CONE Update
EAS Offset Methodology
CONE Reference Technology Selection

August 16, 2018

Agenda

- CONE Update
- EAS Offset Update
- Reference Technology Selection Update

Alberta CONE Study Update

AESO Public

AESO CONE Study

Updates to CONE Estimates

PRESENTED TO

AESO Technical Working Group Session #5

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THE Brattle GROUP

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Agenda

- Summary of changes due to stakeholder feedback
- Updated CONE estimates
- Detail behind updated CONE estimates
  - CC overnight capital costs
  - Sales tax exclusion
  - Incorporation of GUOC
  - Turbine cost foreign exchange hedging
  - CCA class for tax depreciation
  - Discount rate and cost of capital
- Additional feedback considered

Updates Due to Stakeholder Feedback

We made several revisions to our CONE estimates after considering feedback we received from stakeholders at the June meeting:

- Increased labor and materials costs for the CC (increases CONE)
- Excluded sales taxes from capital costs (decreases CONE)
- Incorporated the generating unit owner’s contribution (GUOC) payment and refund (minor increase to CONE)
- Applied foreign exchange hedging to turbine costs (minor increase to CONE)
- Decreased the average CCA rate from 50% to 11-14% (increases CONE)
- Updated Alberta-capacity-market-specific discount rate from 8.0% to 8.5% (increases CONE; yields ≥ 15% IRR on equity investment at 65% debt financing)

Additional feedback was considered as well (see slide 12), but did not yield revisions to our approach

Updated CONE Estimates

CONE estimates have increased for all technologies.

- The CC has increased by $46/kW-year, due primarily to the greater overnight capital costs from updated labor and materials assumptions.
- Frame and Aero CT CONE have risen slightly, mostly due to the higher discount rate and lower tax depreciation

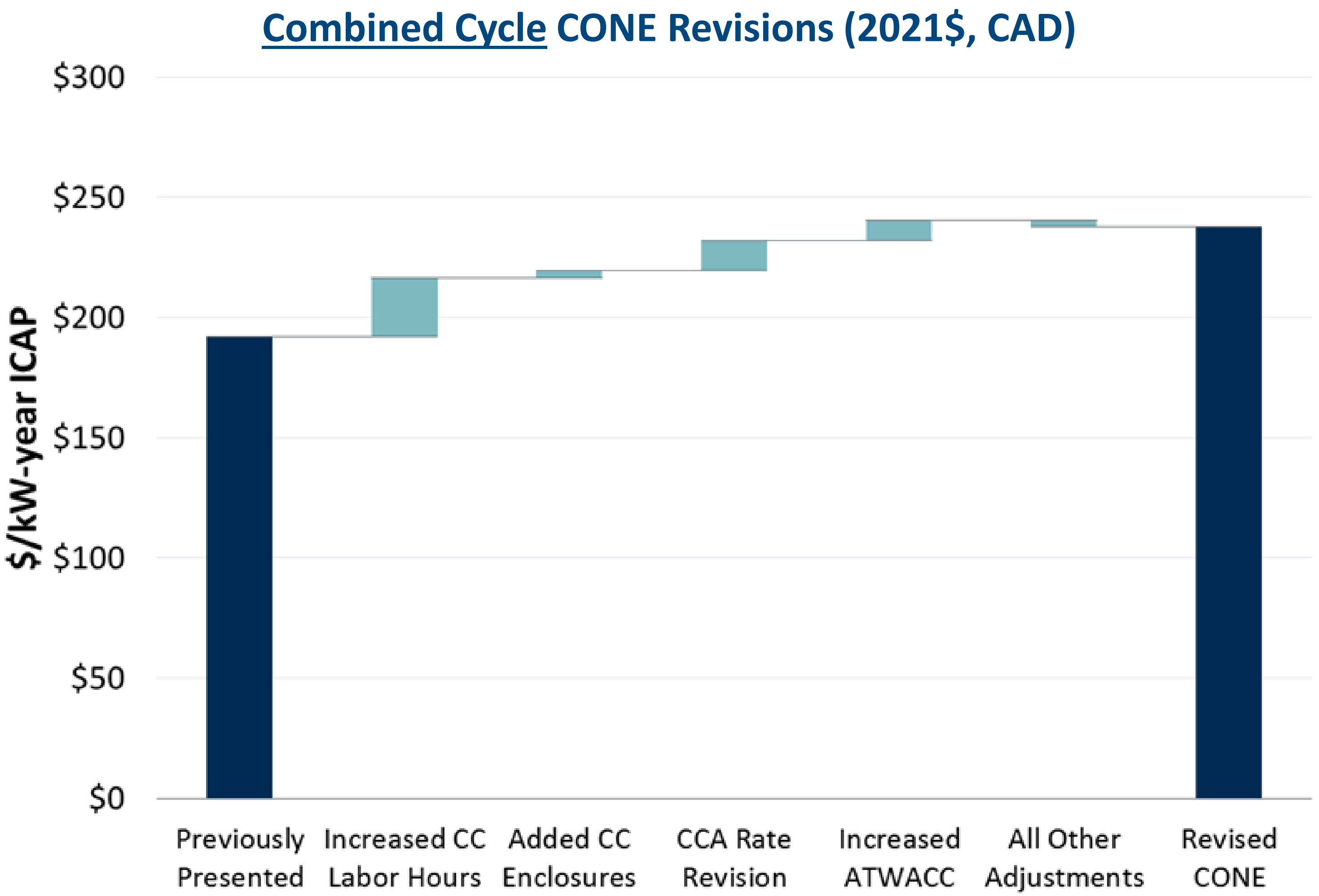
CONE estimates for the Aero CT and CC are now similar; CONE remains lowest for the Frame CT.

Summary of Updated CONE Estimates (2021 CAD)

Reference Technology	Winter Capacity	Overnight Capital Costs	Overnight Capital Costs	Overall (After-Tax) Cost of Capital	Annual Carrying Charge	Plant Capital Costs	Fixed O&M Costs	Updated Gross CONE	June Gross CONE	Change in Gross CONE
	MW	*$million*	*$/kW*	*%*	*%*	*$/kW-yr ICAP*	*$/kW-yr ICAP*	*$/kW-yr ICAP*	*$/kW-yr ICAP*	*$/kW-yr ICAP*
Aeroderivative CT	93	$141	$1,512	8.5%	12.6%	$190.9	$54.8	$245.7	$224.9	$20.8
Frame CT	243	$171	$704	8.5%	12.7%	$89.1	$26.7	$115.8	$107.4	$8.3
Combined Cycle	479	$673	$1,404	8.5%	13.3%	$186.5	$51.4	$237.9	$192.2	$45.7

Note: Debt fraction = 50.0%, cost of equity = 12.6%, cost of debt = 6.0%, tax rate = 27.0%

Summary of Updates and Impact to CONE (CC)



CC Plant Capital Costs

We increased the CC overnight costs by $191/kW in response to stakeholder feedback regarding Alberta labor costs and further research on enclosures.

- *Labor Costs*
  - We increased labor cost for the CC given weather extremes in Alberta and the labor intensity and long construction schedule of the CC.
  - We increased the productivity factor from 1.15 to 1.60, increasing direct craft man-hours by about 50% (from approx. 800,000 hours to 1.2 million hours).
  - This increased capital costs by $171/kW.
- *Materials and Other Equipment Costs*
  - Based on further research for existing and proposed CC facilities in Alberta, we included additional buildings and enclosures for all the CC equipment.
  - This increased capital costs by $19/kW.

Our updated CC overnight costs are within 3% of a CC cost estimate and breakdown provided by a stakeholder on a confidential basis (once adjusted for sales tax exclusion and inclusion of net start-up costs).

Sales Taxes

We now exclude the Canadian GST of 5% from the plant capital costs, decreasing overnight capital costs for all technologies.

- The developer can claim input tax credits for taxes paid on goods and services consumed in the process of their commercial activities.
- Thus, the GST paid on turbines, materials, and other equipment would be credited against other taxes and/or refunded by the Canada Revenue Agency.
- Excluding sales taxes decreases the overnight capital cost for each technology, ranging from approximately $20/kW to $50/kW.

Generating Unit Owner's Contribution (GUOC)

We have updated the CONE estimates to incorporate the GUOC required of interconnecting facilities by the AESO. Because the GUOC is refunded, this has minimal impact to CONE.

