Energy Storage Industry Learnings Forum
Workshop 3

March 19, 2021

Agenda

- Welcome and introduction
- Topic 1: Economic Modeling
  - Paula McGarrigle
  - Robert Stewart
  - Travis Lusney
- Topic 1 Discussion
- Break
- Topic 2: Sharing of experiences in commissioning and testing of new technologies or configurations
  - Hesam Yazdanpanahi
  - Laura Oosterbaan
- Topic 2 Discussion

Agenda

- Topic 3: Process efficiencies within our existing framework
  - Hao Liu
- Topic 3 Discussion
- Wrap up and next steps

Welcome and introduction

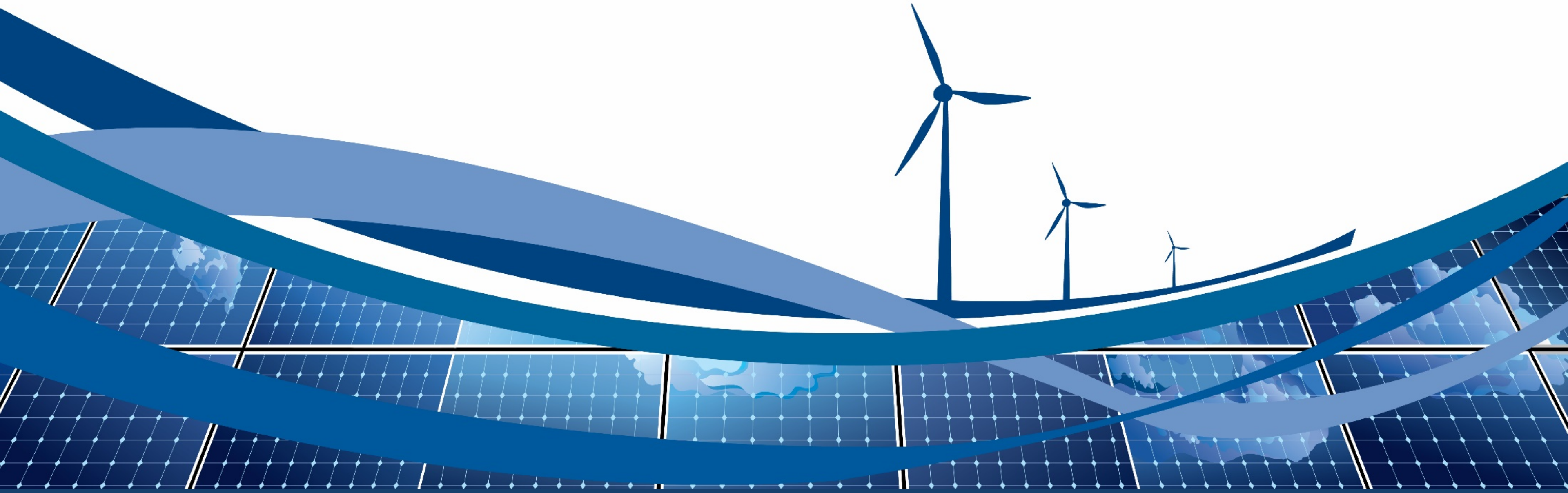
- Welcome
- Introduction

AESO Stakeholder Engagement Framework

ESILF transparency

- The ESILF recognizes not all of the AESO's stakeholders will be represented within the ESILF and to support the AESO's commitment to transparency, the following will be posted on the AESO website on www.aeso.ca:
  - Forum membership
  - Agendas
  - AESO or member presentations
  - Relevant discussion materials
  - Meeting summaries

Topic 1: Economic Modeling



ENERGY STORAGE ECONOMICS

16 March 2021

Presentation to ESLIF

Outline

- Update on BESS – US project
- Economic evaluation of BESS - Alberta

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Worlds largest PV + BESS

California

- The project consists of 1,118 megawatts of solar and 2,165 megawatt-hours of energy storage.
- Largest single solar and battery energy storage project to reach this milestone.
- Site construction will commence in Q1 2021 with expected completion in Q4 2022.

Solas' largest BESS project

- It is likely also the most complicated due to the inclusion of both AC- and DC-coupled BESS using battery modules from two different OEM suppliers both in front and behind the meter configurations coupled with 1,000 MW of PV generation, and supported by multiple substations, a switchyard and an HV transmission line.
- The project also includes a stand-alone grid charged AC-coupled BESS.
- Solas developed the EPC RFPs for the solar plus storage and the HV scope, bid the projects, assisted in the contract negotiations, and was deeply embedded in the development of the design basis, scope of work (SOW), commissioning and testing protocols, and completion certification process.
- We are continuing to support the project with project engineering and project management.

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BESS Economics

2021-05-20

Executive Summary

- Alberta's proposed tariff structure has a negative impact on BESS deployment
- Other regimes are more attractive for BESS

Case Options - Alberta

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		

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Case 1A: BESS ON GRID

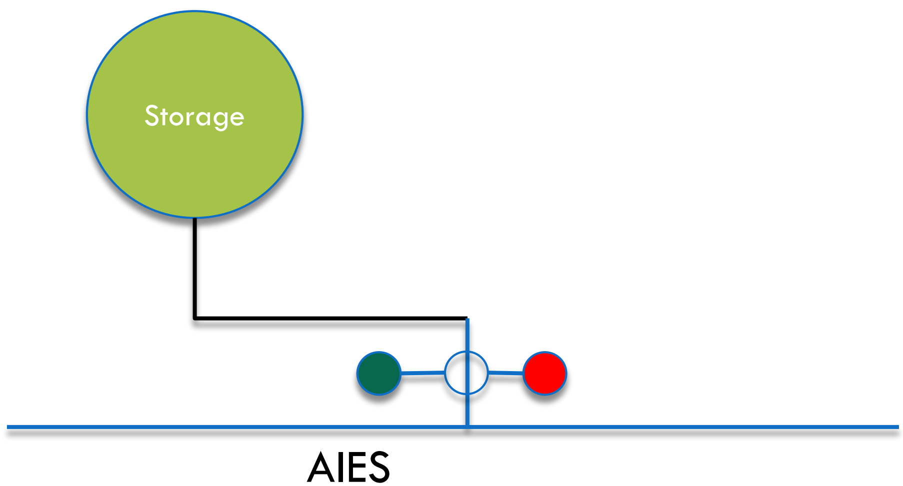
Generation	None	Wind	Solar		
Storage Location	At Generation	On Grid	At Customer		
Storage Timing	Standard	Perfect Forecast	Charge during historical average low hours (HE 2,3,4,5) Discharge during historical average high hours (HE 15,16,17,18)		
Substation Fraction	1.0	0.5	0.1		
Tariff Type	Current	FERC 841	Interruptible		
Region	NW	NE	Edmonton	Central	Calgary	South
Peak	12 CP	Regional 120 CP	System 120 - CP	System- Weekly CP	

Order 841 states that barriers to distributed and behind-the-meter energy storage participating in wholesale electricity markets should be removed. FERC passed the bipartisan rules in February 2018 after a lengthy process that began with it being tabled in 2016, ordering regional transmission operators (RTOs) and independent system operators (ISOs) to reconfigure wholesale markets to accommodate storage resources to allow them to provide capacity, energy and ancillary services.

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

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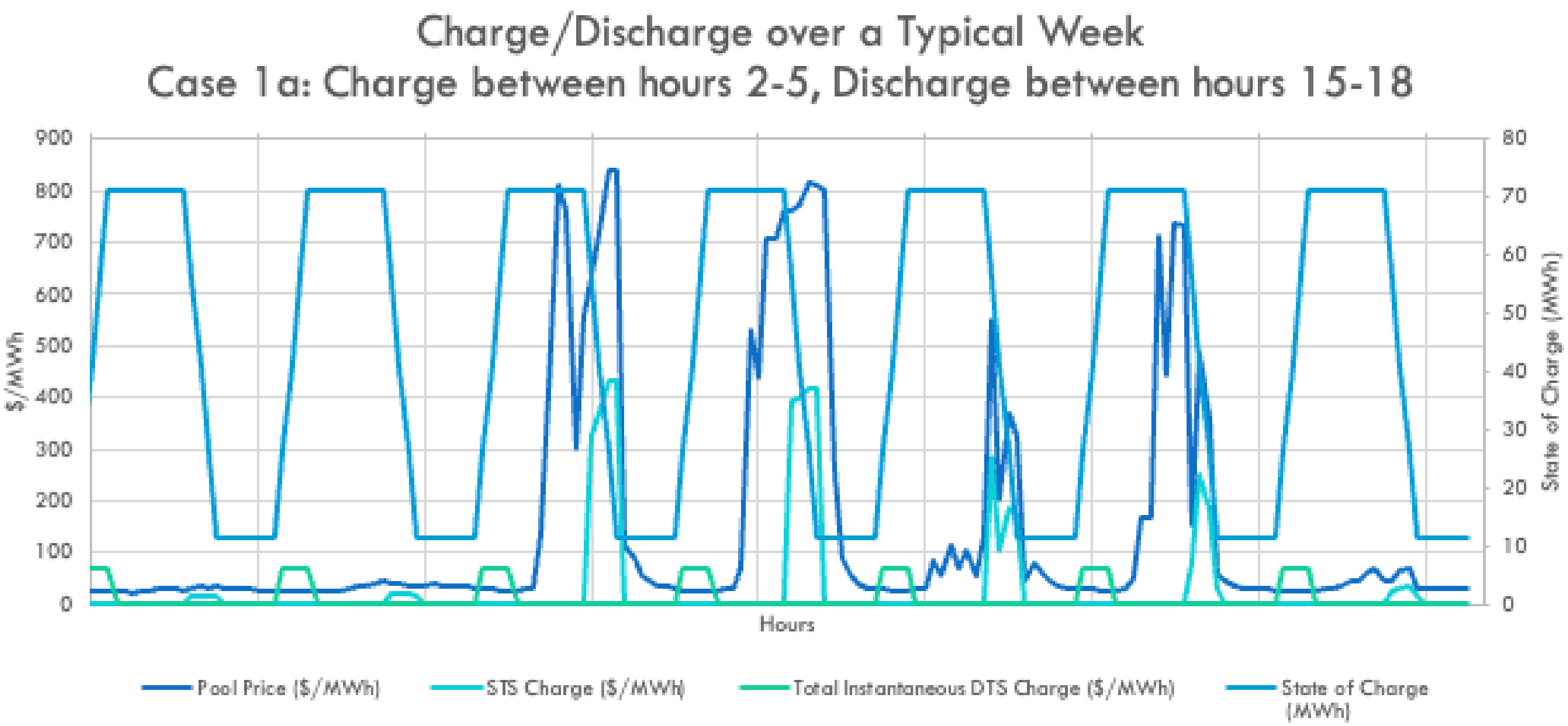
Case 1a: Production Profile & Costs



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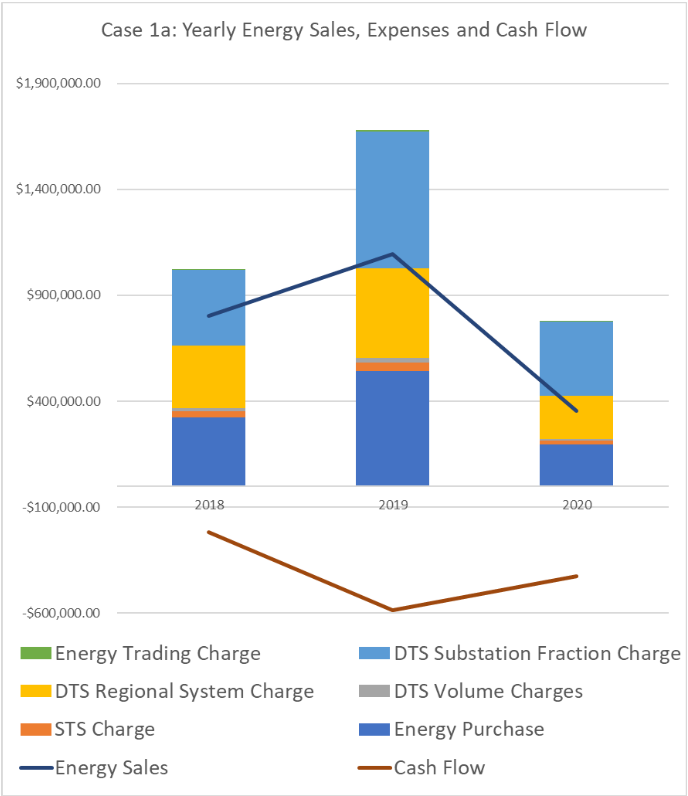
Case 1a: Current Tariff is cost prohibitive for Standalone BESS



