Technical Workgroup #2

April 6th, 2018

AESO External

AESO CONE Study

Reference Technology and Financial Assumptions

PRESENTED TO

AESO Technical Working Group Session #2

PREPARED BY

Michael Hagerty
Mike Tolleth
Hannes Pfeifenberger
Bente Villadsen
The Brattle Group

Sang Gang
Patrick Daou
Sargent & Lundy

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THE Brattle GROUP

Agenda

- Project Overview
- Screening Analysis and Reference Technology Specifications
- Financial Assumptions
- Next Steps

What is CONE and Net CONE?

Cost of New Entry (CONE) is the total annual net revenues a new generation resource would need to earn on average to recover its capital investment and annual fixed costs

- Given reasonable expectations about future cost recovery over its economic life
- CONE represents long-run marginal cost of meeting the Resource Adequacy target

Net CONE is CONE minus expected annual net energy and ancillary service (E&AS) revenues

- Used to anchor the downward-sloping demand curve for the capacity auction
- Net CONE represents an estimate of capacity prices just high enough to attract sufficient new resources to maintain the Resource Adequacy target

Our role in estimating Net CONE for Alberta:

- Identify candidate reference technologies
- Develop estimates of CONE for the candidate reference technologies
- Review methodologies to compute E&AS revenue offsets
- Recommend approach for updating CONE in years between full estimates

Key Objectives for Estimating Alberta CONE

Provide CONE values for several candidate reference technologies that will allow AESO and its stakeholders to select the appropriate Net CONE value to anchor the demand curve

- Reflect the technology, location, and costs that a competitive developer of new generation facilities will be able to achieve at generic sites
- Avoid unusual site characteristics (*e.g.*, too tightly defined locations or specifications) and one-off opportunities that are not widely available
- Provide relevant research and empirical analysis to inform our recommendations, recognizing where judgments have to made; in such cases, discuss tradeoffs and recommendations for best meeting objectives

CONE Methodology

1) **Screen Alberta capacity resources to identify candidate reference technologies**
   - Reliably able to help meet system load when supply is scarce
   - Cost effective as a part of the long-term market equilibrium
   - Able to accurately estimate Net CONE
2) **Develop detailed specification of reference plants specific to Alberta market**
   - Primarily rely on "revealed preference" of recently developed and proposed plants
   - Review environmental regulations, interconnection requirements, fuel supply options
3) **Estimate costs to build and operate the specified reference plants**
   - Plant proper capital costs (equipment, materials, labor, EPC contracting costs)
   - Owner capital costs (interconnection, startup, land, inventories, financing fees)
   - Fixed O&M (labor, materials, property tax, insurance, asset management, working capital)
4) **Develop Alberta-specific financial assumptions used to translate costs into CONE**
   - Identify sample of representative companies and estimate their cost of capital
   - Consider additional reference points and qualitative risk adjustments
   - Select appropriate discount rate for merchant generation
5) **Compute CONE for Alberta capacity market**
   - Translate costs into the annualized cost recovery the plant would need to earn based on its cost recovery path, tax rates, and depreciation schedules over its economic life

Screening Analysis and Reference Technology Specifications

Candidates for Alberta Reference Technology

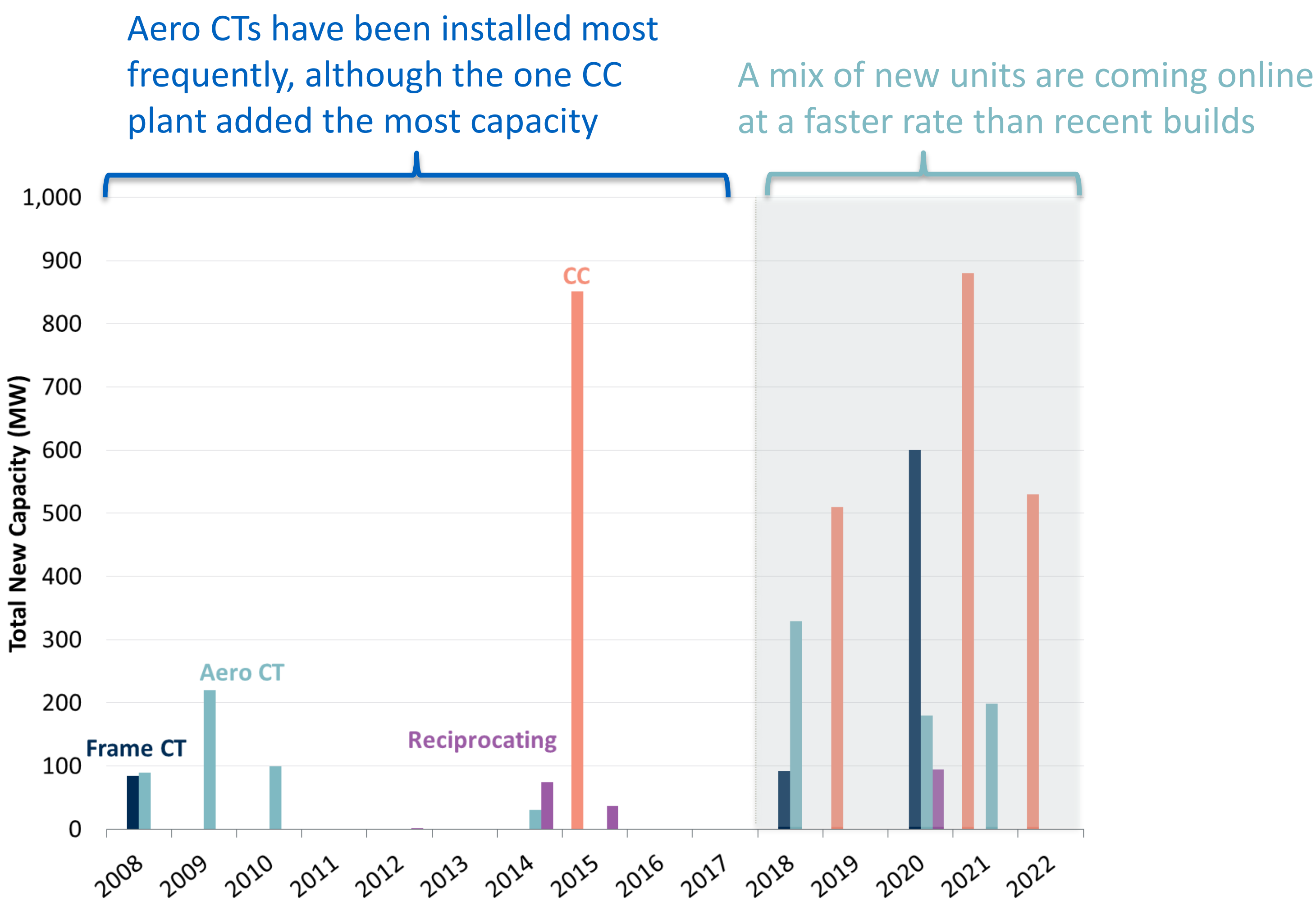
Technology	Typical Capacity (MW)	Alberta Installations (Planned) since 2008 (MW)	Indicative Plant Capital Costs* (CAD/kW)	Efficiency (kJ/kWh, HHV)	Speed of Deployment (months)	Primary Considerations for Including in Cost Estimates	Include in Cost Estimates?
Aero CT	45–115	483 (664)	$1,300–2,000	9,200–9,600	20 months	Most frequently built technology	✓
Frame CT	90–370	85 (692)	$700–1,850	9,500–11,900	20 months	Some recent builds; lowest capital cost	✓
CC	140–850	851 (1,920)	$1,200–1,700	6,500–7,800	36 months	Most recently installed and planned capacity	✓
Reciprocating Engine (RICE)	30–110	112 (94)	$1,450-1,900	8,800	20 months	Limited planned capacity despite low heat rate and similar capital costs	

