1	Connection	42	200.0	0.0	Wind	2	Oct 1, 2019	Mar 7, 2016
1770	NextEra Red Deer Battery Energy Storage System	1	Connection	42	40.0	46.0	Battery	2	Dec 1, 2018	Mar 18, 2016
1780	Sequoia Energy Oyen WAGF	1	Connection	42	100.0	1.0	Wind	2	Dec 14, 2018	Apr 6, 2016
1797	RES Oyen Wind Power Project	1	Connection	42	350.0	2.0	Wind	2	Jun 28, 2019	May 16, 2016
1824	Spirit Pine-Lone Pine WAGF	1	Connection	42	172.8	1.0	Wind	2	Dec 1, 2019	Jul 28, 2016
1893	NextEra Red Deer River Solar	1	Connection	35	150.0	0.5	Solar	2	Mar 26, 2019	Nov 15, 2016
1898	BowArk Energy Lanfine WAGF	1	Connection	42	145.0	0.0	Wind	2	Dec 1, 2019	Dec 2, 2016
1909	TransAlta Garden Plain Wind	1	Connection	42	130.0	4.0	Wind	2	Dec 31, 2019	Dec 22, 2016
1921	FortisAlberta Hayter STS Increase	1	Contract	37	8.0	0.0	STS	1	Oct 25, 2017	Mar 9, 2017

While it is unlikely that all these projects will proceed, it is evident that the Central region provides a strong regime for wind power development. It would be unreasonable to delay the Central region transmission upgrade(s) when considering Alberta's future REP auction capacities and the portfolio of Central region renewable projects currently active in the AESO connection process. Future REP auctions will be reliant upon the availability of transmission capacity. Capital Power encourages the AESO to proceed with the Central region system transmission projects to provide market participants seeking to develop renewable projects in the Central region a fair and reasonable opportunity to compete in future REP auctions..

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta:

Thank you for providing this information.

TransCanada Energy Ltd.:

No comments.

C. Classification by minimum system approach (Slides 50-51):

- ***Demand related cost as ration of minimum system cost and optimal system cost (Slide 50)***
    - ***138kV: minimum system is 1x266 ACSR and optimal system is 1x477 ACSR***
    - ***240kV: minimum system is 2x795 ACSR and optimal system is 2x1033 ACSR***
    - ***500kV: minimum system is 2x2156 ACSR and optimal system is 3x1590***
- ***Classification calculations (Slide 51):***
    - ***Normalize cost to single circuit for 138kV;***
    - ***Normalize cost to double circuit for 240kV; and***
    - ***Escalate cost to common test year (new improvement for this study).***

Alberta Direct Connect Consumers Association:

Appears to be consistent with the London Economics Study.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta:

No comments.

TransCanada Energy Ltd.:

No comments.

D. Regional system classification (Slide 52):

Conductor	1x266 ACSR	1x477 ACSR
2019 $ per kM	487,202	537,349

Class	Demand	Energy
2014-2016	87.4%	12.6%
2018-2020	93.3%	6.7%

Alberta Direct Connect Consumers Association ("ADC"):

ADC would appreciate more detail on what has caused the shift to more demand versus energy on the regional system. Which specific projects have contributed to this result?

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta:

No comments.

TransCanada Energy Ltd.:

No comments.

E. Bulk system classification (Slide 53):

Conductor	2x795 ACSR	2x1033 ACSR
2019 $ per kM	1,764,083	2,306,910

Class	Demand	Energy
2014-2016	93.1%	6.9%
2018-2020	78.2%	21.8%

Alberta Direct Connect Consumers Association:

For the Bulk system classification, what did the AESO use for costs of the 500 kV minimum and optimal system? How does the HVDC facilities get considered, are they already the optimal system because of the losses impact of HVDC? How does this factor into the demand/energy split? Because the demand – energy split is a significant departure from the London Economics study, please provide the details as to what specific projects have influenced the allocation.

AltaLink Management Ltd. ("AltaLink"):

AltaLink requests that the AESO provide stakeholders a reconciliation and detailed explanation of the 2014-16 demand/energy calculation to the 2018-2020 demand/energy calculation given the ~15% change. The reconciliation should include the total costs being recovered by each category.

ATCO Electric Ltd.:

No comment.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta ("IPCAA"):

IPCAA notes a marked increase in the energy / demand split. Can the AESO explain this change from the previous 2014 – 16 classification. Will this have any impact on behaviors in the Capacity market with its focus on demand rather than energy?

TransCanada Energy Ltd. ("TCE"):

No comments.

(4) Critical Infrastructure Protections ("CIPs") Cost Recovery (Slides 54-56)

A. Background to CIPS Cost Recover Issue (Slide 55)

- ***Alberta reliability standard – Cyber Security – BES Cyber System Categorization CIP-002-AB-5.1 is planned to be effective on October 1, 2017***
- ***TransAlta's Sundance Facility (units 1-6) would be the only aggregated generating facility classified with a Medium Impact Rating subject to additional expenditures***
- ***In Proceeding 3443, the Commission directed the AESO state if these costs would recoverable under the ISO tariff or not***

Alberta Direct Connect Consumers Association:

ADC agrees with the AESO position that these costs are the responsibility of the market participant, and not load.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta ("IPCAA"):

IPCAA submits that these CIP costs are better assigned to the market participant that is incurring the costs than socializing them across all consumers.

TransCanada Energy Ltd.:

No comments.

B. AESO's proposed position in upcoming application (Slide 56)

- ***Not recoverable under the tariff; generators should be individually responsible for the costs of complying with Alberta Reliability Standards, including CIPs***
    - ***Based on AESO's internal FEOC assessment (costs that are directly assigned to the market participant are more efficient that if they are socialized);***
    - ***Consistent with the treatment of other Alberta reliability standards that provide a benefit to the AIES and all market participants.***
- ***AESO's rationale will be included in the ISO tariff application and may include evaluation of tariff, cost causation and FEOC principles.***

Alberta Direct Connect Consumers Association ("ADC"):

ADC supports.

AltaLink Management Ltd.:

No comments.

ATCO Electric Ltd.:

No comment.

Capital Power Corporation:

Capital Power disagrees with the AESO's proposed position, and believes it would unfairly impose costs on generators to comply with standards that, by design and intent, are being adopted to provide system benefit. The CIP Standards are being implemented to enhancing the reliability of the AIES. While the benefits will accrue to all users of the AIES, the *Alberta Reliability Standard Cyber Security – BES Cyber System Categorization CIP-002-AB-5.1* states the purpose is "To identify and categorize BES cyber systems and their associated BES cyber assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES cyber systems could have on the reliable operation of the bulk electric system." Therefore, it is not reasonable that the cost of complying with standards beyond the “low” impact CIP Standard rating be assigned to the affected generators, particularly given that the ability for those generators to recover those costs would be highly uncertain given the competitive dynamics of Alberta’s competitive wholesale market. Capital Power submits that CIP costs beyond a “low impact” rating should be allocated to the system and collected through the AESO Tariff - not charged to the specific generator..

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta (“IPCAA”):

IPCAA supports the AESO’s proposed position.

TransCanada Energy Ltd.:

No comments.

(5) Application Process, Timeline and Next Steps (Slides 57 – 62)

C. The AESO discussed the status of a number of 2018 ISO tariff application scope items (Slide 36) and a 2018 ISO tariff tentative timeline.

Alberta Direct Connect Consumers Association (“ADC”):

ADC agrees that any tariff design considering the Coincident metered demand be investigated after this GTA. This matter has been raised in all GTA’s since 2006 and the AUC has approved this tariff mechanism every time. There is a strong and lengthy evidentiary record as to why the CPD method provides the right economic signal to minimize future system build for the benefit of all ratepayers. The ADC would be happy to share that with any interested parties.

