Session 3 – Nov. 5, 2020 Stakeholder Proposals

Stakeholder Proposals [Posted Oct. 29, 2020]

1. Proposal 1:
   - (i) Alberta Direct Connect Consumer Association (ADC);
   - (ii) Dual Use Customers (DUC); and
   - (iii) Industrial Power Consumers Association of Alberta (IPCAA)
2. Proposal 2:
   - (i) Canadian Renewable Energy Association (CanREA); and
   - (ii) Solas Energy Consulting (Solas)
3. Proposal 3:
   - (i) Consumers Coalition of Alberta (CCA) *[Posted: Nov. 22, 2020]*
4. Proposal 4:
   - (i) Canada West Ski Areas Association (CWSAA);
   - (ii) Utilities Consumer Advocate (UCA);
   - (iii) AltaLink Management Ltd. (AML); and
   - (iv) Conoco Phillips Canada
5. Proposal 5:
   - (i) Energy Storage Canada; and
   - (ii) Power Advisory LLC
6. Proposal 6:
   - (i) RMP Energy Storage
7. Proposal 7:
   - (i) Suncor Energy Inc. *[Updated: Nov. 22, 2020]*

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AESO TARIFF
BULK AND REGIONAL RATE DESIGN

ALBERTA DIRECT CONNECT CONSUMER ASSOCIATION (ADC)
DUAL USE COALITION (DUC)
INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA (IPCAA)

Vittoria Bellissimo - IPCAA
Colette Chekerda - ADC
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November 5th, 2020

ADC
Alberta Direct Connect Consumer Association

Dual Use Customers

IPCAA
INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA

PRESENTATION OUTLINE

- About ADC, DUC and IPCAA
- Recommendation
- AESO Design Objectives
- 12 CP Methodology
- Tariff Changes are Premature
- Historical Review
- Other Considerations
- Questions?

ABOUT ADC

Alberta Direct Connect Consumer Association

- The ADC was established in 2002 to represent the interests of large industrial consumers directly connected to the transmission system.
- Membership includes: Alberta Newsprint Company, Dow Chemical, ERCO Worldwide, Lehigh Inland Cement, MEGlobal, Millar Western, Praxair, Sherritt International, and West Fraser Timber.
- ADC members represent approximately 600 MW of peak load and 4,000 GWh of annual energy.
- ADC members are global competitors. Affordable and reliable electricity is essential to our viability. On average, electricity represents about 30% of members operating costs, but is as high as 80% for some.
- ADC members are active participants: price response, ancillary services, LSSi, and on-site generation.
- ADC member facilities are located in Northern and Central Alberta
- AESO proposed tariffs would render PRL uncompetitive and they will exit the grid/province further eroding billing determinants.

ABOUT DUC

Dual Use Customers

- DUC was formed in 2004 to represent industrial cogenerators in Transmission Administrator (AESO) tariff proceedings
- Members include Alberta's largest oil sands and industrial cogenerators
  - 1,300 MW DTS contract capacity
  - 3,000 MW installed cogeneration capacity
- Currently ten members, 15 sites
- Proposed tariff increases will justify additional on-site generation, less reliance on the grid and lower DTS tariff revenue

ABOUT IPCAA

- IPCAA was formed in 1983 as a membership-based society representing Alberta's large industrial electricity consumers.
- Our members are involved in key Alberta industries, including Oil & Gas, Pipelines, Petrochemicals, Agriculture and Steel.
- Our mission is to take a leadership role in ensuring that a competitive marketplace exists for electrical services.
- AESO proposed tariffs would render PRL uncompetitive AND justify additional on-site generation, less reliance on the grid and lower DTS tariff revenue

RECOMMENDATION

The 12 CP methodology for bulk system cost recovery continues to be appropriate for Alberta.

Considerations:

- How one pays for transmission infrastructure is a key piece in ensuring efficient infrastructure development
- The strong price signal is, in our view, working and is leading to reduced bulk transmission investments over the long term
- The cost causation principle holds and leads to longer-term efficiency gains
- The consequences of a major overhaul during a pandemic and economic downturn will be devastating

AESO DESIGN OBJECTIVES

1. Reflect Cost Responsibility
2. Efficient Price Signals
3. Minimal Disruption
4. Simplicity
5. Innovation and Flexibility

In the AESO's view, the current rate design does not achieve the first two design objectives.

We submit that this needs further consideration.

AESO DESIGN OBJECTIVES

1. Going forward ~$2 B will be spent mostly on transmission to connect new generation. None of the bookends reflect cost responsibility for this potential investment.
   - The AESO is attempting to mimic nodal pricing for loads through regional peaks. This is inefficient, confusing and may be in violation of the *EUA*.

2. CP is considered the most efficient price signal option and is widely used throughout North America.

12 CP METHODOLOGY

- 12 CP Methodology sends a strong price signal to flatten consumption, in doing so, creating a need for less:
  - Future transmission
  - Generation capacity
- This is not a short-term effect - it takes time. To achieve this, significant levels of customer investment have and will be required.
- 300 – 400 MW of demand responsive load already exists
- The bulk system was not planned nor built for cogenerators and price responsive loads

12 CP METHODOLOGY

- Cost allocation for transmission infrastructure is a key component in ensuring efficient infrastructure development
- A strong price signal is required to influence participant behavior
- A review of billing determinants shows that CP is the best option to influence participant behaviour

TARIFF CHANGES ARE PREMATURE

- There are many elements that have not been resolved and will ultimately impact the ISO tariff, including:
  - The Transmission Regulation being re-examined by government
  - Any AUC changes resulting from the Distribution System Inquiry (such as aligning transmission and distribution rates)
  - Government changes related to self-supply and export
  - Sub-station fraction and DCG credit issues
- **We are concerned that a major tariff overhaul now will be followed by another overhaul when these elements are resolved.**

TARIFF CHANGES ARE PREMATURE

- Changes to tariff design need to be supported by clear government policy
  - Where is the mandate from the Government to discourage co-generation after 25 years of clear policy direction providing an industry structure and open tariffs to allow co-generation to develop?
- ISO Tariffs need to be based on industry standard cost of service studies
  - Stakeholders have not seen a COSS for this tariff
  - Stakeholders have not had an opportunity to provide input into a COSS for this tariff
  - Stakeholders have not seen the Navigant study results

TARIFF CHANGES ARE PREMATURE

- The world over, large industrials, esp. oil facilities, operate independent from the grid (e.g. Africa). The AESO proposal will lead to grid defections and higher costs to stranded customers.
  - The AESO should recognize that disruptive forces (incl. low cost generation options) are at play and try to encourage price responsive loads to stay connected, rather then sending them the price signal to leave the system

TARIFF CHANGES ARE PREMATURE

- Transmission customers care about delivered costs = generation + transmission
- Alberta policy has been congestion-free transmission to get lower cost generation, which (along with by-passing the regulatory process) has led to increased cost of transmission
- The AESO's proposal will lead to:
  - More costly natural gas generation development (combined cycle vs. co-generation)
  - Reduced net exports from ISDs (as existing co-generators defect from the grid)
  - Higher generation costs, while transmission costs remain
  - Higher delivered costs for those customers who remain grid-connected.
- We need to model these consequences prior to overhauling the tariff.

TARIFF CHANGES ARE PREMATURE

Review of AESO Concerns:

1. Stranded asset risk?
2. Cross-subsidization?
3. Inability for some customer classes to respond to price signals?

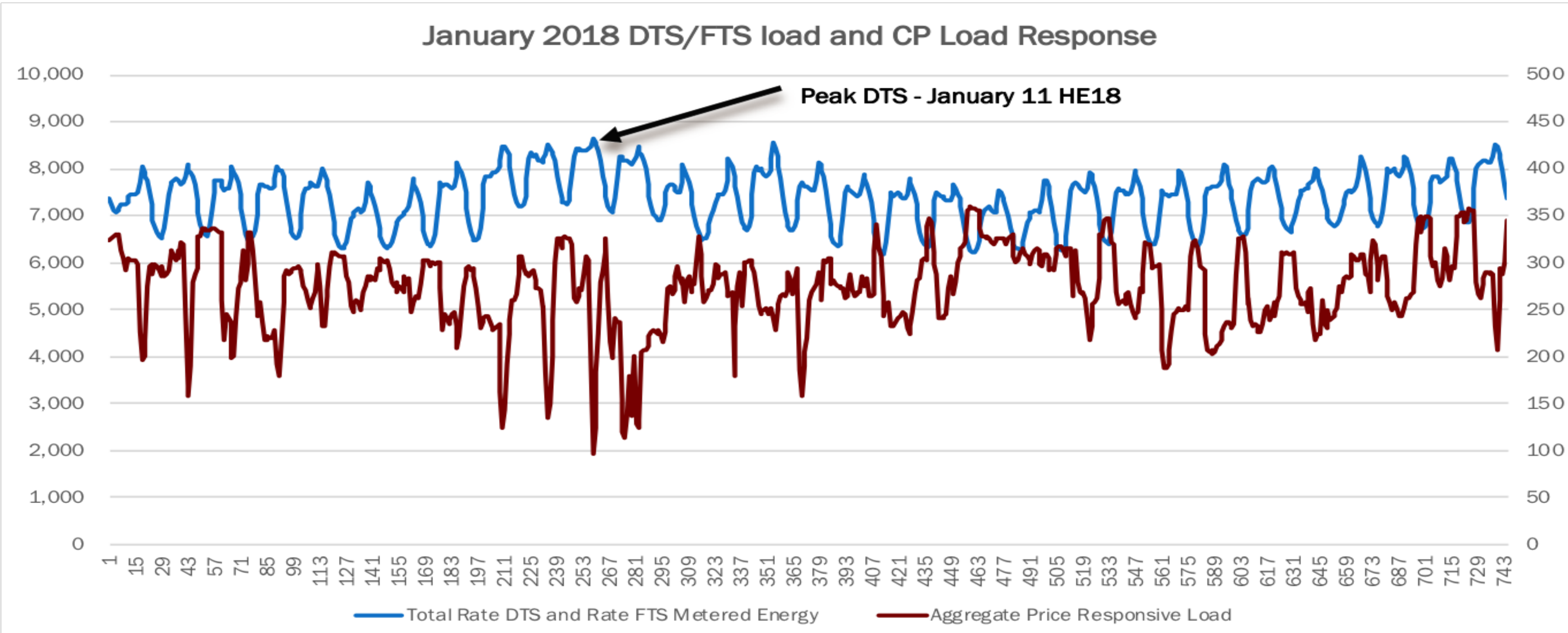
Counterpoints:

- The regulated monopoly utilities have advocated to change Utility Asset Disposition legislation
- Ultimately, having to build less transmission benefits all consumers. There are significant efforts required to reduce demand during peak periods and this leads to a reduced need for transmission and generation capacity in Alberta. This behaviour enhances the efficiency of Alberta's electricity infrastructure for the benefit of all customers.
- There are other mechanisms which would enable more customers to respond to price signals. i.e. distribution tariffs that flow through the CP rate design.
- The AESO tariff should encourage customers to respond to price signals to reduce long term costs

HISTORICAL REVIEW

- Report for Alberta government March 1992 suggested 3,357 MW of cogeneration potential in Alberta by 2005
  - Part of the rationale / justification to move to wholesale energy market and transmission administrator (open access)
- Industry restructuring was intended to reduce transmission costs by putting generation closer to loads
- Result:
  1. 5,000 MW of low-cost cogeneration built at no cost to electricity consumers
  2. Power prices over last 20 years have been lower
  3. Significant transmission investment was delayed until 2008+
- Bill 50 mandated “critical” transmission infrastructure – We have transmission costs ~$37/MWh now.

JANUARY 2018 CP RESPONSE



- 12 CP results in a sustainable response behavior by flexible loads
- In order to achieve CP benefit, loads need to interrupt their business operation several times during a month – the idea that a load can respond in one 15 min interval to reduce costs is simply not true. Facilities incur significant production losses in order to manage costs. These facilities were never intended to operate this way, they must do so in order to remain viable.
- January Peak DTS would have been at least 200 MW higher without this important price signal (this data includes behavior of only 7 price responsive loads).

NORTHWEST REGION – INDICATIVE RATE IMPACT

Rate Impact - 4 Interruptible NW Loads				
Bill Determinants of the 4 combined interruptible loads in the Northwest				
1. Average CPD:	49	MW		
2. Peak Demand:	230	MW		
3. Average Monthly Demand	160	MW		
4. Average Monthly Energy	116800	MWh		
5. Average Coincident Region Peak	220	MW		
1. Current Tariff - Cost for Average interruptible Load				
Monthly DTS Cost Projection:				
April 2020 Tariff Update	Rate	Units		Cost
Bulk System Charge				
Coincident Demand Charge ($/MW/month)	10,814.00	49	$	533,788
Metered Energy Charge ($/MWh)	1.13	116800	$	131,984
Regional System Charge				
Billing Capacity Charge ($/MW/month)	2,799.00	230	$	643,770
Metered Energy Charge ($/MWh)	0.86	116800	$	100,448
Monthly Total			$	1,409,990
Annual Total			$	16,919,878
2. Bookend A: Fixed Charge				
Billing Capacity	$9,700	230	$	2,231,000
Monthly Total			$	2,231,000
Annual Total			$	26,772,000
3. Bookend B: Peak Charge				
Billing Capacity	$3,100	230	$	713,000
Coincident Region Peak (120 * $1000 / 12)	$10,000	220	$	2,198,436
Monthly Total			$	2,911,436
Annual Total			$	34,937,230
		%		$
Bookend A Annual Increase:		58%	$	9,852,122
Bookend B Annual Increase:		106%	$	18,017,352

- Examined the rate impact for the 4 energy-intensive trade exposed loads in the NW Region.
- They comprise of 25% of the NW load, so when they are on, the NW Region is peaking – no value for interruptible loads.
- Bookend A would increase TX costs by 58%
- Bookend B would increase TX costs by 106%
- Of the $85M impact of Bookend B – Heavy CP Responders, 21% is for these 4 customers.

NORTHWEST REGION – INDICATIVE RATE IMPACT

- Regional Coincident Peak Charge may make sense for regional assets (i.e. current regional charge) but does not reflect cost causation of bulk system assets.
- Either rate design will accelerate grid defections. Energy-intensive trade exposed loads cannot afford this increase and will defect.
- What is at risk for these 4 loads?
  - $17 M in revenue contributed for Bulk and Regional Charges
  - 1000’s of primary and secondary jobs
  - Tax Revenue for NW Alberta communities
  - Community investment
  - Material impact to Alberta’s Forestry Sector

WHY AESO BOOKEND A DOES NOT WORK

- Capacity Charges that are the same for all customers do not recognize the different levels of reliance on the grid for standby, interruptible, and firm load customers.
- The bulk system was not built or planned for the total contract billing capacity or the highest metered demand.
  - Billing Capacity –13,380 MW
  - Highest metered Demand –10,016 MW
  - Coincident Metered Demand –7,600 MW
- The proposed AESO Bookend A will further erode billing determinants.

WHY AESO BOOKEND B DOES NOT WORK

- Regional CP does not reflect the major bulk system investments (e.g. HVDC, Heartland, SATR, Ft. Mac)
- No real time visibility of regional peaks.
- Regional loads are too dependent on a small number of large loads.
- Primarily harms the price responsive loads.
- Improves the DCG credits.
- Will further erode billing determinants as sites who can no longer respond to tariff prices will defect from the grid.

WHY LOAD RETENTION RATES DO NOT WORK

Grandfathering of existing price responsive loads through a load retention rate does not work.

- Deters any new investment from these industries if a load change triggers an end to the load retention tariff.
- Could potentially interfere with international trade agreements.
- Who decides what an appropriate tariff is for each company/industry?

AESO IMPACT MODEL CONCERNS

- In general there are two types of AESO customers
  - Price takers – all customers served on non-AESO rates and most cogeneration customers (steam driven, not electricity)
  - Price responsive – customer who respond to AESO tariff price signals
- Looking at 2 years of time of use data for cogeneration price takers is not indicative of the times when customers rely on grid for standby
- Looking at historical data for price responders is not a good indication of future behaviour with different tariff price signals
- Conclusion - AESO Impact Model results are not a good indication of tariff impacts and should not be used to influence rate design

CONCLUSIONS

- Continue with the current Rate Design
  - The proposed bookends are untenable and will accelerate grid defections.
  - Rolling out a tariff overhaul during a pandemic is IRRESPONSIBLE.
- The timing for a change is pre-mature. There are many elements that have yet to be resolved by government and the AUC.
  - Customers do not want to see two tariff overhauls in a 5-year window.
  - Customers deserve cost-based rates - based on an industry standard cost of service study.
  - We need STABILITY to encourage INVESTMENT.

QUESTIONS?

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RENEWABLE ENERGY AND ENERGY STORAGE MARKET OPPORTUNITIES

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05 November 2020

Presentation to Bulk and Regional Tariff Team

Introduction and Outline

Paula McGarrigle

Solas Energy Consulting Inc.