High-level screen ruled out the following as reference technology candidates for Alberta:

- *Cogeneration* and *coal-to-gas conversions*: significant capacity in Alberta, but non-standard costs and economics; inherent constraints on future capacity
- *Renewables*: not dispatchable resources; built for non-resource adequacy purposes
- *Energy Storage*: costs remain high (~$400-500/kW-yr, but declining); limited capacity deployed
- *Demand Response*: non-standard costs and economics; inherent constraints

*Plant costs are high-level estimates intended for screening purposes only. A full bottom-up cost estimate will be used to calculate CONE values.
Source: Data downloaded from Ventyx's Energy Velocity Suite and S&P Global in February 2018, cross referenced with AESO LTA Study

Alberta Capacity by Generation Unit Type



Source: Data downloaded from Ventyx's Energy Velocity Suite and S&P Global in February 2018, cross referenced with AESO LTA Study.

Notes: Includes units that are at least permitted. Many of the units in 2018 have finished construction. Cogen units are excluded.

TECHNOLOGY SPECIFICATON

Turbine Models and Configurations

Simple cycle CTs

- LM6000 is the most built turbine type (total capacity and number of units)
- Both F-class and E-class frame turbines built
  - Table does not include turbines installed for cogen facilities

Combined cycles

- Most common CC configuration is 1x1 with H/J-class turbine
- CC capacity ranges from 350-850 MW

Recently Built and Planned CT Turbines in Alberta

Turbine Model	Turbine Type	Capacity Installed and Permitted since 2008 (MW)	Number Installed and Permitted since 2008
GE LM6000	Aero	719	15
Siemens SGT6-5000F	Frame	600	3
GE LMS100	Aero	200	2
Rolls-Royce Trent 60	Aero	198	3
GE 7EA	Frame	177	2
Wartsila 18V50SG	Reciprocating	94	5
Caterpillar-G16CM34	Reciprocating	65	10
Solar Turbines Inc-Titan 130	Aero	30	2
Cummins C2000 N6C	Reciprocating	20	10
Jenbacher JGS 620	Reciprocating	18	6
Wartsila 20V34SG	Reciprocating	9	1
Total		2,130	59

Recently Built and Planned CC Units in Alberta

Plant	Online Year	Turbine Model	Configuration	Capacity
Shepard Energy Centre	2015	Mitsubishi M501G1	2x1	851
Genesee (CAN)	2021	Mitsubishi 501J	1x1	530
Genesee (CAN)	2022	Mitsubishi 501J	1x1	530
Heartland Generating Station	2019	Siemens SGT6-8000H	1x1	510
Saddlebrook Power Station	2021	Siemens SGT6-5000F	1x1	350

Source: Ventyx's Energy Velocity Suite and S&P Global in February 2018, cross referenced with AESO LTA Study. Includes units built since 2008 and units that are under construction or permitted .

TECHNOLOGY SPECIFICATON

Frame CT Turbine Choice

✓ **We recommend specifying the F-Class turbine for the frame CT reference technology given its capital cost and efficiency advantages over the E-Class and its smaller size relative to the H-Class.**

Consideration	Units	E-Class	F-Class	H-Class
Summer Capacity per Turbine	MW	90–115 MW	240 MW	370 MW
Indicative Plant Capital Costs	CAD/kW	$1,300–1,850/kW	$700-1,100/kW	$650-1,000/kW
Efficiency	kJ/kWh, HHV	11,500–11,900	10,150	9,500
Alberta Capacity since 2008	Operating MW (Planned MW)	85 MW (92 MW)	0 MW (600 MW)	0 MW (0 MW)
Primary Considerations for Including in Cost Estimates		Smallest capacity and only existing frame CT in Alberta, but high capital costs and heat rate	Better efficiency and lower capital costs; most planned in Alberta	Best efficiency and lowest capital costs; none built or planned in Alberta; much larger than CTs built in Alberta
Include in Cost Estimates?			✓	

Source: Data downloaded from Ventyx's Energy Velocity Suite and S&P Global in February 2018, cross referenced with the AESO LTA Study

Environmental Controls (NO_x and CO)

NO_x Emissions

- Alberta Environment and Parks' (AEP) current (2005) emissions standards likely require dry low NO_x (DLN) burners
- AEP is updating standards and is evaluating SCR costs and performance, but has not provided an indication whether new standards will require gas-fired projects to include an SCR
- Recent CCs in Alberta have proposed including an SCR (*e.g.*, TransAlta, ATCO); likely being proposed to minimize opposition and project delays related to permitting