AltaLink Management Ltd. (“AltaLink”):

As AltaLink has expressed to the industry, including the AESO, AltaLink is concerned that the current rate design (i.e. coincident peak charge) is resulting in cross-subsidization of transmission costs between customer classes. This tariff structure needs to be reviewed in 2018 with decisions implemented in 2019 tariff structures. AltaLink is open to a separate module to address this industry issue if it is not addressed within this AESO GTA, in order to enable expedience for the overall AESO tariff decision.

ATCO Electric Ltd.:

No comments.

Capital Power Corporation:

No comments.

Dual Use Customers:

No comments.

Industrial Power Consumers Association of Alberta:

Thank you for providing the update.

TransCanada Energy Ltd.:

No comments.

Additional Comments

ADC appreciates the opportunity to provide comments.

AltaLink requests the AESO confirm with stakeholders that the TRIP model will be updated and filed with the AESO’s 2018 application.
Capital Power appreciates the opportunity to participate in the AESO’s 2018 Tariff development.
DUC appreciates the opportunity to provide comments.

June 13, 2017

AESO Stakeholders
AESO 2018 ISO Tariff Consultation Participants

Dear Stakeholder:

Re: **Invitation to Attend Information Session on AESO 2018 ISO Tariff Application**

The AESO is finalizing the development of the 2018 ISO tariff application, which the AESO currently anticipates filing with the Alberta Utilities Commission by July 31, 2017. The AESO invites stakeholders to an information session to discuss the proposals that will be included in the application:

Date:	Monday, June 26, 2017
Time:	1:00 pm to 4:00 pm
Place:	Meeting Room 6006, 6th Floor, BP Centre, 240 – 4th Avenue SW, Calgary, Alberta. Note that the glass doors on the 6th floor are locked; please knock to have them opened.
Teleconference:	Within Calgary calling area: 403-410-3051, Conference ID 9232504 Outside Calgary calling area: 1-855-453-6957, Conference ID 9232504
RSVP:	By 5 pm on **June 21, 2017** to, Tatiana Aparicio-Caris Tatiana.Aparicio-Caris@aeso.ca or 403-539-2664.

The AESO will present information on the following topics to be addressed in its 2018 ISO tariff application:

- transmission cost causation study update;
- point of delivery cost function update and options analysis;
- Rate DTS, *Demand Transmission Service*, update to reflect cost causation study and point of delivery function;
- Critical Infrastructure Protection (CIPs) Alberta reliability standard compliance cost recovery;
- tariff treatment of energy storage;
- update on Rider C, *Deferral Account Adjustment Rider*, amendment application;
- updated investment levels;
- terms and conditions amendments;
- response to the Commission's Proceeding 20922 closure letter; and
- application process.

The AESO plans to present information on these topics to facilitate discussion and will post a presentation before the meeting.

All information relating to the 2018 ISO tariff consultation is available on the AESO website at www.aeso.ca by following the path Rules, Standards and Tariff ► Stakeholder engagement ►

Alberta Electric System Operator, Calgary Place, 2500, 330 – 5th Avenue SW Calgary, AB T2P 0L4
Phone: 403-539-2450 Fax: 403-539-2949 www.aeso.ca @theaeso

2018 ISO tariff application. As well, new information posted by the AESO on this topic will be mentioned in the AESO stakeholder newsletter, which you can subscribe to at the bottom right of the AESO's home page at www.aeso.ca.

If you have any questions on the AESO's 2018 ISO tariff consultation, please contact me at 403-539-2555 in Calgary or by email to larhonda.papworth@aeso.ca.

Yours truly,

LaRhonda Papworth
Manager, Tariff Design

cc: Doyle Sullivan, Director –Tariff Design

AESO 2018 ISO Tariff Consultation

Application Preview
June 26, 2017

AESO Office, Calgary

Public

Agenda

- Session objectives(slide 3)
- Application objectives(slides 4)
- Transmission Cost Causation Study Results (slides 6-13)
- Rates and Riders updated(slides 14-36)
- Revised Terms & Conditions(slides 37-45)
  - Substantive changes to allow for tariff mechanisms to address past cost allocation issues and Commission's closure letter from Proceeding 20922
    - Issue #1 – legislative framework
    - Issue #2 – advanced system-related classification of radial transmission projects
    - Issue #3 – load forecasting
  - Shift of AESO's position to require a non-refundable advancement charge if a load connection requires a system upgrade

Agenda (cont'd)

- Other matters(slides 46-51)
  - Other revisions to terms and conditions
  - Include updated GUOC rates into ISO tariff
  - Tariff treatment for energy storage
  - Cost recovery of CIP Alberta reliability standards
  - Riders A1 - Dow Duplication Avoidance Tariff revision
- Tariff target timelines (slide 52)
- Discussion and wrap-up(slide 53)

Session objectives

- Provide an overview of upcoming 2018 ISO tariff application
- Provide draft calculated rates and investment based on 2017-2018 Budget Review Proposal, TFO applied-for or approved wires costs, Transmission Cost Causation Study results and results from POD cost function cost curve
- Provide tariff timeline targets

Application objectives

- Close off a number of past tariff initiatives
  - Cost classification proceedings
  - Point-of-delivery cost function (contract vs installed capacity)
  - Rider C, deferral account reconciliation process
- Capacity market and other issues raised by stakeholders during consultation to be addressed post-application:
  - Capacity market cost recovery
    - Export rates
  - Coincident metered demand recovery of bulk transmission
    - Review classification (demand and energy) method
  - Good electricity industry practice/investment policy
- Share with stakeholders as soon as possible the scope and timing of the additional work

Transmission Cost Causation Study Results

Raj Sharma

Public

Preliminary 2018-2020 capital cost functionalization

Year/Function	Bulk	Regional	Point of Delivery
2016	66.9%	18.1%	15.0%
2018	57.5%	23.9%	18.6%
2019	56.5%	23.8%	19.6%
2020	55.1%	24.2%	20.7%

Preliminary 2018-2020 operating and maintenance cost functionalization

Year/Function	Bulk	Regional	Point of Delivery
2014-2016	20.8%	39.2%	40.0%
2018-2020	21.2%	36.5%	42.3%

Preliminary 2018-2020 non-capital costs to capital costs ratio

Year	Non-capital	Capital
2014	19.5%	80.5%
2015	18.0%	82.0%
2016	16.3%	83.7%
2018-2020	17.1%	82.9%

Preliminary combined 2018-2020 functionalization

Year/Function	Bulk	Regional	Point of Delivery
2016	59.4%	21.5%	19.1%
2018	51.3%	26.1%	22.6%
2019	50.5%	26.0%	23.5%
2020	49.3%	26.3%	24.4%

Preliminary final combined 2018-2020 functionalization

Includes revenue from regulated generation unit charge, and cost from Fort McMurray West 500kV project

Year/Function	Bulk	Regional	Point of Delivery
2016	59.2%	21.6%	19.2%
2018	51.2%	26.1%	22.7%
2019	52.4%	25.0%	22.6%
2020	51.2%	25.3%	23.5%

Bulk system classification

Results of update following the same minimum system methodology do not seem reasonable so the AESO is proposing to continue 2016 bulk system classification for 2018 to 2020.

500 kV Conductor	3x1590 ACSR	2x2156 ACSR
Cost per kM	$2,100,000	$1,900,000

240 kV Conductor	2x795 ACSR	2x1033 ACSR
Cost per kM	$1,593,624	$1,701,334

Class	Demand	Energy
2014-2016	93.1%	6.9%
2018-2020	93.7%	6.3%

Regional system classification

Results of update following the same minimum system methodology do not seem reasonable so the AESO is proposing to continue 2016 regional system classification for 2018 to 2020.