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- AESO held:
  - March 13, 2020
    - Bulk and Regional Tariff Design Stakeholder Engagement 1
  - Delay for 6 months
  - September 24, 2020
    - Bulk and Regional Tariff Design Stakeholder Engagement Session 2
  - October 14, 2020
    - Joint Stakeholder Engagement session on Energy Storage and Distributed Energy Resources (DER) This presentation focused on the aspect of renewable energy and energy storage
    - Bulk and Regional Tariff Design Technical Information Session

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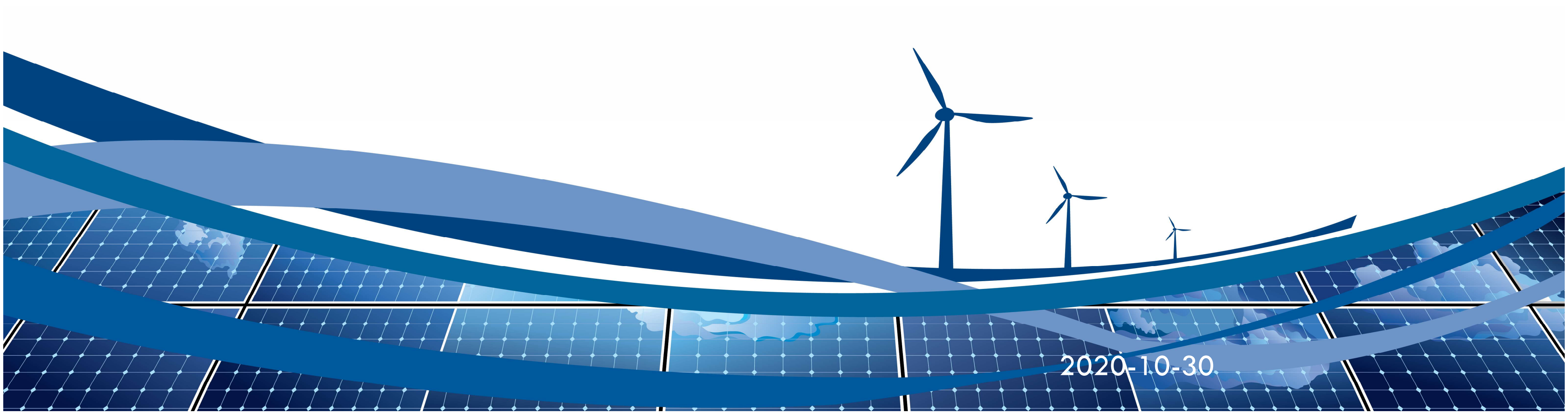
3

What is Storage?



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Is it a Load, Generator, Transmission facility/Substation?

- Guiding documents
  - Section 1(1)(u) of *Electric Utilities Act* (EUA)
    - Section 1(1)(bbb) of EUA
  - Section 1(1)(k) of *Hydro and Electric Energy Act* (HEEA)
    - Section 1(1)(n) of HEEA
  - *AUC's Electric Transmission Facilities Process Guidelines*
- No references to Storage in any document
- **Energy storage fits best with the definition of the EUA "substation"**

What is Storage? – Is it a generation facility under EUA? – It's not a generator

Reference	Definition	Energy Storage
EUA "generating unit"	*component of a power plant that produces, from any source, electric energy and ancillary services, and includes a share of the following associated facilities that are necessary for the safe, reliable and economic operation of the generating unit*	Energy storage does not produce electric energy, but rather stores electric energy. Energy storage provides ancillary services, but not through the production of electricity, but rather through the injection of electricity.
	Fuel and Fuel handling equipment	Energy storage does not have fuel
	Cooling water facilities	Not applicable
	Switch yards	Switches are included in the balance of system of the energy storage system, but not a switch yard
	Other items	Energy storage balance of system are included here.

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What is Storage? – Is it a Transmission Facility, under EUA? – It's not a transmission facility.

Reference	Definition	Energy Storage
EUA "Transmission facility"	*arrangement of conductors and transformation equipment that transmits electricity from the high voltage terminal of the generation transformer to the low voltage terminal of the step-down transformer operating phase to phase at a nominal low voltage level of more than 25 000 volts to a nominal low voltage level of 25 000 volts or less*	Not applicable. Voltages in the energy storage facility are lower than those identified in this definition.
	(i) transmission lines energized in excess of 25 000 volts, *(ii) insulating and supporting structures,* *(iii) substations, transformers and switchgear,* *(iv) operational, telecommunication and control devices* *(v) all property of any kind used for the purpose of, or in connection with, the operation of the transmission facility….*	(i) Not applicable (ii) Not applicable (iii) Connects to the substation and includes transformers (iv) Includes telecommunication and control devices (v) The energy storage facility is not associated with the operation of the transmission facility.

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What is Storage? Is it a Power Plant or a substation under HEEA? – It's not a power plant. BEST FIT IS SUBSTATION.

Reference	Definition	Energy Storage
HEEA "Power Plant"	*facilities for the generation and gathering of electric energy from any source*	The energy storage facility does not generate electricity, but rather stores electricity. The energy storage facility does potentially gather electric energy but does not gather electricity like a conductor or collector system.
HEEA "substation"	*part of a transmission line that is not a transmission circuit and includes equipment for transforming, compensating, switching, rectifying or inverting of electric energy flowing to, over or from the transmission line*	The energy storage facility includes equipment for transforming and inverting of electric energy flowing to or from the transmission line. The energy storage facility does not include compensating equipment.

ES receives an asset ID to participate in the market (Energy and A/S)

Maslow's Hammer – cognitive bias with a familiar tool

"I suppose it is tempting, if the only tool you have is a hammer, to treat everything as if it were a nail." –

- Abraham Maslow – 1966

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AESO Approach to Energy Storage

- Apply Demand Transmission Service to Energy Storage Charging
- Apply Supply Transmission Service to Energy Storage Discharging

Seven (7) Components of DTS

- Bulk System Charge
  - Coincident metered demand - /MW/Month for MW at coincident peak
  - Metered energy - $/MWh of metered demand
- Regional System Charge
  - Billing capacity - /MW/Month of demand
  - Metered energy - $/MWh of metered demand
- Point of Delivery Charge
  - Substation fraction - /MW/Month based on the share of DTS over the total of all DTS and STS in substation
- Operating Reserve Charge Estimate - $/MWh to cover AESO procurement of Operating Reserves
- Transmission Constraint Rebalancing Charge Estimate - $/MWh (minimal charge)
- Voltage Control Charge - $/MWh (minimal charge)
- Other System Support Services Charge - $/MWh (minimal charge)

These charges form most of the DTS bill

Two (2) Components of STS

- Losses Charge

  Metered Energy x Pool Price x Loss Factor

- Regulated Generating Unit Connection Cost
  - Only for regulated units - $/MW

DOUBLE DOUBLE

Double Cream
Double Sugar

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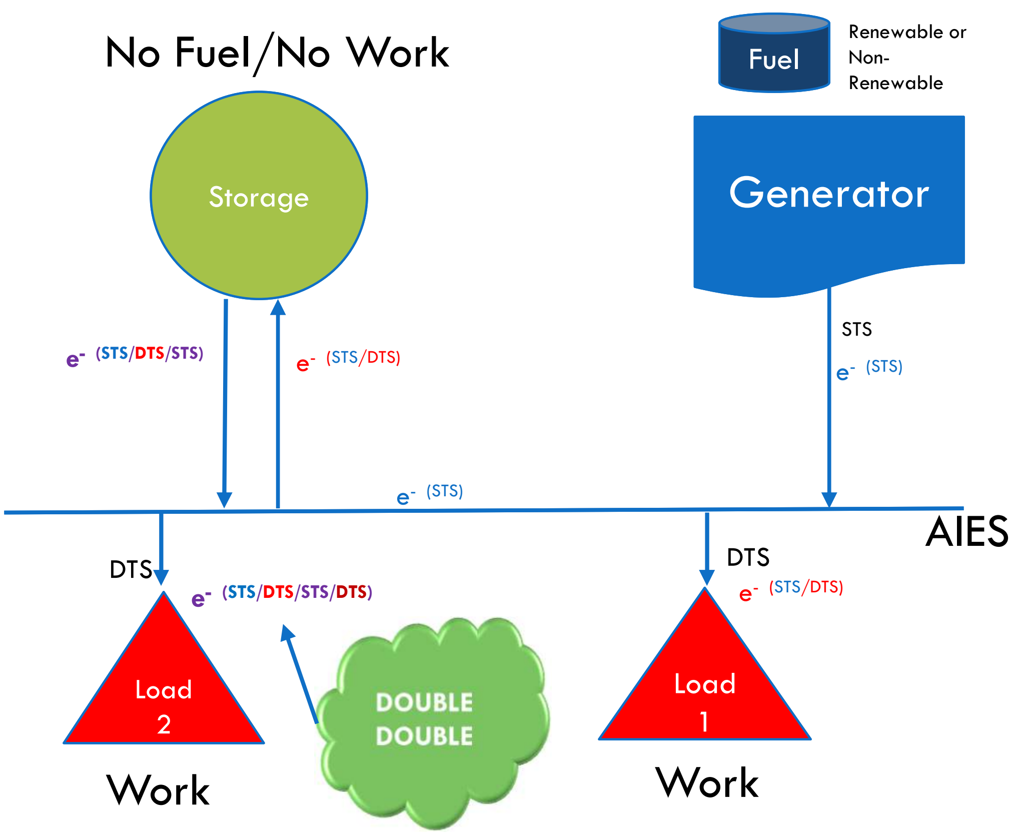
DOUBLE, DOUBLE ISSUE – UNFAIR, UNECONOMIC, UNCOMPETITIVE.

Charging DTS and STS on Energy Storage doubles up the charges on this electricity.



Generators pay STS. These electrons have paid for STS [$e^{-\,(STS)}$]

Load receives electrons that have already been loaded with STS. [$e^{-\,(STS)}$]

Then load pays DTS so the final consumed electrons have had both STS and DTS payments [$e^{-\,(STS/DTS)}$]

Energy storage currently gets charged DTS to charge (treated as a load) and the same electricity delivered back to the grid is also charged STS.
Now we have $e^{-\,(STS/DTS/STS)}$]

Load purchasing from the storage facility through the grid would now have to pay DTS, on top of electricity that has already now paid DTS, and STS twice. DOUBLE DOUBLE

Power used from energy storage has had twice the DTS and the STS applied.
This does not align with Fair, Efficient, and Openly Competitive

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Treatment of Electrons

Electrons from the AIES

e^- (STS/DTS)

FEOC = YES

Electrons that have been through Storage

e^- (STS/DTS/STS/DTS)

FEOC = NO

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Session 1 – Option 1 identified for Storage

(as a market asset and not as a transmission asset)

AESO SUGGESTED OPTIONS	IMPACT ON ENERGY STORAGE	
1. Charge based flows DTS for inflows and STS for outflows (current tariff)	**DOUBLE DOUBLE all the time.**	

FEOC = NO

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Session 1 – Option 2 identified for Storage

(as a market asset and not as a transmission asset)

AESO SUGGESTED OPTIONS	IMPACT ON ENERGY STORAGE	
2. No DTS costs while providing "Market Services (FERC Order 841 treatment)"	**DOUBLE DOUBLE sometimes, even if you are not profitable.**	

FEOC = NO

Session 1 – Option 3 identified for Storage

(as a market asset and not as a transmission asset)

AESO SUGGESTED OPTIONS	IMPACT ON ENERGY STORAGE	
3. **Interruptible service with lower rate, since storage can be off if transmission system is stressed.** Direct physical control by AESO, asset can be tripped off without notice (AESO has certainty) Dispatch control based on bids and offers: Financial incentive to comply (not full certainty) May not qualify for Operating Reserves or FFRSi, - incompatible with current A/S requirements	Slightly cheaper DOUBLE DOUBLE, significant uncertainty, and less control of asset.	

FEOC = NO

Conclusion

- The application of DTS and STS to energy storage does not comply with FEOC
- Adding DTS/STS to energy storage creates a Double Double scenario for energy to customers of energy storage.
- Energy storage is most consistent with Substation definition under the current laws/regulations
- Energy storage is heavily disadvantaged under any of the proposed tariff schemes including DTS/STS
- Energy Storage Administration fee (rather than DTS/STS) is most appropriate.
- None of the options presented by the AESO are appropriate for Energy Storage

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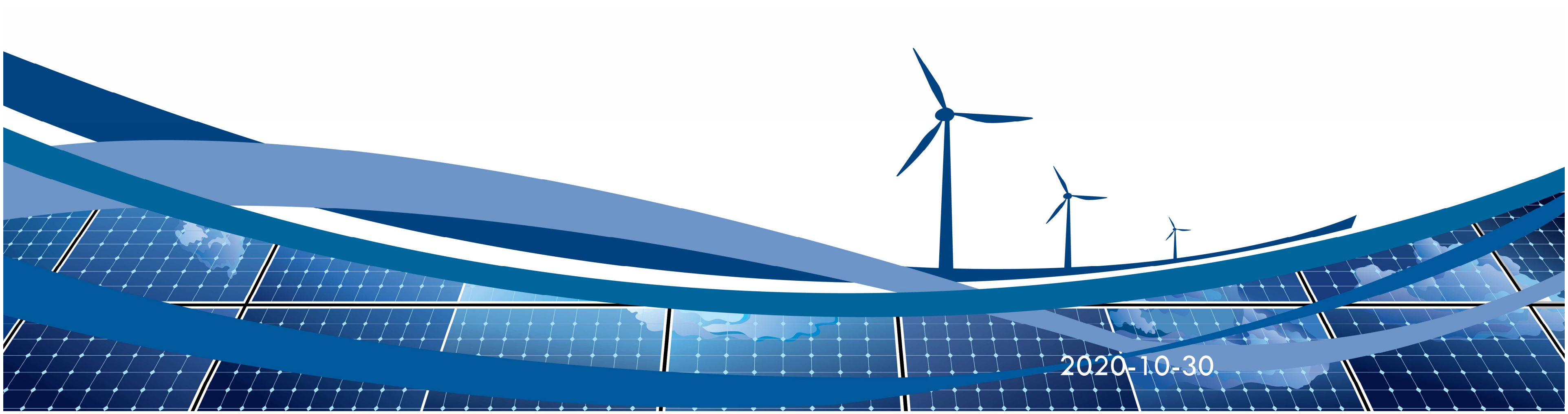
19 Appendix



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Case Options

Generation	None	Wind	Solar			
Storage Location	At Generation	On Grid	At Customer			
Storage Timing	Standard	Perfect Forecast				
Substation Fraction	1.0	0.5	0.1			
Tariff Type	Current	FERC 841	Interruptible			
Region	NW	NE	Edmonton	Central	Calgary	South
Peak	12 CP	Regional 120 CP	System 120 - CP	System- Weekly CP		

Case 1A: BESS ON GRID

Generation	*None*	*Wind*	*Solar*			
Storage Location	*At Generation*	*On Grid*	*At Customer*			
Storage Timing	*Standard*	*Perfect Forecast*				
Substation Fraction	*1.0*	*0.5*	*0.1*			
Tariff Type	*Current*	*FERC 841*	*Interruptible*			
Region	*NW*	*NE*	*Edmonton*	*Central*	*Calgary*	*South*
Peak	*12 CP*	*Regional 120 CP*	*System 120 - CP*	*System- Weekly CP*		

Charge during historical average low hours (HE 2,3,4,5)
Discharge during historical average high hours (HE 15,16,17,18)

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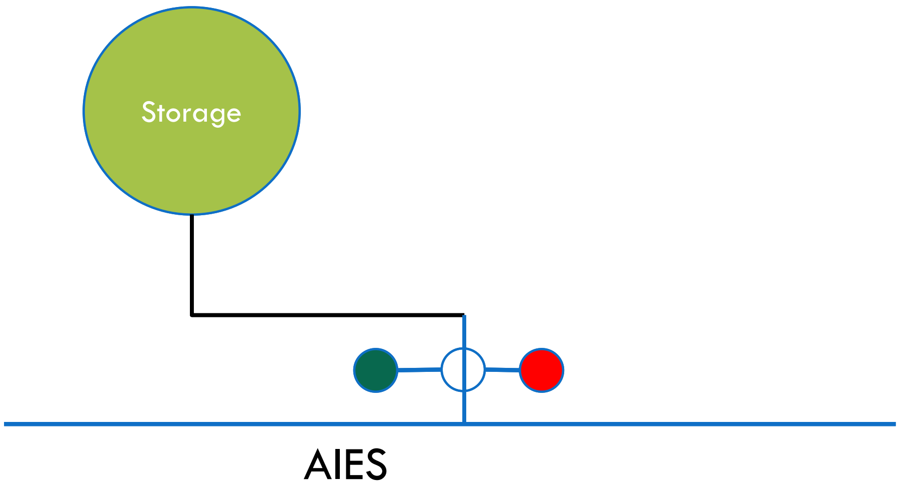
CASE 1A