CO Emissions

- A national source standard of 50 ppm CO was established in 1992
- Current CO emissions standard likely will not require oxidation catalyst

Implications for Alberta Reference Technologies

- *CTs* would likely only require DLN burners
- *CCs* would likely include an SCR in anticipation of future NO_x regulation and to minimize opposition during permitting, although currently not strictly required

CO_2 Emissions Regulations and Turbine Choice

Federal CO_2 Emissions Regulations

- CO_2 limits apply to units with capacity factors (CF) of 33% or greater
- Units > 150 MW: 0.42 tons/MWh
- Units 25-150 MW: 0.55 tons/MWh

Implications for Alberta Reference Technologies

- *Aero CTs* and *CCs* are expected to be able to meet their respective emissions limits
- *Frame CTs* will have to operate at less than 33% CF, although historical run times of CTs indicate this limit is not likely to be binding

Alberta's *Carbon Competitiveness Incentive Regulation* may further deter higher heat rate CTs from entering the market

Fuel Supply Arrangements in Alberta

Reference CTs and CCs will not include dual fuel capability but instead will obtain firm transportation contracts and operate as "gas-only" units

- New gas-fired facilities likely to be required to sign 5-8 year Firm Transportation–Delivery (FT-D); 5 year min. if NGTL builds metering station, 8 year min. for lateral
- Beyond initial period, generators can choose to either renew FT-D contract or procure interruptible (IT) service and burn oil when gas is unavailable
  - Limited supply of IT service contracts; no guarantee of availability
  - IT service tariff comes with 10% premium over FT-D service
- Dual fuel capability can add approximately $30 – 60/kW to capital costs

Alberta Fuel Supply Cost Considerations

Cost Type	Gas Only	Dual Fuel
Capital Costs	Gas lateral/metering station	Gas lateral/metering station *plus* dual fuel capability
Fixed Costs	Firm Transportation – Delivery (FT-D) for all years	FT-D Years 1 – 5 (assuming NGTL only builds metering station)
Operating Costs	Gas hub price	Gas hub price + IT cost or ULSD

Proposed Reference Technology Specifications

Plant Characteristic	Aero CT	Frame CT	Combined Cycle
Turbine Model	LM6000	F-class	H-class
Configuration	2x0	1x0	1x1
Approx. Net Summer ICAP (MW)	90 MW	240 MW	550 MW
Without Duct Firing (MW)	--	--	500 MW
Cooling System	--	--	Wet Cooling Tower
Power Augmentation	None		
Net Summer Heat Rate, Without Duct Firing, ISO Conditions (kJ/kWh, HHV)	9,580	10,150	6,495
Dual Fuel Capability	No, gas-only with firm transportation service contracts		
Environmental Controls	Dry low NOx burners; no CO catalyst	Dry low NOx burners; no CO catalyst	SCR and dry low NOx burners; no CO catalyst
Maximum Allowable Annual Capacity Factor (*proposed federal CO_2 regulations*)	100%	33%	100%
Black Start Capability	No		
Onsite Gas Compression	No		
Interconnection (kV)	138 kV	240 kV	240 kV
Plot size (acres)	10	10	30

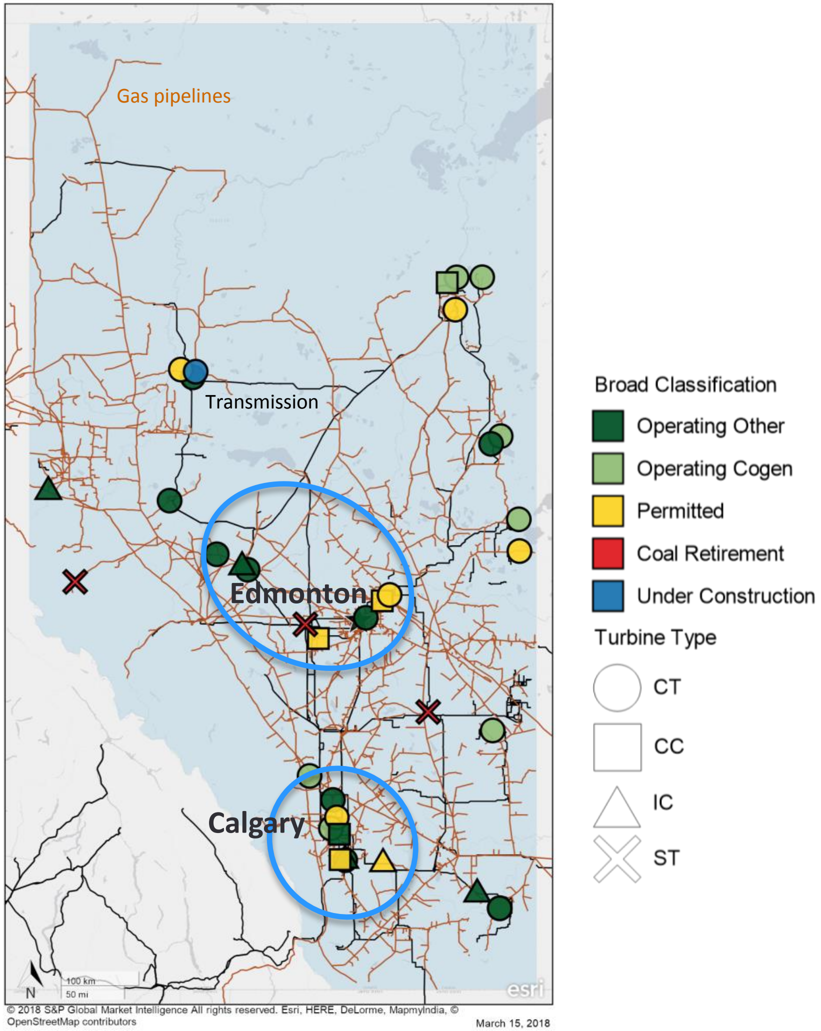
LOCATIONAL ANALYSIS

Alberta Reference Location

Both Edmonton and Calgary are potential locations for development with limited cost variation between the two

- *Recent Gas Builds*: Majority of gas plants are located near Calgary and Edmonton
- *Interconnection:* Gas and electric infrastructure available in both locations
- *Labor Costs*: Crew rates in Calgary and Edmonton are comparable; labor costs will not be major driver of location
- *Permitting*: Water supply may be an issue in the Calgary area
- *Losses Factors*: Similar, average is slightly higher in Edmonton than Calgary
- *Ambient Conditions*: Similar temp, relative humidity; lower elevation in Edmonton

Recommend the region around Edmonton for bottom-up cost estimates



Note: ST units are coal units scheduled to retire 2019-2025.