- The GUOC for Edmonton is $30,000/MW. This is included as a capital cost within the "electric interconnection" costs.
- The GUOC is fully refunded (assuming certain facility performance criteria are met) over 10 years, with half of costs refunded in the last three years.
- The GUOC refund payments are treated as revenue over the first 10 years of operations.
- Because the net effect of the GUOC is strictly a matter of timing and discounting, the impact to CONE is very small.

Foreign Exchange Hedge on Turbine Costs

We incorporate foreign exchange hedging on the turbine costs given that the turbines will be purchased in U.S. dollars. This yields a very minor increase to CONE.

- We apply forward USD/CAD exchange rates on a monthly basis to a typical turbine payment schedule.
- The turbine payment schedule begins in the first month of the construction schedule for each reference technology and spans 12 months to final payment 30 days after delivery.
  - Note this implies turbine payments begin in November 2018 for the CC and in March 2020 for the Aero and Frame CTs
- The forward rates utilized over this time frame range from 1.29 to 1.31 CAD to USD.
- We do not explicitly incorporate the administrative transaction costs; these are expected to be less than 1% of total costs and assumed to be part of owner's costs.

This foreign exchange hedging applies to turbine costs only.

- Turbine costs are approximately 38% of plant costs for the CTs and 23% of plant costs for the CC.
- Some other materials costs are estimated in USD and converted to CAD, but these are a small portion of plant costs and assumed to be globally sourced commodities not especially sensitive to USD/CAD exchange rate.

CCA Class and Tax Depreciation

We updated the CCA class for the income tax depreciation shield, which increases CONE for all technologies by $6/kW-yr to $13/kW-yr.

- Our original CONE estimates were based on CCA Class 53, which applied a rate of 50% to undepreciated capital costs.
- Based on further research and stakeholder feedback, we now apply a blended CCA rate of 12% for the Aero CT, 11% for the Frame CT, and 14% for the CC, which pushes back the timing of the tax benefits of depreciation
- The blended rate is a weighted composite of classes 1, 17, 43.1, 47, and 48, relating to relative contributions of electric generating equipment, gas and electric interconnection infrastructure, and materials.
- Other depreciable costs are assumed to be spread evenly across categories.

CCA Rate Calculation (CC)

Cost Category	CCA Class	Share of Costs	Rate
Combustion Turbines	48	31.1%	15%
HRSG/Steam Turbine	43.1	18.3%	30%
Electrical Interconnection	47	13.2%	8%
Materials and Equipment	17	36.1%	8%
Gas Interconnection	1	1.4%	4%
Weighted Average			**14%**

Discount Rate and Merchant Cost of Capital

Based on stakeholder feedback concerning the relative risk of the Alberta market to other markets, we increased the overall after-tax cost of capital from 8.0% to 8.5%.

- Equivalent to 9.3 – 9.6% cost of capital (before considering tax benefits of debt payments)
- Translates to Cost of Equity (IRR) of 12.6 – 15.5% depending on debt fraction

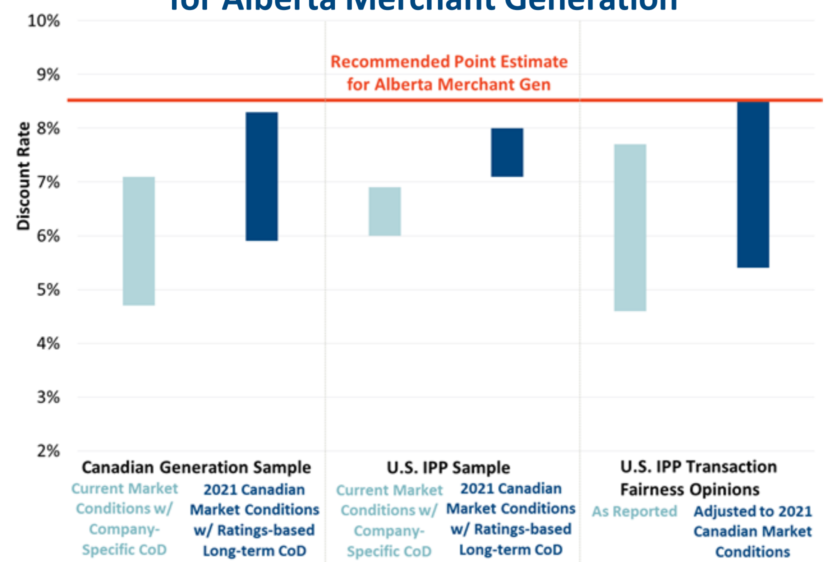
We considered the following aspects of the risks for new merchant generation in Alberta:

- Smaller market size
- Limited liquidity and forward hedging
- Shorter (1-year) contract period
- New capacity market design
- No multi-year lock in, but risk mitigated by 3-year forward capacity payments relative to energy-only market
- Less restrictive market power mitigation
- Greater political, regulatory, and governance risks

Components of Overall (After-Tax) Cost of Capital Consistent with 50% and 65% Debt Financing

Debt Fraction	50%	65%
Cost of Debt	6.0%	6.5%
Cost of Equity	12.6%	15.5%
Overall Cost of Capital	**9.3%**	**9.6%**
Income Tax Rate	27%	27%
Overall After-Tax Cost of Capital	**8.5%**	**8.5%**

Cost of Capital Reference Points for Alberta Merchant Generation

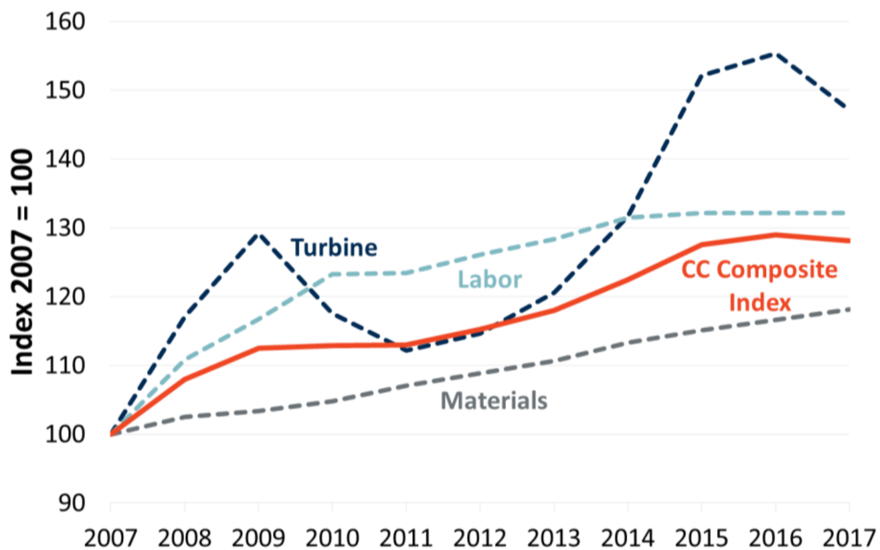


Annual Updating Index

We also updated the composite index used to escalate CONE annually based on stakeholder feedback. This has no impact on current CONE estimates.

- For costs related to the turbines, we now recommend using the Producer Price Index, reported by the U.S. Bureau of Labor Statistics, for turbines and generator sets, adjusted for the USD/CAD exchange rate.
- This is intended to capture both fundamental changes in U.S.-sourced turbine costs as well as changes to the USD/CAD exchange rate.

Example: Combined Cycle Updating Index



Additional Feedback Considered

Additional stakeholder feedback was considered but ultimately did not factor into revisions to CONE.

- SCRs are not included for the Aero and Frame CTs based on current environmental regulations and recent new builds. We will provide indicative costs for including an SCR should the regulations change.
- No change were made to the CC cooling system given our assessment that water is available in the Edmonton area.
- Net revenues associated with fuel costs and energy production during start up are still included as (an offset to) plant capital costs.
- We reviewed our approach to estimating turbines costs and have confidence in the quotes provided by vendors for the turbine costs.
- We reviewed pipeline infrastructure in the Edmonton area and still assume a 2 km lateral for gas interconnection costs.
- We further discussed electric interconnection costs and regulations with AESO and have not adjusted these costs.