Use Case: Arbitrage, Tx/Dx connected, 4 hours storage

Tariff: Current Tariff



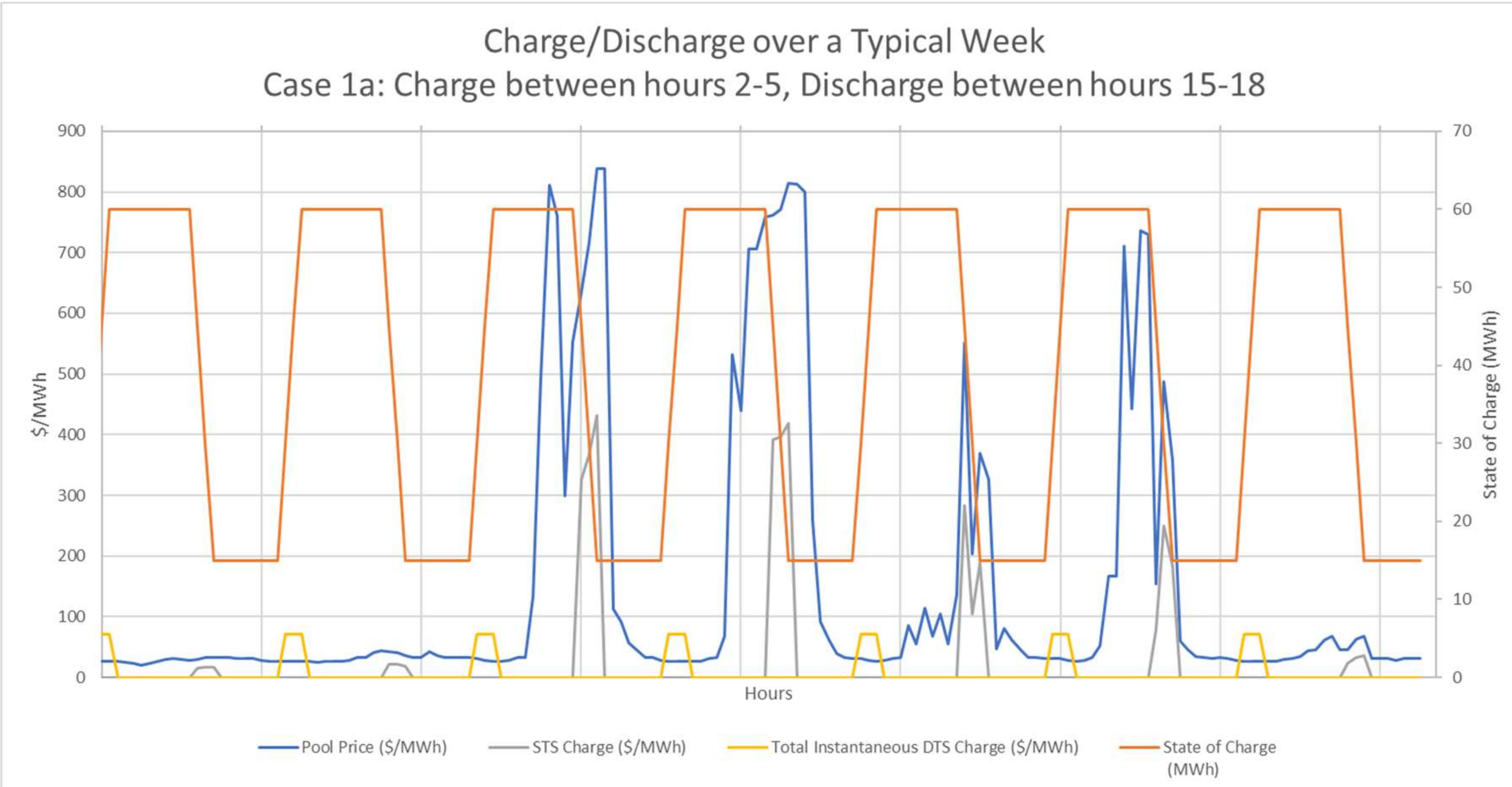
Physical Meter
Measurement Point
Dispatch Point

Case Details

- 15 MW/60 MWh Storage
- 0 MW Generation
- Charge from Grid
- Discharge to Grid
- STS based on injecting near Blackspring Ridge
- DTS Substation Fraction POD equal to 1

Using 2016-2018 AESO data provided in the Tariff Bulk and Regional Impact Hourly Model

Case 1a: Production Profile & Costs



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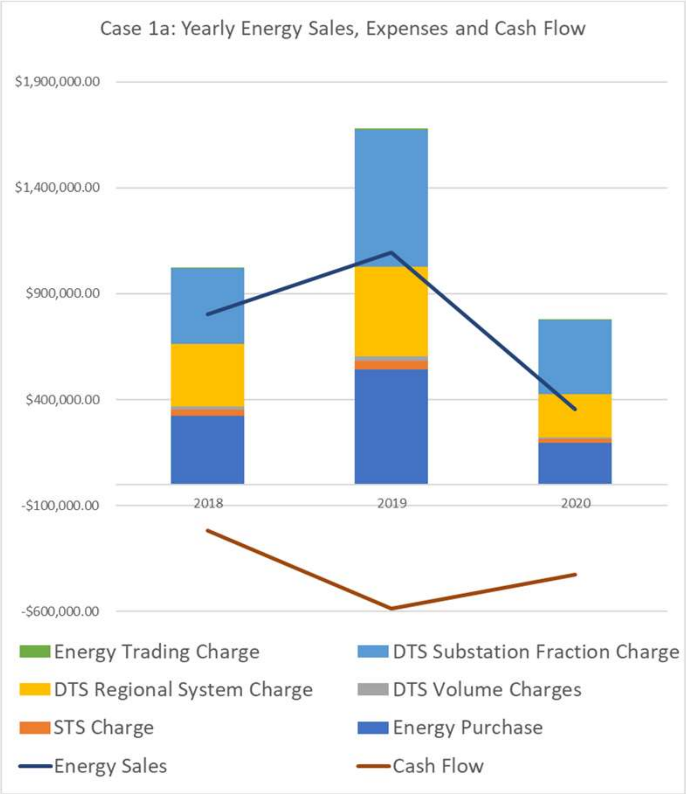
Case 1a: Current Tariff is cost prohibitive for Standalone BESS



- DTS Regional System Charge and DTS Substation Fraction Charge are the largest components of annual expense
- Simple cash flow analysis shows negative cash flow. Does not cover system costs (Energy, DTS, STS, AESO Trading Charge)

Year	Average Cost ($/MWh)	Average Revenue ($/MWh)
2018	-102	+96
2019	-97	+76
2020	-104	+60

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Case 1B: BESS ON GRID – Perfect Forecast

Generation	None	Wind	Solar			
Storage Location	At Generation	On Grid	At Customer			
Storage Timing	Standard	Perfect Forecast				
Substation Fraction	1.0	0.5	0.1			
Tariff Type	Current	FERC 841	Interruptible			
Region	NW	NE	Edmonton	Central	Calgary	South
Peak	12 CP	Regional 120 CP	System 120 - CP	System- Weekly CP		

THIS ONE CHANGED FROM CASE 1A to 1B

Charge during the lowest hours, discharge during highest hours

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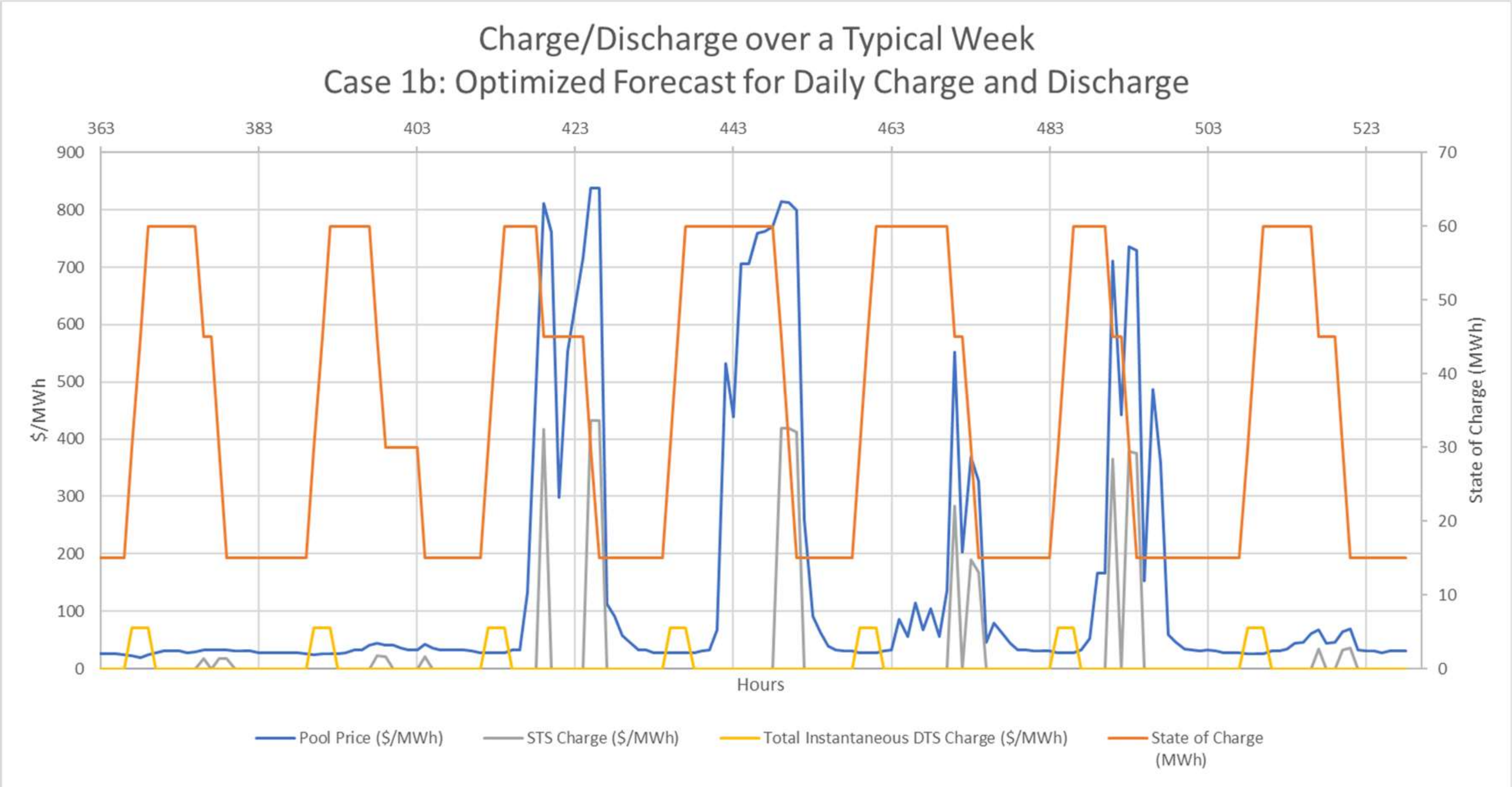
Case 1b: Production Profile & Costs



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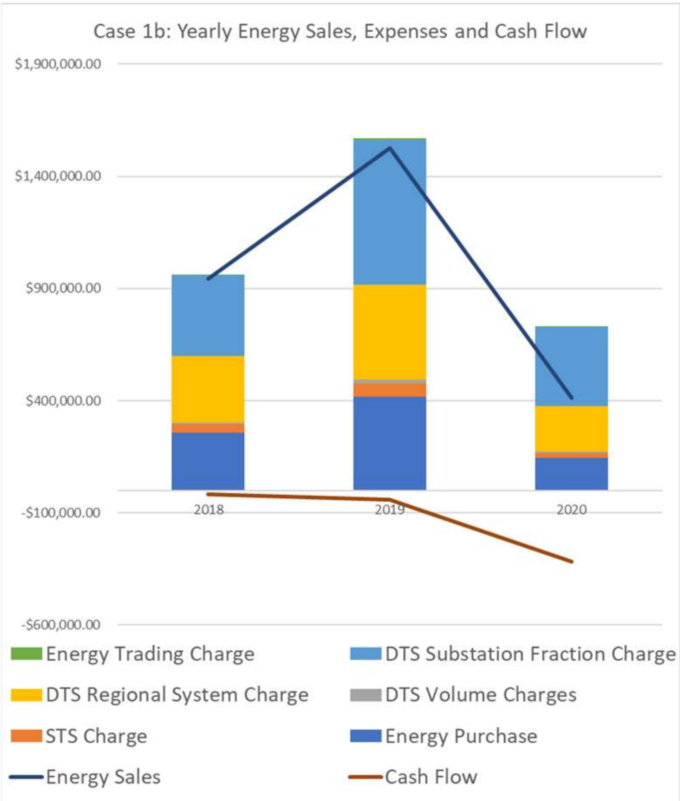
Case 1B: Perfect foresight is insufficient to make BESS economic.



- 1/3 of years has negative simple cash flow. Cashflow is insufficient for covering capital costs.

Year	Average Cost ($/MWh)	Average Revenue ($/MWh)
2018	-110	+130
2019	-107	+128
2020	-118	+86

SOLAS ENERGY CONSULTING

Case 1A: BESS ON GRID

Generation	None	Wind	Solar			
Storage Location	At Generation	On Grid	At Customer			
Storage Timing	Standard	Perfect Forecast				
Substation Fraction	1.0	0.5	0.1			
Tariff Type	Current	FERC 841	Interruptible			
Region	NW	NE	Edmonton	Central	Calgary	South
Peak	12 CP	Regional 120 CP	System 120 - CP	System- Weekly CP		

Charge during historical average low hours (HE 2,3,4,5)
Discharge during historical average high hours (HE 15,16,17,18)

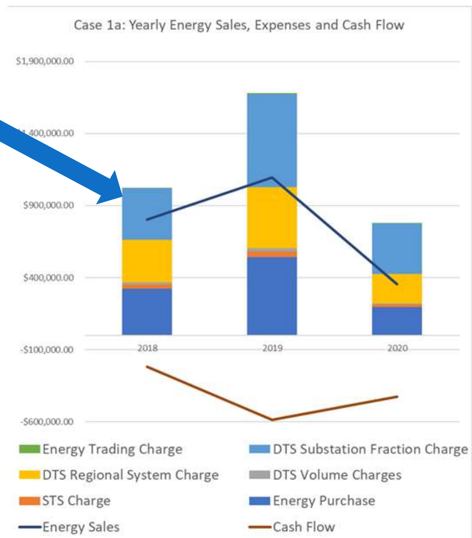
What's the impact of this?

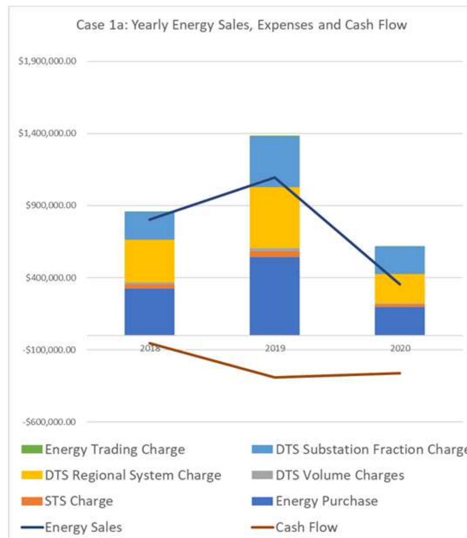
Massive DTS substation fraction costs push BESS locations to substations with other generators/loads (urban/industrial). But still uneconomic!