Next Steps: Plant Capital Cost Estimates

Major Equipment

- Current major OEM pricing in Alberta, validate OEM pricing against market trends
- Internal database of major BOP components for remainder of pricing

Labor

- Labor rates will reflect Edmonton labor pools as well as applicable overhead costs
- Per diem added if the site is considered remote or quantity of local labor is not sufficient
- Labor hours and productivity will be reflective of the local labor pools

Balance of Plant, Materials, & Commodities

- High level design to account for all the major systems required for plant operation
- Material and commodity quantities to match the BOP design
- BOP design will take into account site specific conditions, *i.e.* greenfield/brownfield, location ambient conditions, etc.

Owner's Development Costs

- Development, testing/startup, non-fuel inventories based on internal database
- Land, net startup fuel costs, and fuel inventories rely on local Edmonton market conditions
- Gas/electric interconnection costs based on recently observed project costs

Financial Assumptions

FINANCIAL ASSUMPTIONS

Cost of Capital Principles for CONE Discount Rate

Forward-looking opportunity cost of capital appropriate to the *risk of the enterprise being contemplated*:

- Development and operation of green-field gas-fired generating plant in Alberta
- Revenue from merchant sales into Alberta wholesale market—not PPA contracted capacity—since…
  - PPA transfers market risk from generator to counterparty
  - Capacity market is intended to attract investment without bilateral contracting

After-tax Weighted Average Cost of Capital (ATWACC)

- Represents total after-tax cost of financing:

$$ATWACC \;=\; \%E \times r_E \;+\; \%D \times r_D \times (1 - t)$$

- Appropriate formulation for discounting unlevered free cash flows (which CONE calculation does to annualize plant costs)
- *Independent of specific financing* over a broad middle range of capital structures
  - Recognizes that required return on equity increases with financial risk of additional debt leverage

Approach to Estimating Alberta Cost of Capital

Public Sample Companies
- Risk-appropriate proxy groups
- Estimate ATWACC from market data
- Forward-looking inputs as of 2018

Recent IPP Transactions
- Discount rates (ATWACC) used for valuations (fairness opinions)
- Adjust for changes in market conditions

Range of Risk-Appropriate ATWACC Estimates for Merchant Operations

Qualitative Risk Assessment

Alberta-Specific ATWACC

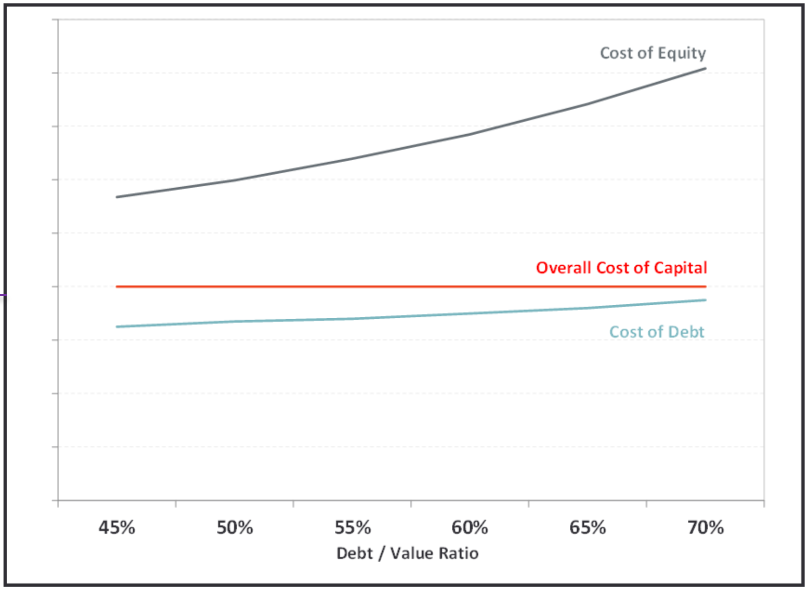
Internally Consistent Financing Components

Debt-to-Equity Ratio

Cost of Equity

Cost of Debt

Overall Cost of Capital and Its Components



Sample Electric Generation Companies

- *Goal*: find publicly-traded companies that proxy the systematic market risk of Alberta gas-fired merchant generation as closely as possible
  - Ideally:
    - Pure-play independent power producers with gas-fired capacity
    - Selling power on a merchant basis in North American markets
- Considered U.S. IPPs and Canadian companies with unregulated generation