Net-CONE Methodology

Key Messages

- The forward market methodology **has evolved** from earlier DCWG sessions
  - Capacity factors include forced outage rates and seasonal impacts
  - Natural gas commodity charge included

- The forward market methodology is **transparent** and **replicable**

- Forward Market methodology and Market Simulation are **reasonably aligned**

Energy and Ancillary Service (EAS) Off-set During the Transition Period

- During the transition period, the forward period for the capacity market is less than the post-transition three year period
  - Shorter time-frame for incorporation of the forward market methodology

Pre-qualification Starts	Auction Date	Obligation Period	Forward Period Approx. Months
Nov. 2019	Jun. 2020	2021/22 (Nov. – Oct.)	16
May 2020	Jan. 2021	2022/23 (Nov. – Oct.)	21
Nov. 2020	Jun. 2021	2023/24 (Nov. – Oct.)	28
Mar. 2021	Oct. 2021	2024/25 (Nov. – Oct.)	36

- The initial EAS off-set for the November 2021 to October 2022 obligation period will be proxied with Cal 2022
  - 2021 Forward Market includes ten months of the energy-only market

EAS Offset Calculation

- EAS offset is calculated as energy market revenue minus variable expenses
  - The EAS offset will initially exclude revenues from ancillary services

- **Revenue** is the product of forward base load power prices and generation (calculated based on a capacity factor that incorporates seasonal capacity de-rates and forced outages) for the chosen reference technology
  - Alternate forward power product types will be assessed based on technology margins

- **Variable Costs** represent operating costs for the chosen reference technology:
  - Fuel consumption: heat rate multiplied by forward market natural gas price plus a pipeline commodity charge
    - *Forward natural gas price based on NGX Phys FP (CA/GJ) , AB-NIT settlements that capture the same period as the power market forward settlements*
  - Variable operations and maintenance: as defined for the reference technology
  - Carbon cost: based on CCIR where the value is the reference technology heat rate less the established benchmark multiplied by the carbon price
  - Transmission Losses: proxied based on Fort Saskatchewan area losses
  - AESO power pool trading charge: current year’s charge

2021/22 EAS Offset Illustration

Market Input		
Energy Price Forward	$/MWh	43.64
Gas Price Forward	$/GJ	1.97
Transmission Loss Factor	% of Energy Price	3.17%
Trading Charge	$/MWh	0.265
Carbon Pricing	$/tCO2	30
CCIR Benchmark	tCO2/MWh	0.3595
Commodity Fuel Charge	% of Gas Price	1.63%

CONE Technology Input		
Gross CONE	$/kW-yr ICAP	246
ICAP Nameplate	MW	93
ICAP Annual Average	MW	87
UCAP / ICAP	%	79.70%
Forced Outage	%	3.00%
Capacity Factor	%	90.7%
VOM	$/MWh	4.60
Heat Rate Annual Avg (HHV)	GJ/MWh	9.677

EAS Offset		
Energy Market Revenue	$/kW-yr ICAP	347
Variable Expenses	$/kW-yr ICAP	234
EAS Offset	$/kW-yr ICAP	113

Note: tables shown for illustrative purpose. Estimates should be considered as preliminary and subject to revisions

Market input based on forward market and relevant regulations, costs

Forward market pricing is the average forwards for Feb 20 to June 20 2018 (random sample chosen for illustrative purposes)

Reference technology input provided by Brattle/S&L report

Capacity factor based on seasonal capacity (annual average) and forced outages – CF = 87 x (1-0.03) / 93

EAS offset translated from $/MWh to $/kW-yr using assumed generation

See spreadsheet addendum for more details on underlying calculations

Question

Are there improvements to the Forward Market methodology that the DCWG recommends?

Forward Market versus Simulation Comparative

Methodology Comparison Simulation Assumptions

- The AESO compared the Forward Market methodology to an internal 2022 hourly simulation to provide a comparison of EAS offsets
- The Aeroderivative was used as the CONE technology to have EAS offsets calculated for
- To complete the analysis the following simulation assumptions were made:
  - *Gas prices set to the forward curve ($1.97/GJ)*
  - *Carbon price was set at $30/tonne*
  - *2022 demand aligned with the 2017 LTO*
  - *Generation capacity reflecting existing generation, anticipated retirements, and known new additions (such as REP wind)*
  - *3X variable costs mitigation in all hours*
  - *Reference technology set to run at variable cost*
- Brattle gross CONE and VOM used in both model

Methodology Comparison – 2021/2022 Obligation (Illustrative)

Element (AERO/ICAP)	Power ($/MW)	Natural Gas ($/GJ)	Capacity Factor (%)	CONE ($/kW-yr)	EAS Offset ($/kW-yr)	Net-CONE ($/kW-yr)
Forward Market						
$30/t Carbon Pricing	43.64	1.97	91	246	113	132
$50/t Carbon Pricing	43.64	1.97	91	246	93	152
Simulation						
$30/t Carbon Pricing	41.30	1.97	89	246	96	150
$50/t Carbon Pricing	52.40	1.97	90	246	161	85

Note: for illustrative purpose. Estimates should be considered as preliminary and subject to revisions

- Simulation results created based on stakeholder feedback
- Simulation and Forward Market are reasonably aligned given a $30/t carbon price
  - Simulated 2022 power prices are comparable to the forward market approach in the $30/t scenario and substantially higher in the $50/t scenario
  - For the $30/t scenario, Net-CONE results are similar between the models
  - The simulation results showed that using the 2021/2022 obligation timeframe yields similar results to using the 2022 calendar year (A 1% drop in the EAS Offset)
- Simulation results would be impacted by:
  - Offer strategy, portfolio behavior, and coal flexibility
  - Carbon pricing, natural gas pricing
  - Number of simulated runs

Key Risks to the EAS Off-set

- Three variables that can shift the actual value for the forecast EAS off-set over a three year time span
  - Carbon pricing
    - Three years ago, carbon pricing was expected to remain low under SGER
    - CCIR increased the price of carbon significantly, making natural gas units more competitive than coal
  - Unanticipated changes in supply
    - New additions (ie, Three Creek (up to 700 MW), Suncor (800 MW))
    - Early retirements or unexpected life extensions (ie, coal)
    - Force Majeure type outages (ie, generator rewinds)
  - Natural gas prices
    - Three years ago, the May 2018 natural gas price forecast was $2.98/GJ
    - Actual May 2018 natural gas prices was $0.70/GJ

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    - Actual May 2018 natural gas prices was $0.70/GJ

WILL IMPACT BOTH THE FORWARD MARKET AND THE SIMULATION APPROACH

Reference Technology Selection

Fitting the Unique Needs of the Alberta Market

Key Messages

- The AESO **supports** the selection of **a reference technology** that
  - **Promotes system reliability**
  - **Encourages competitive market forces** to select the **optimal new generation build** for the Alberta market
- The AESO developed a **selection criteria** methodology that factors **low development cost** and the **unique nature** of the Alberta market
- Base on a combination of the selection criteria and stakeholder feedback, the **reference unit to set net-CONE** on the demand curve **is proposed to be an aeroderivative**
- An aeroderivative allows for the **greatest diversity** of future generation builds while **earning a reasonable return**
- Developers will select their preferred asset development **based on their expectations of the market and competition**