- 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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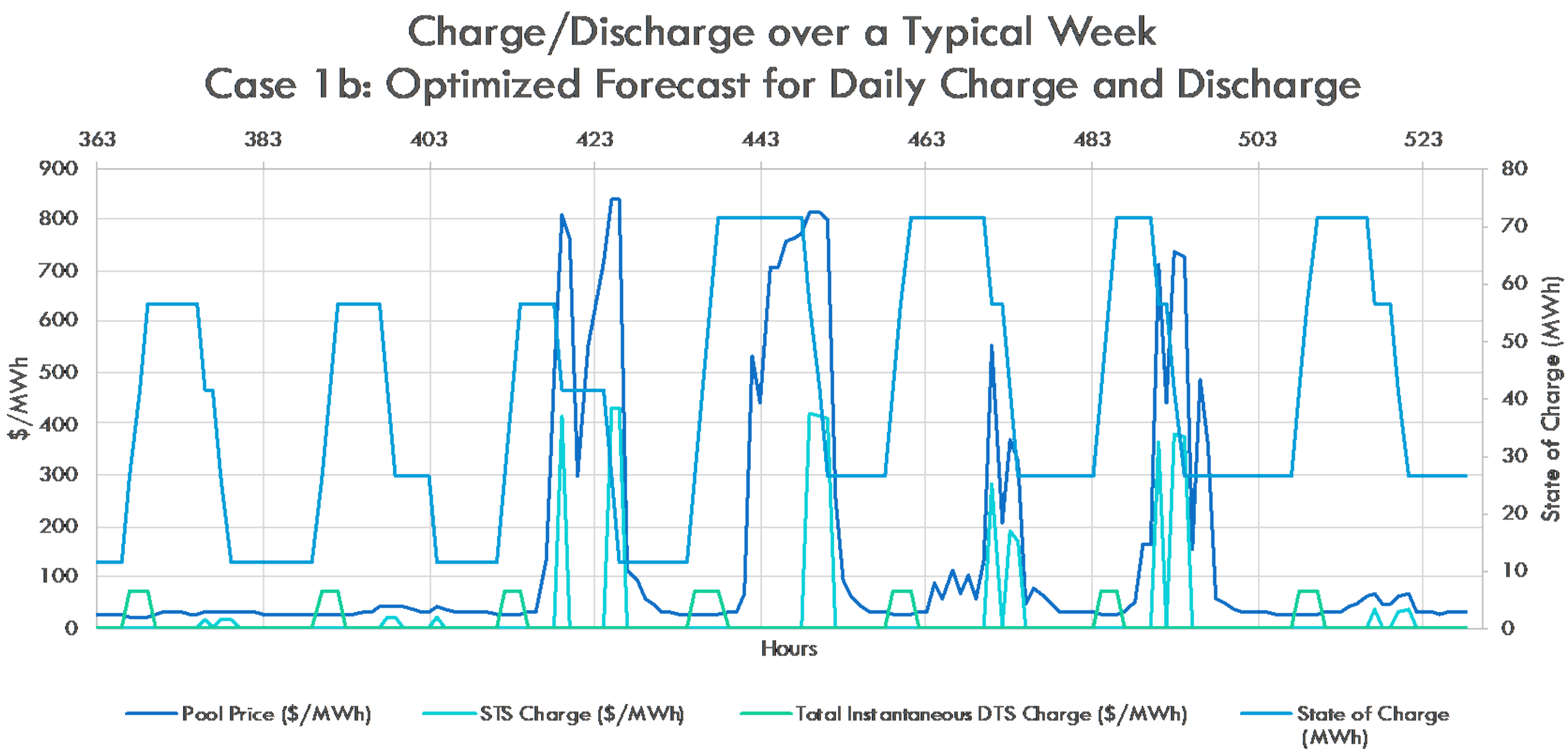
Case 1B: BESS ON GRID – Perfect Forecast

THIS ONE CHANGED FROM CASE 1A to 1B

Generation	None	Wind	Solar			
Storage Location	At Generation	On Grid	At Customer			
Storage Timing	Standard	Perfect Forecast	Charge during the lowest hours, discharge during highest hours			
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 1b: Production Profile & Costs



2021-05-20

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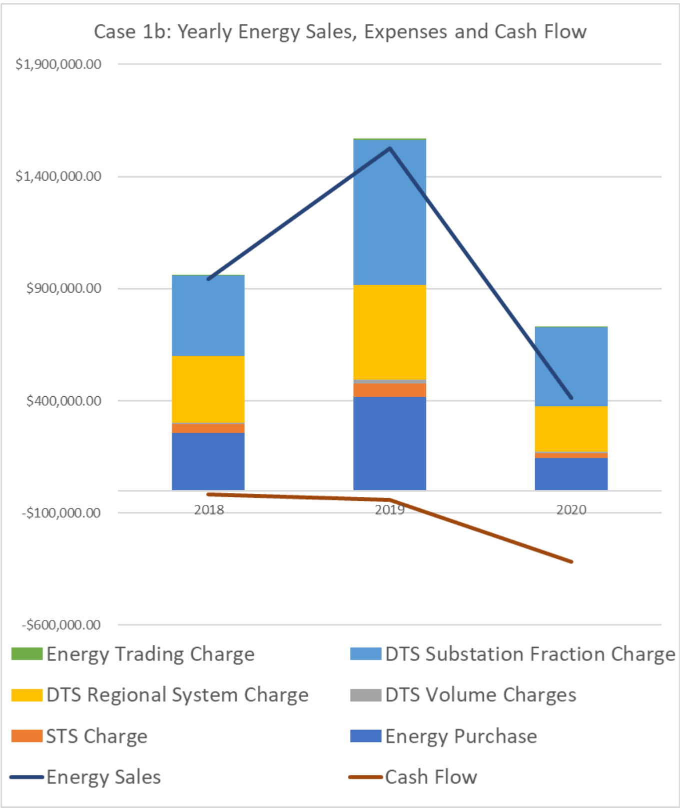
Case 1B: Perfect foresight is insufficient to make BESS economic.



- 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

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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?

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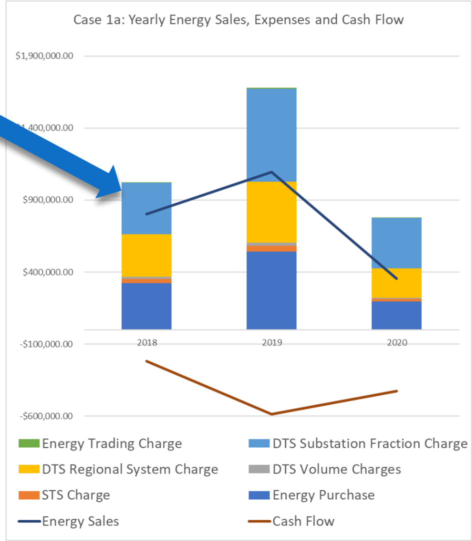
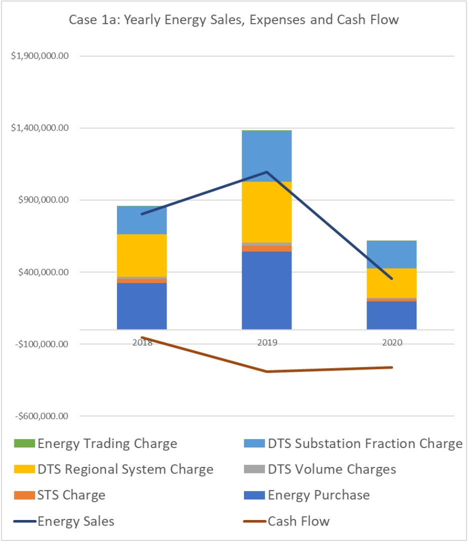
Massive DTS substation fraction costs push BESS locations to substations with other generators/loads (urban/industrial). But still uneconomic!

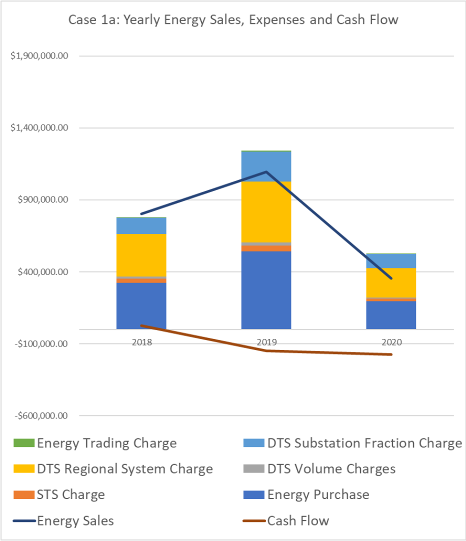
Current tariffs

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







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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)

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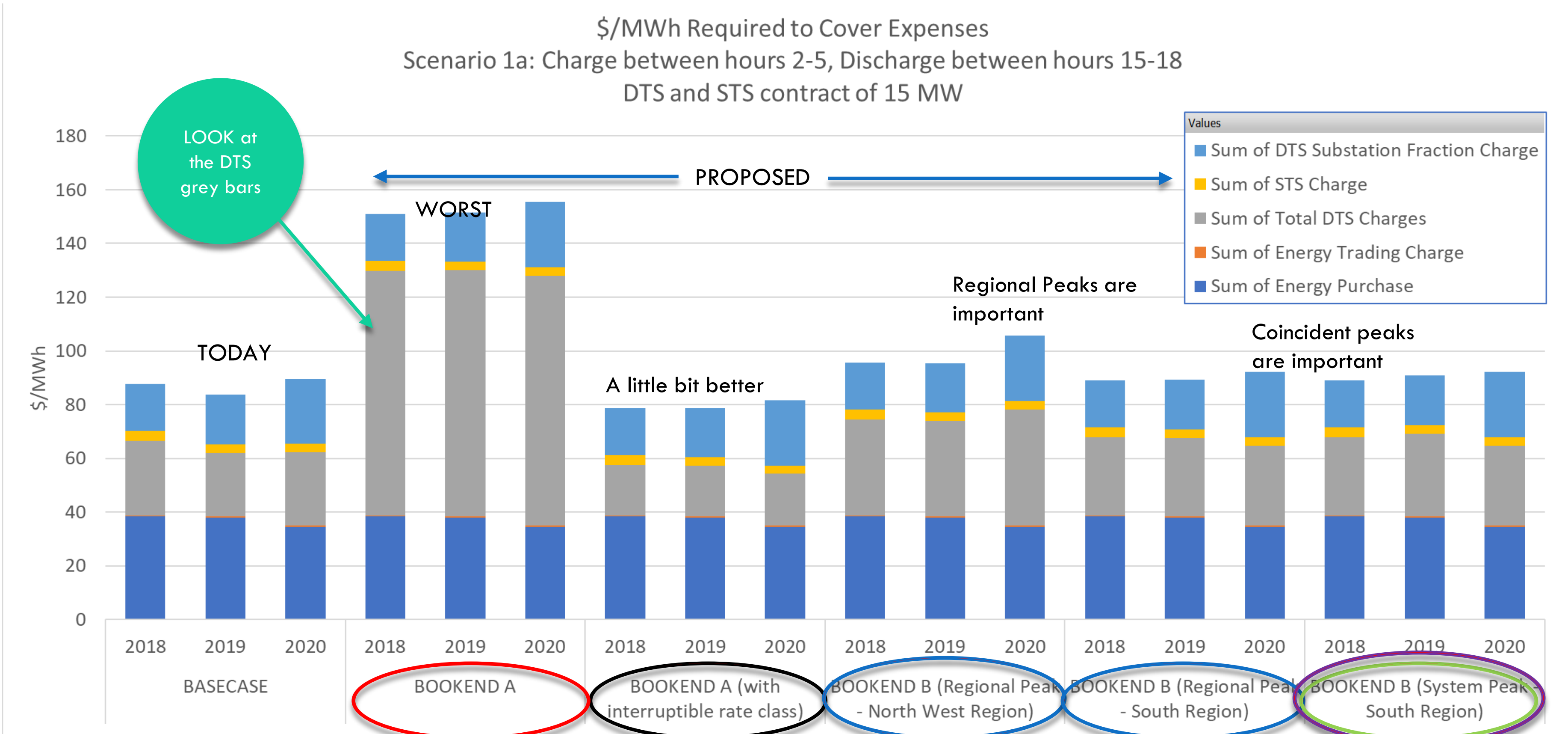
Impact of AESO Tariff Cases



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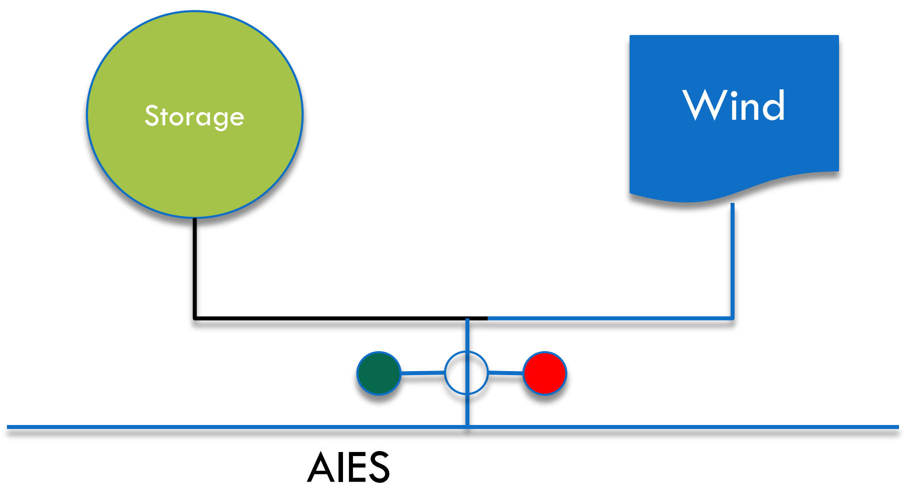
CASE 2A