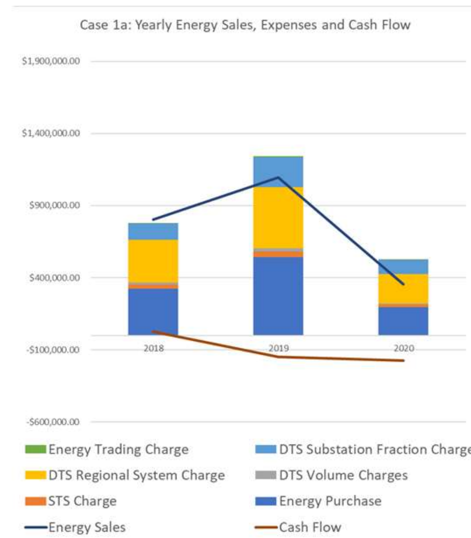
Current tariffs

Substation Fraction	1	0.5	0.1
Example configuration	Stand-alone TX connected	DX connected to sub with total STS and DTS contracts of 30 MW	TX connected to sub with total STS and DTS contracts of 150 MW

Look at DTS Substation Fraction POD Charge in each case







Case Options – 5 options reviewed by AESO

Generation	*None*	*Wind*	*Solar*			
Storage Location	*At Generation*	*On Grid*	*At Customer*			
Storage Timing	*Standard*	*Perfect Forecast*				
Substation Fraction	*1.0*	*0.5*	*0.1*			
Tariff Type	*Current*	*FERC 841*	*Interruptible*	*Fixed Network Cost*		
Region	*NW*	*NE*	*Edmonton*	*Central*	*Calgary*	*South*
Peak	*12 CP*	*Regional 120 CP*	*System 120 - CP*	*System- Weekly CP*		

Bookend A modified + Interrupt rate class

Bookend A

Bookend B (Regional Peak)

Bookend B (System Peak)

Bookend B (Weekly Peak)

2020-10-30

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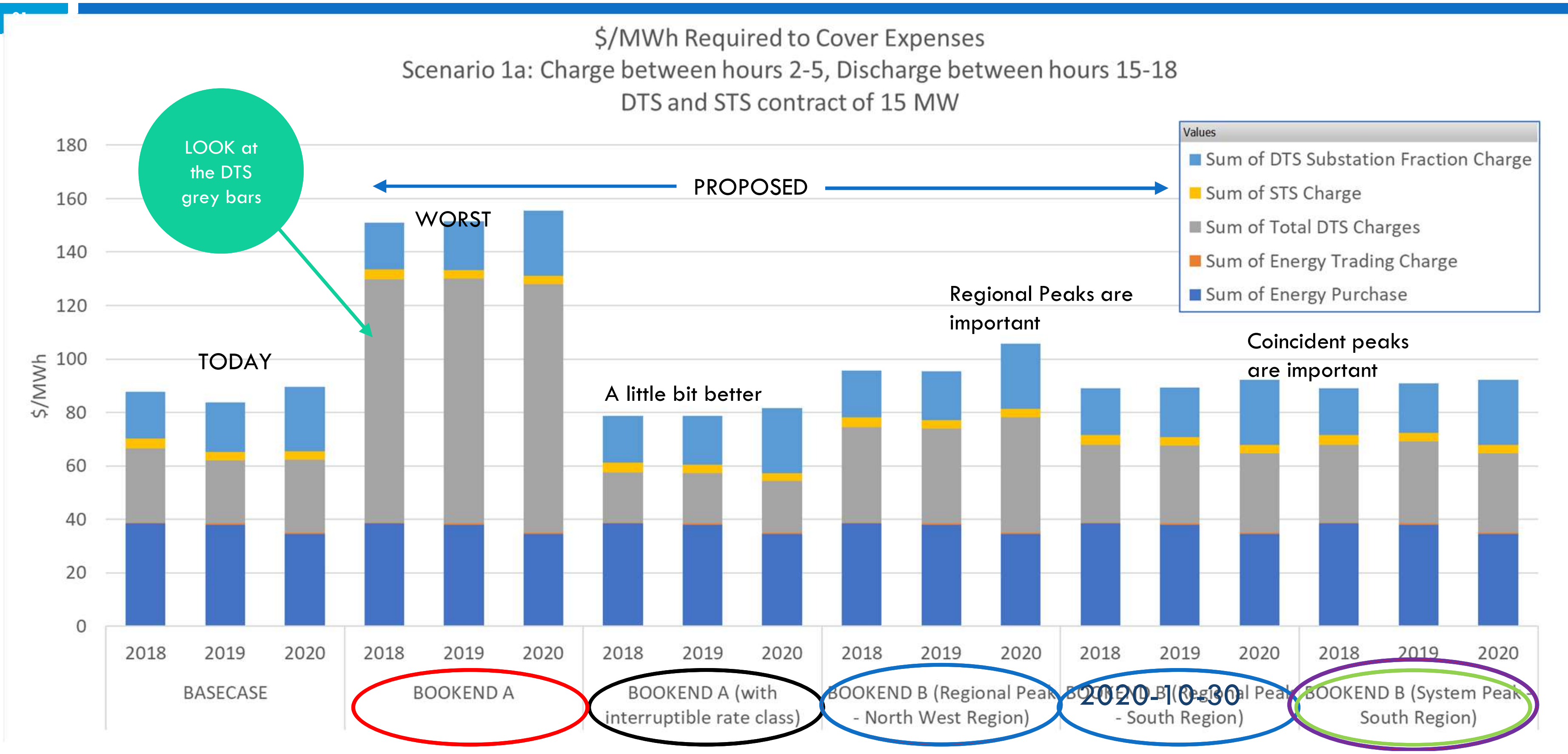
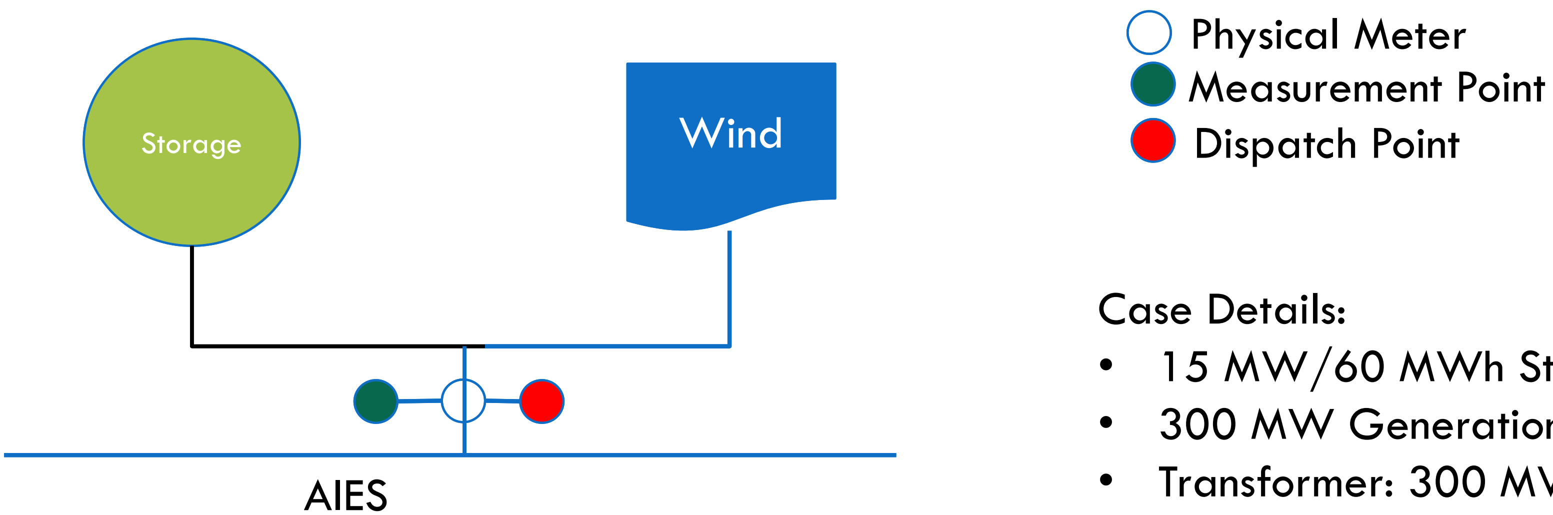
Impact of AESO Tariff Cases



CASE 2A

Use Case: BESS + Wind, Arbitrage, Tx connected, 4 hours storage

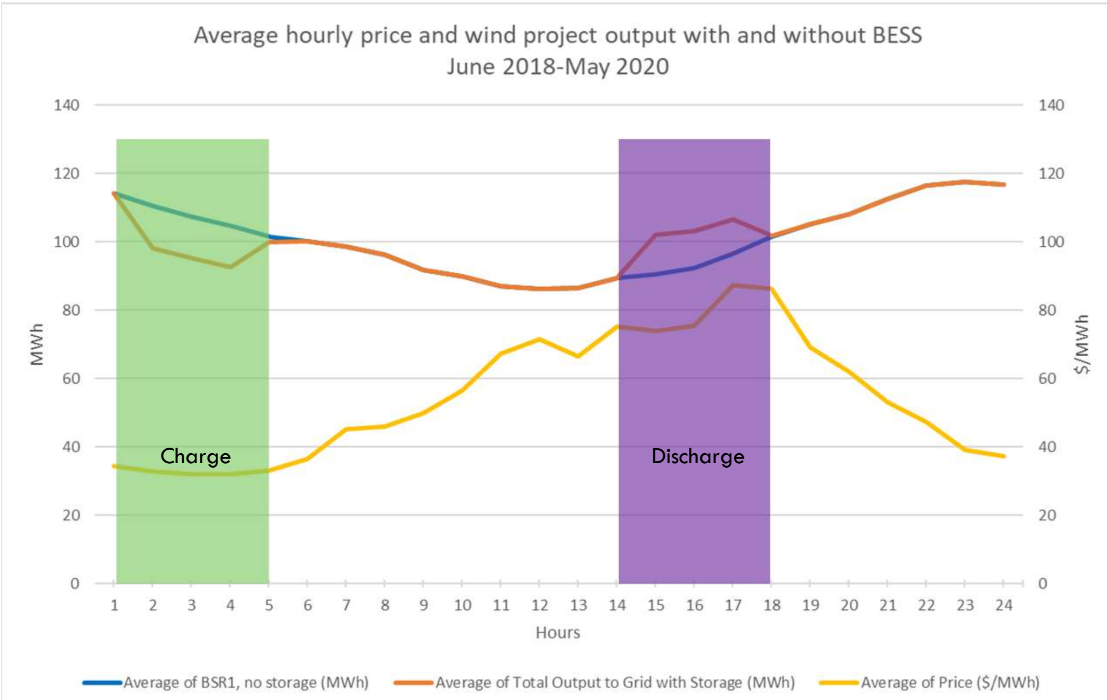
Tariff: Current Tariff



Case Details:

- 15 MW/60 MWh Storage
- 300 MW Generation
- Transformer: 300 MW
- Charge from Wind Only
- Discharge to Grid

Case 2a: BESS improves revenue, but not sufficient for positive economics. Hybrid BESS has better, but insufficient, economics than standalone BESS.



Year: 2019	No BESS	With BESS
Total Revenue	$30.7M	$31.3M
Total STS Charges	-$1.2M	-$1.2M
Simple Cash Flow	$29.5M	$30.0M

Does not include BESS operating costs, or BESS capital costs.

No incremental DTS or STS

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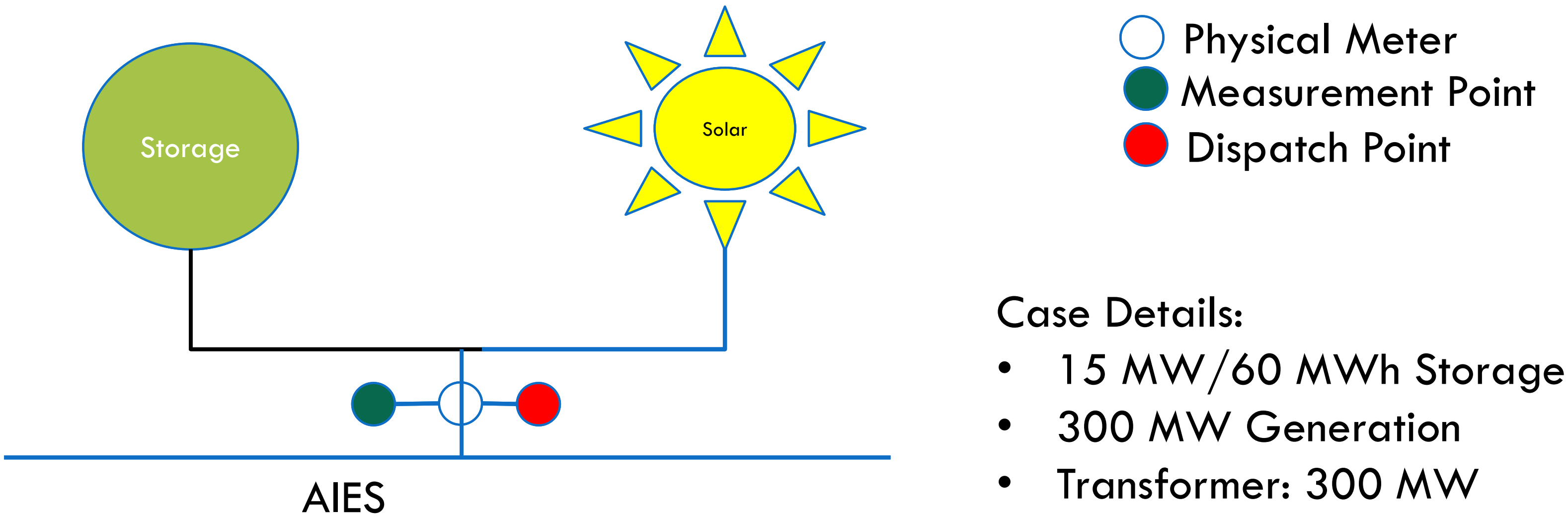
CASE 3A

Use Case: BESS + Solar, Arbitrage, Tx connected, 4 hours storage

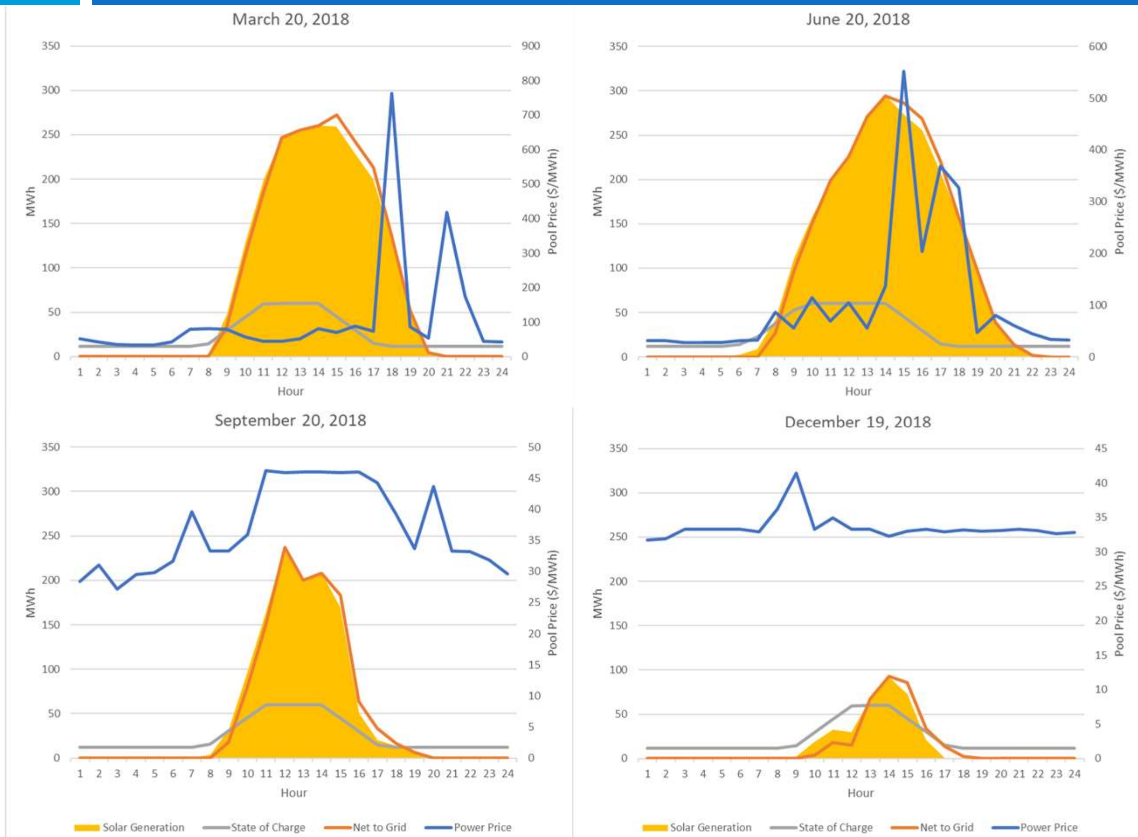
Tariff: Current Tariff



Case Details:

- 15 MW/60 MWh Storage
- 300 MW Generation
- Transformer: 300 MW
- Charge from Solar Only
- Charges starting at sunrise
- Discharge to Grid starting at HE 13

Case 3a: BESS improves revenue, but not sufficient for positive economics. Hybrid BESS has better, but insufficient, economics than standalone BESS.



Year: 2019	No BESS	With BESS
Total Revenue	$28.7M	$28.9M
Total STS Charges	-$1.1M	-1.1M
Simple Cash Flow	$27.6M	$27.8M

Does not include BESS operating costs, or BESS capital costs.