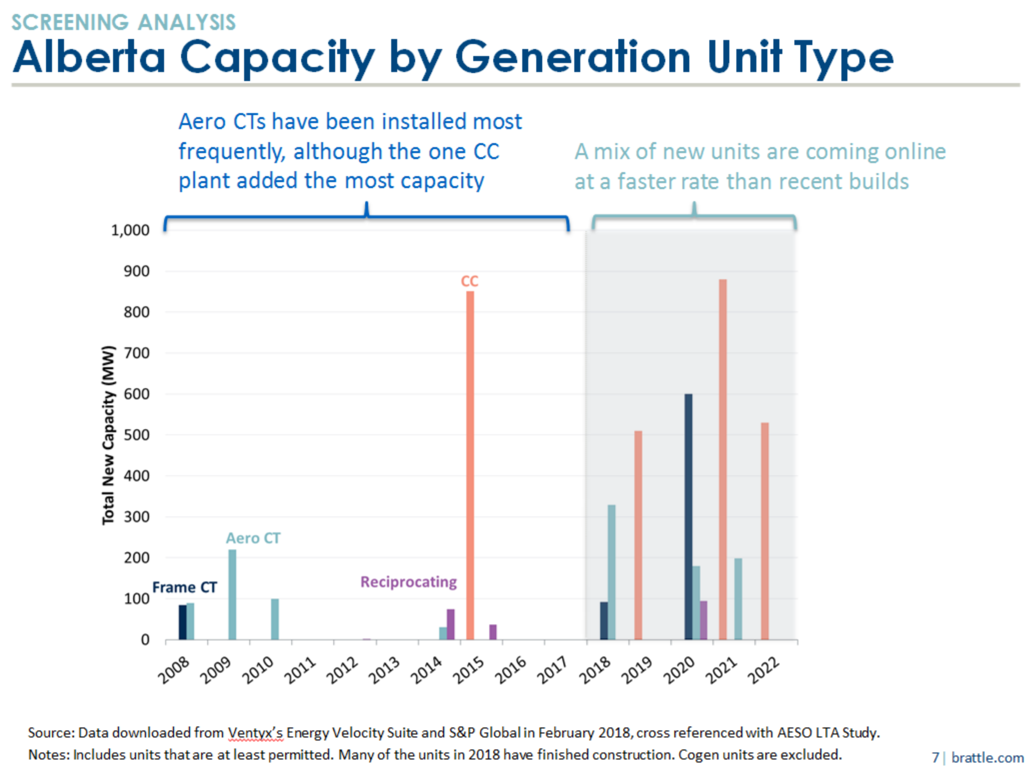
Reference Technology Selection Criteria

- Three reference technologies were considered, which reflect a broad range of efficiencies, operating characteristics, and costs
  - A simple cycle 93 MW aeroderivative, a 243 MW simple cycle frame unit and a 429 MW combined cycle unit
- The aeroderivative was selected for the following reasons:
  - **Frequency of Development/Planned Development (ie, expectations)**
  - **Impact to Alberta Market –** Most suitable asset for the relatively small market size and its unique characteristics:
    - suitable alignment to future load growth and changes in supply
    - system flexibility requirements due to increased renewables penetration
    - increased flexibility and reliability as the two turbines can operate independently
    - is not limited by proposed federal and provincial environmental regulations (ie, frame)
  - **Time to Energization** – Short lead time versus combined cycle
  - **Plant Costs** – Less total capital placed at risk as Alberta transitions to a new market that has political, regulatory and environmental risks
  - **Flexibility of Generation Options** - Does not restrict the development of assets that may enhance system reliability at a reasonable cost

Frequency of Development/Planned Development

- The frequency of development/planned development indicates developers actual and future interest in technologies
- Brattle's screening analysis for the March 23, 2018 TWG provided the following insights:
  - Aeroderivatives were the most frequently built and potentially significant future additions
  - One combined-cycle unit was constructed; future expectations are expected at existing coal sites and near Edmonton but not under construction
  - One merchant frame unit was built in 2009; future frame units are remnants of the cancelled Shell Carmon Creek cogeneration facility

- **Historically, aeroderivatives were the merchant assets developed with greatest frequency by multiple developers with similar trends into the future**



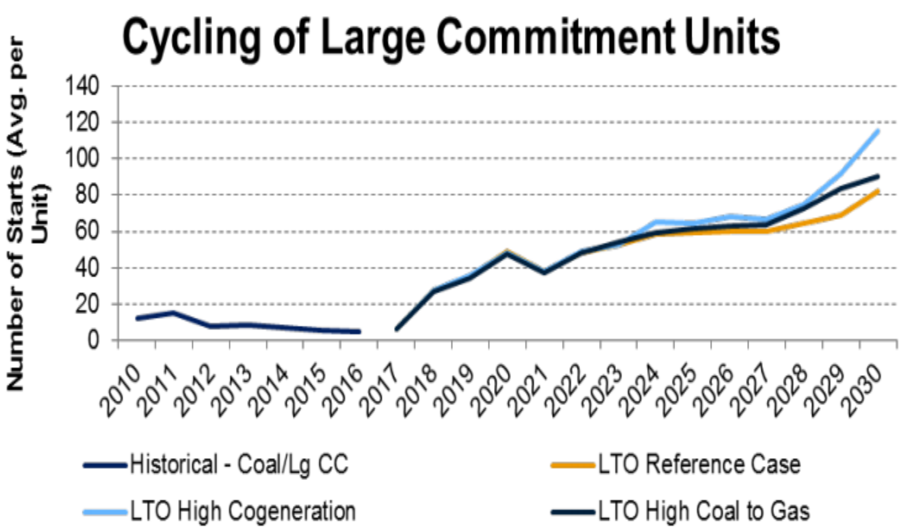
Impact to Market

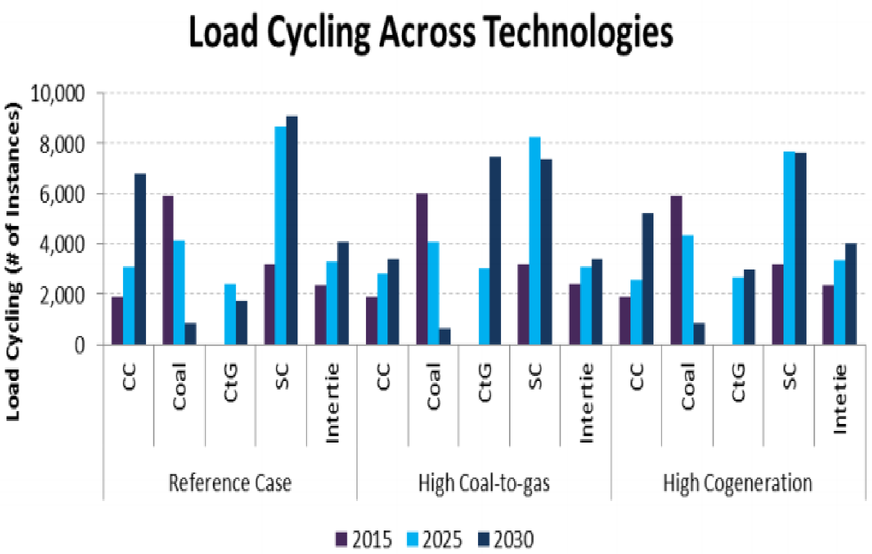
The reference technology selection needs:

- To acknowledge Alberta’s relatively small market size and unique characteristics
- To contribute to supporting a supply mix that promotes reliability at a reasonable cost

Impact to Market

- As renewables penetration increases, the requirement for more flexible assets into the system to promote system reliability
  - The NDV study referenced below highlights that cycling increases when the capacity market moves through the initial obligation periods
  - Simple cycle units are leaned on heavily to meet NDV requirements compared to combined cycle through 2025
  - Frame units are not suitable for non-structured “cycling due” to high start costs and size
  - Of three technologies, the AERO is most suitable to meet NDV requirements





2017 AESO LTO Scenarios

https://www.aeso.ca/assets/Uploads/WG9-Net-Demand-Variability-Final2.pdf Slide 9

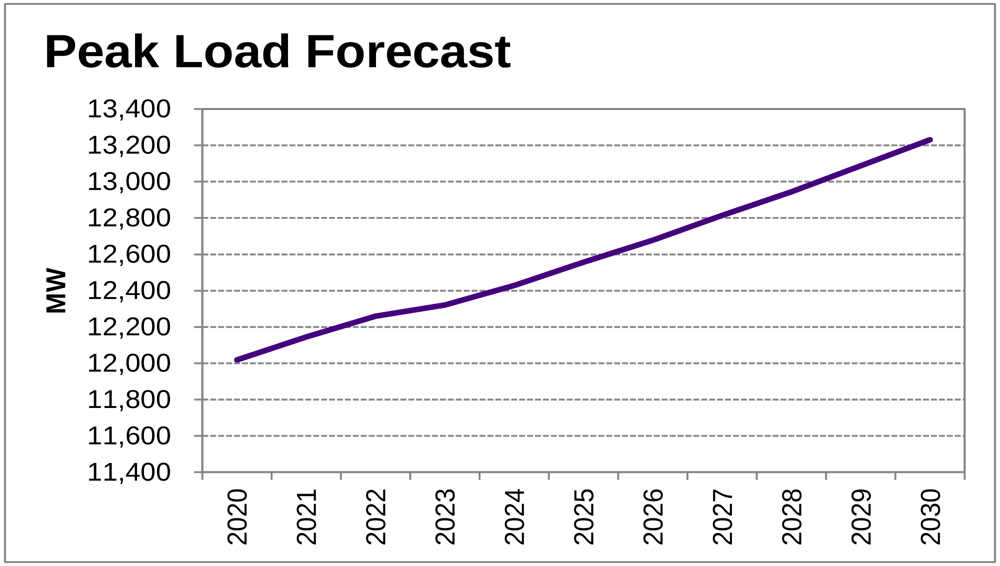
Reliability – Reference Technology UCAPs