138/144 kV Conductor	1x266 ACSR	1x477 ACSR
Cost per kM	$362,336	$442,662

Class	Demand	Energy
2014-2016	88.2%	11.8%
2018-2020	87.4%	12.6%

POD Cost Function Database, Rates and Investment

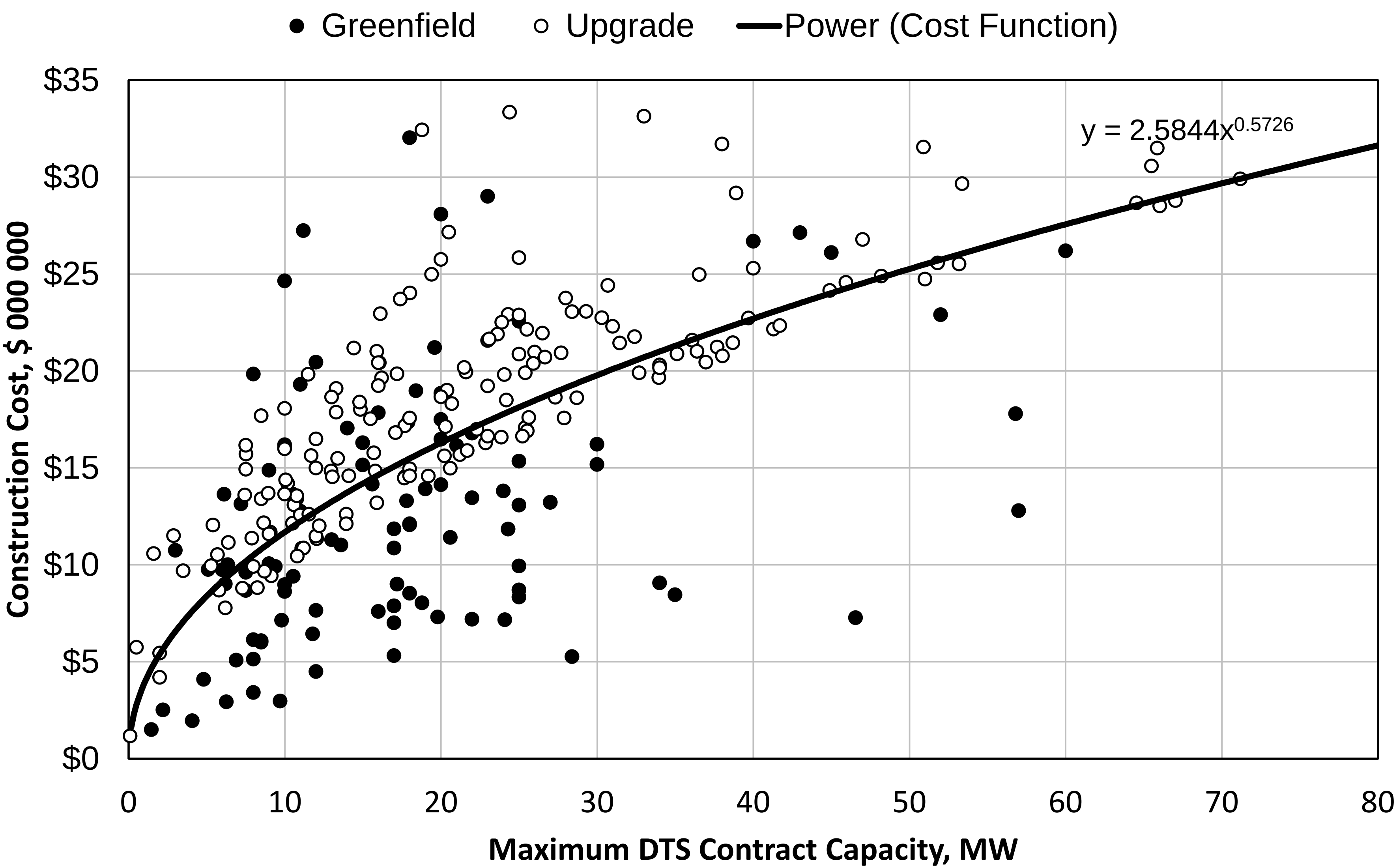
LaRhonda Papworth

Public

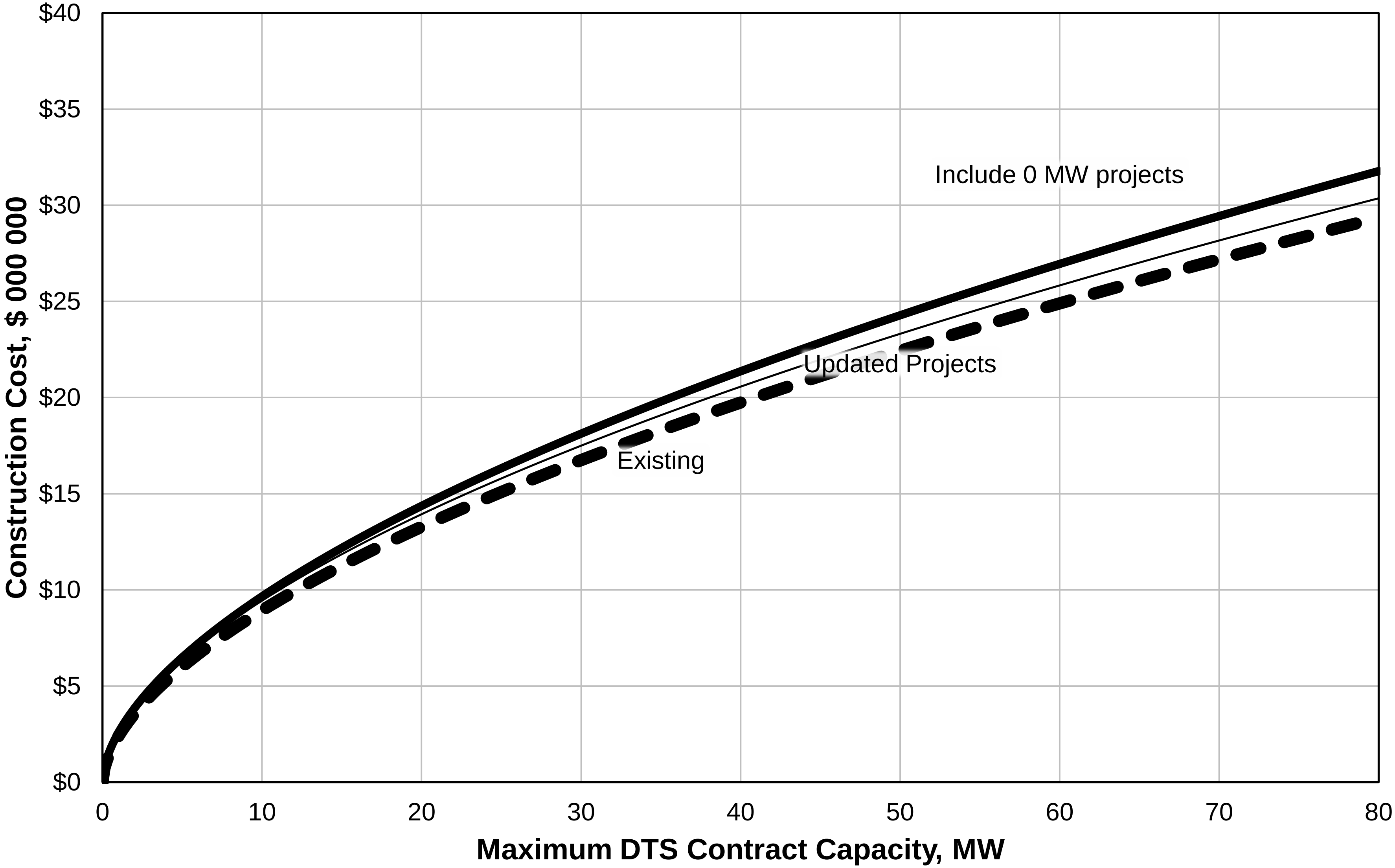
2017 POD cost function database includes a total of 285 projects