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

Tariff: Current Tariff



Physical Meter

Measurement Point

Dispatch Point

Case Details:

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

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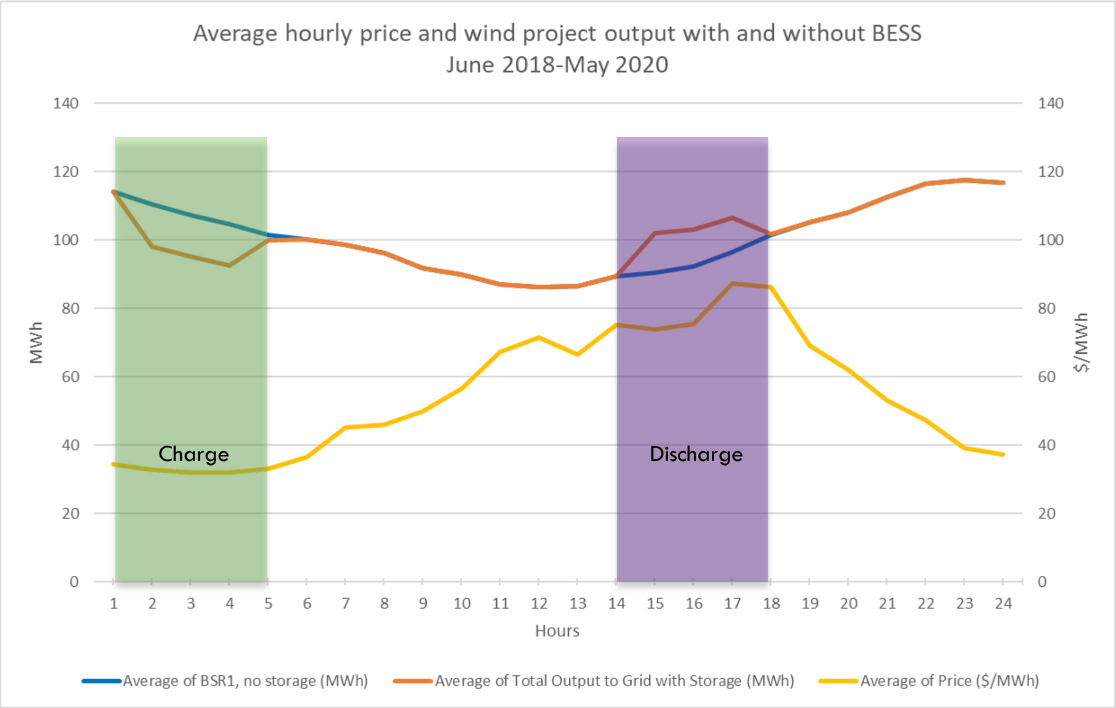
Case 2a: BESS improves revenue, but not sufficient for positive economics. Hybrid BESS has better, but insufficient, economics than standalone BESS.



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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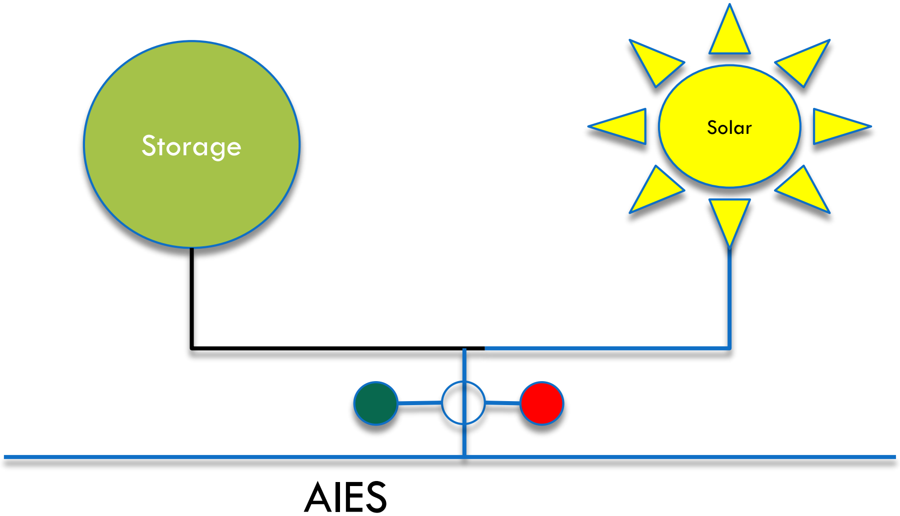
CASE 3A

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

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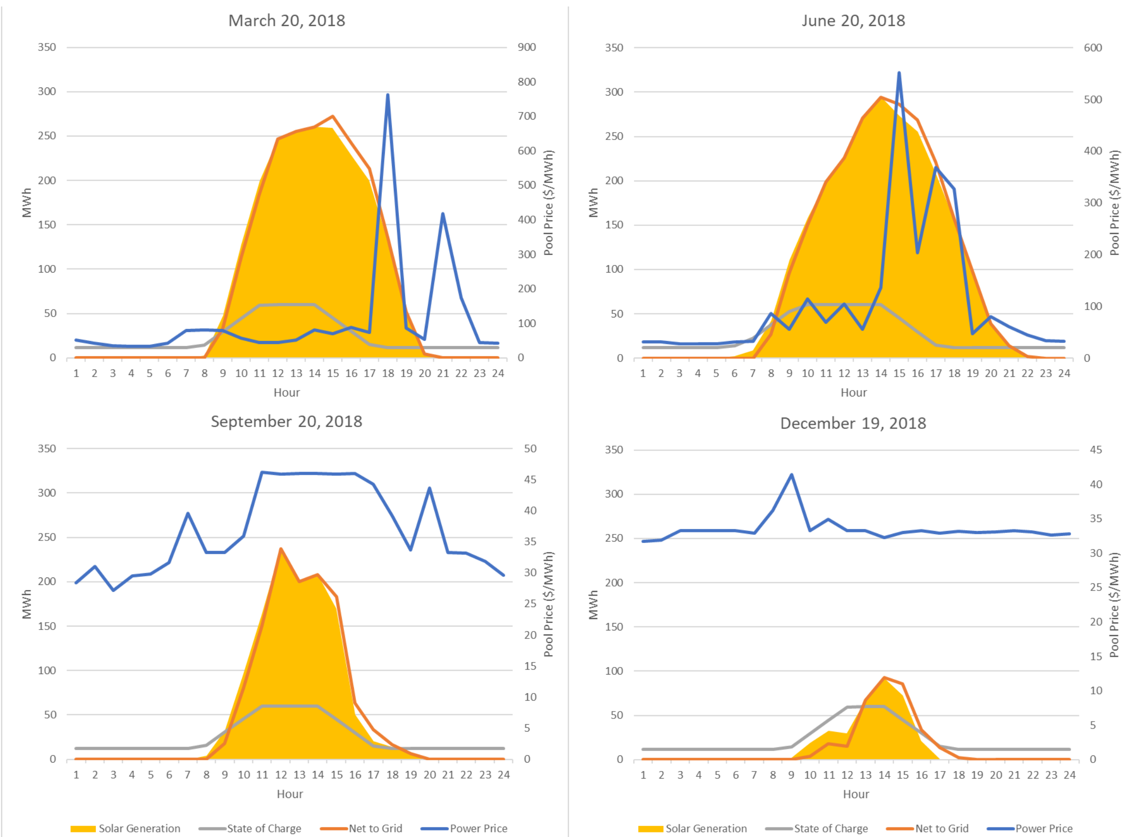
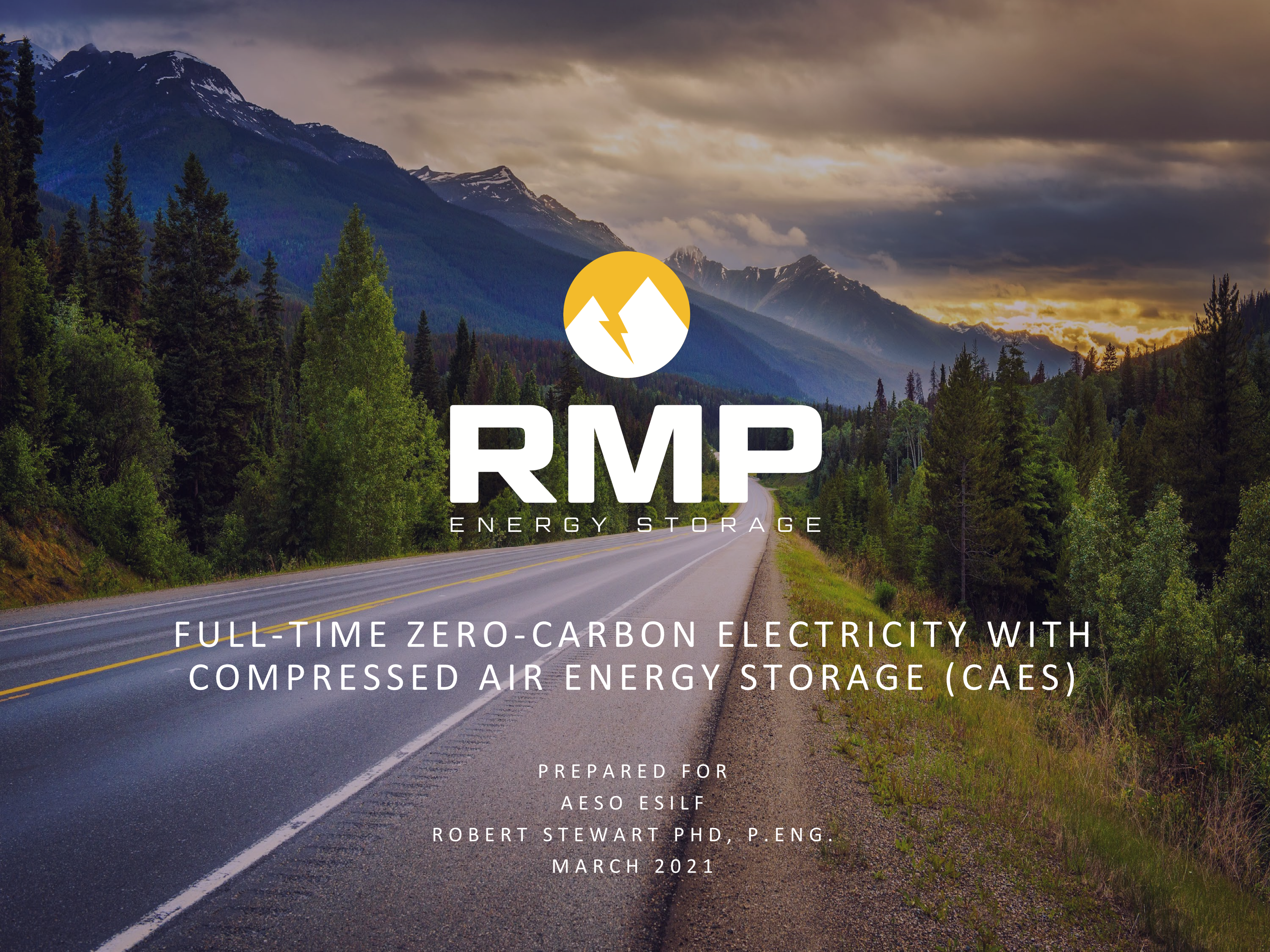
Case 3a: BESS improves revenue, but not sufficient for positive economics. Hybrid BESS has better, but insufficient, economics than standalone BESS.