Electric Generation Companies With Stock Traded on U.S. and Canadian Exchanges

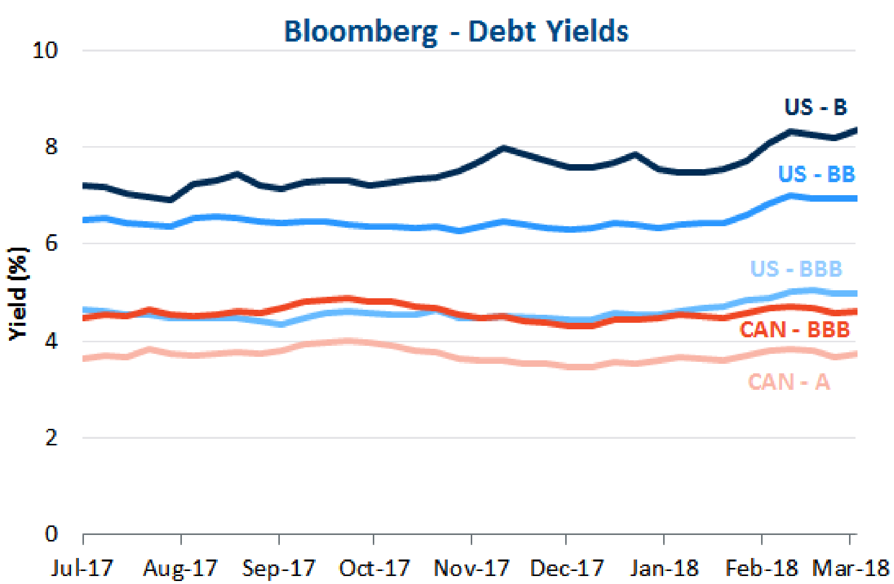
Category	Company	Business Segments Including Electric Generation	Generation as a % of Operations	Merchant Share of Generating Capacity
Canadian Sample				
Electric generation	Capital Power Corporation	Operation of electrical generation facilities	100%	47%
	Northland Power Inc.	Thermal, on-shore and off-shore renewables	100%	Small
	TransAlta Corporation	Canadian, U.S., and Australian generation, energy marketing	100%	10%
Generation with utilities	Algonquin Power & Utilities Corp.	Renewable power group	13%	Small
	ATCO Ltd.	Electricity global business unit (only 20% unregulated)	41%	24%
Generation with other segments	AltaGas Ltd.	North american generation	11%	4%
	TransCanada Corporation	Power generation	33%	7%
U.S. Sample				
Electric generation	Atlantic Power Corporation	Eastern U.S., Western U.S., and Canadian generation	100%	12%
	Calpine Corporation	Power generation	100%	Most
	Dynegy Inc.	Power generation	100%	Most
	NRG Energy, Inc.	U.S. generation and renewables	66%	Majority

Source: 2017 annual reports

Estimating ATWACC – Sample Companies

Canadian and U.S. Generator Summary

Category	Company	Ticker	Credit Rating (S&P)	Beta	Equity Ratio	Market Capitalization
Canadian Sample						
Electric generation	Capital Power Corporation	TSX:CPX	BBB-	0.94	47%	2,553 CAD
	Northland Power Inc.	TSX:NPI	BBB	0.86	42%	4,088 CAD
	TransAlta Corporation	TSX:TA	BBB-	1.55	32%	2,163 CAD
Generation with utilities	Algonquin Power & Utilities Corp.	TSX:AQN	BBB	0.80	53%	6,109 CAD
	ATCO Ltd.	TSX:ACO.X	A-	0.90	38%	6,109 CAD
Generation with other segments	AltaGas Ltd.	TSX:ALA	BBB	1.09	53%	5,053 CAD
	TransCanada Corporation	TSX:TRP	A-	0.95	51%	54,595 CAD
U.S. Sample						
Electric generation	Atlantic Power Corporation	NYSE:AT	B+	1.16	19%	278 USD
	Calpine Corporation	Acquired 3/9/18	B+	0.97	35%	5,444 USD
	Dynegy Inc.	NYSE:DYN	B+	1.29	29%	1,651 USD
	NRG Energy, Inc.	NYSE:NRG	BB-	1.14	27%	8,858 USD



Source: Bloomberg

Canadian Generators

Three categories:

- Pure-play: CPX, NPI, TA
- Mixed with regulated utility: AQN, ACO
- Mixed with other businesses: ALA, TRP

Characteristics:

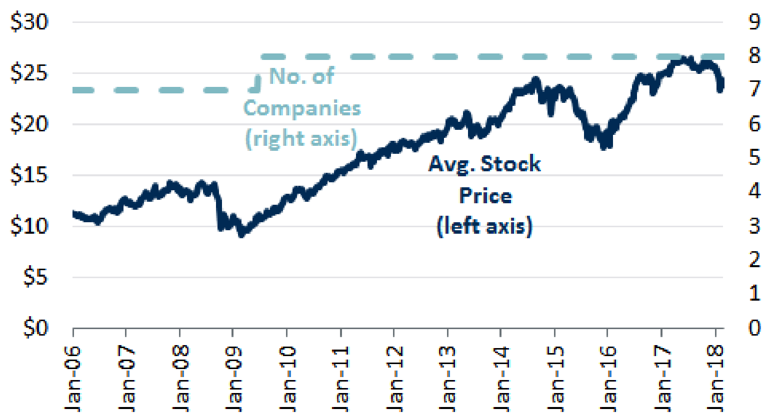
- **Most capacity under PPA**
- Moderate leverage
- Strong credit -> low debt cost

U.S. Generators

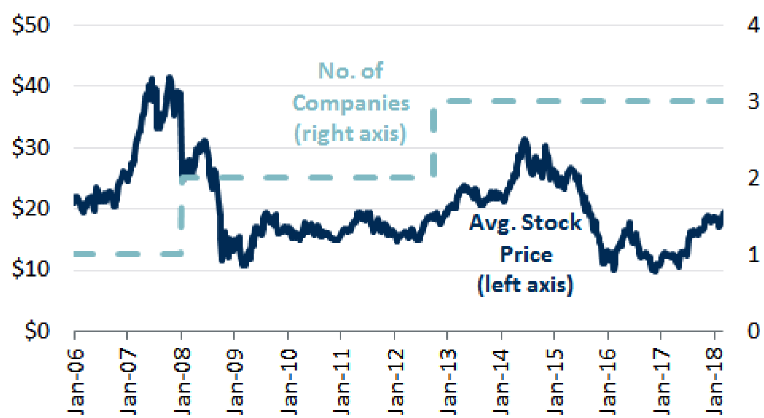
- Mostly merchant (except AT)
- Highly leveraged
- Weaker credit -> higher debt cost

Estimating ATWACC – Sample Companies

Stock Prices of Canadian Generator Sample



Stock Prices of U.S. Generator Sample



Source: Bloomberg

Canadian and U.S. Samples

- Canadian generators mostly earn revenue under long-term PPA contracts
  - Company composition fairly stable
  - Some have unregulated generation integrated with other business segments
- U.S electric generator sample is characterized by greater degree of merchant sales into wholesale power markets
  - Relatively "pure play" independent power producers
  - Few companies, frequent M&A activity, and some bankruptcies
- Directionally, we believe U.S. IPPs have higher systematic risk, but neither group may fully capture risk of merchant gas-fired generation in Alberta power market