Type of Project	Number	Average Contract Capacity (MW)	Total Contract Capacity (MW)	Average Cost ($ 000 000)	Total Cost ($ 000 000)
Greenfield	112	21.9	2,017.7	$14.6	$1,338.9
Upgrade	173	7.7	1,386.2	$3.4	$599.4

Final cost function represents all 285 connection project data points



Updating project data had the largest impact on the existing cost function



Existing and proposed cost functions

- Existing cost function

$$\text{Costs} = \$2{,}392{,}400 \times MW^{0.5721}$$

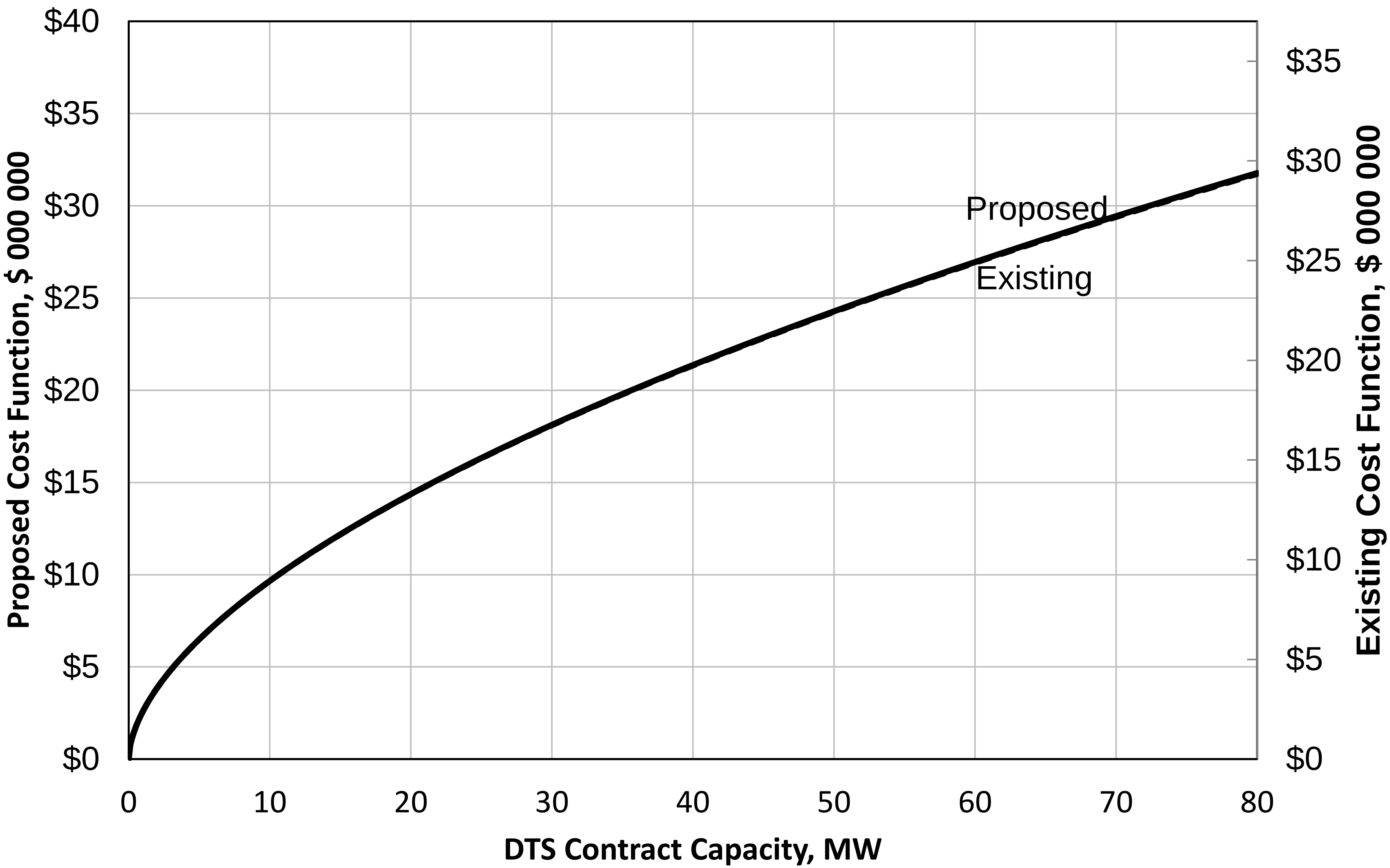
- Proposed cost function

$$\text{Costs} = \$2{,}584{,}400 \times MW^{0.5726}$$

How are rates impacted?

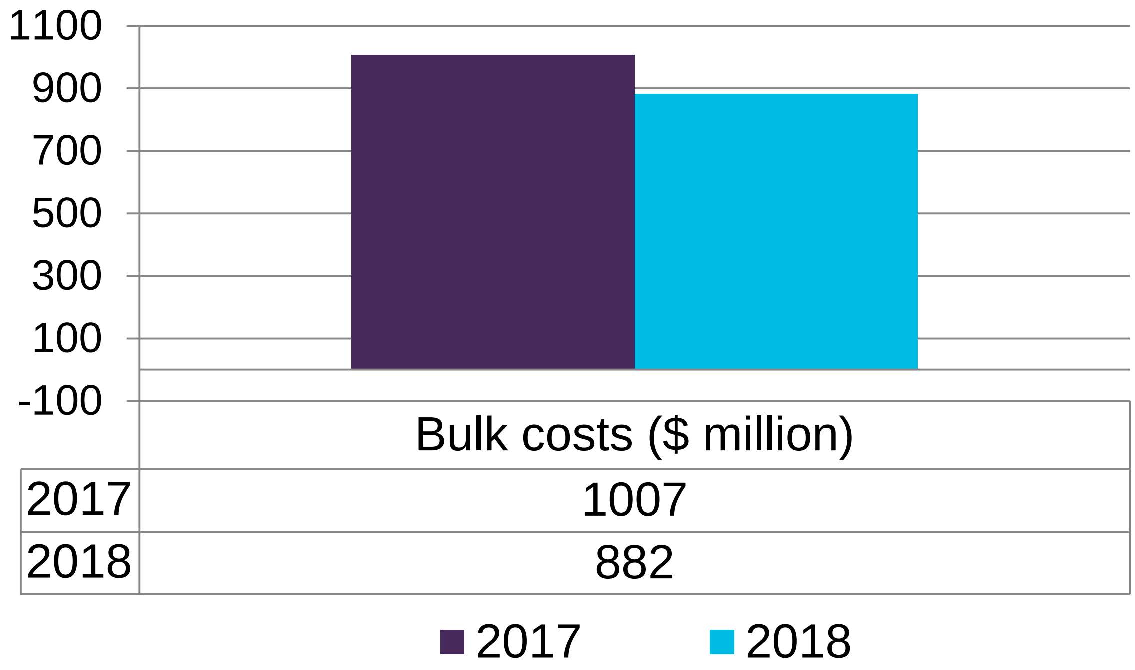
- Revision of the cost function will affect the average rates paid for system access service by all market participants
  - The cost function provides the cost causation basis for the point of delivery charge in Rate DTS
- Point of delivery charge components are affected by the shape of the cost function, not the level