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



RMP
ENERGY STORAGE

FULL-TIME ZERO-CARBON ELECTRICITY WITH COMPRESSED AIR ENERGY STORAGE (CAES)

PREPARED FOR
AESO ESILF
ROBERT STEWART PHD, P.ENG.
MARCH 2021

HIGHLIGHTS

Compressed Air Energy Storage (CAES)

Low cost and emissions dispatchable power - 80% lower emissions and competitive price with CCGT using CAES + wind generation in Western Canada with opportunity for ZERO emissions

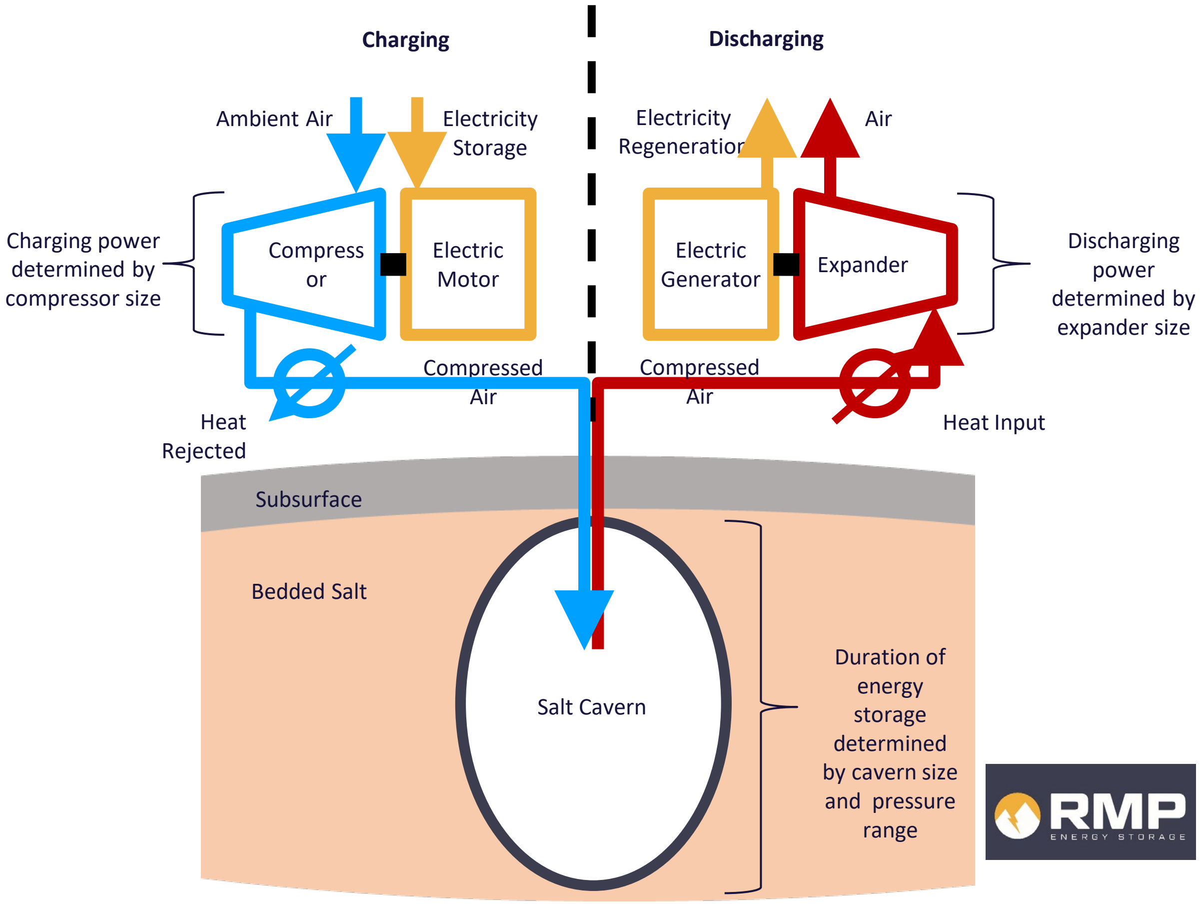
Jobs - Hundreds of jobs for skilled workers (oilfield drillers, pipefitters, welders, electricians, geologists, engineers, etc.)

RMP Energy Storage is an energy storage project developer with over 8 years focus on CAES in SK and AB

- CAES is a proven technology
- >15 x duration capacity for same capital cost as Li-Ion
- SK and AB have the world's best and known geology
- Expertise required can be transitioned from O&G

Current DTS Tariff creates financial risk that prevents this opportunity from being deployed in Alberta

HOW CAES WORKS

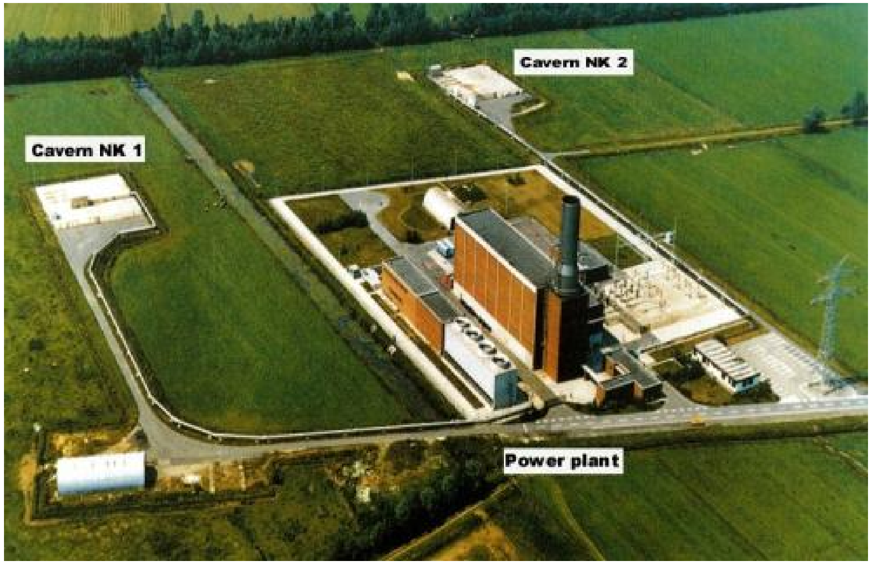


- Synchronous machines
- High ramp rate

Heating can be done in two ways:

1. Diabatic CAES (DCAES), which uses natural gas to produce heat, or
2. Adiabatic CAES (ACAES), which uses captured heat generated as a bi-product of the compression process.

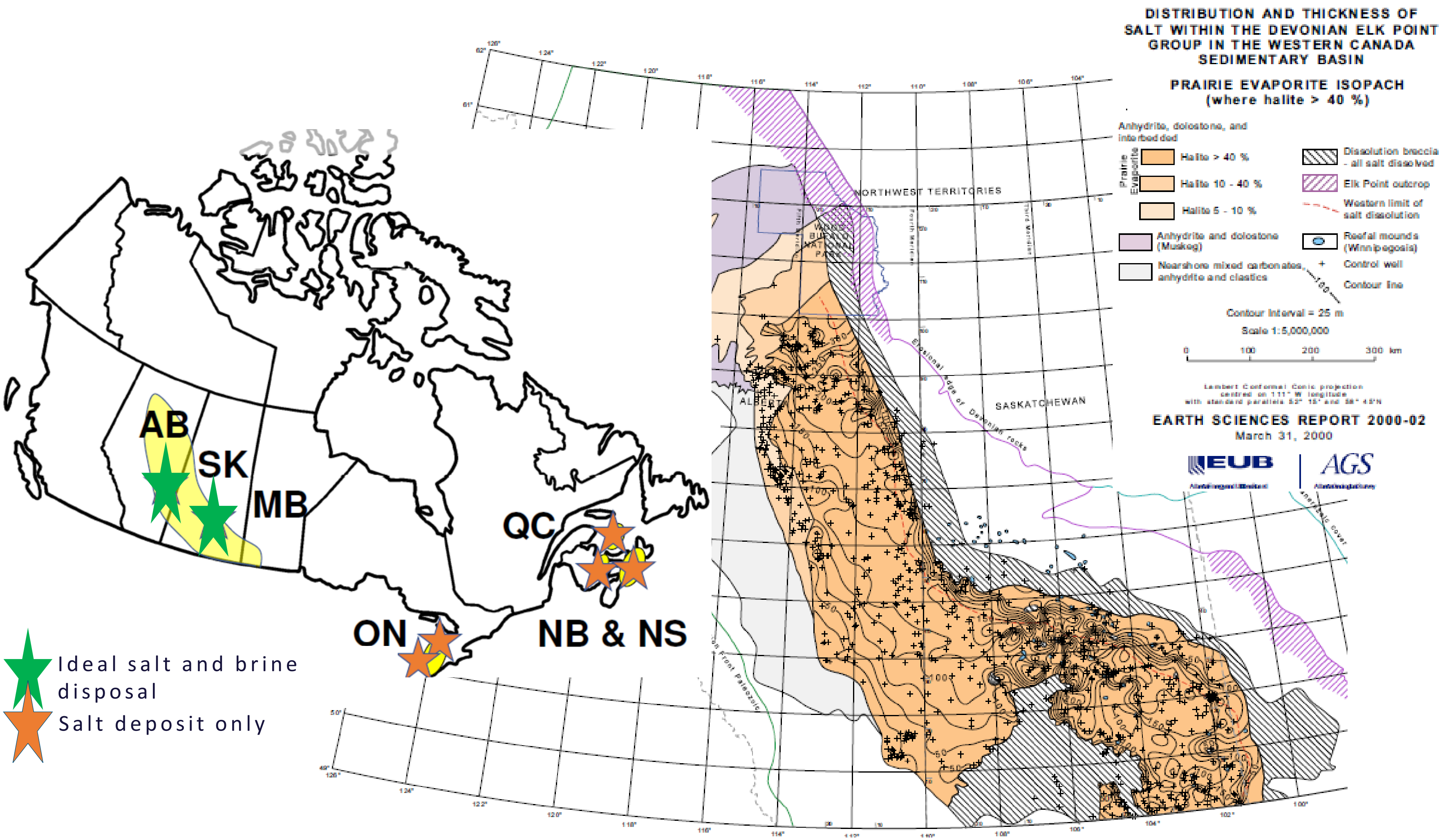
HISTORY



290MW CAES Huntorf Germany
Commissioned 1978
Still operating and
Considering expansion

110MW CAES McIntosh
Alabama
Commissioned 1991
Still operating

RESOURCE



AB
SK
MB
QC
ON
NB & NS
Ideal salt and brine disposal
Salt deposit only
DISTRIBUTION AND THICKNESS OF SALT WITHIN THE DEVONIAN ELK POINT GROUP IN THE WESTERN CANADA SEDIMENTARY BASIN
PRAIRIE EVAPORITE ISOPACH (where halite > 40 %)
Anhydrite, dolostone, and interbedded
Prairie Evaporite
Halite > 40 %
Halite 10 - 40 %
Halite 5 - 10 %
Anhydrite and dolostone (Muskeg)
Nearshore mixed carbonates, anhydrite and clastics
Dissolution breccia - all salt dissolved
Elk Point outcrop
Western limit of salt dissolution
Reefal mounds (Winnipegosis)
Control well
Contour line
Contour Interval = 25 m
Scale 1:5,000,000
0 100 200 300 km
EARTH SCIENCES REPORT 2000-02
March 31, 2000
EUB
AGS
NORTHWEST TERRITORIES
ALBERTA
SASKATCHEWAN

BOOK END ANALYSIS

Significant market based modeling has been completed proving CAES operation in Alberta is economic with historical prices.

Question remained of how much storage is required. Shows how competitive in the future ES+VRE is with alternatives.

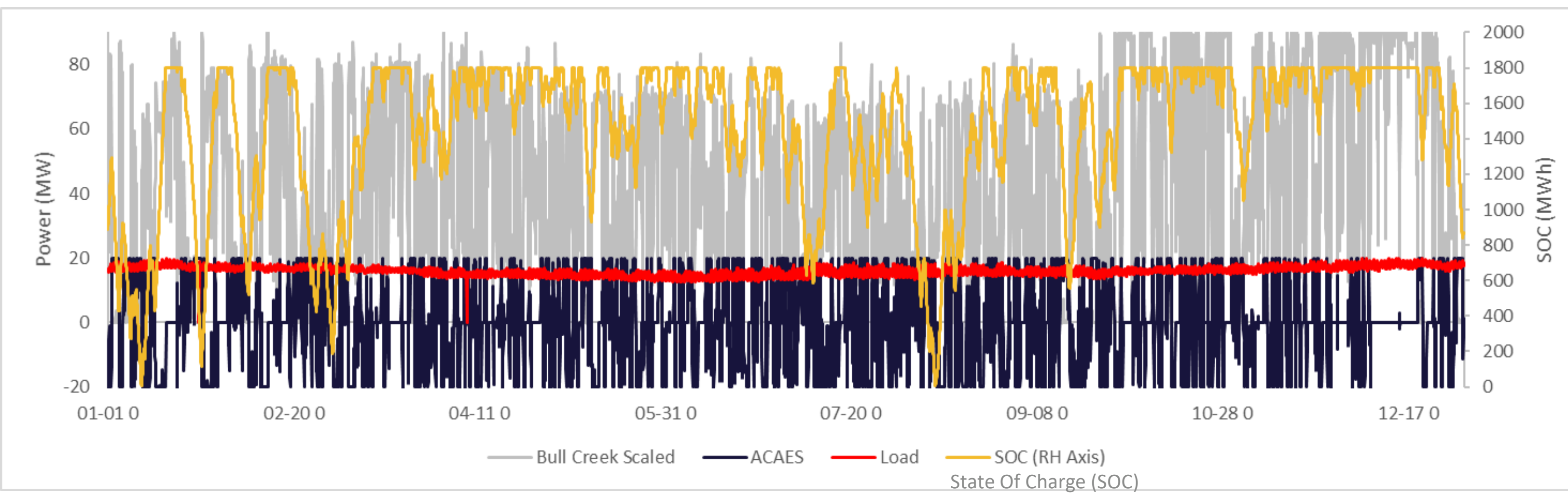
Meet load with wind energy 24/7/365 using storage to understand what a 100% renewable system would require. This could also be a firm renewable product within the current system.