- UCAP indicates the reliability value of an asset in Alberta
- As a proxy, the UCAP for the most similar assets in Alberta are used
  - The Frame is limited by future federal regulations to a capacity factor below 33%
    - NPP is closest asset type without federal regulation restrictions
    - Although not yet finalized, UCAP may be between 33% to 78%
    - Limited operating characteristics hinder optionality of asset
  - The AERO configuration has two independent units
    - Potentially may have higher UCAP

Reference Technology	Comparative	UCAP
Combined Cycle (1X1)	Calgary Energy Centre	70%
CT-AERO	Cloverbar, Crossfield, Poplar Hill, Valleyview	80%
CT-Frame	Northern Prairie Power	33% to 78%

Impact to Market

- The reference technology should fit into the supply/demand mix with a positive impact to the market (ie, price fidelity)
  - Alberta has had a recent example of a large asset entering into a reasonably balanced market
- Reinforces a suitable alignment to future load growth and changes in supply
- The peak load forecast from the *2017 Long Term Outlook*
  - The average load growth is 0.9% per year
  - Peak load growth from 2021 to 2022 is 126 MW
- The AESO LTA identifies potential large supply additions and coal retirements in the queue for 2020/21
  - BR3, HR Milner
  - Suncor Cogen Project (800 MW)
  - Kineticor Three Creek Project (690 MW)
- **Given the size of the aero (one or two units), it may be absorbed into the system more effectively given the above supply/demand conditions**



Time to Energization

- A simple-cycle unit will take two years to construct versus three to five years for a combined-cycle unit
- Access to firm natural gas supply may be a limiting factor outside of generator development lead time
  - Potentially 2 to 3+ years depending upon location
- The initial obligation period on November 2021 to October 2022 challenges the ability for a new combined-cycle unit to enter the market
  - Combined cycle final investment decision may have to be made prior to the auction for the obligation period
  - Decisions on combined cycle units of 500 MW in size made be more transparent if there are highly probable significant changes to the supply demand mix
    - Coal or coal to gas converted units retiring based on environmental requirements
    - Conversions of boilers to cogeneration at oilsands facilities may further challenge final investment decisions

Gross CONE

- Brattle/Sargent & Lundy provided updated draft cost parameters
  - Overnight costs and gross CONE increased for combined-cycle units by 15% and 24% respectively
    - Complexity of development warrants assessing a 20% capital cost overrun sensitivity
      - Reflect most recent data point (ie, Shepard was $1.4B for 860 MW or $1,626/kW in 2015$)
    - **Magnitude of capital investment may range from $670MM to $800MM, which may negatively impact final investment decisions**
  - Frame and Aero have marginal cost increases

Summary of Updated CONE Estimates (2021 CAD)

Reference Technology	Winter Capacity	Overnight Capital Costs	Overnight Capital Costs	Overall (After-Tax) Cost of Capital	Annual Carrying Charge	Plant Capital Costs	Fixed O&M Costs	Updated Gross CONE	June Gross CONE	Change in Gross CONE
	MW	*$million*	*$/kW*	*%*	*%*	*$/kW-yr ICAP*	*$/kW-yr ICAP*	*$/kW-yr ICAP*	*$/kW-yr ICAP*	*$/kW-yr ICAP*
Aeroderivative CT	93	$141	$1,512	8.5%	12.6%	$190.9	$54.8	$245.7	$224.9	$20.8
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Net-CONE (Illustrative)

- From a cost perspective the combined cycle asset has the lowest net CONE
- The combined cycle is not aligned to meet the unique requirements of the Alberta market
- Assessment based on Calendar 2022 average forwards for February 20 to July 20, 2018
  - $43.64/MWh power and $1.97/GJ natural gas
  - Assumes $30/t carbon price

Asset	Gross CONE $/kW-yr ICAP	EAS Offset $/kW-yr ICAP	Net-CONE $/kW-yr ICAP
AERO	246	113	132
Frame	116	0	116
CC	238	197	41
CC+20%	285	197	88

Note: for illustrative purpose. Estimates should be considered as preliminary and subject to revisions

Creating the Ability to Enhance Reliability via Generation Optionality

- Selecting the AERO as the reference technology, creates optionality for generators to develop the appropriate assets based on the Alberta market
  - Revenue sufficiency modeling highlighted that combined cycle and frame units may also be developed if an AERO is a reference unit
    - CC high reflects the potential of a capital cost overrun of 20%
    - Combined cycle results DO NOT include a pool price impact, which would lead to lower results
    - Frame units collect revenues predominantly from capacity payments

Internal Rate of Return	2017LTO Reference Case Supply Mix				2017LTO High Coal to Gas Supply Mix			
	Aero	Frame	CC	CC +20%	Aero	Frame	CC	CC +20%
$50/t & $2/GJ	9%	13%	14%	12%	12%	16%	17%	14%
$50/t & $4/GJ	9%	13%	15%	13%	11%	14%	17%	15%
$30/t & $2/GJ	9%	14%	13%	11%	12%	16%	15%	13%
$30/t & $4/GJ	9%	12%	15%	12%	11%	14%	16%	14%

Note: for illustrative purpose. Estimates should be considered as preliminary and subject to revisions

  - If a combined cycle is used as the reference technology, flexible technology may not achieve reasonable returns and consequently not be developed
    - Under the same scenarios as above, flexible simple cycle units may have a negative IRR to a modest IRR, which would not justify development

Reference Technology Selection - Summary

- AERO best fits the unique nature of the Alberta market
- AERO allows competitive forces to meet reliability and market needs

Criteria	Frame SC	Aero SC	CC	Comments
Frequency of Development	Disadvantage	Advantage	Neutral	-AERO and CC units are also in the development queue
Suitable to supply mix and load growth in the 5 year window	Neutral	Advantage	Disadvantage	-Smaller unit is able to more easily absorb into a market with limited demand growth
Flexibility requirements to meet renewables penetration	Disadvantage	Advantage	Neutral	-AERO highly flexible including starts -Frame limited: high start costs, limited operating hours, large size
Adaptable to multiple market conditions (ie, supply shock)	Disadvantage	Advantage	Advantage	-Proposed Federal Regulation limits the Frame to a 33% capacity factor
Time to energization	Advantage	Advantage	Disadvantage	-CC could take 3 to 5 years versus up to 2 years for a SC unit
Capital investment (magnitude)	Advantage	Advantage	Neutral	-Consideration to scale of investment
UCAP (Existing fleet comparative)	Disadvantage	Advantage	Disadvantage	-AERO has highest UCAP and may be higher with two independent units
Gross CONE ($/kW-yr)	Advantage	Neutral	Disadvantage	-Potential cost escalation risk for Combined-Cycle
Net-CONE ($/kW-yr)	Neutral	Neutral	Advantage	-CC has significant advantage
Supports diversity of supply if reference technology	Advantage	Advantage	Disadvantage	-CC may limit other technologies from being developed

Annotation: Advantage (green) Neutral (yellow) Disadvantage (red)

Summary

- The AESO **supports** the selection of **a reference technology** that
  - **Promotes system reliability**
  - **Encourages competitive market forces** to select the **optimal new generation build** for the Alberta market
- The AESO developed a **selection criteria** methodology that factors **low development cost** and the **unique nature** of the Alberta market
- Base on a combination of the selection criteria and stakeholder feedback, the **reference unit to set net-CONE** on the demand curve **is an aeroderivative**
- An aeroderivative allows for the **greatest diversity** of future generation builds while **earning a reasonable return**
- Developers will select their preferred asset development **based on their expectations of the market and competition**

Question

Can the DCWG support the reference technology selection?