Changes to the shape of the cost function will impact rates



Public

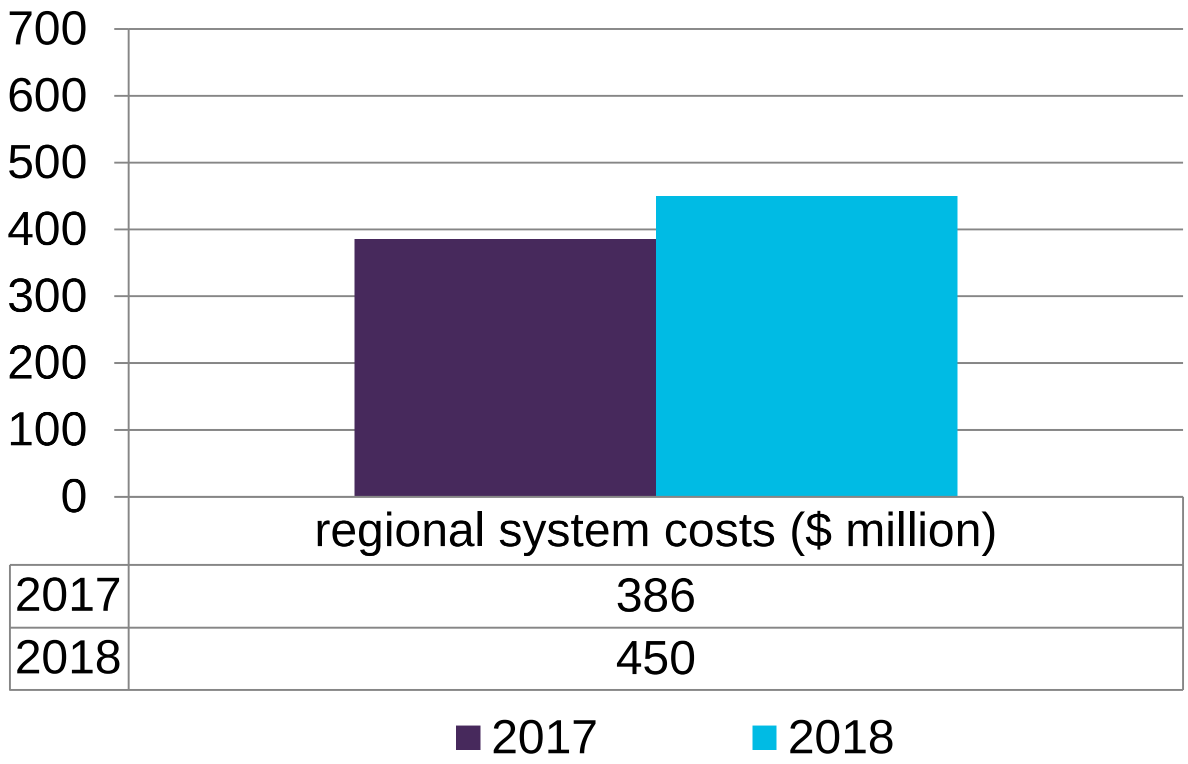
How is Rate DTS bulk system charge changing?



Rate DTS – Bulk system charge	2017	2018
Coincident demand charge ($/MW/month)	10,670.00	9,219.00
Metered energy charge ($/MWh)	1.25	0.99

Initial rate calculations. May change for application

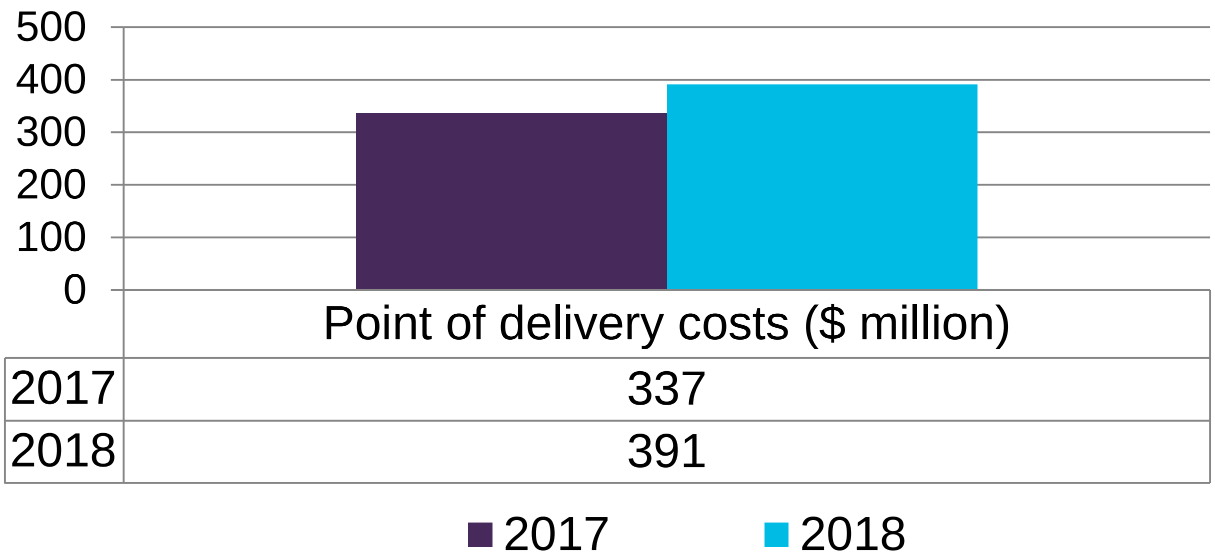
How is Rate DTS regional system charge changing?



Rate DTS – Regional system charge	2017	2018
Billing capacity charge ($/MW/month)	2,356.00	2,694.00
Metered energy charge ($/MWh)	0.87	1.01

Initial rate calculations. May change for application

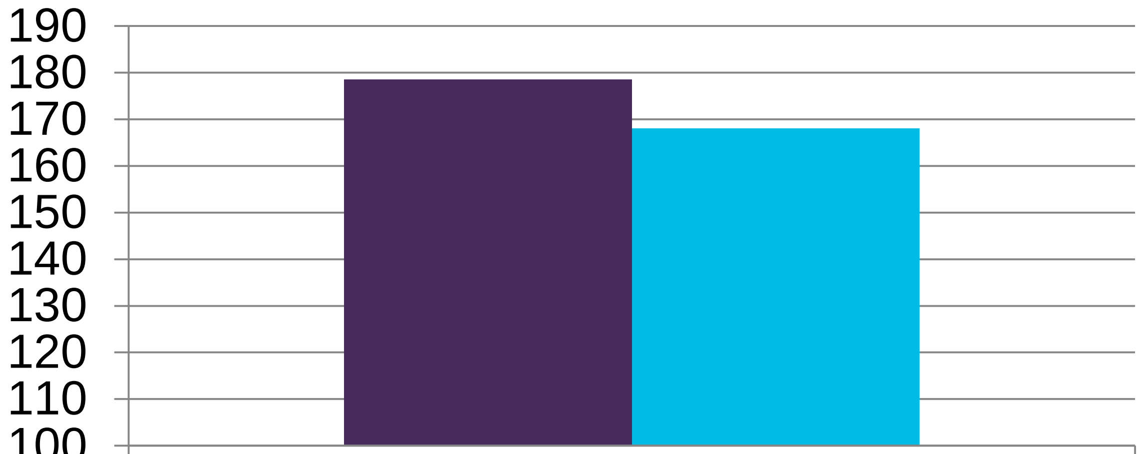
How is Rate DTS point of delivery charge changing?



Rate DTS – Point of delivery charge	2017	2018
Substation Fraction ($/month)	8,789.00	10,109.00
First (7.5 x SF) MW ($/MW/month)	3,559.00	4,100.00
Next (9.5 x SF) MW ($/MW/month)	2,229.00	2,569.00
Next (23 x SF) MW ($/MW/month)	1,555.00	1,795.00
All remaining MW ($/MW/month)	1,007.00	1,157.00

Initial rate calculations. May change for application

How is Rate DTS operating reserve charge changing?