No incremental DTS or STS

2020-10-30

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OptionD

Priorities

- Design tariffs in the context of an evolving electricity system:
  - Increasing share of distributed generation including intermittent renewables
  - Increased potential for creation of microgrids as an economic bypass option
  - Capturing the integrating value of digital technology for two way flows
- Grid connection has value due to serving as conduit for energy exchanges and digital coordination; a fixed customer charge may be warranted in order to capture this value
- Encourage efficient use of the system based on planning of the system and long run marginal costs
- Eliminate price signals that may promote cost avoidance rather than future cost reduction
- Mitigate rate shock arising from restructuring via transitional credit

Tariff design Objectives

- **Reflect Cost Causation in the design of demand charges**
  - Consider long run incremental costs (proxy for marginal cost) in designing demand charges
- **Recognize there is a limited role for load signals based on a system peak. Incremental investment is driven primarily by generation; constraints are location dependent and will vary over time.**
  - Use of un-ratcheted monthly NCP to replace current CP
  - Eliminate distinction between bulk and regional costs
- **Ensure Cost recovery**
  - All bulk and regional costs not recovered by way of demand charges to be recovered by way of a declining block customer charge based on billing capacity

Tariff Design Objectives

- **Rate Mitigation**
  - Rate mitigation specifically to mitigate rate shock from restructuring, should be considered
  - Rate mitigation in view of poor economy is the responsibility of Govt., not rate making
  - Undue subsidies in the form of load retention rates to industry in transition may result in distorted economic price signals
  - Apply a transitional credit against fixed customer charges such that future customer bills corresponding to a historical base level billing capacity and costs ($/MW of billing capacity) would be capped at no more than 10% of the customer's previous average (3 yr. av. as base) bulk and regional costs, in year 1
  - The transitional credit would ensure load customers seeing increases due to restructuring are shielded from rate shock-the amount of shielding would go down to 80% in year 2, 60% year 3, 40% year 4, 20% year 5 and 0 year 6
  - Transitional credit to be calculated on the difference in total bill for a given billing capacity in $/MW and a credit rider applied to the customer charge at each POD on a per MW of billing capacity basis

Tariff Design Objectives

- **Facilitate load additions and Minimize Load Defections**
  - Declining block design for customer charge to incent additions to billing capacity at the margin
  - Transitional credit on $/MW of billing capacity against customer charge to shield existing customers from rate shock
- **Enhance Flexibility**
  - An un-ratcheted monthly NCP demand charge based on LRIC maximizes flexibility of use

Alternative D:
Network on un-ratcheted NCP; customer charge

Proposed Charges (Conceptual)

Demand charge:

Monthly un-ratcheted customer NCP demand charge	• MW = customer's peak monthly demand (NCP demand; un-ratcheted) • Establish demand charge having regard to the long-run incremental cost of transmission ($/MW) as well as other rate design considerations such as rate shock, after shielding ends

Customer charge:

Base a fixed charge on the difference between total bulk and regional costs net of recoveries via demand charge	• Customer charge would be a declining block charge. Design of declining blocks to take into consideration:
	    • Cost of incremental billing capacity additions to system
	    • Value of incremental billing capacity additions for customers
	• Declining block charge determined having regard to cost of economic bypass by customer as well as other rate design considerations such as rate shock, after shielding ends

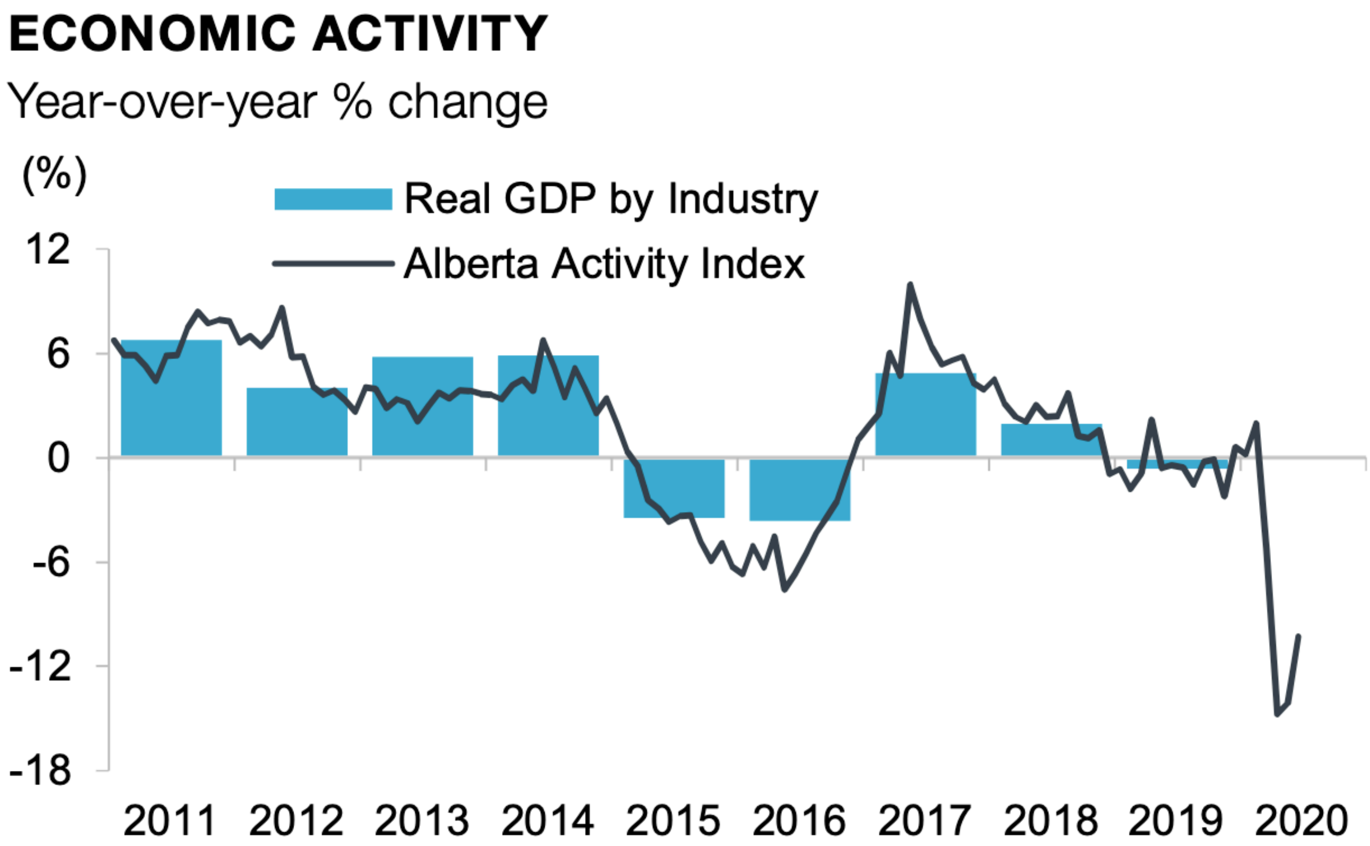
Summary Comments

- While the larger group (Proponents of Option C) agrees with the principles under Option D, they believe the path towards implementation would be more practical under option C, given the current circumstances of the Alberta economy
- The overall recommendation of the entire group is that the AESO take the ideas presented under Options C, D and all other presentations today and come forward with a bulk and regional tariff design that will achieve the AESO’s rate design objectives

Alternative C
for AESO Tariff Consultation:
~
Minimum Change Proposal

November 5, 2020

Alberta’s current situation



Source: Statistics Canada, Alberta Treasury Board and Finance

The future is profoundly uncertain

- **The immediate future is profoundly uncertain**
  - "the ongoing COVID-19 pandemic and related economic and financial market uncertainty/volatility continued to preclude the immediate successful resumption of the [GCOC] proceeding." [24110_X0486_2020-08-07 AUC letter - Proceeding status]
  - "the Commission will continue to assess when, and under what conditions, the GCOC proceeding can resume as relevant factors and specific market conditions change."
- **The longer-term future is profoundly uncertain**
  - Many customers and industries will continue to struggle
  - Major tariff changes would add unnecessary stress

Goals

- **Minimize customer disruption & uncertainty**
  - Now is not the time for major structural tariff changes
  - Propose freezing 12-CP benefits to existing loads for the foreseeable future
- **Consider tariff incentive schemes**
  - Load retention strategies to reduce future loss of load and avoid higher rates for the remaining customers
  - Provisions to attract new load and incent efficient use of the transmission system (e.g. expanded/modified use of DOS)
  - Subject to AUC approval

Minimum change proposal – Alternative C

Proposal makes minimal changes to the current 2018 rate design

- **Bulk charge - change from 12-CP to gross un-ratcheted NCP**
  - Uses traditional, well-understood NCP determinant currently on gross basis, as determined by AUC
  - Provides signals to encourage efficient use of the grid and provides customer cost management flexibility
  - NCP applies to all loads – however existing load to receive continued rate credits
- **Regional charge – continuation of current billing capacity design**
  - Reflects the approximate costs for minimum system use
- **Energy charge under both bulk and regional remains unchanged (same classification %)**

Minimize customer disruption & uncertainty

- **Minimize disruption for <u>existing</u> customers that would see large rate increases in moving away from current 12-CP tariff**
- **Shield existing users of 12-CP cost reduction option**
  - Use recent behaviour (2017-19 ?) to determine rate credits
  - Transmission peak-hour avoidance no longer required: clear focus on energy market price response benefits all
  - Will require a broader stakeholder discussion on precisely how a shielding mechanism will work
- **For How Long ?**
  - UCA/CWSAA/Conoco support beginning credit phase-out once economy has stabilized
  - AML supports a permanent credit mechanism

Other design options for consideration

- **Consider longer-term credits based on customer business stress**
  - AUC approval on a case-by-case basis (load retention rates)
- **For non-wires alternatives, use an area-specific short term contract (instead of the tariff)**
- **Expansion of existing Demand Opportunity Service (DOS)**
  - Make more attractive to customers to use any surplus on the system
- **Load Attraction rate**
  - Apply a discount to the bulk/regional rates
  - Apply to loads above existing contract levels or for new loads
  - Available where incremental transmission would not have to be built for customers
  - Rate could be interruptible
  - Target new loads such as data centers, greenhouses, agricultural use, incremental industrial load growth

Alternative C against AESO's tariff design objectives

AESO objective	Objective Description	Current State	Alternative C	Assessment of Alternative C
Reflect cost responsibility	Cost recovery is based on the benefit and value transmission customers receive from the existing grid			Existing regional charge reflects the minimal use of the system. All customers pay the bulk charge based upon peak NCP usage.
Efficient price signals	Cost recovery is based on the benefit and value transmission customers receive from the existing grid			An un-ratcheted demand charge will allow customers to vary their use throughout the year and to reduce their costs.
Minimal disruption	Customers that have responded to the 12-CP price signal and invested to reduce transmission costs are minimally disrupted			Load customers who have responded to 12-CP price signals will be shielded from rate increases through credit mechanism. Rate impacts will be lower than AESO Bookends A and B.
Simplicity	Simplicity and clear price signals while achieving design objectives			Regional rate remains; bulk rate is similar to regional rate with no ratchet; energy ratio unchanged. Credit mechanism will require ISO system changes and/or manual calculations.
Innovation and flexibility	ISO tariff provides optionality for transmission customers to innovate while not pushing costs to other customers			The un-ratcheted demand bulk charge will allow customers to reduce their bills. Expanded DOS will provide customers with the choice to go above their contracted demand where surplus exists. Attraction rates will defray transmission costs to new load.

Legend: Achieves objective Partially achieves objective Does not achieve objective

Energy Storage Canada with Power Advisory LLC Presentation to AESO Bulk & Regional Tariff Design Consultation – Session 3

November, 2020

Who is Energy Storage Canada?

Advance Canadian Storage Industry

- Energy Storage Canada is **THE** voice of the energy storage industry in Canada
- Established in 2014 in Ontario, expanded nationally in 2016
- Represent the industry at all levels: Grid Level, Distribution Level, and Behind the Meter

Drive Advocacy & Strategic Initiatives

- Advocate for fair markets for energy storage across the country
- Ensure energy storage awareness at policy levels
- Engage with national government to raise profile of energy storage in climate change programs

Build Stakeholder Engagement & Membership

- Hold the biggest conference solely focused on energy storage in Canada
- Our membership represents all players along the energy storage value chain
- We represent some of the largest energy companies in Canada as well as some of the most innovative clean-tech organizations.

ENERGY STORAGE CANADA

Who is Power Advisory LLC?

MANAGEMENT CONSULTING

- Market Analysis & Assessments
- Forecasts & Studies
- Project Management
- Contract Management & Negotiations

ENGINEERING & ECONOMIC

- Power System Planning
- Resource Need Justification
- Grid Connection Assessment
- Financial Modelling
- Avoided Cost Analysis

Power Advisory LLC

POLICY & REGULATORY

- Regulatory Support
- Market Design & Rule Development
- Consultation & Stakeholder Engagement

BUSINESS STRATEGY

- Business Development
- New Market Strategies
- Investment & Acquisition
- Asset Valuation & Due Diligence
- Feasibility Assessment

Background

- Evolution of the tariff design for Energy Storage Resources was identified in the Alberta Electricity System Operator's (AESO's) Energy Storage Roadmap
- Changes to tariff design for Energy Storage Resources were included in broader tariff design changes under the Bulk & Regional Tariff stakeholder engagement
- The AESO has hosted two webinars to discuss potential tariff design change options along with unique treatment for Energy Storage Resources
- The objectives of Session 3 are:
  - Stakeholders to present and discuss alternative rate design options, including energy storage options and implications
  - Understand which rate design options stakeholders support and why
- This presentation provides Energy Storage Canada's high-level alternative rate design option for Energy Storage Resources

Power Advisory LLC

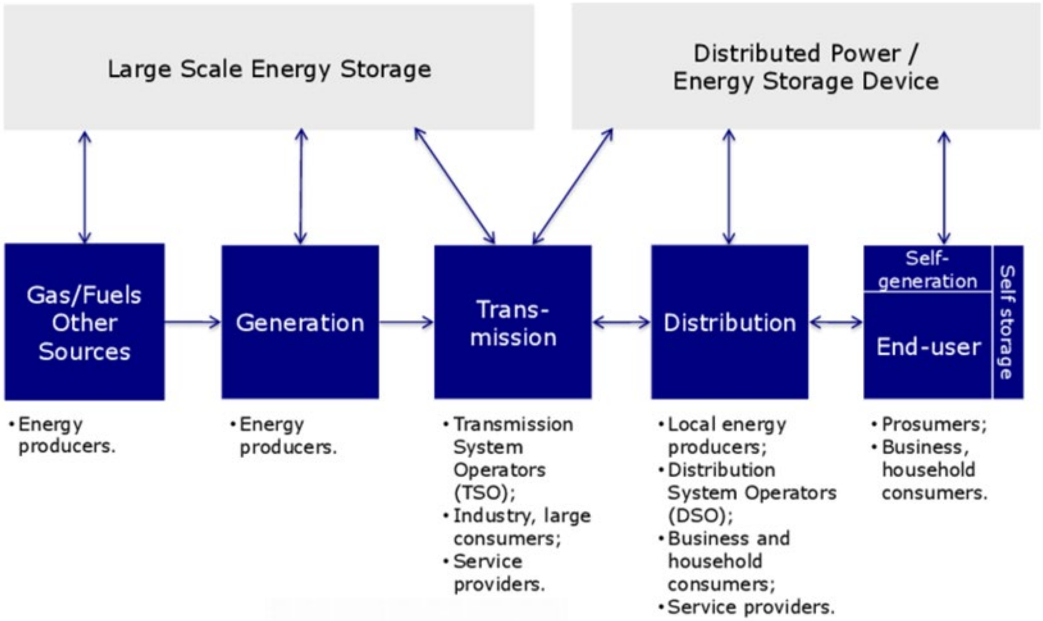
ENERGY STORAGE CANADA

Definition of Energy Storage Resources and Intermediate Load

- As described in the AESO energy storage roadmap, energy storage resources are a unique asset that will require market design changes to integrate energy storage resources fairly and equally into the Alberta electricity market
- In the Alberta Electricity System Operator's (AESO's) energy storage roadmap, the AESO put forward a definition for energy storage
  - *Energy storage is any technology or process that is capable of using electricity as an input, storing the energy for a period of time and then discharging electricity as an output*
- While energy storage can act as a load, **energy storage is not an end-use customer** that ultimately consumes electricity produced by generators
- Energy storage is an intermediary market participant; energy consumed is re-injected for end-use consumption at a later time

Energy Storage Resource Use Cases

- Energy storage resources are first and foremost a utilization tool to increase the efficiency and effectiveness of the electricity system
- Changes to the bulk & regional tariff should reflect the uniqueness of energy storage resources and not result in additional costs that must be borne by end-use electricity customers



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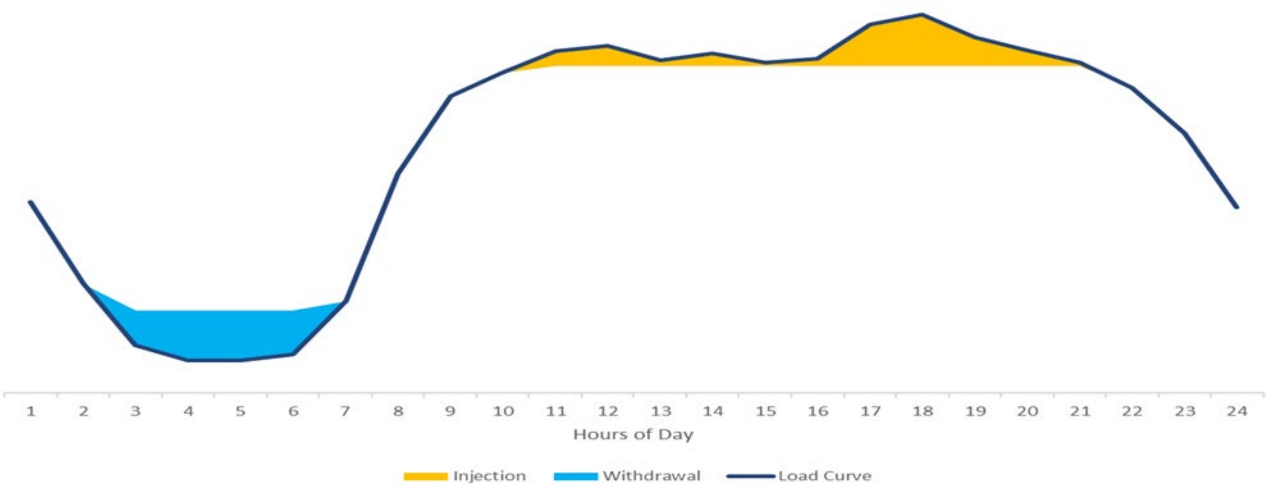
Natural Operation of Energy Storage