Resource Adequacy Modeling update

Technical Workgroup #5

August 16, 2018

AESO External

Demand Curve Workgroup Objective: AESO Resource Adequacy Model

- Through the WG process, AESO seeks workgroup members' review and feedback on the methodology, key inputs, and outputs of the AESO resource adequacy modeling that will determine the amount of capacity required to meet the defined reliability standard
  - Through the review feedback, acceptance is sought from the workgroup to validate that the AESO is using:
    - Reasonable assumptions and methodologies
    - Clear transparent process
    - Industry standard practices
- Today we will review changes to the Resource Adequacy Model (RAM) since the June 4 Working Group and review the latest draft outputs

Areas the AESO has Investigated and Adjusted

- Reviewed and validated planned outages
- Forced Outage Distributions
  - Redefined seasonal distributions
  - Reviewed and adjusted some forced outage instances
  - Tested significant extended forced outage events
- Intertie Distributions
- New Load Forecast
- Updated Results

Updated Planned Maintenance

- Reviewed and validated planned maintenance rates by looking at different 2-year periods and the AESO is comfortable with the current settings
- Due to data issue, no planned maintenance rates assigned to units that are less than 20 MW because the forced outages of these units capture the planned maintenance off-line time

	Maintenance Outage Rates			
Fuel	**Minimum**	**Maximum**	**Average**	**NERC POF[1] (2012 - 2016)**
Coal	0.0%	9.0%	3.9%	7.3%
CC	0.8%	3.6%	2.2%	8.1%
SC	0.0%	6.3%	0.6%	3.8%
Other	0.0%	5.9%	2.0%	N/A

1 – Planned Outage Factor - https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx (Brochure 4)

Updated Forced Outage

- Added seasonal forced outage distributions
  - A distribution of time-to-fail hours (TTF) and time-to-repair (TTR) hours were developed for winter and summer
  - The RAM randomly draws from two different sets of forced outage events. One set is for winter months and one set is for summer months
- By reviewing the model inputs, some planned outage events were identified and removed, while some forced outage events were identified and added

	Forced Outage Rates currently in the model						NERC FOF[2]
	Winter			Summer			(2012-2016)
	Minimum	Maximum	Average	Minimum	Maximum	Average	All Size
Coal	0.8%	11.4%	4.5%	1.6%	12.3%	4.8%	4.7%
CC	0.0%	6.6%	2.7%	0.0%	6.8%	3.5%	2.6%
SC	0.5%	13.6%	2.9%	1.1%	8.5%	3.9%	4.1%
Other	1.4%	8.0%	4.9%	2.5%	6.8%	5.6%	N/A
	Partial Outage Rates currently in the model						
Coal	0.5%	11.5%	3.8%	0.9%	9.3%	4.4%	N/A

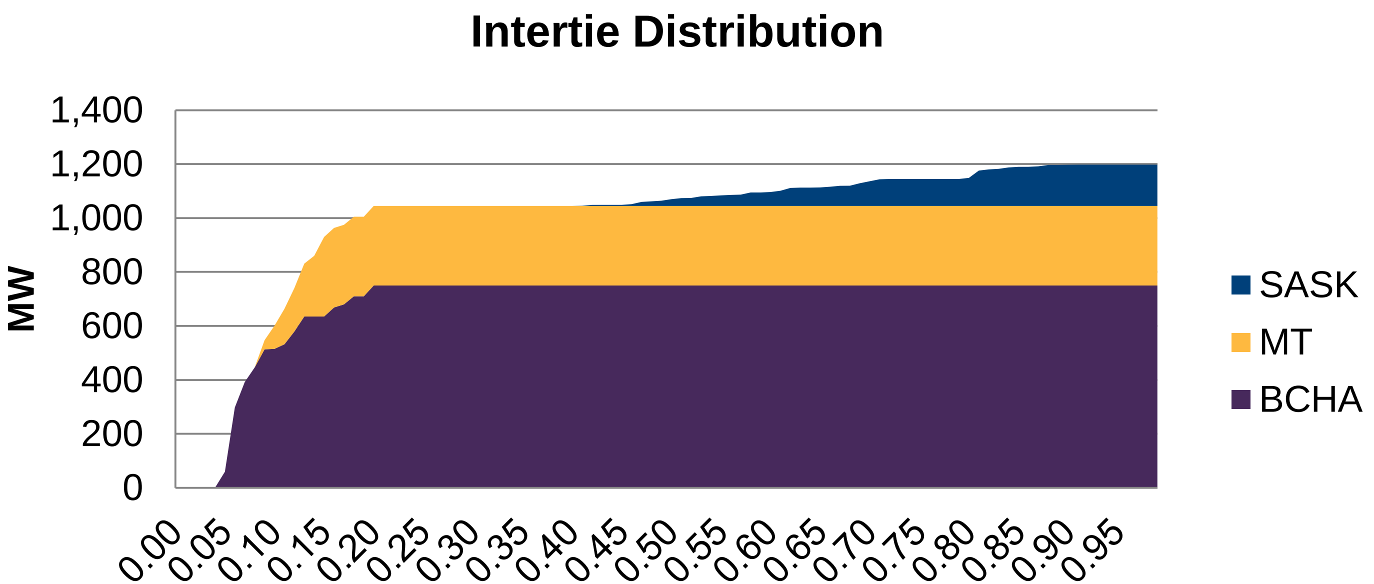
2 – Forced Outage Factor - https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx (Brochure 4)

Significant Extended Forced Outage Events

- The calculation of time-to-fail hours (TTF) and time-to-repair (TTR) hours are calculated from historical thermal Energy Trading System (ETS) data from 2012-2017.
  - EGC1; May 23, 2015 (~700 hours)
    - Event occurred shortly after commercial operations began
    - With only 2.5 years of historical data probability of this event is overstated within current distribution.
    - Weighting within the distribution has been reduced to approximately 1 in 5 year occurrence.
  - KH1; Mar 5, 2013 (~5,000 hours)
    - Full rewind of the generator stator was required
    - Unique event believed to be not representative of future potential outages
    - Removed from distribution

Updated Intertie Distributions

- Interties are modeled as pseudo units and a distribution of transmission availability was created to model impact of import capability from neighboring power grids and capture the effects of transmission constraints and outages
- For BC & MT, a tie-line availability distribution, based on historical ATC data and subject to transfer constraints, was developed
- For SASK, both historical ATC and historical gross offers were used to developed an availability distribution
- Overall the changes have lead increased instances of zero availability and increased limits when the intertie was available



2021/2022 Load Forecast Updated

	Min	Low	Ref	High	Max
Peak Load (MW)	12,227	12,309	12,395	12,493	12,591
Average* Values (MW)	9,929	9,994	10,061	10,141	10,221
Average* Total Annual Energy (TWh)	86,978	87,547	88,134	88,838	89,534

*Table values are average values of all weather years

- Updated the new load forecast using available 2018 data
  - Entrance of Fort Hills, Cryptocurrency Miners and Sturgeon Refinery
  - Between all weather years and scenarios, growth rate ranges between 0.95% and 1.82%[3] from 2017 actual to 2022.