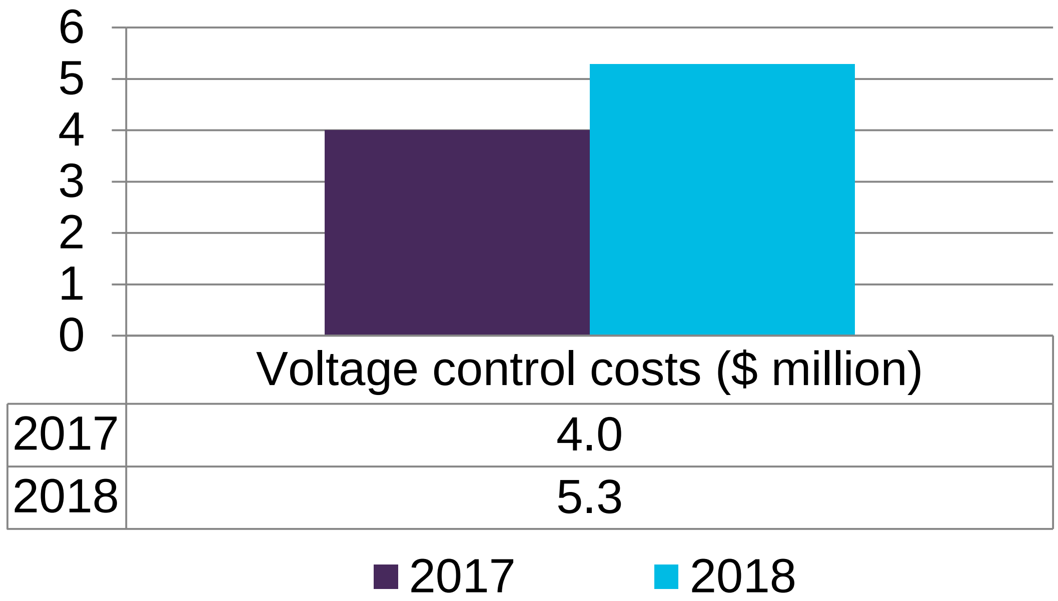


	operating reserve costs ($ million)
2017	179
2018	168

Rate DTS – Operating Reserve Charge	2017	2018
Operating reserve charge (allocated hourly)	6.99%	6.58%

Initial rate calculations. May change for application

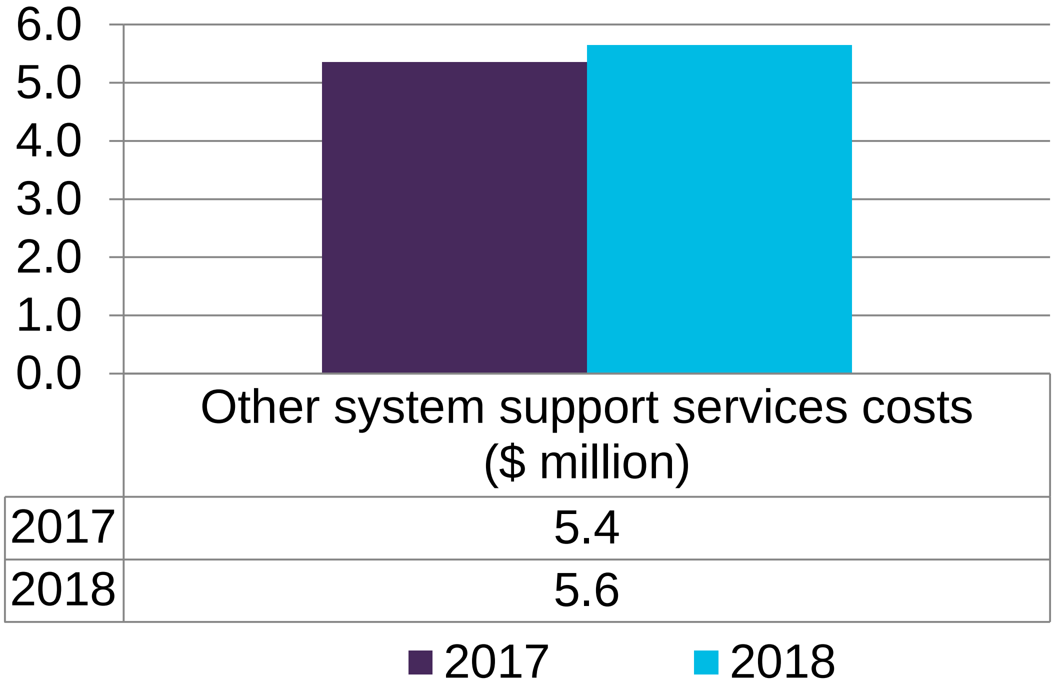
How is Rate DTS voltage control charge changing?



Rate DTS – Voltage control charge	2017	2018
Voltage control charge ($/MWh)	0.07	0.09

Initial rate calculations. May change for application

How is Rate DTS other system support services charge changing?



Rate DTS – Other system support services charge	2017	2018
Other system support services charge ($/MW/month)	46.00	47.00

Initial rate calculations. May change for application

How is Rate DOS changing?

- No change to Rate DOS language
- Rate DOS 7 Minute reflects full payment of usage ($/MWh) components of bulk system and regional system, and operating reserves
- Rate DOS 1 Hour reflects additional contribution to fixed cost of bulk system and regional system over Rate DOS 7 Minute
- Rate DOS Term reflects additional contribution to fixed cost of bulk system and regional system over Rate DOS 1 Hour

Rate DOS	2017	2018
DOS 7 Minutes ($/MWh)	4.99	4.80
DOS 1 Hour ($/MWh)	16.47	15.67
DOS Term ($/MWh)	94.79	103.71

Initial rate calculations. May change for application

How is Rate XOS changing?

- No change to Rate XOS language
- Rate XOS 1 Hour reflects full payment of usage ($/MWh) cost of bulk system and regional system, plus components of operating reserve and fixed cost of bulk system and regional system

Rate XOS	2017	2018
XOS 1 Hour ($/MWh)	7.63	7.24

Initial rate calculations. May change for application

How is Rate PSC changing?

- No change to Rate PSC language
- Rate PSC equals 79% of first four tiers and 100% of last tier of Rate DTS point of delivery charge
- Rate PSC compensates market participant whose connection does not include conventional transformation facilities

Rate PSC	2017	2018
Substation Fraction ($/month)	6,939.00	7,986.00
First (7.5 x SF) MW ($/MW/month)	2,809.00	3,239.00
Next (9.5 x SF) MW ($/MW/month)	1,759.00	2,030.00
Next (23 x SF) MW ($/MW/month)	1,228.00	1,418.00
All remaining MW ($/MW/month)	1,006.00	1,157.00

Initial rate calculations. May change for application

How is Rate STS changing?

- Rate STS language change to include requirement for all behind the fence generating units must contract for Rate STS

Rate STS	2017	2018
System average loss factor (%)	4.44%	3.65%
Regulated generating unit connection cost charge ($/MW/month)	95.00	75.28

How is Rate IOS changing?

- No change to Rate IOS language
- Rate IOS losses charge in an hour
  - (import interchange transaction) x (Pool Price) x (loss factor for the intertie)
  - Rate IOS transaction fee of $500 in a settlement period in which at least one Rate IOS transaction was approved

How big is the 2018 Rate DTS change?