Estimating ATWACC – Transaction Benchmarks

Discount Rates Used in Recent Generation Asset Transactions

- U.S. M&A transactions are accompanied by Proxy Statements, which include valuations, often performed by discounting projected cash flows at the ATWACC
  - Assumptions underlying the ATWACC calculation are not typically explained
  - Transaction proxy statements are a reference point to help benchmark the cost of capital
- We view three recent/ongoing acquisitions in the U.S. IPP space as relevant
  - **Talen**, a public company that controlled 16,000 MWs of capacity, was acquired by the private company Riverstone Holdings in 2016
  - **Calpine**, a public company that owned 26,000 MWs of capacity, was acquired by Energy Capital Partners and a consortium of other private investors (closed in 2018)
  - **Dynegy**, a public company that owns 22,000 MW of capacity, is being acquired by Vistra

Discount Rates Applied in Transaction Proxy Statements

Announce Date	Close Date	Buyer	Target	Valuation Date	Stated Discount Rate Range (ATWACC)	Adjusted Forward-Looking Range
30-Oct-2017	ongoing	Vistra Energy	Dynegy	01-Jan-2018	4.6% - 7.7%	5.9% - 9.0%
18-Aug-2017	08-Mar-2018	Energy Capital Partners	Calpine	01-Jun-2017	5.75% - 6.25%	7.1% - 7.6%
03-Jun-2016	06-Dec-2016	Riverstone Holdings	Talen	02-Jun-2016	5.9% - 7.3%	7.6% - 8.6%

Source: SEC DEFM14A Proxy Statements

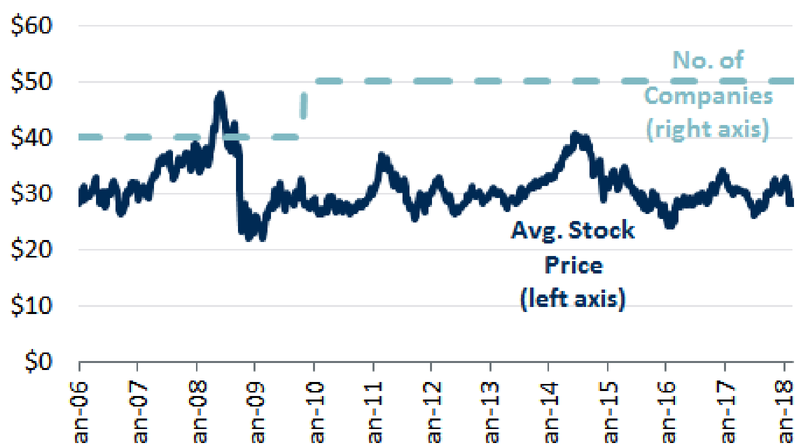
Notes: Talen Proxy Statement range includes valuations from January 2016 as well as May/June 2016. Forward-looking adjustments based on changes in risk-free rate: U.S. 20-yr T-bond yields were 2.6% in both January 2016 and January 2018, and 2.2% in June 2016; current yields are 3.0% and forecasts 4.2% for 2022.

Reference Point Sample: Oil Sands Companies

Canadian Oil Sands Sample

Company	Ticker	Credit Rating (S&P)	Beta	Equity Ratio	Market Capitalization (CAD)
Canadian Natural Resources Limited	TSX:CNQ	BBB+	1.78	73%	53,910
Cenovus Energy Inc.	TSX:CVE	BBB	1.45	73%	14,138
Husky Energy Inc.	TSX:HSE	BBB+	1.39	77%	16,862
Imperial Oil Limited	TSX:IMO	AA+	1.08	87%	32,182
Suncor Energy Inc.	TSX:SU	A-	1.18	80%	73,247

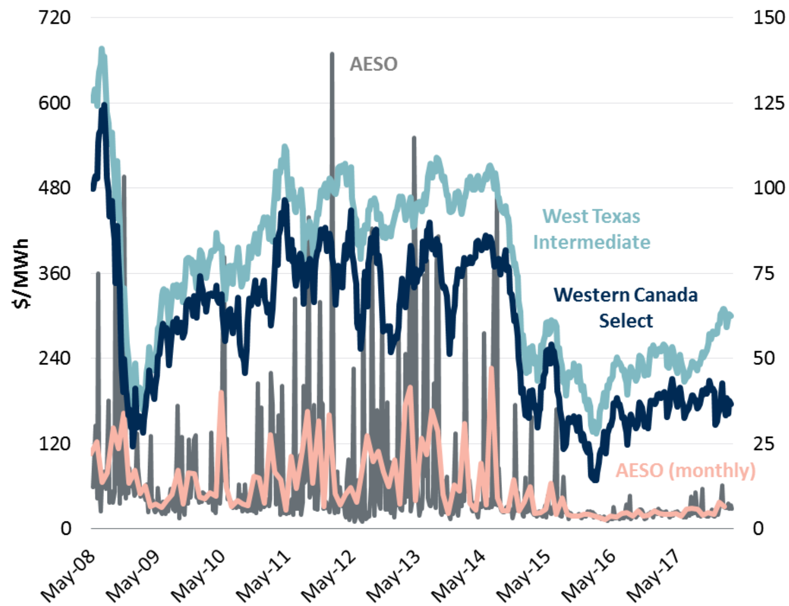
Stock Price History



Alternative Sample – Canadian Oil Sands

- Brattle is also investigating as a reference point a sample of petroleum producers with operations focused in the Alberta oil sands.
- Characteristics: low leverage / strong credit, but high systematic equity risk