- Use historical hourly load and wind generation data
- Model DCAES, ACAES and Li-Ion operation to enable wind to meet load
- Compare additional wind to additional storage duration
- Determine levelized cost of system and compare

LONG DURATION NEEDED

- Lower wind periods are weeks long meaning long duration storage is required
- Event duration driving storage selection, higher efficiency doesn't significantly help
- E.g. if wind is not generating for 24 hours then you need 24 hours duration and it doesn't matter how you got that energy.
- Much lower cost of additional duration for CAES resulting in it providing the service

One year CAES + wind to fully supply load



ECONOMICS

Possible TODAY

Storage Technology (efficiency)	Baseline $45/MWh, $2.5/GJ	Wind $30/MWh	Gas $5.31/GJ	Carbon Emissions (tCO_2/MWh)
	Price per MWh delivered			
DCAES (145% output vs. input)	89	70	92	0.06
ACAES (65%)	133	103		0
Li-Ion (90%)	594	540		0
BC Site C Hydro (@$10.8B now $16B)	82-112			0
ON Nuclear Refurbishment	80.7 – 87.9			0
New Combined Cycle Gas Turbine	49.4		97.5	0.325

80% lower emissions than CCGT

- Modeled to meet load 24/7/365 with wind and DCAES
- Carbon price, tariff and ancillary services not included
- At $170/tCO_2$, CCNG cost increases to $104-$153/MWh and DCAES + Wind increases to $99-102/MWh

HURDLES

- In Alberta, energy storage currently pays consumption tariff (DTS) when charging from the grid the same as a non-dispatchable firm load customer.
- AESO needs an interruptible opportunity rate for Energy Storage to enable fair competition and value of energy storage to be realized in AB.
  - Shedding interruptible sink is faster and cheaper than a fast ramping product or current AS
- Financial risk of hitting a CP12 event renders storage uneconomic. This is a market design issue that prevents ES technology from competing fairly making the market biased.
  - CP12 at ~$10k/MW/month is more than potential monthly arbitrage revenue in 2018/19 with a 60 hour duration storage asset
- Option to bid charging price increases risk to storage operator if still under CP12

ASISt PROJECT

Alberta Saskatchewan Intertie and Storage

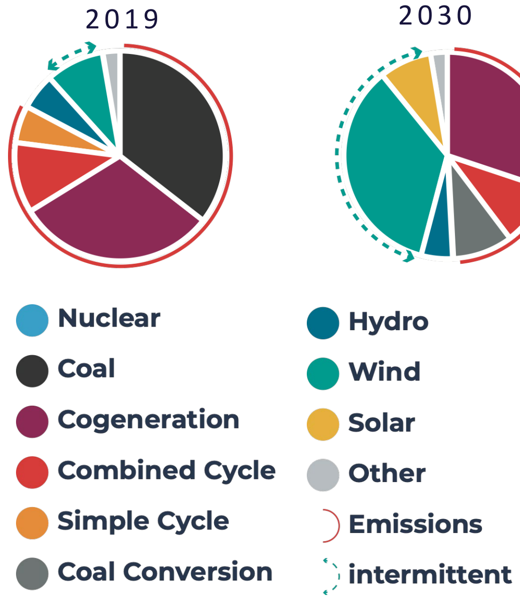
RMP's first CAES project under development at Lloydminster

- Virtual Intertie between SK and AB.
- Size – 300MW of generation capability.
- Duration up to 60 hours (18 GWh). Supply Saskatoon peak load (200MW) for 3.5 to 4 days.
- Geology – Well known Prairie Evaporite, depth to top of salt circa 1000m, salt thickness circa 142m
- Capex – ~$720MM
- Jobs - Hundreds of jobs for skilled workers (oilfield drillers, pipefitters, welders, electricians, geologists, engineers, etc.)
- FEED can be leveraged on multiple other projects through design one build many methodology

CONCLUSIONS

- Technology available and suitable for Western Canada can meet load demand 24/7/365 using wind energy with 80% lower emissions than CCGT
- CAES is ideally suited to Western Canada due to workforce skills, proven geology, and wind generation
- Many projects could be interconnected with existing grid to support wind generation in replacing coal
- Opportunity for significant VRE generation with widely dispersed economic benefits
- Become global leaders in burgeoning energy storage space by building off oil and gas history

Alberta



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rmpenergystorage.com

BACK UP

The following slides were previously shared through the AESO 2020 Bulk and Regional Tariff Design stakeholder process.

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

INTERRUPTIBLE TARIFF

2018									
Case	**8**			**9**			**10**		
Region	**5**			**3**			**6**		
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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

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%

Carbon policy impacts for storage in Alberta’s electricity market

March 19, 2021

Power Advisory LLC

www.poweradvisoryllc.com

Prepared for AESO ESILF

Progress Meeting

- Prepared the following high-level analysis on the implications of the Canadian Government's new climate action plan (i.e., $170/tonne) and the impact on storage in the AB electricity sector.

- Key Take-Aways
  - The impact of carbon allowance levels on storage economics is complex
  - Large uptake of renewables expected if new climate action plan is implemented; renewable energy spill is key hurdle
  - Current carbon allowance policy severely limits the value of storage (i.e., grid-connected) capturing potential renewable spilled

Energy Storage Industry Learning Forum

March 19, 2021

Travis Lusney, Manager of Procurement & Power Systems

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Power Advisory LLC

Canada plans significant increase in carbon pricing

- The federal government plans to increase the carbon price by $15/tonne per year starting in 2023 rising to $170/tonne in 2030.
- Currently, the price of carbon is $40/tonne in AB. Under the federal Greenhouse Gas Pollution Pricing Act (“GGPPA”), the price of carbon increases $10/tonne every year until 2022, when the price will be $50/tonne.
- Alberta has confirmed it will increase the Technology Innovation and Emissions Reduction (TIER) regulation rate to $40/tonne in 2021; but has not formally confirmed anything beyond that date.
  - TIER establishes a carbon offset allowance of 0.37 t/MWh (“current policy”) allowing fossil generation units to not have to pass the entire carbon price into electricity supply offers.
- Of note for the electricity sector, 2030 electricity emissions are modeled at 11 MT for Canada (emissions after plan), which is well below actual emissions for Alberta in 2020 (~35 MT for grid electricity)

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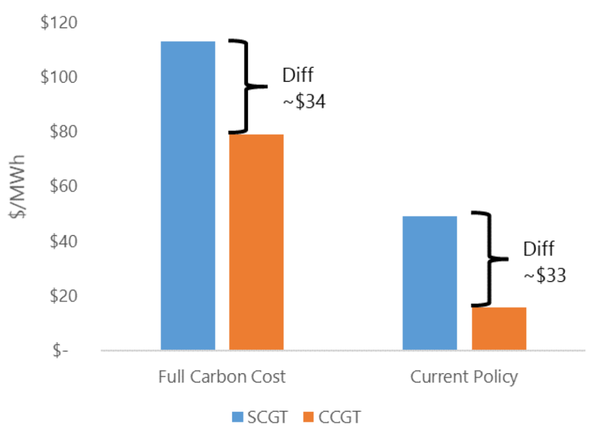
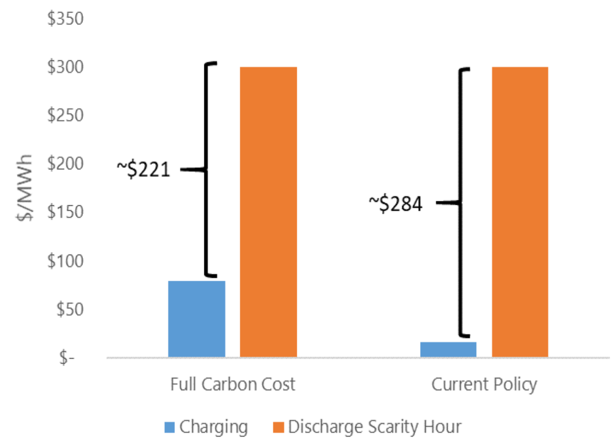
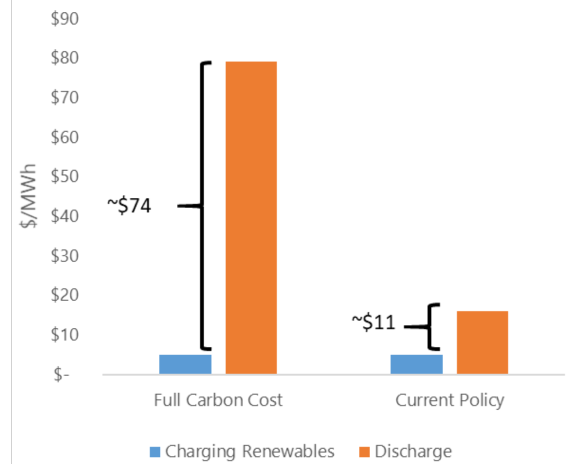
Impact of carbon policy on storage value

- The arbitrage opportunity for storage is impacted both positively and negatively by carbon policy







Situation 1: Common Arbitrage

- The spread between CCGT & SCGT is not impacted
- High carbon price benefits storage but **full carbon cost has practically no impact**

Situation 2: Scarcity Hour

- Value captured during scarcity hour does not change due to allowance policy
- *Charging* during 'gas on the margin' hours **negatively impacted by full carbon cost**

Situation 3: Renewables Charging

- Value captured during low price hours does not change due to allowance policy
- *Discharging* during 'gas on the margin' hours **positively impacted by full carbon cost**

The impact of carbon allowance levels on storage economics is not a simple one-way answer. Storage assets both gain and lose as the allowance level is changed.

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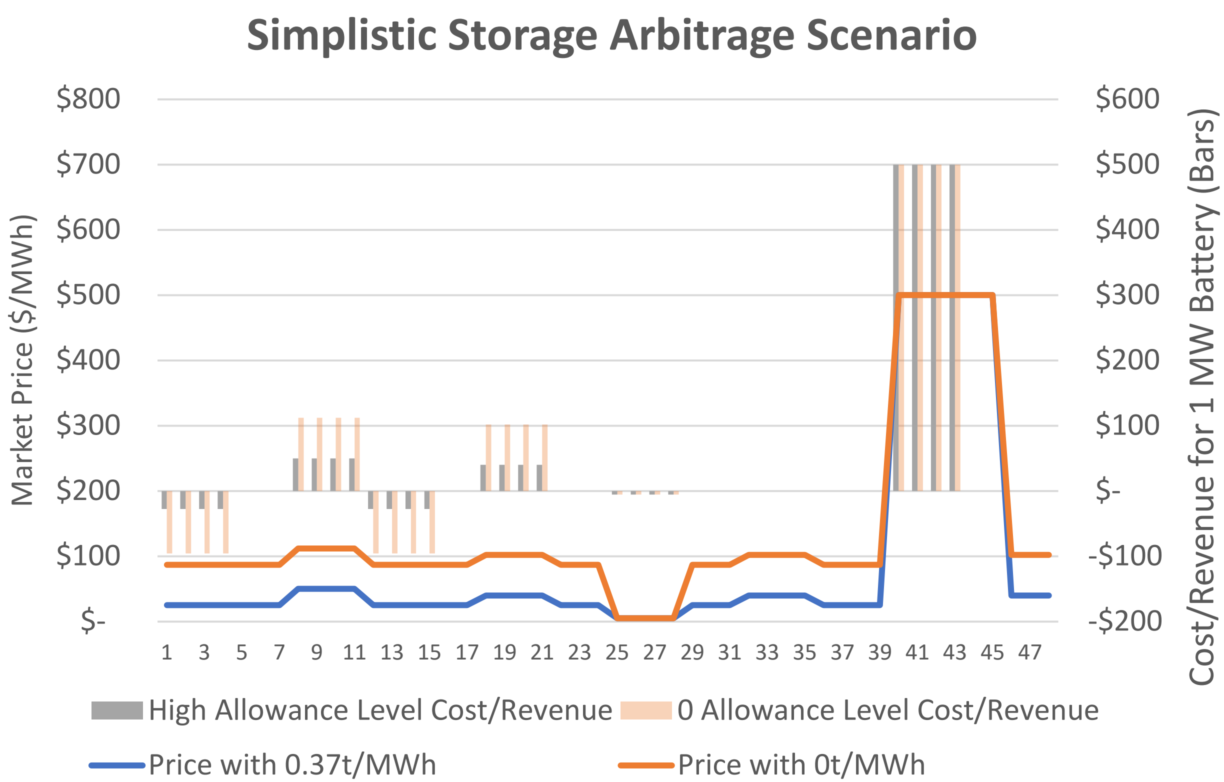
Impact of carbon policy on storage value



Source: Power Advisory

- The graphic illustrates two days of storage operation under carbon policy with 0.37t/MWh allowance and 0t/MWh allowance
- The lines illustrate market prices with natural gas setting the price most of the hours and one low priced excursion and one high priced excursion
- In this simplistic example the profits are nearly identical for the storage facility under both policy scenarios.

Impact of carbon policy on storage value

- Overall storage results are not overly sensitive to the carbon policy choice in the modeling.
  - There is a small benefit (<10% gross margin impact) to storage from scenarios with no carbon allowance but this result varies with the frequency of over-supply relative to scarcity.

- Storage is modeled as capturing price arbitrage, but it also adds value by avoiding renewable energy spill and thereby displacing emitting generation in subsequent periods.

- This zero-emission energy raises policy considerations; for example, if a credit policy is maintained under what scenarios should storage create an emission credit (such as an offset or EPC)?