- The natural operation of energy storage is to consume during lower price off-peak hours and produce during higher price on-peak hours
- This operation decreases the average wholesale electricity price for customers and the strain on the existing transmission system



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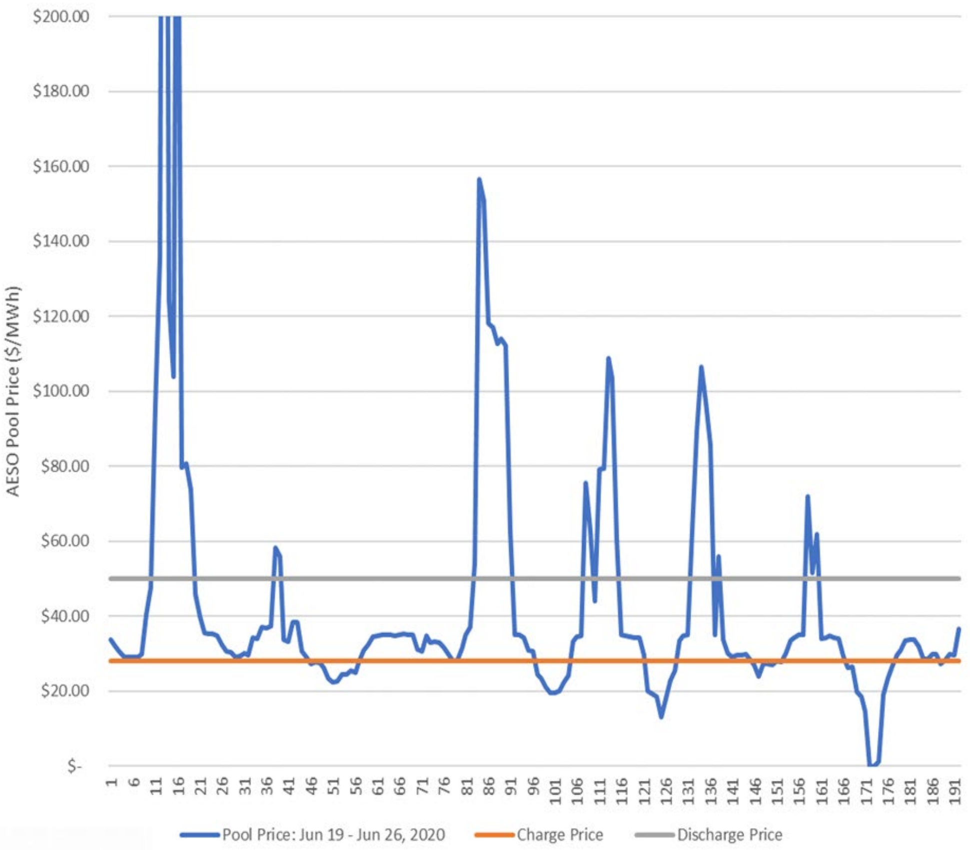
Pool Price Impact on Energy Storage Operation

- If transmission system constraints occur, energy storage is a curtailable resource that can cease operation if required, or potentially offer service needed to resolve the constraint
- As a market participant, the operation of energy storage resources would be governed by dispatch instructions and pool price setting
    - Would require energy storage resources to bid for energy for charging



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Recommendations for Energy Storage Tariff Treatment

Recommendation	Description
Energy storage should be treated as a supply resource	• The primary objective of energy storage is to shift energy injection to higher value hours
Energy storage should pay ISO/TFO admin fees based on the services being used	• Energy storage can use and provide a variety of services therefore ISO/TFO admin fees should be applied based on the actions of energy storage resources • ISO/TFO admin fees include cost required to administer the market & transmission grid
Energy storage should pay, and be paid, based on wholesale electricity prices (i.e., AESO pool price).	• Energy storage is dispatchable and able to participate in the real-time energy markets • Energy storage should pay the variable costs of the Alberta electricity system and the real-time wholesale electricity price is the most accurate

Recommendations for Energy Storage Tariff Treatment

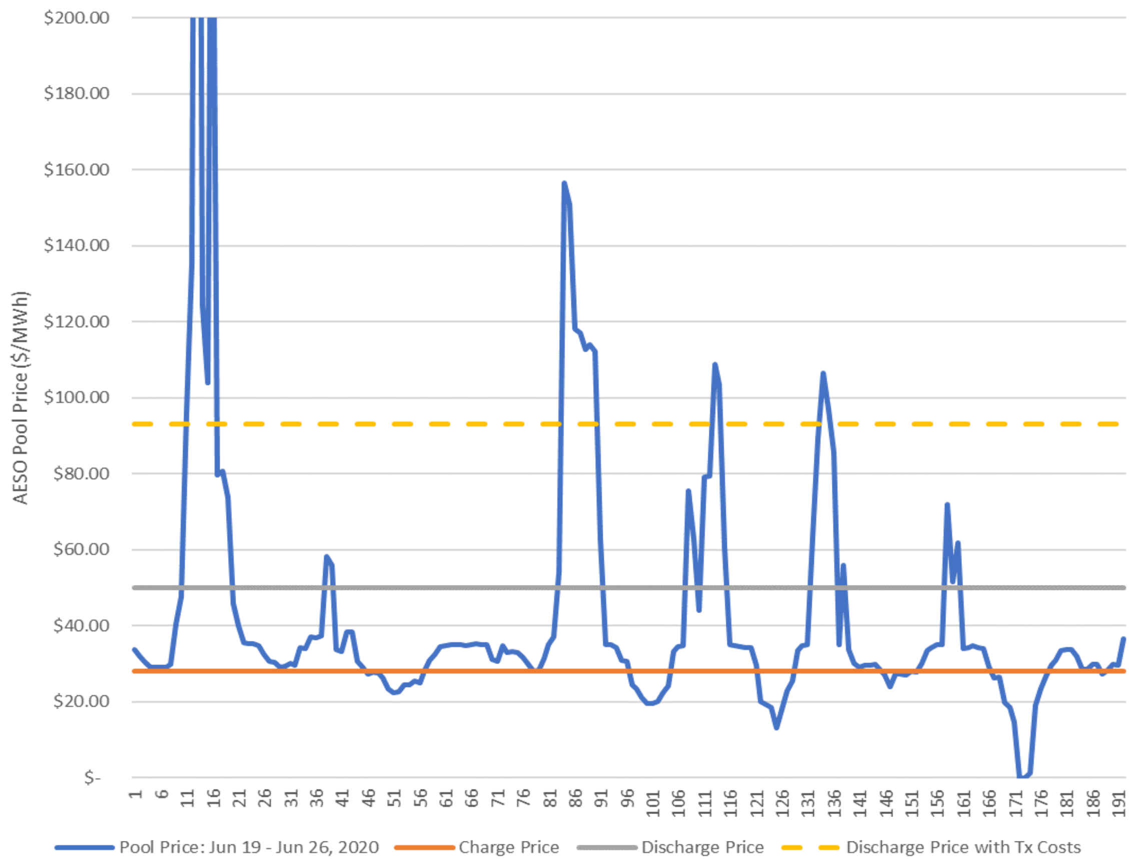
Recommendation	Description
Energy storage should not pay transmission system costs	• The primary objective of energy storage is to shift energy injection to higher value hours • Applying transmission system costs to energy storage will increase the cost for services provided by energy storage to the detriment of end-use customers (e.g., like a fuel tax) • Unless instructed by the AESO for specific service provision (e.g., frequency response), energy storage will not consume when the transmission system is constrained; instead, energy storage will increase the utilization of the existing transmission assets, defer the need for new transmission system investments and lower the cost of electricity service for end-use customers

Pool Price Impact on Energy Storage Operation

Transmission charges for storage devices will reduce market efficiency by distorting charge/discharge decisions

Other market participants are end-use customers for separate infrastructure networks to delivery fuel (e.g., gas-fired generation), where there are no benefits passed back to the network

Since energy storage is not an end-use consumer, the costs applied to energy storage will ultimately be charged back to end-use customers, at a premium for cycling losses



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Power Advisory LLC

ENERGY STORAGE CANADA

RMP

ENERGY STORAGE

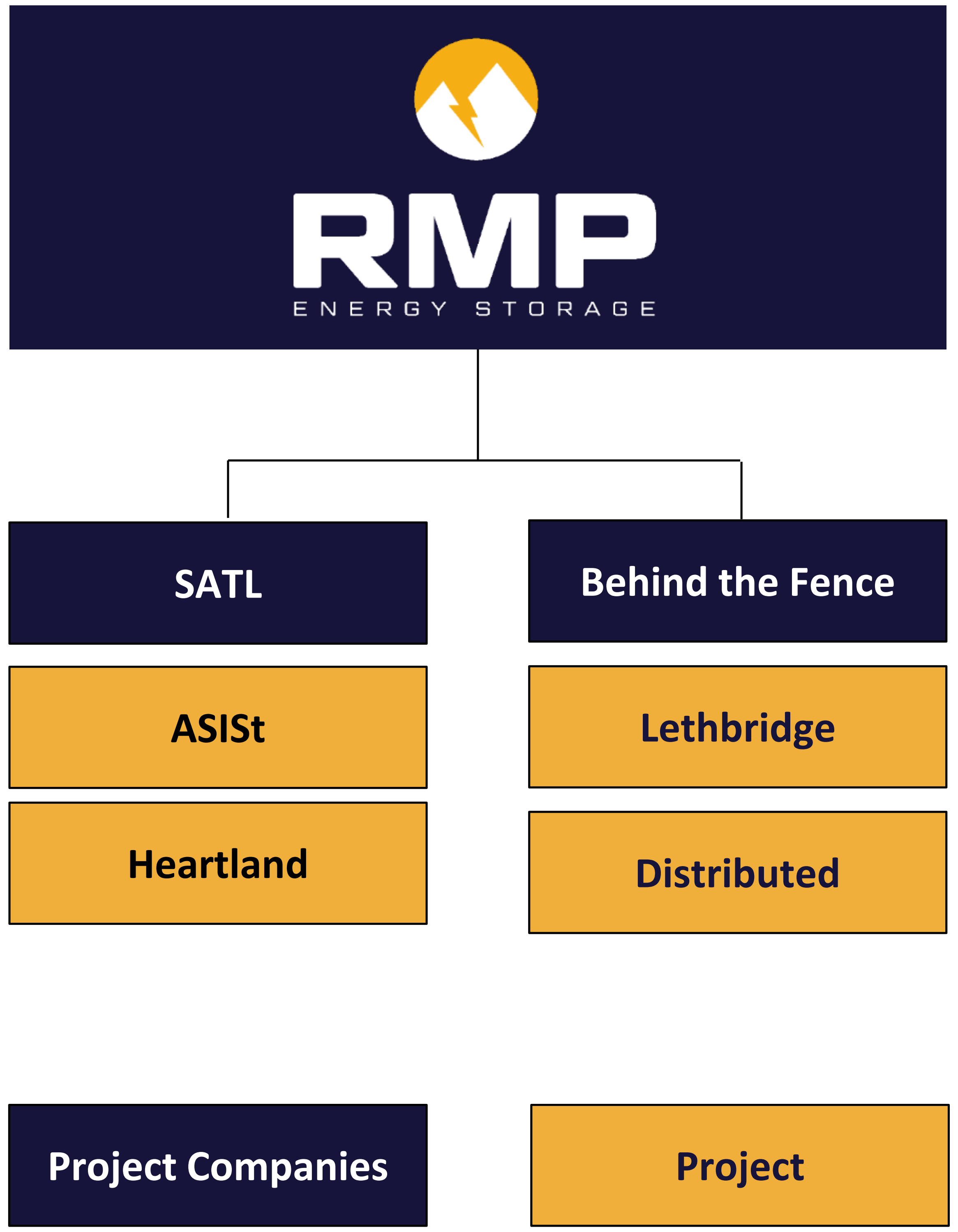
AESO 2020 BULK AND REGIONAL TARIFF DESIGN

FALL 2020

WHO WE ARE

- AB based energy storage infrastructure project development company since 2006
- Technology agnostic
- Developing CAES in AB since before 2012
- Has been requesting a different treatment of non-firm customers including energy storage since 2012
- CAES and wind can provide a competitive firm renewable product in Alberta

Project	Technology	Capacity (MW)	Location
ASISt	CAES	~300 (>18000 MWh)	AB/SK
Heartland	CAES	~300 (>18000 MWh)	AB
BTF Battery	Battery	1 to 10	AB/BC/SK



PRINCIPLES

- FEOC
- Cost causation
- Technology agnostic
- Consumers (load) pays for system to deliver power from generation as otherwise would be embedded in power price
- Transmission system is for the benefit of the consumers (load)

- AESO principle is that all customers want the same product:

firm power at very high reliability

TARIFF ISSUES

DECOUPLE two issues

1. Tariff costs are high enough to cause increasing interest in grid defection of those who can

Customers determine value of the system. If they are considering defecting then the value is not there. Only way around 1 is greater amount of load sharing the cost OR lowering the cost. Must reduce spending either way as current practice proven unsustainable.

2. Energy storage tariff

ENERGY STORAGE

- Bulk of value is due to better utilization of low cost electricity (renewables, cogen, etc.)
- Buy low sell high, putting power back onto the grid like peaker
- Will not draw power from grid when prices signals direct it not to
- Pool price is the only real time price signal from AESO
- Merit order shape means ES reduces peak prices like additional generation
- By design, current and proposed tariff bookends do not allow ES market participation due to the definitions of generation and firm load

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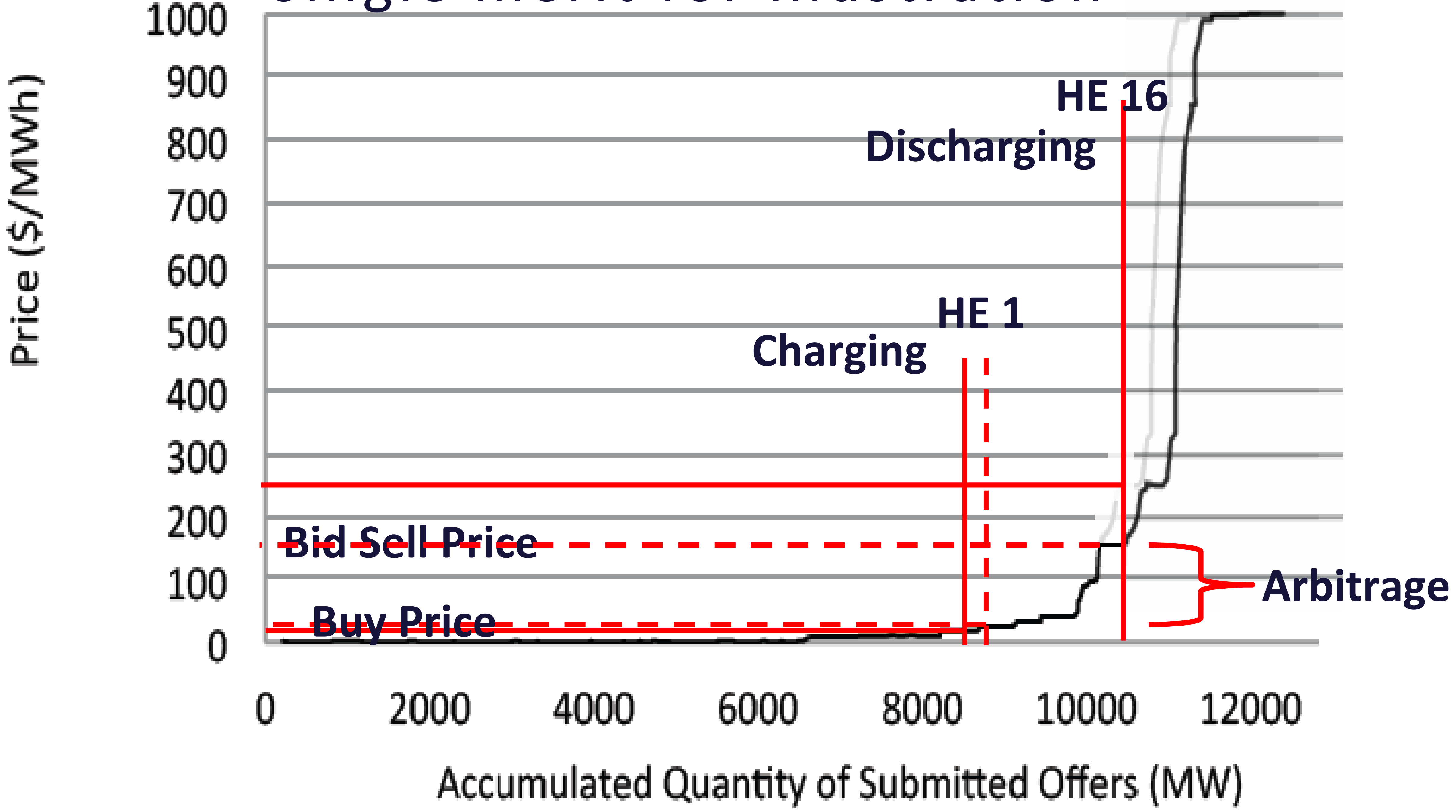
MARKET VOLATILITY

- If by design, tariff doesn't allow ES participation, storage can't enter the market
- Increasing number of $0/MWh bids due to additional renewables means other generation will have to bid higher
- Only storage can increase demand during lower price periods and shift stored energy to higher price periods to reduce volatility
- ES innately benefits consumers and supports renewable integration

Single merit for illustration



CURRENT PARTICIPANTS

Generation	(Does not pay for bulk transmission)		
Peaker	(1 - 10% CF)	High prices	Most similar to ES
Solar	(15-22% CF)	Intermittent and correlated across province	
Wind	(30-50% CF)	Uncertain and correlated across province	
Cogen	(70-90% CF)	Process driven	
CCGT	(70-90% CF)		
Intertie	(5-25% CF)	External market arbitrage	Second most similar to ES

Firm Load (Full capacity available on demand, pays for transmission)

Flexible Load (Pay for portion of system they want as firm load) may get some power through DOS rates

MOST LOGICAL ES TARIFF

Treat as a peaking generator, Pay STS only

- STS pays for right to generate when in merit, has wires connected all the time
- AESO controls or provides signal for immediate ramp down or disconnect when charging at specific line rating threshold
- Storage makes all its revenue from in market generation and acts accordingly
- FEOC - Storage acts most like a peaker
- Cost Causation - AESO to provide signal or have direct control to avoid storage charging when it might cause a system constraint
- Storage pays GOUC and is incented to go to locations based on GOUC, loss factor and technology specific attributes
- Storage pays DTS for any station load like other generation
- If non-ES participants can disconnected immediately they should also get this rate

INTERRUPTIBLE TARIFF

If ES is not treated as generation, then due to nature of its operation an interruptible rate is the most appropriate.