Rate DTS Components	Percentage Change (from 2017)
Connection Charge	
Bulk System Charge — Demand	(13.6%)
Bulk System Charge — Usage	(20.8%)
Regional System Charge — Demand	14.3%
Regional System Charge — Usage	16.1%
POD Charge — Customer × SF	15.0%
POD — Demand ≤ (7.5×SF) MW	15.2%
POD — Demand > (7.5×SF) to ≤ (17×SF) MW	15.3%
POD — Demand > (17×SF) to ≤ (40×SF) MW	15.4%
POD — Demand > (40×SF) MW	14.9%
Total connection charge	**(2.0%)**

Initial rate calculations. May change for application

How big is the Rate DTS change? (cont'd)

Rate DTS Components	Percentage Change (from 2017)
Operating Reserve Charge — % of PP	(5.9%)
Voltage Control Charge — Usage	28.6%
OSS Service Charge — Demand	2.2%

Total Rate DTS Tariff % Change	(2.5%)

Initial rate calculations. May change for application

How big is the Rate STS change?

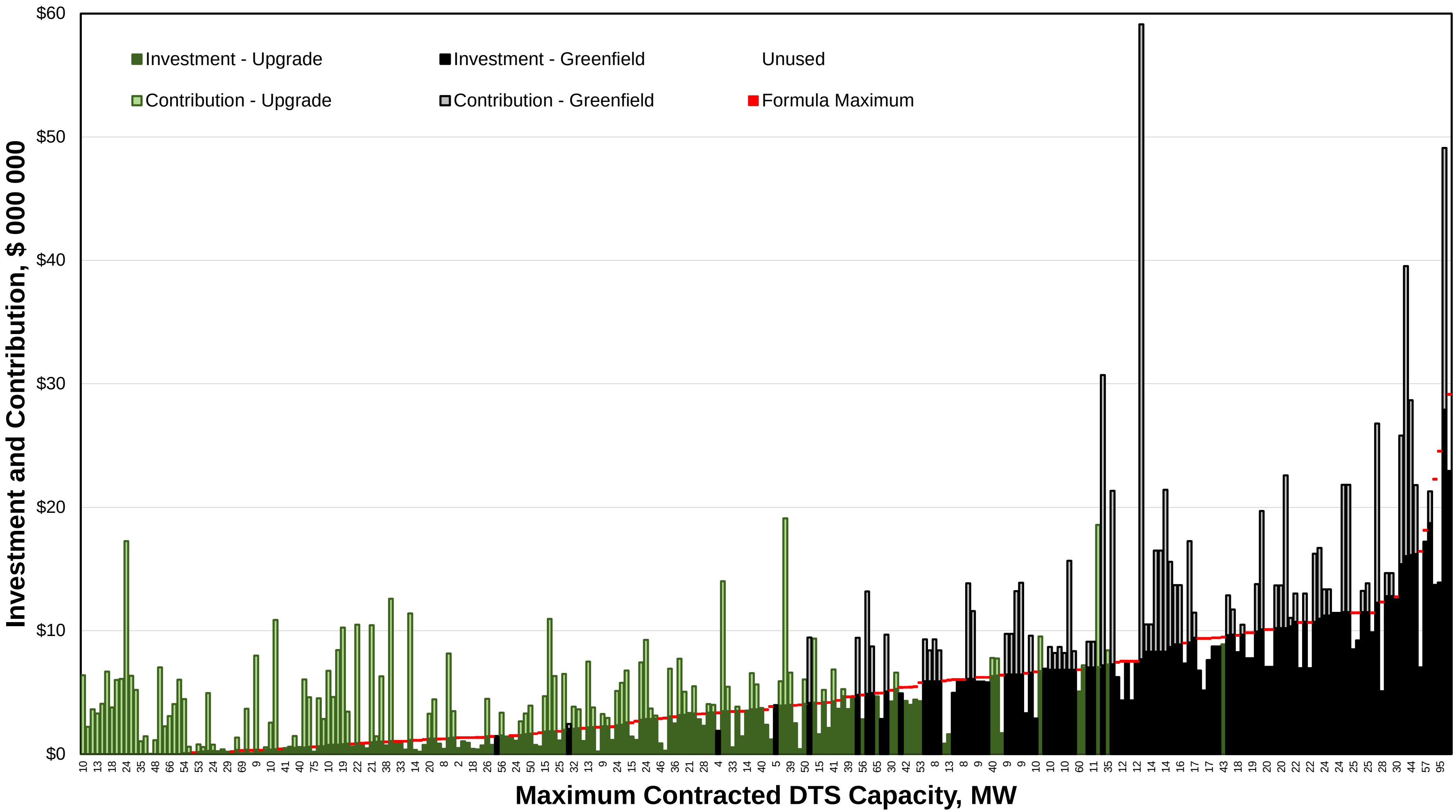
Rate STS Components	Percentage Change (from 2017)
Losses Charge — % of PP	(13.5%)
RGU Connection Costs — Demand	(20.8%)

Total Rate STS Tariff % Change	**(13.9%)**

Initial rate calculations. May change for application

Multiplier of 0.72 results in 60% investment coverage over all 285 projects

Investment and Contribution Using Proposed Investment Levels



Comparison of investment levels

Tier	2017 Investment	2018 Investment	PSC Investment
Substation fraction	$80 150/year	$72 950/year	$15 320/year
First (7.5 × SF) MW	$32 450/MW	$29 600/MW	$6 220/MW
Next (9.5 × SF) MW	$20 350/MW	$18 550/MW	$3 900/MW
Next (23 × SF) MW	$14 200/MW	$12 950/MW	$2 720/MW
All remaining MW	$9 150/MW	$8 350/MW	$0/MW

Initial calculations. May change for application

Terms and Conditions

Doyle Sullivan

Public

<u>Tariff principles</u> driving cost classification change

1. Strong locational price signal to load and generation
   - Sending adequate price signals reflecting cost causation
   - Greater emphases on adequate price signals as compared to certainty, with respect to the classification of system transmission project costs, in order to restore the balance between these two principles
   - Advancement costs as price signals to market participants.
   - Advancement costs should be actively used, where required.
   - Presumption of customer-related costs if “shades of grey”
2. System facilities are only built when there is sufficient certainty
   - Use AESO discretion to ensure that future development of transmission projects is achieved in both a timely and economic manner
   - AESO’s willingness to exercise its discretion (T-reg s. 15(2) and (3))

Tariff principles driving cost classification change (cont'd)

3. Adjust in-service dates to reduce transmission costs, if possible, or assess "accelerated costs" to market participant
   - Incent change in behavior by the end-use customer to make an economic decision to shift its in-service date
   - Incremental transmission project costs related to the advancement of in-service dates should be borne by the customer
   - In-service dates are reasonable targets that are moveable
4. Increased communication between market participant, TFO and AESO to reduce costs
   - Tariff provisions to clarify the role expected of a TFO in relation to project execution
5. Generation does not pay for system facilities
   - They are only responsible for "local interconnection costs", the GUOC and losses, per the *Transmission Regulation*
   - Generators not charged for advancement or accelerated costs

Tariff principles driving cost classification change (cont'd)

6. Commission-initiated proceeding closure letter

- Issue #1 – legislative framework
  AESO will address this issue in the application. We don't anticipate our responses to Issue #1 will result in changes to the terms and conditions
- Issue #2 – advanced system-related classification of radial transmission projects
  To address this issue, the AESO will be proposing revisions to the terms and conditions.
- Issue #3 – load forecasting
  AESO will address this issue in the application. In particular, proposed changes to the terms and conditions include project certainty, critical information from market participants regarding projects to ensure that the ISO tariff incents timely and accurate information sharing between the AESO and market participants.