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Emission Policy Considerations for Storage

Hybrid Site

- Storage charged directly by renewable energy
- If metered separately credits cannot be justified as there would be double counting, i.e. the renewable generation is already metered and credited
- If at a single meter credits should accrue to the metering point and the storage treated as de facto renewable
- For example, a storage device capturing energy behind the inverter at a solar facility is storing energy that would otherwise be spilled – it is appropriate to credit as though the stored energy was coming directly

Emission Policy Considerations for Storage

Grid Storage; stand-alone or separately metered hybrids

- Grid storage is challenging to define credits as credits should only be allocated where the energy would otherwise be spilled but the credits from not spilling will already accrue to the renewable facilities that would otherwise have been curtailed
- Transferring credits to storage in this scenario is challenging logistically
- For example, under supply surplus renewables would be curtailed but storage allows the production to occur. The renewables will receive offsets or EPCs and therefore the storage cannot create credits without double counting
- Three potential solutions
  - No carbon allowance: Carbon policy that does not have allowances and therefore no credits/offsets
  - Market-based: Negative pricing could resolve the issue as value of production will be transferred to storage charging during negative priced hours
  - Bi-lateral agreements: Storage and renewables could enter agreements to charge when spill is expected and share credits created during those hours.
- **Both market-based (i.e., negative pricing) or bi-lateral agreements (e.g., agreements with storage to capture spill) may be required to maintain renewables value in the long-term as spill expectations increases.**

Power Advisory LLC

Contact information

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Discussion

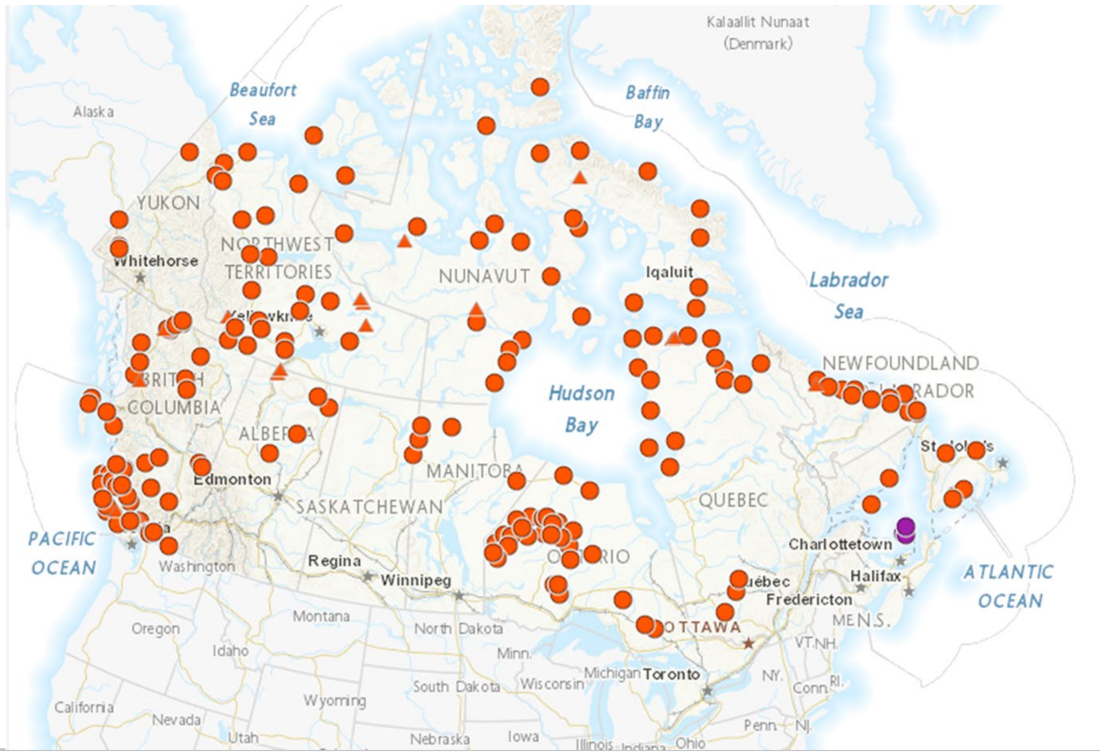
Topic 2: Sharing of experiences in commissioning and testing of new technologies or configurations

ATCO Fort Chipewyan Solar and BESS Microgrid Project

Hesam Yazdanpanahi, P.Eng.
ATCO

March 2021

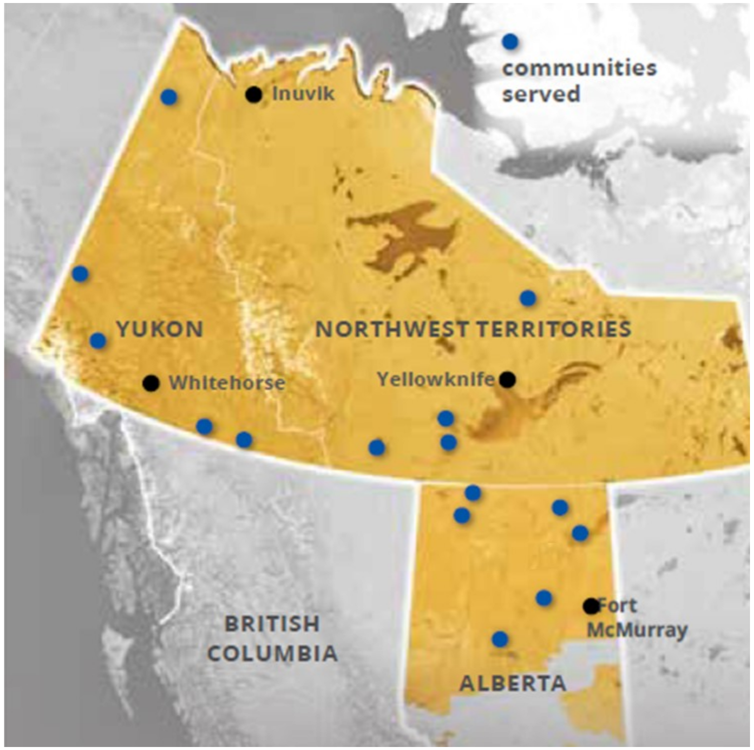
Remote Communities in Canada



200+

Diesel Dependent Communities

ATCO Diesel Reduction Program



15 Diesel Dependent communities

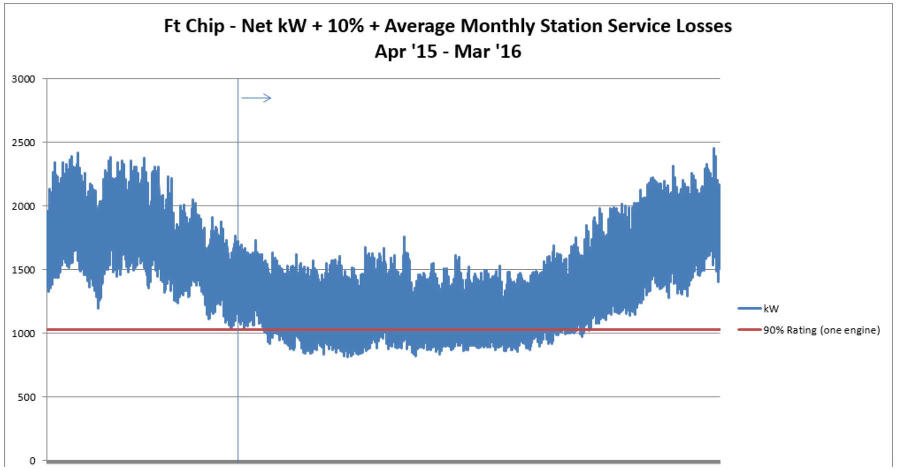
5 Projects In Execution

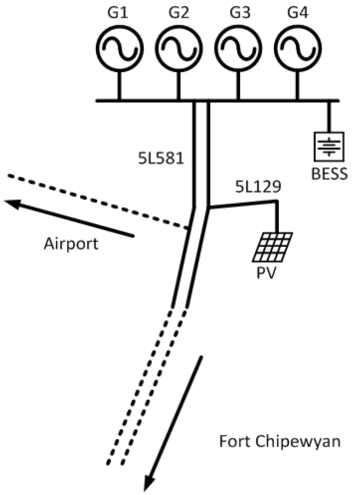
11 Projects Under Development


Fort Chipewyan Unique Isolated Microgrid
No Grid, No Natural Gas
3 Indigenous Communities:
ACFN, MCFN, Metis
Oldest AB Community
1788
Load Growth
Canadian Shield
Beautiful. Lake Athabasca
Winter-only Road.
Fly-in. Barge.

Plant Topology

- 4 x 4.16kV, 1.145 MW Diesel Generators
- 25kV three-phase distribution
- Town is about 8km south of plant





Challenge – LIMITED Ice Road Availability

3,310,000L Diesel Storage

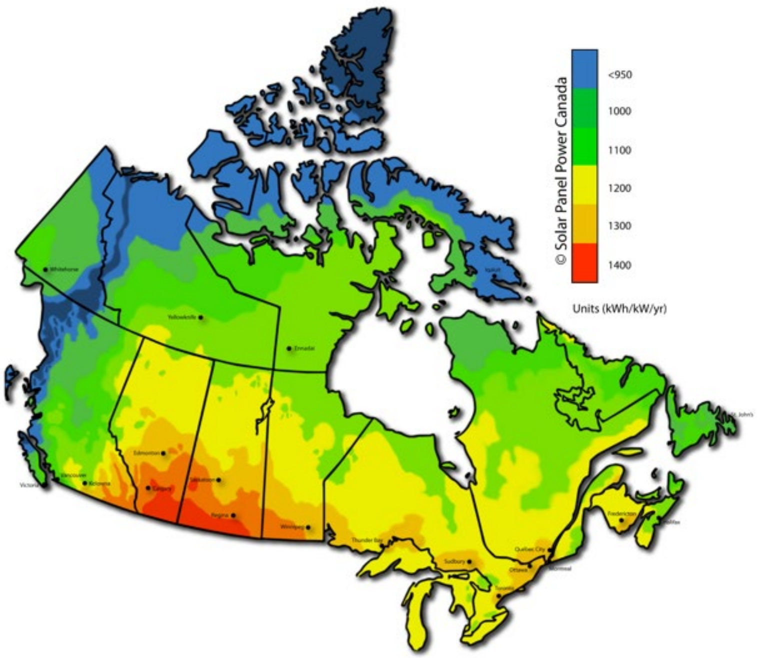
Consumed (2018): 3,294,000L

Ice Road Availability			
Year	Open	Closed	Days Open
2007	28-Jan-07	18-Mar-07	49
2008	18-Jan-08	21-Mar-08	62
2009	27-Jan-09	25-Feb-09	29
2010	19-Jan-10	14-Feb-10	26
2011	15-Jan-11	04-Mar-11	48
2012	27-Jan-12	08-Mar-12	44
2013	30-Jan-13	13-Mar-13	42
2014	24-Jan-14	10-Mar-14	45
2015	30-Jan-15	11-Mar-15	40
2016	04-Feb-16	24-Mar-18	48
2017	30-Jan-17	22-Mar-17	51
2018	29-Jan-18	10-Mar-18	40
AVG			43