But an interruptible rate does not recognize that storage is different than dual-use/non-firm customers providing additional benefits for the grid and power market operations.

An Interruptible rate:

1. Is Not FEOC – because ES operates most like a peaker and should only pay STS and DTS for firm station load
2. Does not fully recognize the benefits of AESO controlling an expedited ramp down during charging
3. Should reflect cost causation – Therefore the rate must be $/MWh because ES does not use and therefore should not pay for firm capacity.
4. Should not include GUOC payments as this would be double counting transmission costs
5. Should be available for a long term, not renewed like DOS

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INTERRUPTIBLE TARIFF

Must be lower than DOS as completely interruptible

Proposed Interruptible rate	$	2.00	/ MWh
DOS 7 min	$	6.11	/ MWh
DOS 1 hr	$	17.85	/ MWh
XOS/XOM	$	8.00	/ MWh

Built ES model for two long duration and one battery storage assets based on historical pool prices

Long duration defined as able to firm wind to meet load requirement

Very basic, not optimized, buy/sell strategy not aware of CP12 events

INTERRUPTIBLE TARIFF

2018									
Case	8			9			10		
Region	5			3			6		
Name	**Actual Export BC**			**DCAES (320 MW, 60 hr)**			**Battery (100 MW, 4 hrs storage)**		
12-CP Response Factor	97%			100%			91%		
Highest metered demand	939			322	MW		103		
Energy	934,092			128,096	MWh		75,275		
Load factor	11%			5%			8%		
Cost of energy $/MWh	52.13		Total $/MWh	27.56		Total $/MWh	37.73		Total $/MWh
Current ISO Tariff	$ 37,450,000		92.22	$ 11,070,000		113.97	$ 4,840,000		102.03
Bookend A	$ 109,300,000	192%	169.14	$ 37,480,000	239%	320.15	$ 11,930,000	146%	196.22
Bookend A (interrupt, 0% firm)	$ 22,540,000	-40%	76.26	$ 7,730,000	-30%	87.90	$ 2,460,000	-49%	70.41
Bookend B (Reg. wkday pk)	$ 43,680,000	17%	98.89	$ 11,990,000	8%	121.16	$ 4,920,000	2%	103.09
Proposed interruptible rate	$ 1,870,000	-95%	54.13	$ 260,000	-98%	29.59	$ 150,000	-97%	39.72

- Even with 100% CP12 avoidance the current tariff prevents ES from competing in the market
- Proposed bookends do the same thing or make it worse
- Proposed interruptible rate enables ES to compete in the market
- For Clarity, Total $/MWh is input MWh not including any storage losses


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INTERRUPTIBLE TARIFF

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Load factor	11%			5%			8%		
Cost of energy $/MWh	52.13		Total $/MWh	27.56		Total $/MWh	37.73		Total $/MWh
Current ISO Tariff	$ 37,450,000		92.22	$ 11,070,000		113.97	$ 4,840,000		102.03
Bookend A	$ 109,300,000	192%	169.14	$ 37,480,000	239%	320.15	$ 11,930,000	146%	196.22
Bookend A (interrupt, 0% firm)	$ 22,540,000	-40%	76.26	$ 7,730,000	-30%	87.90	$ 2,460,000	-49%	70.41
Bookend B (Reg. wkday pk)	$ 43,680,000	17%	98.89	$ 11,990,000	8%	121.16	$ 4,920,000	2%	103.09
Proposed interruptible rate	$ 1,870,000	-95%	54.13	$ 260,000	-98%	29.59	$ 150,000	-97%	39.72
2019									
12-CP Response Factor	100%			100%			99%		
Highest metered demand	600	MW		322	MW		103		
Energy	102,327	MWh		140,749	MWh		70,031		
Load factor	2%			5%			8%		
Cost of energy $/MWh	39.16		Total $/MWh	28.17		Total $/MWh	35.87		Total $/MWh
Current ISO Tariff	$ 20,360,000		238.13	$ 11,120,000		107.18	$ 3,720,000		88.99
Bookend A	$ 69,840,000	243%	721.68	$ 37,480,000	237%	294.46	$ 11,930,000	221%	206.23
Bookend A (interrupt, 0% firm)	$ 14,400,000	-29%	179.88	$ 7,730,000	-30%	83.09	$ 2,460,000	-34%	71.00
Bookend B (Reg. wkday pk)	$ 23,540,000	16%	269.20	$ 11,990,000	8%	113.36	$ 5,510,000	48%	114.55
Proposed interruptible rate	$ 200,000	-99%	41.11	$ 280,000	-97%	30.16	$ 140,000	-96%	37.87

RMP ENERGY STORAGE

INTERRUPTIBLE TARIFF

Application of new opportunity rate to load requires that they can disconnect within same constraint (e.g. 5 sec)

2018																		
Case	1			3			8			9			10			11		
Region	1			1			5			3			6			3		
Name	Price responsive			Price responsive			Actual Export BC			DCAES (320 MW, 60 hr)			Battery (100 MW, 4 hrs storage)			ACAES (100 MW, 60 hr)		
12-CP Response Factor	87%			63%			97%			100%			91%			91%		
Highest metered demand	106			42			939			322	MW		103			103	MW	
Energy	524,032			278,627			934,092			128,096	MWh		75,275			174,131	MWh	
Load factor	56%			75%			11%			5%			8%			19%		
Cost of energy $/MWh	43.42		Total $/MWh	48.45		Total $/MWh	52.13		Total $/MWh	27.56		Total $/MWh	37.73		Total $/MWh	33.04		Total $/MWh
Current ISO Tariff - Rate DTS Bulk and Regional Charges	$ 6,400,000		55.63	$ 3,990,000		62.77	$ 37,450,000		92.22	$ 11,070,000		113.97	$ 4,840,000		102.03	$ 4,920,000		61.29
Bookend A	$ 12,370,000	93%	67.02	$ 4,930,000	24%	66.15	$ 109,300,000	192%	169.14	$ 37,480,000	239%	320.15	$ 11,930,000	146%	196.22	$ 11,930,000	142%	101.55
Bookend A (with interruptible rate class, 0% firm)	$ 2,550,000	-60%	48.28	$ 1,020,000	-74%	52.11	$ 22,540,000	-40%	76.26	$ 7,730,000	-30%	87.90	$ 2,460,000	-49%	70.41	$ 2,460,000	-50%	47.17
Bookend B (At time of Regional Weekday Peak)	$ 14,860,000	132%	71.77	$ 3,850,000	-4%	62.27	$ 43,680,000	17%	98.89	$ 11,990,000	8%	121.16	$ 4,920,000	2%	103.09	$ 4,480,000	-9%	58.77
Proposed interruptible rate	$ 1,050,000	-84%	45.42	$ 560,000	-86%	50.46	$ 1,870,000	-95%	54.13	$ 260,000	-98%	29.59	$ 150,000	-97%	39.72	$ 350,000	-93%	35.05

2019																		
Case	1			3			8			9			10			11		
Region	1			1			5			3			6			3		
Name	Price responsive			Price responsive			Actual Export BC			DCAES (320 MW, 60 hr)			Battery (100 MW, 4 hrs storage)			ACAES (100 MW, 60 hr)		
12-CP Response Factor	95%			87%			100%			100%			99%			91%		
Highest metered demand	108			41	MW		600	MW		322	MW		103			103	MW	
Energy	524,047			262,078	MWh		102,327	MWh		140,749	MWh		70,031			130,966	MWh	
Load factor	55%			73%			2%			5%			8%			15%		
Cost of energy $/MWh	35.39		Total $/MWh	39.70		Total $/MWh	39.16		Total $/MWh	28.17		Total $/MWh	35.87		Total $/MWh	32.98		Total $/MWh
Current ISO Tariff - Rate DTS Bulk and Regional Charges	$ 5,430,000		45.75	$ 2,550,000		49.43	$ 20,360,000		238.13	$ 11,120,000		107.18	$ 3,720,000		88.99	$ 4,920,000		70.54
Bookend A	$ 12,610,000	132%	59.45	$ 4,740,000	86%	57.78	$ 69,840,000	243%	721.68	$ 37,480,000	237%	294.46	$ 11,930,000	221%	206.23	$ 11,930,000	142%	124.07
Bookend A (with interruptible rate class, 0% firm)	$ 2,600,000	-52%	40.35	$ 980,000	-62%	43.43	$ 14,400,000	-29%	179.88	$ 7,730,000	-30%	83.09	$ 2,460,000	-34%	71.00	$ 2,460,000	-50%	51.76
Bookend B (At time of Regional Weekday Peak)	$ 14,180,000	161%	62.44	$ 5,790,000	127%	61.79	$ 23,540,000	16%	269.20	$ 11,990,000	8%	113.36	$ 5,510,000	48%	114.55	$ 5,370,000	9%	73.98
Proposed interruptible rate	$ 1,050,000	-81%	37.39	$ 520,000	-80%	41.68	$ 200,000	-99%	41.11	$ 280,000	-97%	30.16	$ 140,000	-96%	37.87	$ 260,000	-95%	34.96

ES OPERATION

For reference, calendar year example revenue

One month bulk system charge CP12 is $1M for 100 MW asset

Under Current tariff DCAES pays more in DTS than revenue

	100 MW ES arbitrage revenue in millions pre tariff		
	DCAES (60 hr, 3.8 GJ/MWh, 145%)	ACAES (60 hr, 55%)	Battery (4 hr, 85%)
2018	$10.1	$10.6	$4.2
2019	$13.1	$11.2	$4.8
Q1 Q2 2020	$6.2	$3.7	$0.5

	Capacity factor		
	DCAES (60 hr)	ACAES (60 hr)	Battery (4 hr)
2018	5.3%	7.9%	4.3%
2019	7.9%	8.4%	5.8%
Q1 Q2 2020	4.9%	4.0%	2.5%

Bulk & Regional Tariff Design

Session 3 – November 5, 2020

Overview

- Design Objective
- Bulk & Regional Transmission in Alberta
- Billing Determinant Principles
- Billing Determinants for
  - Point of Delivery (for Context)
  - Regional Transmission
  - Bulk Transmission
- Putting it all Together
- Note on the Frequency of Coincidence Measures
- Appendix
  - Responses to AESO questions
  - Comments regarding AESO rate design objectives
  - "Nice to Have" objectives
  - Assessment against "Nice to Have" objectives

Legislative Intent – *Electric Utilities Act (EUA)*

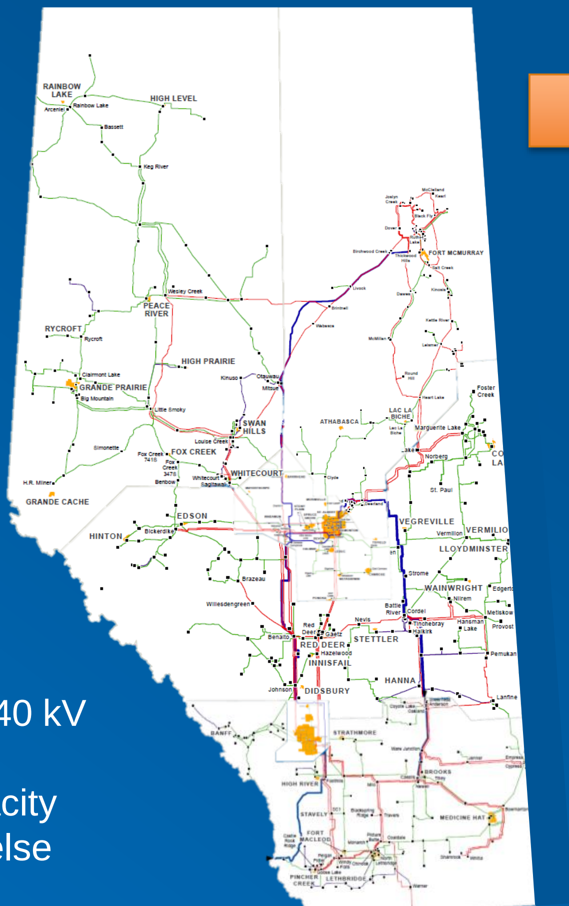
- Background: “the failure of an administrative decision-maker to take into account a highly relevant consideration is just as erroneous as the improper importation of an extraneous consideration” [SCC]

Purpose of the *EUA*: Promote an efficient market based on fair and open competition	[Section 5]
Rates must reflect prudent costs that are reasonably attributable	[Section 30(2)]
Rates cannot differ based on location	[Section 30(3)]
Tariff must be just and reasonable	[Section 121(2)]
Tariff cannot be unduly preferential, arbitrarily or unjustly discriminatory	[Section 121(2)]
Tariff is not unjust or unreasonable because it provides efficiency incentives	[Section 121(3)]

Cost-Causation

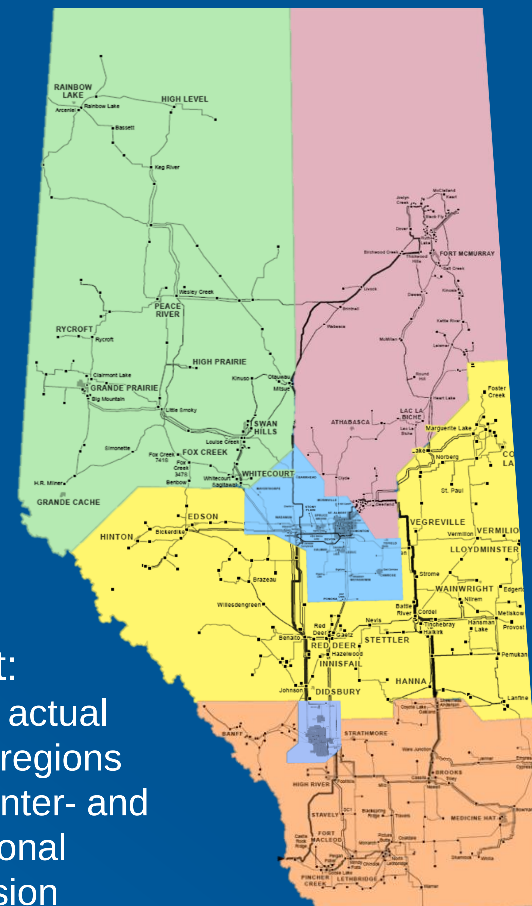
Rates must result in cost recovery	[Section 30(2)]

Alberta Bulk & Regional Transmission System in the Tariff



Current Tariff:

- 12-CP for 240 kV or higher
- Billing Capacity everything else



Refinement:

- Consider actual planning regions
- Analyze inter- and intra-regional transmission