Spot Crude and Power Prices



Sources: Bloomberg, Ventyx

ATWACC Models and Inputs

Market-based Estimates for Public Companies

- *Cost of Equity* (r_E) estimated using Capital Asset Pricing Model (CAPM):*

$$r_E = r_f + \beta \times MERP$$

  - r_f - risk-free interest rate based on long-term Treasury yields
  - *Market Equity Risk Premium (MERP)* - historical arithmetic averages and market-implied forward-looking estimates
  - *Equity beta (β)* estimated based on historical stock returns as measured by Bloomberg
- *Cost of Debt* (r_D) based on market yields of corporate bonds with same credit rating
  - Yields for market indexes based on issuer credit ratings
  - Yields for specific issuances by sample companies (where available)
- *Capital structure* based on market values of debt and equity
  - Usually average over period of beta estimation
- *Tax rate* (t) – marginal composite (federal and provincial) corporate tax rate

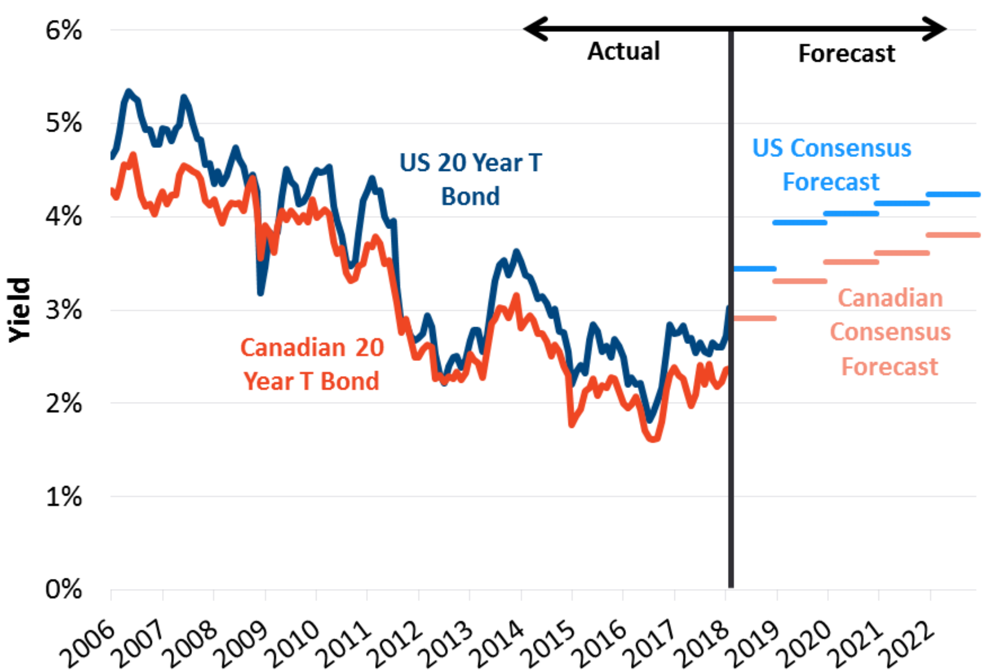
* Additional models (e.g., the DCF) are also estimated, but data limitations restrict their use for CONE estimation. We are evaluating their use for the Alberta CONE study.

Cost of Equity Inputs

Risk-free rate and Market Equity Risk Premium (MERP)

- We analyzed Canadian and U.S. 20-year government bond yields:
  - 3.8% and 4.2%, respectively, by the end of 2022
- We use MERP of 7%, which is broadly consistent with historical and forward-looking (market-implied) estimates for Canada and the U.S.

Canadian and U.S. Treasury Bonds



Source: Bloomberg, Consensus Forecasts.

Market Equity Risk Premium

	Historical Average MERP	Current Market Implied MERP
	[1]	[2]
Canada	5.7%	9.0%
U.S.	6.9%	6.8%

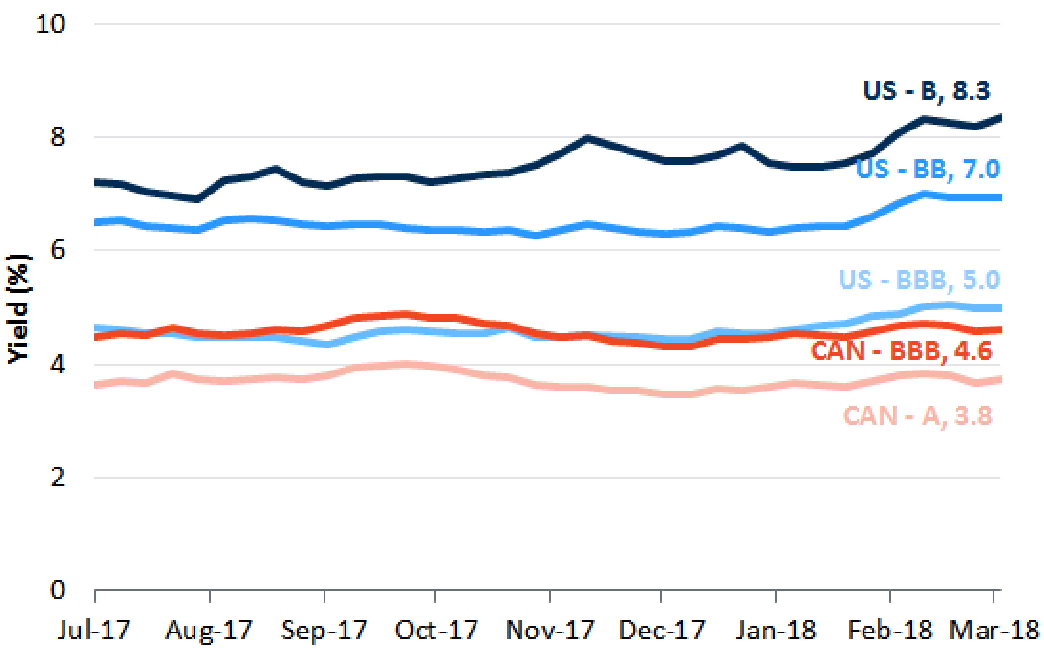
[1]: Duff and Phelps, International Guide to the Cost of Capital, 2017. 1926-2016 for U.S.; 1935-2016 for Canada
[2]: Bloomberg; adjusted to be expressed relative to 20-year T-bond yield.