REQUIRED FUEL RESERVE NOT MET

Solar Potential

- 1200 kWh/kWp/year
- Capacity factor 13.4%
- Better than any place in Germany



Solar Farm – Phase 1

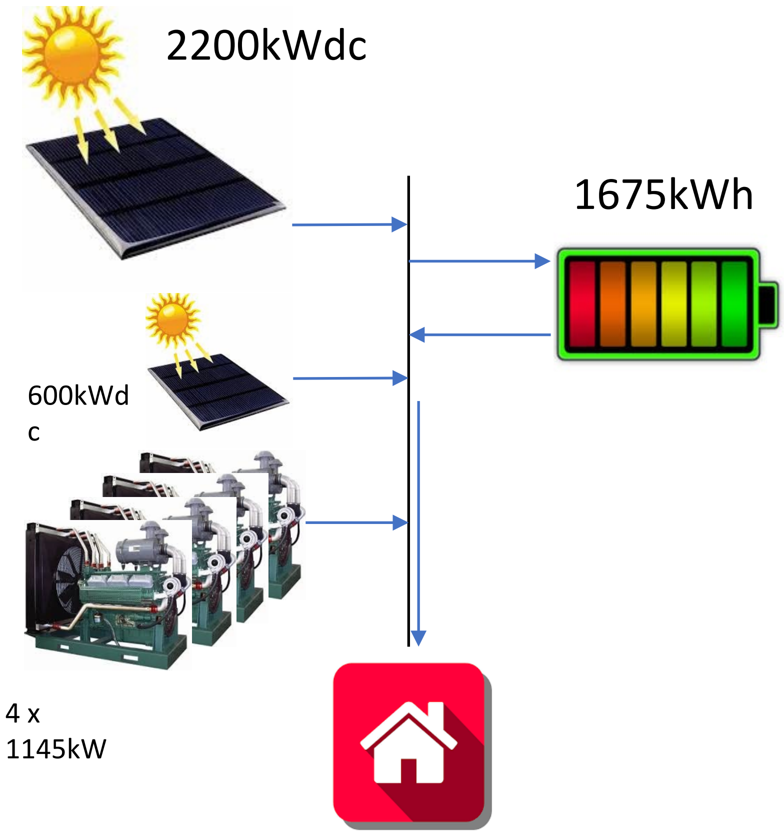
600kWdc Phase 1 PV solar array

Lowest Cost Alternative

160,000L Diesel Reduction

May 15, 2019 Construction Completion

Increased Penetration: Microgrid – Phase 2



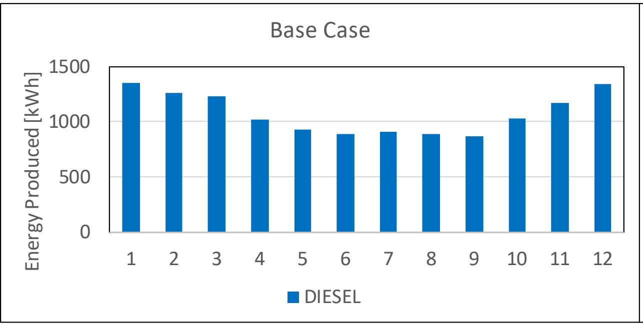
2200kW Phase 2 PV solar array

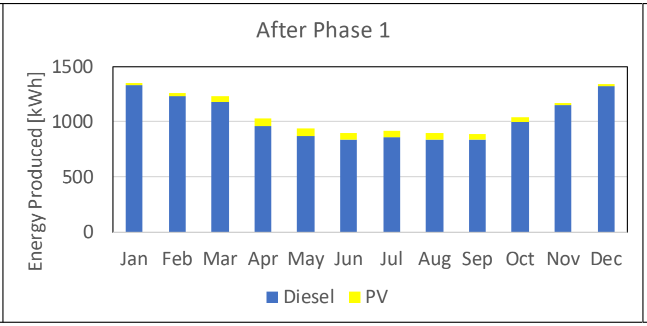
1675kWh Battery Storage

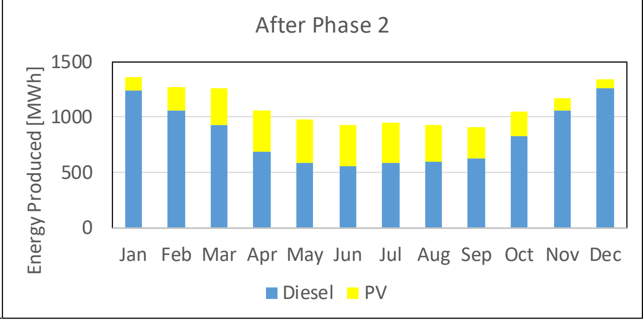
~25% Diesel Reduction

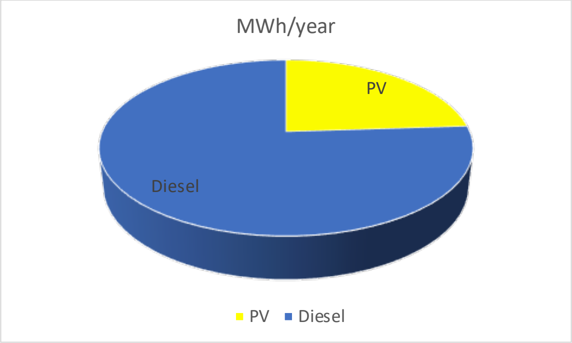
~800,000L Diesel Reduction

Optimization Studies

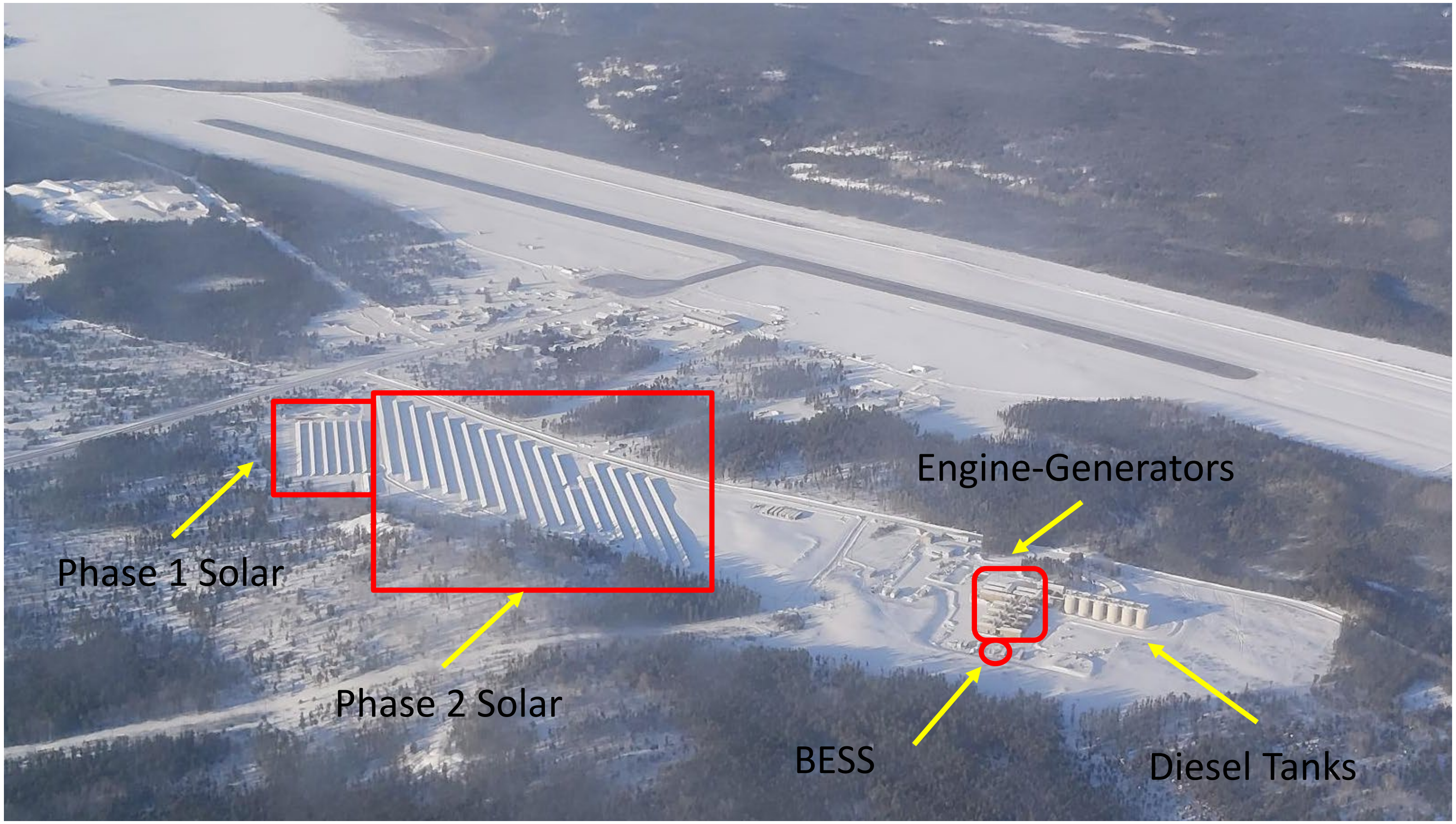








Ft. Chip Generation System - Aerial View



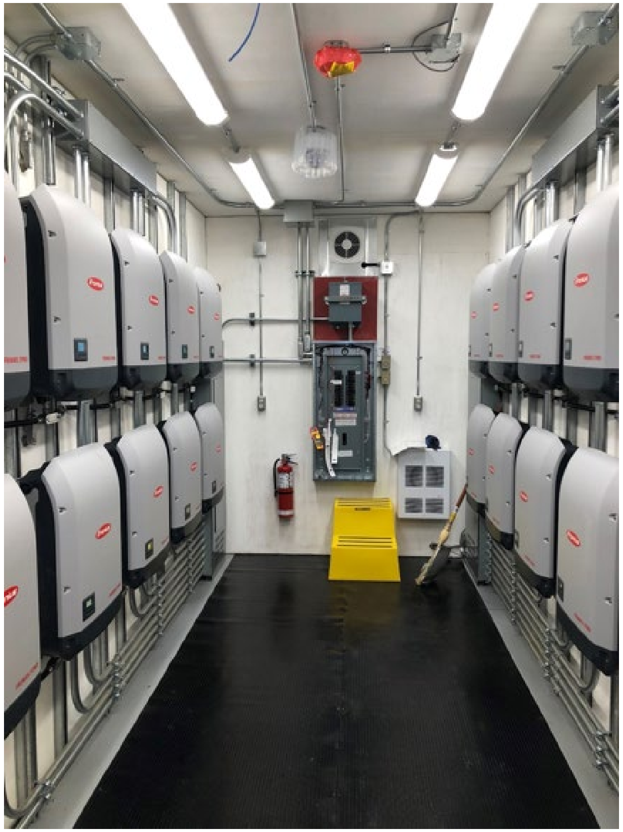
Limited Access via Temporary Ice Road

- Ice road open for only 6 weeks for heavy haul.
- Sharp cut off date for construction and pre commissioning.
- Had to modify FAT to make it to the ice road!

Extreme Temperatures, Insulation and Air conditioning

- No equipment rated for operation below -40C!
- Insulation required for -40C, in some cases -60C is required!
- 456 kW power conversion at 98% efficiency --> 9kW heat in summer!

×9 !!



Stablish Communication between new and legacy devices

- Battery modules with BMS
- BMS with BESS Inverter
- Microgrid Controllers with
  - BESS inverters,
  - solar inverters,
  - generators,
  - feeder OVRs,
  - meters, and
  - with each other.
- Working with several communication protocols and make devices talk to each other!

Conclusion

- Plan ahead of time.
- Make sure you have complete knowledge of the existing system (SLDs, communication protocols, network maps, settings, etc.).
- Allocate enough time and budget for commissioning.
- Manage your expectations, i.e., do NOT expect the system to work in day 1!
- Deficiencies may not reveal during the commissioning period. Expect “fine tunings” at least during year 1!

Questions?

Hesam.yazdanpanahi@atco.com

AESO Energy Storage Industry Learnings Forum

Workshop #3

TransAlta - Laura Oosterbaan

WindCharger Project Overview

- WindCharger Battery Storage Project is located 13km northeast of Pincher Creek in the MD of Pincher Creek
- Located next to the existing Summerview Wind Farm Substation
  - Project is connected behind-the-fence
- Project charges from TransAlta's Summerview II Wind Farm making it a renewable BESS
- Nameplate capacity is 10MW/20MWh
- WindCharger came online October 15, 2020
- Emissions Reduction Alberta provided co-funding for the project of up to 50 per cent of capital cost
- WindCharger utilizes Tesla Megapack lithium-ion technology

WindCharger Site View

Commissioning and Testing of Battery Energy Storage Systems

- First of its Kind technology
- AESO Energization Checklist
  - Commissioning Plan
  - WECC Testing
- Commissioning differences from traditional technologies
  - BESS specific commissioning / testing requirements
    - Voltage Support Testing
    - Operating Reserve Testing

WindCharger & Summerview Substation

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Laura_Oosterbaan@transalta.com

1-403-267-7486

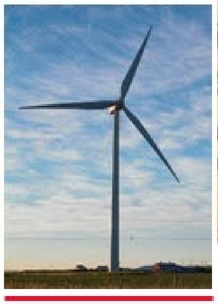
Discussion

Topic 3: Modeling economics of transmission storage under the current framework

Economics of Transmission Storage under the Current Industry Framework

AESO ESILF WORKSHOP #3

MARCH 19, 2020



ALTALINK

A BERKSHIRE HATHAWAY ENERGY COMPANY

SustainableElectricityApproved™
Canadian Electricity Association

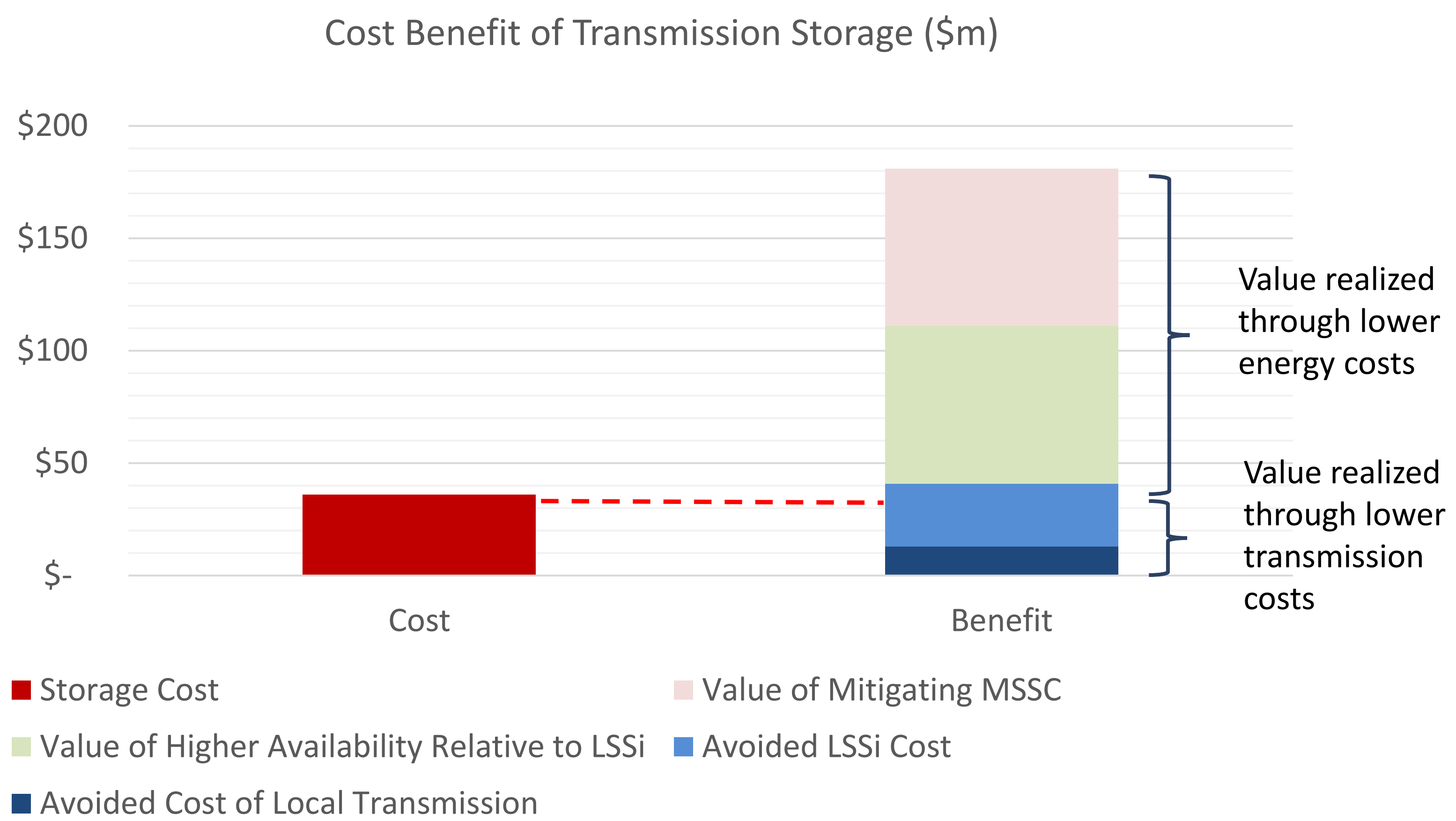
Transmission storage can play an unique role in optimizing grid development and operation under the current industry and regulatory construct