3 – Compound Annual Growth Rate

Updated Draft – Results

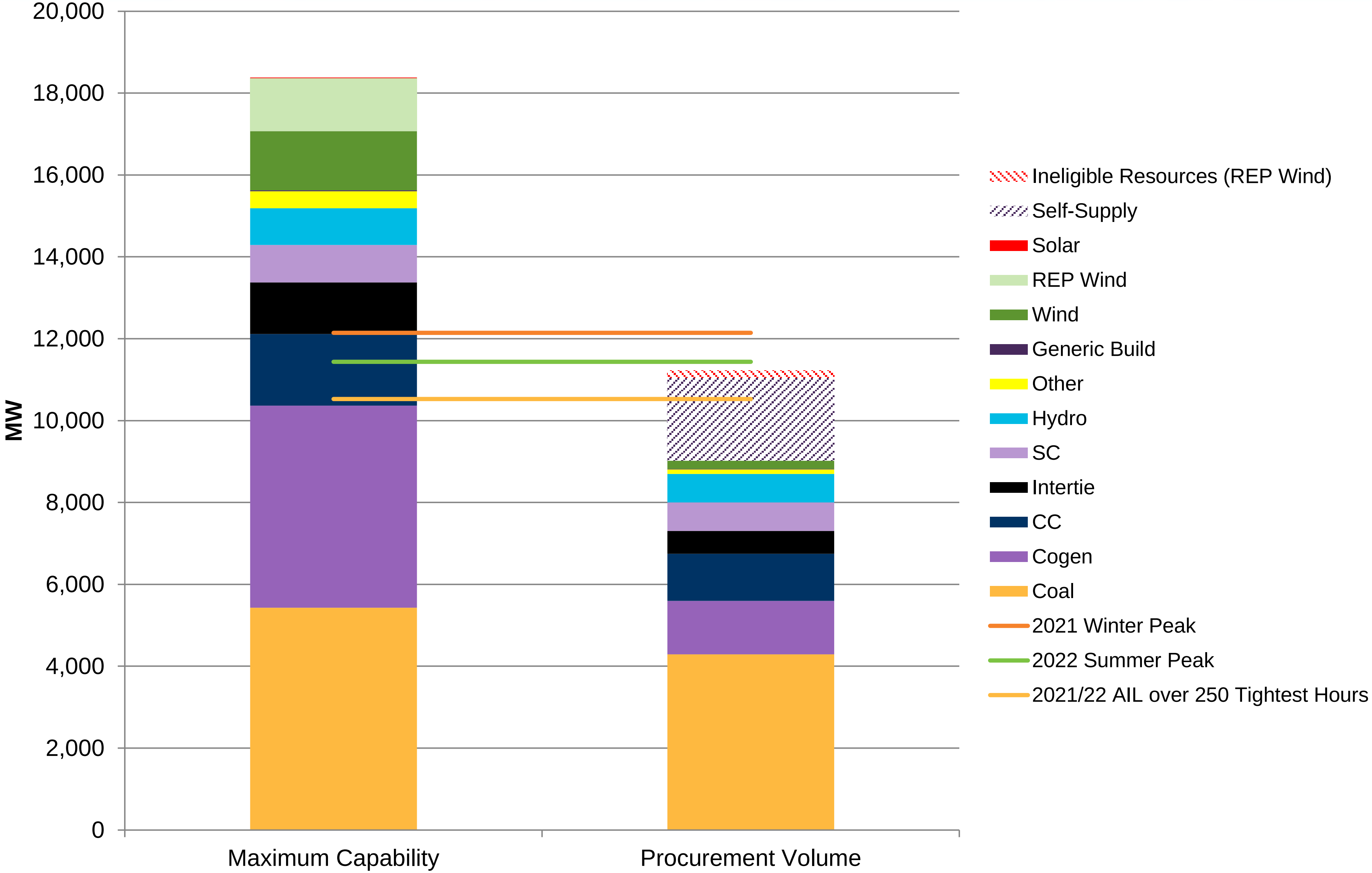
- The updated base case was run for the reference period Nov 2021 – Oct 2022
- The anticipated base generation fleet MC is 18,313 MW plus MC increments of reference technology
- The NEUE & Procurement Volume corresponding to the Resource Adequacy Standard was obtained by using a curve line fit to achieve the required %NEUE

Reserve Margin (ICAP)	Procurement Volume	%NEUE	EUE (MWh)	LOLE Capacity (Events per Year)	LOLH Capacity (Hours)
Base	9,012	0.001201%	1,058	3.79	10.37
Resource Adequacy Standard	**9,027**	0.001100%	970	3.52	9.70
RM1 (+95)	9,088	0.000770%	679	2.53	7.21
RM2 (+190)	9,164	0.000500%	440	1.70	5.11
RM3 (+285)	9,240	0.000338%	298	1.17	3.59
RM4 (+380)	9,316	0.000209%	184	0.75	2.43
RM5 (+475)	9,392	0.000125%	110	0.47	1.65
RM6 (+570)	9,468	0.000080%	70	0.31	1.13
RM7 (+665)	9,544	0.000050%	44	0.20	0.74
RM8 (+760)	9,620	0.000029%	25	0.11	0.50
RM9 (+855)	9,696	0.000018%	15	0.08	0.33
RM10 (+950)	9,772	0.000012%	10	0.05	0.20
RM11 (+1,045)	9,848	0.000006%	5	0.02	0.12
RM12 (+1,140)	9,924	0.000004%	3	0.01	0.08
RM13 (+1,235)	10,000	0.000001%	1	0.01	0.05
RM14 (+1,330)	10,076	0.000001%	1	0.01	0.03

Procurement Volume Translation

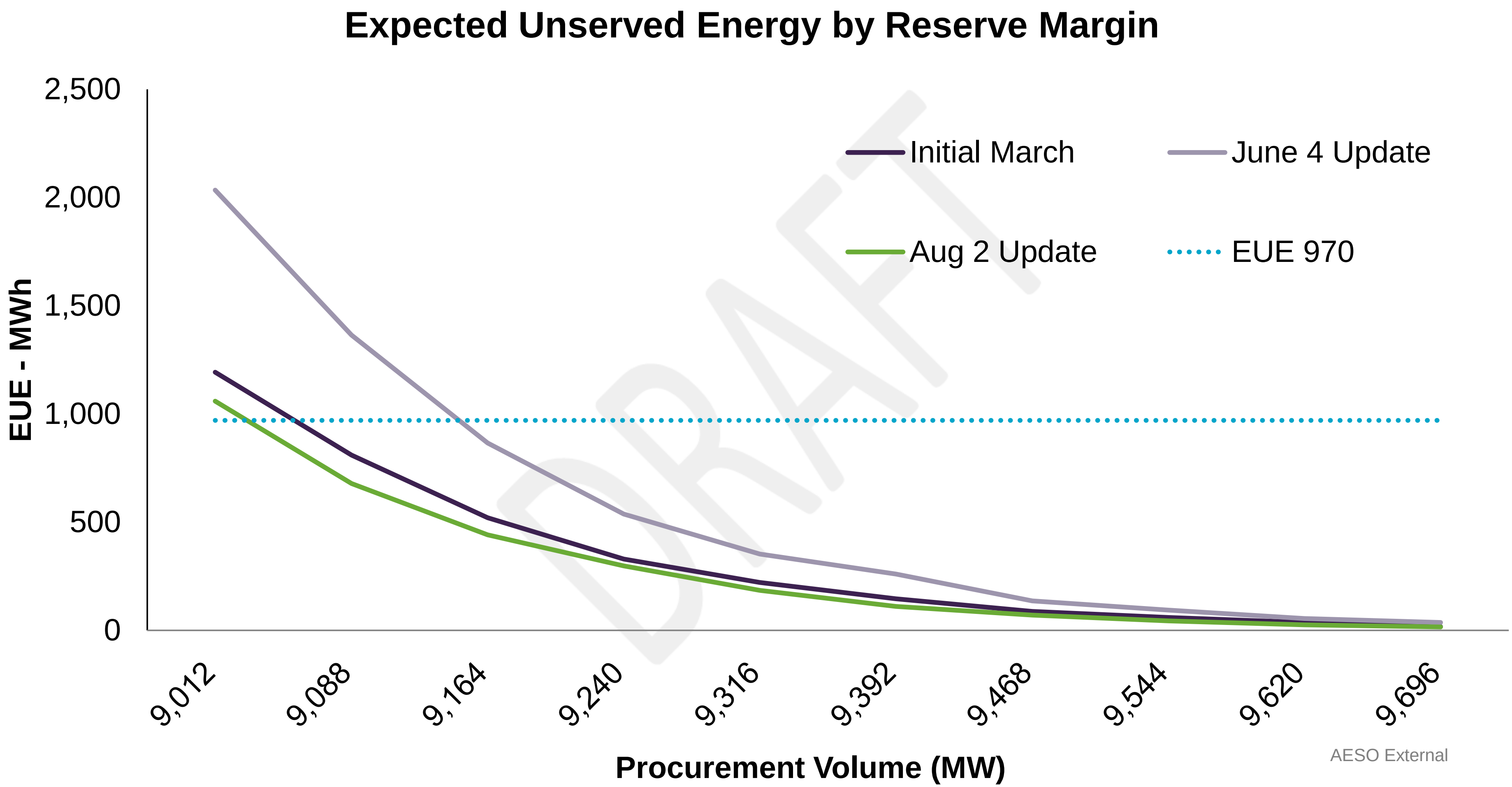
	RAM Output - 970 EUE (MW)	Performance Factor	UCAP (MW)	Self-Supply & Ineligible UCAP (MW)	Implied Gross UCAP (MW)
Coal	5,430	79%	4,290	0	4,290
Cogen	4,935	27%	1,309	1,686	2,995
CC	1,748	66%	1,146	147	1,293
REP Wind	1,296	0%	0	178	178
Wind	1,445	14%	198	0	198
Intertie	1,263	44%	562	0	562
SC	916	76%	696	28	723
Hydro	894	78%	695	0	695
Other	418	26%	109	158	266
Generic Build	18	80%	15	0	15
Solar	15	50%	8	0	8
Total	**18,378**	**49%**	**9,027**	**2,197**	**11,224**