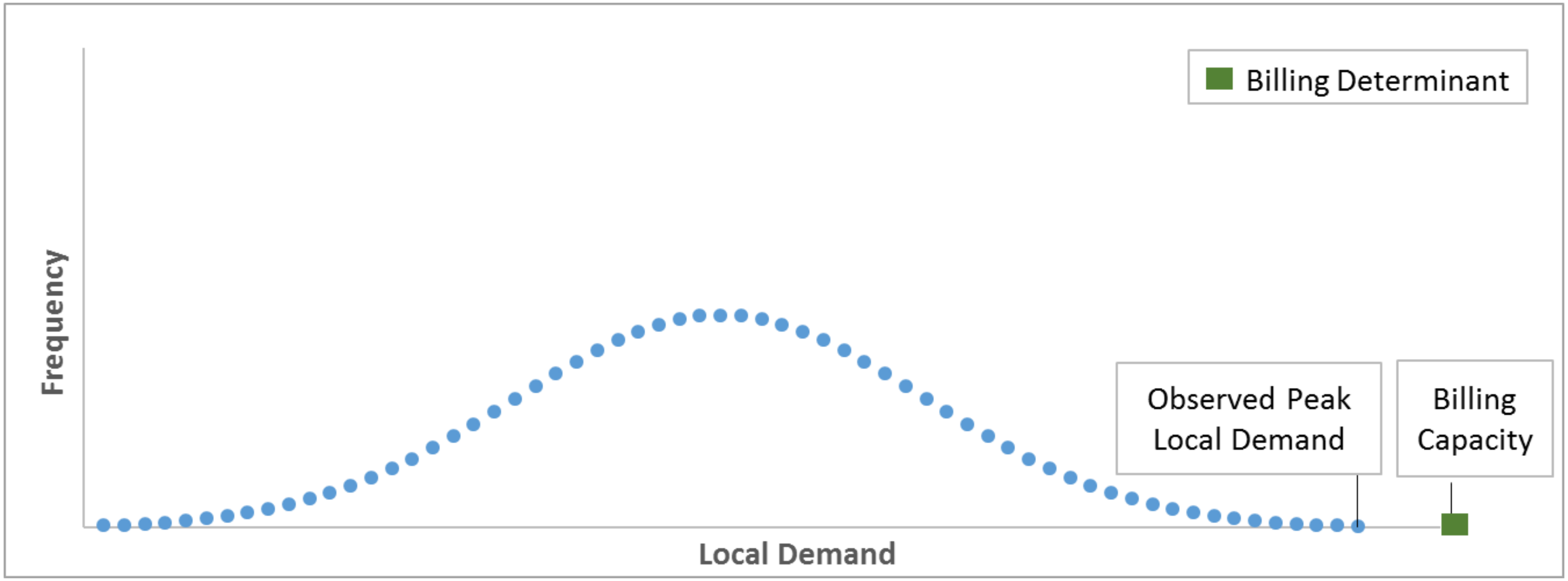
Billing Determinant Principles

- Primary cost driver is some form of an observed coincident peak
  - Need for transmission facilities is driven by peak usage
  - The more customers are using a transmission facility, the more peak usage will be influenced by diversity
- Billing capacity can be a secondary cost driver
  - Risk of peak need exceeding observed peak usage
  - AESO might plan to mitigate against this risk through incremental transmission
  - Risk reduces with the number and diversity of customers
- (Total) energy is not a cost driver for transmission
  - Facility utilization outside of the peak hour is irrelevant
  - Energy could be a cost driver for other tariff components, *e.g.* Ancillary Services costs

Point of Delivery (for Context)

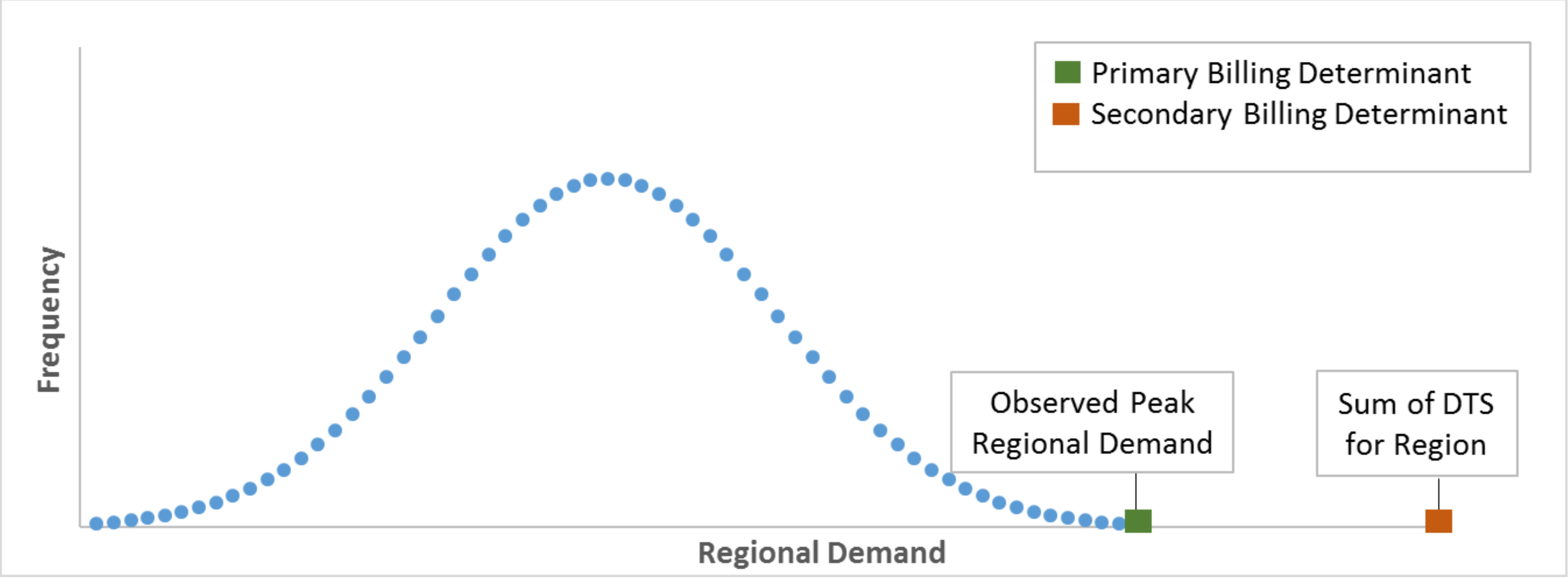
- The need for local (POD) transmission facilities is driven by a customer’s individual peak demand
  - Potentially less than its billing capacity
- High risk that transmission need is greater than indicated by the observed peak
  - Participant requested the AESO to plan for billing capacity through contracting

➢ Billing capacity is the cost driver, *i.e.* billing determinant



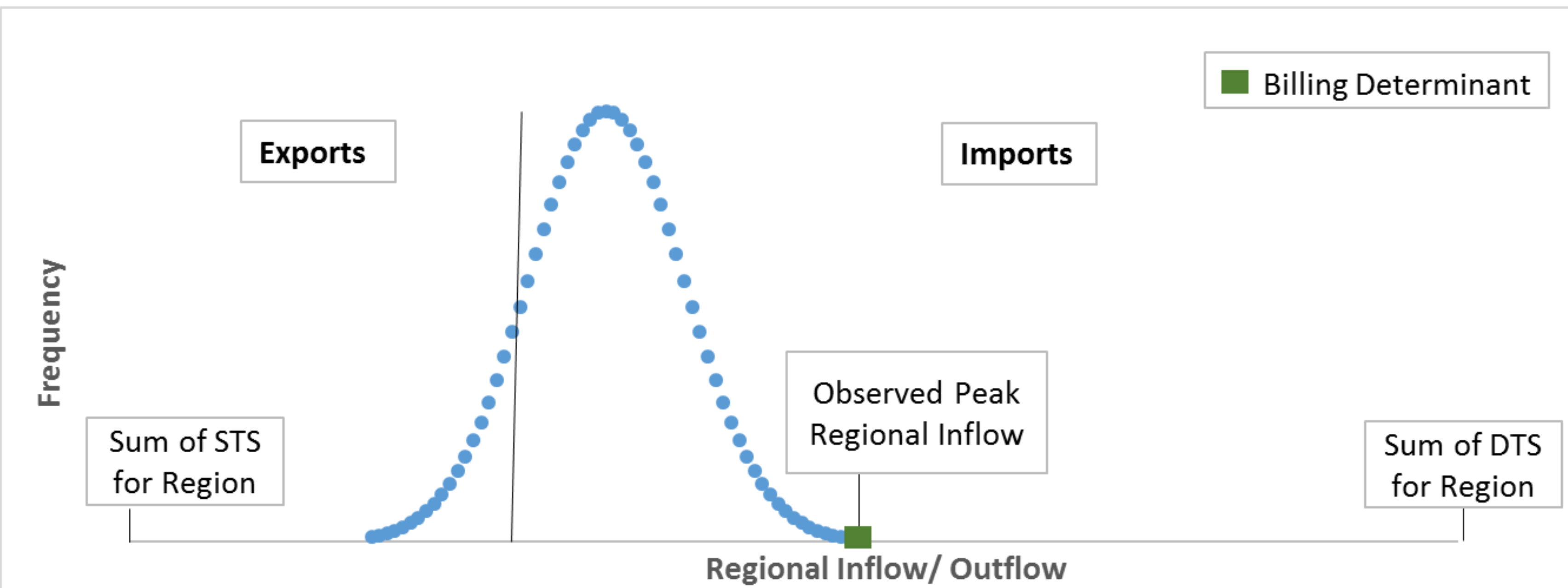
Regional Transmission

- The need for regional transmission facilities is driven by the peak demand in the region
  - Less than the sum of billing capacity
- Some risk that transmission need is greater than indicated by the observed peak
  - AESO should plan for some additional need but planning for the sum of DTS would be excessive
- Coincident regional peak demand (**CRPD**) is primary cost driver, *i.e.* primary billing determinant
- Billing capacity is secondary cost driver, *i.e.* secondary billing determinant



Bulk Transmission

- The need for bulk transmission facilities is driven by peak power inflows into regions
  - Power outflows could theoretically be used but that approach would not align with the requirement of loads paying for transmission
  - Significantly less than the sum of demand site billing capacity
- Low risk that transmission need is greater than indicated by the observed peak
  - Billing capacity does not provide a meaningful indication of need
- Coincident regional peak inflow (**CRPI**) is the cost driver, *i.e.* billing determinant



Putting it all Together

- For each billing determinant, the rate is equal to its marginal transmission cost impact
  - Goal is to estimate the cost impact as accurately as possible
  - If no better estimate is available, average cost could be used as a starting point for approximation

Charge	Billing Determinant(s)
Point of Delivery	Billing Capacity
Regional	Coincident Peak Regional Demand Billing Capacity
Bulk	Coincident Peak Regional Inflow

- Because of the mismatch between average cost and marginal cost, collected charges will not result in total costs recovery
  - Likely a shortfall but theoretically a surplus is possible
  - Section 30(2) of the *EUA* requires full recovery
- Since all causal relationships have been addressed, the remaining amount is independent of customer attributes or behaviour
  - Recovery has to therefore occur on a per customer connection basis
  - Other recovery mechanisms would send inefficient signals

Rate DTS Example Structure

Current: Level Based

Volume in Settlement Period	Charge
Bulk System Charge	
Coincident Peak Regional Inflow (CRPI)	I_b [/MW/month]
Connection	C_b [/month]
Regional System Charge	
Coincident Peak Regional Demand (CRPD)	D_r [/MW/month]
Billing Capacity	B_r [MW/month]
Connection	C_r [/month]
Point of Delivery Charge	
Billing Capacity	B_p [MW/month]
Connection	C_p [/month]

Potential: Billing Determinant Based

Volume in Settlement Period	Charge
Coincident Peak Regional Inflow (CRPI)	I_b [/MW/month]
Coincident Peak Regional Demand (CRPD)	D_r [/MW/month]
Billing Capacity	$(B_r + B_p)$ [MW/month]
Connection	$(C_b + C_r + C_p)$ [/month]

Note on the Frequency of Coincidence Measures

- Monthly assessment aligns with monthly billing
  - For CRPD, months with lower peaks could potentially be skipped
    - Different regions may have different peak profiles
  - For CRPI, all months should be used
    - Generation outages are generally placed in order to offset seasonal load patterns
- Annual assessment is an alternative that aligns with the tariff cycle
- For each assessment period, the peak hour should be used for the determination
  - Customers that want to respond, will respond in all similar hours due to uncertainty of the exact peak timing
  - Automatically results in responses for the top hours without arbitrarily cutting off relevant hours or including irrelevant hours
  - If the peak condition is not met in an assessment period, the billing determinant for all customers in the region is zero

Appendix

Responses to AESO questions from the proposal template (1)

- What tradeoffs does your proposal create between the Rate Design Objectives? Why are those tradeoffs appropriate? Is one objective more important than another? Why or why not? (Mar. 19 and Oct. 1)
  - The proposal is aligned with the requirement to provide for an efficient electricity market through fair and open competition
- Why is your proposed rate design preferable to the current tariff structure and the AESO's rate design options? (Mar. 19)
  - Regional supply/demand imbalances are a better indicator for the need for bulk transmission, which makes 12-CRPI superior to 12 CP
  - The proposed AESO tariff structure has various flaws:
    - Billing capacity has no cost causal relationship with bulk transmission costs
    - The effect of billing capacity on regional transmission costs is overstated
    - The coincident regional peak is not a driver for bulk transmission but for regional transmission
    - Assessing coincidence factors over more than one hour per assessment period is inefficient

Responses to AESO questions from the proposal template (2)

- Why is this rate design best for all Albertans? (Oct. 1)
  - The fundamental purpose of deregulation has always been efficiency – achieving more for less to the benefit of Albertans. This proposal is to date the one best aligned with this objective
- How does your proposal incorporate energy storage and what are the implications of your rate design on energy storage resources? (Oct. 1)
  - Special treatment for storage is unnecessary since the billing determinants in the proposal send the efficient cost-causation signal. Storage facilities will therefore pay charges that are appropriate for the cost they are causing

Responses to AESO questions from the proposal template (3)

- Are rate classes included in your rate proposal? Why or why not? (Mar. 19 and Oct. 1)
  - When costs are properly attributed according to cost causation, rate classes seem unnecessary (See also the following two responses)
- Are any considerations made for certain resource types, for example standby, interruptible, or energy storage? Why or why not? (Mar. 19)
  - Proper billing determinants based on cost causation efficiently reflect costs caused by different resource types
  - Rates have to work holistically with rule requirements. Relative rule advantages/disadvantages for different resources need to be balanced through the tariff

Responses to AESO questions from the proposal template (4)

- Are there additional rate design options you considered but would not support/and decided against? Explain why (Mar. 19/Oct. 1)
  - Suncor evaluated the AESO's suggestion from March to allocate costs based on energy and the AESO's March & September proposals to allocate costs based on billing capacity. These proposals provide inefficient signals and create cross subsidies between market participants
  - Suncor supports the development of accessible opportunity rates to more efficiently utilize the transmission system. These rates should reflect the incremental costs attributable to them and should be made available via market based processes

SUNCOR

Comments regarding the AESO's "rate design objectives"

- In the Mar. 19 guidelines, the AESO asked how the proposal meet each rate design objective and what are the tradeoffs relative to the rate design objectives. The listed objectives were:
  - Effective long term price signals
  - Facilitate innovation and flexibility
  - Reflect accurate costs of grid connection and services
  - Explore options within legislation and regulation
  - Path to change that is effective and minimally disruptive
- In the Oct. 1 guidelines, the same question was asked around similar, yet different objectives:
  - Reflect cost responsibility
  - Efficient price signals
  - Minimal disruption
  - Simplicity
  - Innovation and flexibility
- The Oct. 1 guidelines also states that the proposed rate design must fit within current legislation

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“Nice to Have” Objectives

- As stated previously, the legislative objective is efficiency based on fair and open competition
- Any other objectives are at most “Nice to Have”
  - Evaluation can be informative
  - Evaluation can only impact the choice of design if the alternatives meet the legislative objective equally well
- For information only, the following slide shows how Suncor’s proposal fares with regard to the Oct. 1 “Nice to Have” objectives

SUNCOR

Assessment against “Nice to Have” Objectives

“Objective”	AA	Comment
Reflect Cost Responsibility		The proposal reflects cost causation to the extent possible. Remaining cost recovery occurs equally from all customers connected to the system without sending inefficient signals
Efficient Price Signals		The proposal reflects cost causation to the extent possible. Remaining cost recovery occurs equally from all customers connected to the system without sending inefficient signals
Minimal Disruption		Since the 12-CPRI signal is a refinement of the 12-CP signal, customer tools and investments maintain their usefulness
Simplicity		While forecasting CRPI and CRPD requires more information, it is not necessarily more difficult. The AESO needs to provide additional information and customers need to change their analytics or contract for third party services
Innovation and Flexibility		Clear cost causation signals incentivize customers to look for efficient ways to lower costs. “Provide new avenues/incentive for both load and generation” For example, a consumer might contract with regional generators to align outages