- **Transmission storage characteristics**
  - A transmission facility designed to perform transmission functions (e.g. contingency support, maintain stability)
  - Its operation follows control signals from the transmission system and is 100% under the AESO's control
  - Infrequent charge and discharge (operation linked to contingencies)
  - Does not participate in energy and ancillary markets. No FEOC concerns
  - Is consistent with current industry and regulatory construct for regulated transmission.
- **Questions**
  - Is transmission storage economic? Will it save costs for customers?
  - Is NWA service from market participant owned storage a more cost-effective solution?

The value proposition of transmission storage stems from its capability to deal with a variety of reliability issues at local and macro levels synergistically

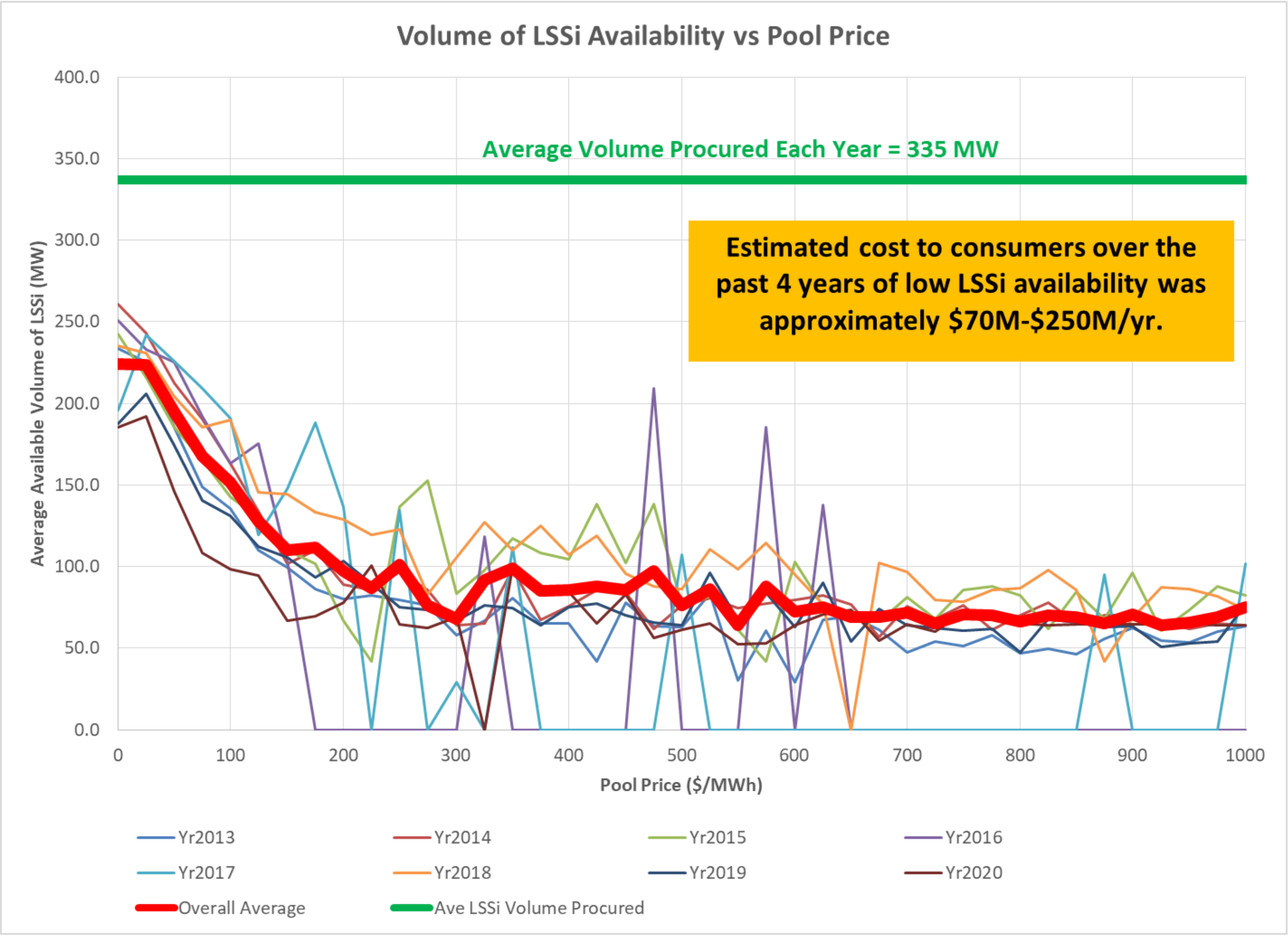
Reliability Issue	Transmission Storage Solution	Value Proposition
N-1 contingency driving local transmission expansion	• Provide dynamic support when the contingency occurs • Leverage capabilities of existing transmission to enhance storage's capability through DTLR	• Delay and/or reduce costs associated with traditional transmission solutions
Frequency stability issues associated with AB-BC tie outages driving procurement of LSSi and/or FFR	• Provide contingency support when intertie is tripping • Significantly higher availability than LSSi and/or market based FFS	• Avoid cost associated with procuring LSSi or market based FFR • Market benefit to customers from higher availability relative to LSSi provided by market participants
Voltage stability issues of BC tie associated with MSSC limits BC tie Total Transfer Capability (TTC)	• Provide contingency support when MSSC occurs	• Market benefit to customers associated with increased intertie exchanges • Reduce costs associated with intertie restoration

A transmission storage project could save significant costs for customers when it is used to provide multiple grid functions under a finite set of applications



Analysis based on 20 MW transmission storage for White Court project

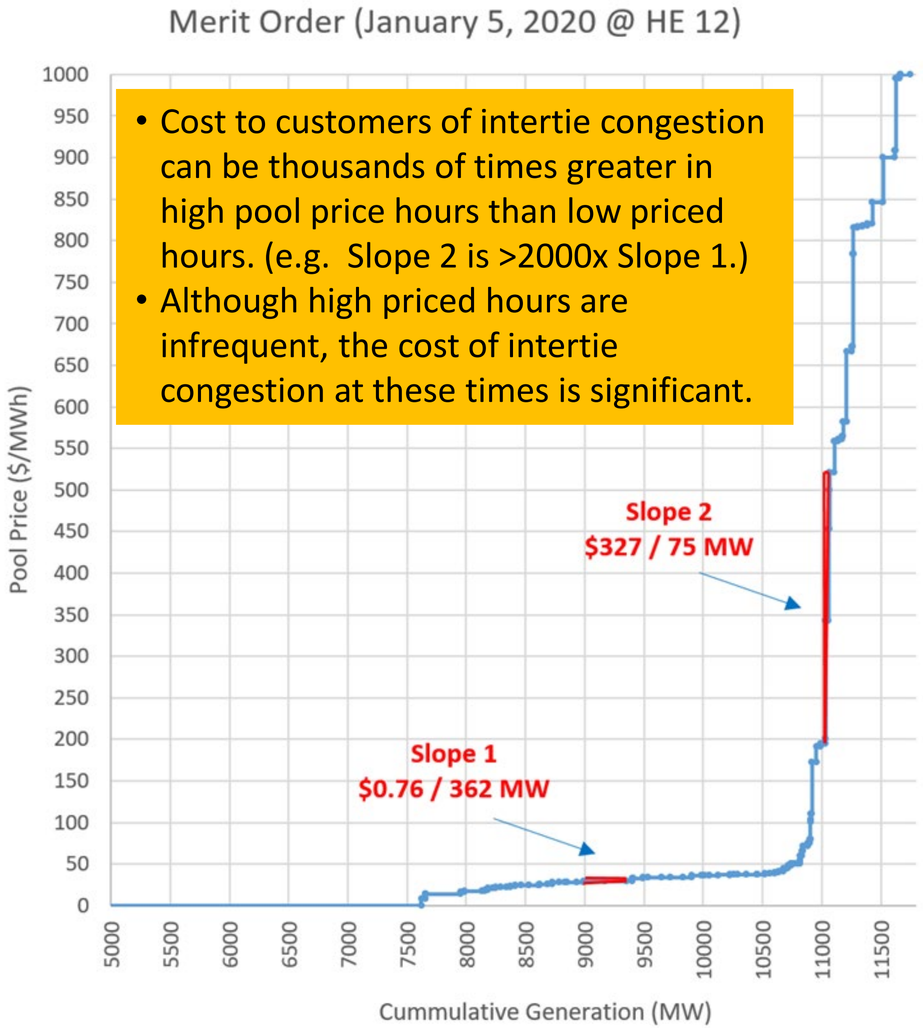
Contracted LSSi has low availability, particularly during high price hours, resulting in congestion on interties



Reduced intertie congestion enabled by transmission storage has significant value for customers

Based on the actual import congestion experienced over the past four years, a 20 MW transmission storage is expected to save the following costs for customers:

- $7m - $180m per year by enabling imports during high price hours when ATC is constrained due to low LSSi availability
- $7m - $140m per year by enabling imports with higher TTC of AB-BC tie as a result of MSSC being mitigated



Could NWA services from market participant owned storage be a more cost effective alternative to transmission storage?

- **It is impractical for a non-TFO market participant owned energy storage to provide NWA service to deal with the previously described range of reliability issues while maximizing value from energy market operation**
  - Energy storage would have to remain fully charged almost all the time in order to support local, intertie, and MSSC contingencies which are uncertain in terms of timing
- **Even if a market participant is willing to give up its market value and instead be dedicated exclusively for transmission services, such an arrangement would be in conflict with current regulatory construct which requires such an entity being an TFO**
- **A market participant owned storage providing NWA services and market services simultaneously would result in higher cost to customers**
  - Conflicting operational requirements for maximizing market value versus supporting grid (e.g. when price is high, a market storage would be incented to generate power instead of remaining fully charged waiting for contingency)
  - The availability of a storage facility for transmission service will likely be lower, particularly during high price hours
  - Lower availability could result in significant cost to customers in the form of higher market prices (see previous slides)

Both regulated transmission storage and market participants owned NWA storage should be in the AESO's tool box

- **Regulated transmission storage focuses on a finite set of unique applications with dedicated facilities for reliability support**
  - Transmission storage's operation is characterized by remaining being fully charged most of the time to support unplanned grid contingencies
  - Service from market based solutions may prove to be difficult to implement and conflict with market incentives resulting in higher cost to customers or violating current regulatory construct
- **Market participant owned storage providing NWA service should focus on applications that are synergistic to its market operation**
  - Wind arbitrage – synergic to removing congestion on lines transferring power out of ~~in~~ wind zones

Key messages

- **Transmission storage is an unique asset for grid optimization under the current industry and regulatory construct**
- **The value proposition of transmission storage stems from its capability to deal with a variety of reliability issues at both local and macro levels synergistically**
- **A transmission storage project could save significant costs for customers when it is used to deliver multiple grid services under a finite set of applications**
- **Market participant owned storage is challenged to provide non-wires-alternative (NWA) services to address multiple reliability issues in a way that is comparable to transmission storage, rendering higher costs to customers**
- **Both regulated transmission storage and market participant owned storage providing NWA services should be in AESO's tool box in order to minimize customer costs, ensure FEOC market operations, and respect the current industry and regulatory construct**

Discussion

Wrap up and next steps

- Workshop 4
  - To be determined; guest speakers from other jurisdictions to share their energy storage learnings

- **Please send your energy storage questions to:**
  - Email: energystorage@aeso.ca

Contact the AESO

- ***Twitter:*** *@theAESO*
- ***Email:*** *energystorage@aeso.ca*
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Thank you