Procurement Volume Translation

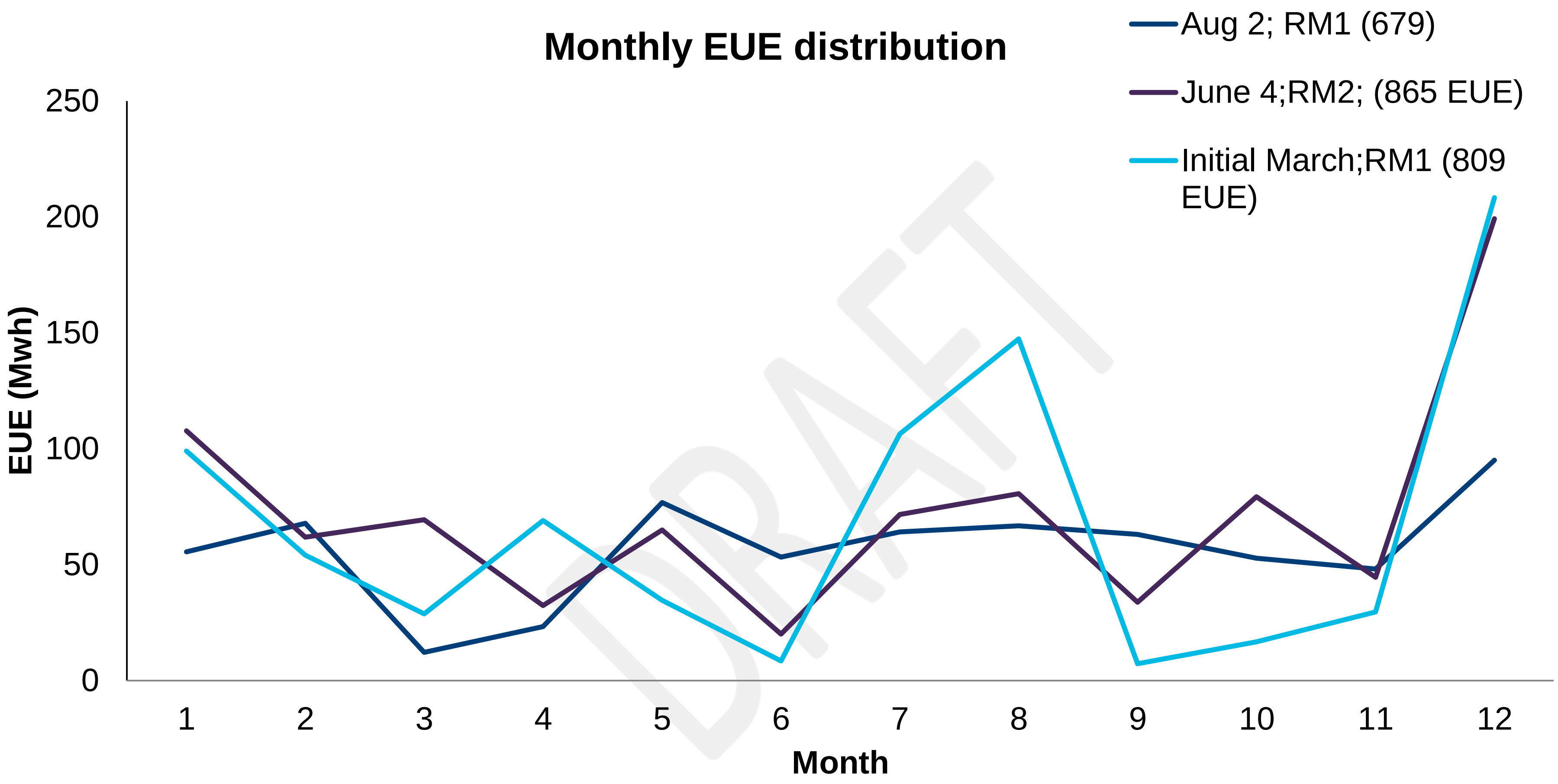


Updated Draft – Results

- The decreased need for procurement volumes for all levels of EUE, is due to the combination of changes in forced outage distribution and intertie distribution

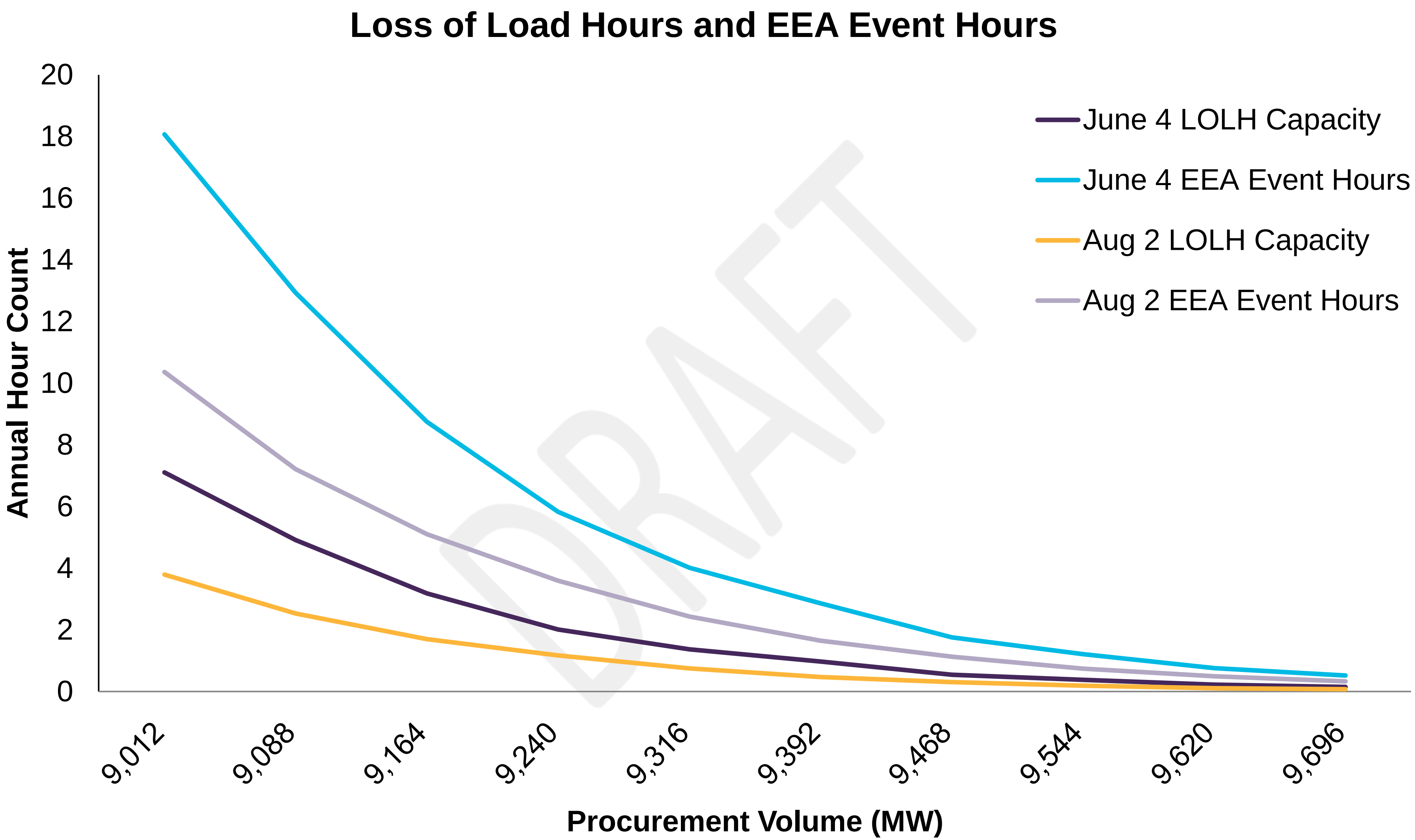


Updated Draft – Results Monthly



- The updated results show a smoother distribution of monthly outage events, representing tight supply conditions that are feasible anytime of the year

Updated Draft – Results



Next Steps

- AESO generally comfortable with model and outputs
  - The AESO will continue to review and recalculate inputs and rerun the model as needed
- Some continued areas of validation and minor refinements
  - Review and refine forced outage distributions
  - Update and run model with new load forecasts
  - No additional changes anticipated at this time prior to rule filing with AUC
- Any outstanding concerns from workgroup members?

Next Steps

- H2 2018: Details of methodology to be developed in demand curve rules
- H1 2019: Demand curve rules filing including procurement volume for first auction(s) for approval
  - UCAPs won't be finalized before filing so the procurement volume will be in ICAP

Thank You