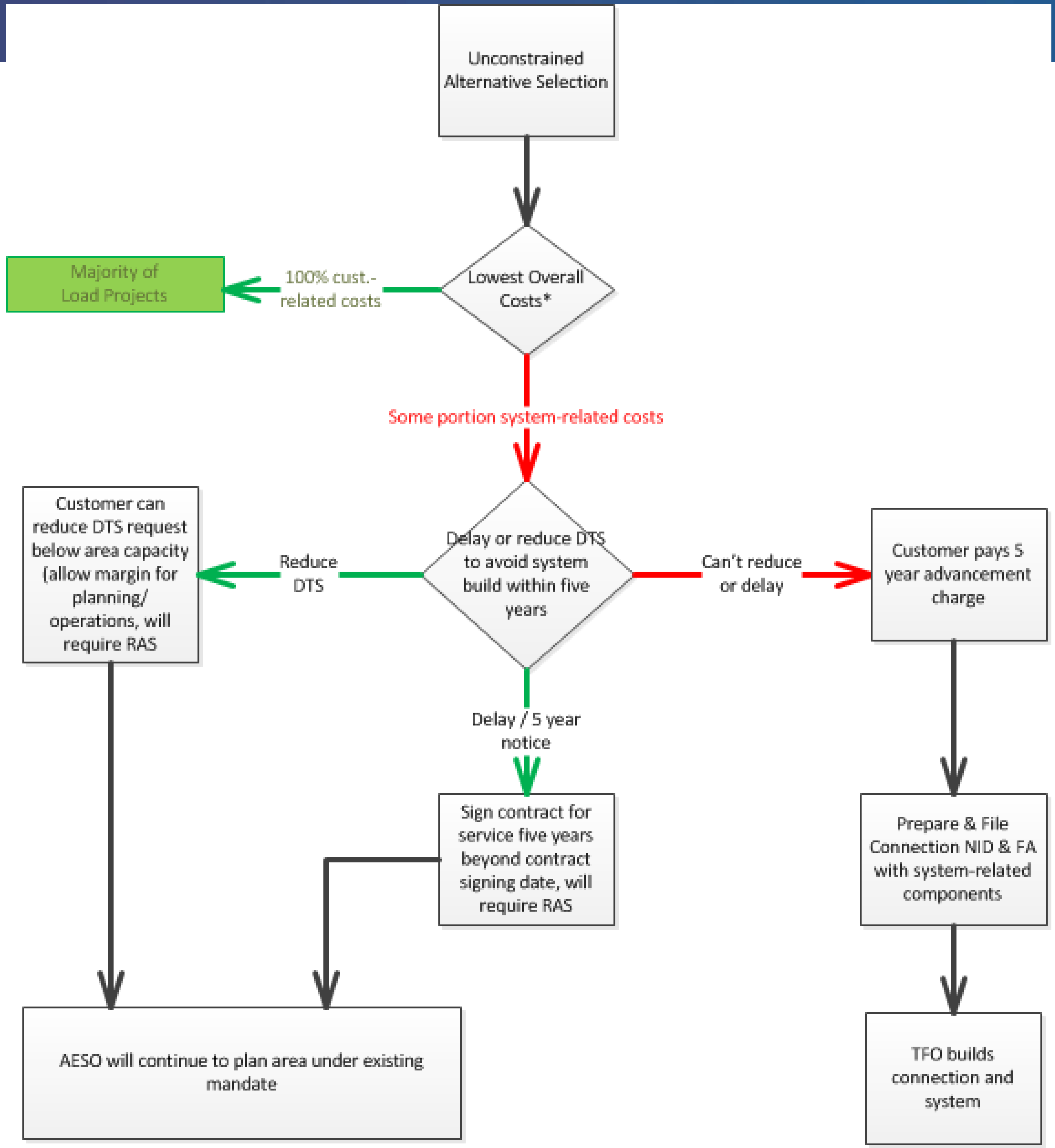
Tariff mechanisms to be applied for in AESO's terms and conditions

- Critical requirements for connection projects to ensure that market participants are applying for projects with high degree of confidence
  - If critical requirements (MWs, ISD or location) change, the AESO must reassess or cancel project
  - Area assessment required if more than one SASR in an area is submitted
- Lowest overall long-term costs (distribution + connection + system-related costs + non-wires costs) evaluation of connection alternatives
  - Unconstrained alternative comparison, generation connections allowable with permanent N-1 RAS
  - AESO may apply discretion to meet its planning obligations

Tariff mechanisms to be applied for in AESO's terms and conditions

- For load, if lowest overall long-term cost alternative includes portion of system-related costs*, market participant will be required to pay 5-year advancement charge, or:
  - Market participant can reduce MWs and allow time for planning and operational flexibility; or
  - Market participant can sign contract for service out 5 years to allow sufficient notice for the AESO to forecast and plan.
- For generation, Generator Unit Owner's Contribution to be paid earlier in connection process

Load evaluation process



<u>Tariff mechanisms</u> to be applied for in AESO’s terms and conditions

- <u>Accelerated construction costs</u> provision to ensure that market participants are charged for additional system costs that could have been saved if the market participant had been willing to adjust their in-service date.
  - A choice to adjust in-service date and save costs <u>or</u> be charged the additional cost.

Tariff mechanisms to be applied for in AESO's terms and conditions

- Project certainty definitions to allow the AESO to reasonably forecast and plan
  - Earlier signing of DTS and STS contracts (prior to NID filing) to ensure the commitment of market participants aligns with forecasting, planning and regulatory processes in connecting and planning system reinforcements
  - The market participant will also be required to:
    - For load connections, payment of 5-year advancement cost prior to NID filing (if applicable)
    - For generation connections, payment of Generator Owner's Unit Contribution
  - Therefore, at the time of NID filing, the project will have certainty to be included in AESO forecasting and planning processes

Other Items

LaRhonda Papworth

Public

Other terms and condition changes

- Minor changes to terms and conditions beyond discussed earlier
  - To remove “radial . . . plan to be looped”
  - Clarify that generator’s STS connection only pays local interconnection costs, does not pay for system or advancement costs
  - Add provisions to allow shared costs calculations for facilities to be shared with system
  - Update provisions to allow for abbreviated needs approval process, current system access service agreements, market participant choice, and transmission direct connected distribution customers.

Other items

- Administrative clean up of other terms and conditions
  – Sections 1, 2, 3, 6, 7, 12, 13, 14 and 15
- Update GUOC rates and include in Section 10 of tariff
  – Regional $/MWs updated to reflect current expectation of region load and supply (2018 – 2020)
  – Include rates as part of ISO tariff. Currently rates are in a document outside of the tariff
  – Changing terms to be applicable to maximum capability (MC) not Rate STS MWs

Other items

- Energy Storage
  - Confirm that Rate DTS and Rate STS will be applicable to these facilities, and these facilities will be considered dual-use
  - Rates and terminology in the tariff will be updated to address energy storage facilities (primarily affects applicability subsections in tariff).

Other items

- <u>CIPs Cost Recovery</u>
  - Responding to the Commission’s request from Proceeding 3443 that the AESO address the issue of cost recovery for CIP reliability standard compliance in its tariff application
  - The AESO will propose that the costs of complying to CIP standards should be borne by the market participant, based on the AESO’s FEOC analysis
  - It is the role of the Commission under Section 30(2)(a)(iv) of the Electric Utilities Act to determine whether this is appropriate.

Other items

- Rider A1 – Dow duplication avoidance tariff amendment
  - Modernize and update current Rider A1 to allow for expiry in 2041
  - Include annual forecast benefit amounts from Dow to rate payers to recover annual O&M and losses costs to account for the credible bypass threat option, if it had been built.

Tariff timing targets

Step	Timing
File Rider C amendment application	As soon as possible
File 2018 ISO tariff application	Early August 2017
File 2016 deferral account reconciliation	September 2017
File 2018 ISO tariff update application	September – October 2017

Q&A