Cost of Debt Inputs

Corporate Bond Yields

- We analyzed yields from 20-year Canadian and U.S. corporate bond indexes to infer marginal cost of debt
  - Match sample companies' issuer ratings to the ratings range of the index
  - Forward-looking adjustments made to reflect forecast rising interest rates
- Also researching yields on company-specific bond issues, which may differ

Canadian and U.S. Corporate Bond Index Yields



Source: Bloomberg

Financing New Power Generation Projects

Capital required to fund new generation projects is typically a combination of equity investments and debt financing. The debt can be financed in two ways:

- *Project financing* (non-recourse financing)
  - Debt is repaid strictly through project revenues; in the event of insolvency, lenders can only recover their investment from the project itself
  - Higher costs due to higher risk of default; exposure to transitory periods of cash flow shortfall from merchant operations in volatile markets
  - Despite high cost, may be attractive to developers as the only source of available financing or because it limits the equity investor's risk to initial equity investment
  - Generally requires long-term PPAs because lenders must be confident in project's revenue stream in order to accept the higher risk of default
- *Balance sheet financing*
  - Debt is funded with recourse to owner/developer's entire balance sheet
  - Greater certainty for lenders; repayment tied to solvency of a large, diversified company
  - Requires investors with sufficient scale and diversification, but increases financing opportunities for merchant generation projects without PPAs

Our CONE estimates will rely on balance sheet financing, because

- The discount rate used to translate costs into CONE should depend on project risk, not the method of financing
- When available, balance sheet financing is generally lower cost than project financing
- The Alberta market, like other deregulated power markets, does not support investment cost recovery through long-term PPAs (as would be required to obtain project financing); suppliers must bear the risk that a particular investment will be uneconomic. This makes Alberta unattractive to investors who typically provide project-financing.

Project Finance Debt Costs

We researched projects since 2000 that relied on project financing and found that most project financing is for projects with long term PPAs

- Limited public data on project financing for merchant gas plants
- Merchant plants tend to have higher interest rates than those backed by a PPA

Project Financing Summary for Sample Companies

Company	Project	Project Location	Type of Project	Interest Rate	Project/PPA Start Year	PPA Length (Years)	PPA Counterparty
Canadian Projects							
Northland	Kirkland Lake	Ontario	Thermal plant	2.8%	1991	24	IESO
TransAlta	Poplar Creek	Alberta	Cogen	4.8%	2001	Merchant	Merchant
Northland	Cochrane Solar	Ontario	Solar	5.3%	2015	20	IESO
Capital Power	East Windsor (acquisition)	Ontario	Cogen	6.3%	2009	20	IESO
ATCO	Muskeg River Cogeneration Plant	Alberta	Cogen	7.6%	2003	39	Athabasca Oil Sands Project
ATCO	Cory Cogeneration Plant	Saskatchewan	Cogen	7.6%	2003	25	Saskatchewan Power Corporation
ATCO	Scotford	Alberta	Cogen	7.9%	2003	40	Athabasca Oil Sands Project
Capital Power	Joffre Cogeneration Project	Alberta	Cogen	8.3%	2001	Merchant	Merchant
ATCO	Joffre Cogeneration Project	Alberta	Cogen	8.6%	2001	Merchant	Merchant
Non Canadian Projects							
Northland	Nordsee One	Germany	Offshore wind	2.2%	2014	13	German Govt. Renewable Energy
Northland	Deutsche Bucht	Germany	Offshore wind	2.8%	2019	13	German Govt. Renewable Energy
Calpine	Los Esteros	California	Combined Cycle	3.7%	2013	10	Pacific Gas and Electric
Northland	Gemini	Netherlands	Offshore wind	3.8%	2017	14	N.A.
NRG	Agua Caliente	Arizona	Solar	5.4%	2014	25	Pacific Gas and Electric
NRG	Alta Wind II	California	Wind	5.7%	2011	30	Southern California Edison
NRG	Alta Wind IV	California	Wind	5.9%	2011	30	Southern California Edison
NRG	Alta Wind III	California	Wind	6.1%	2011	30	Southern California Edison
NRG	Alta Wind V	California	Wind	6.1%	2011	30	Southern California Edison
Atlantic Power	Cadillac	Michigan	Biomass	6.2%	1993	35	Consumers Energy Company
Calpine	Russell City	California	Combined Cycle	6.5%	2013	10	Pacific Gas and Electric
Capital Power	Macho Springs	New Mexico	US Wind	7.0%	2011	20	Tuscon Electric Power Company
NRG	Alta Wind I	California	Wind	7.0%	2010	30	Southern California Edison
Calpine	Bethpage Energy Center 3	New York	Combined Cycle	7.2%	2005	20	Long Island Power Authority
Calpine	OMEC	California	Combined Cycle	7.2%	2009	10	San Diego Gas and Electric
Atlantic Power	Piedmont	Georgia	Biomass	8.2%	2013	19	Georgia Power Company
Calpine	Pasadena	Texas	Cogen/Combined Cycle	8.9%	2000	Merchant	Merchant

Source: 2017 annual reports and S&P Global in March 2018

Next Steps and Schedule

Next Steps

- Finalize candidate Alberta reference technology specifications
- Develop bottom-up cost estimates
- Calculate and finalize recommended ATWACC for Alberta generation investment
- Apply financial model to calculate CONE
- Review Alberta net E&AS revenue methodologies

Stakeholder Meeting Schedule

- *May*: Provide progress update
- *June*: Present draft CONE results

Appendix

Alberta Capacity by Gen Type

	Capacity					Count				
Year	CC	Frame CT	Aero CT	RICE	Cogen	CC	Frame CT	Aero CT	RICE	Cogen
2008	0	85	90	0	0	0	1	2	0	0
2009	0	0	220	0	0	0	0	4	0	0
2010	0	0	100	0	151	0	0	1	0	3
2011	0	0	0	0	50	0	0	0	0	1
2012	0	0	0	1	133	0	0	0	1	2
2013	0	0	0	0	85	0	0	0	0	1
2014	0	0	30	74	0	0	0	2	11	0
2015	851	0	0	37	285	1	0	0	15	4
2016	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0
2018	0	92	329	0	380	0	1	5	0	2
2019	510	0	0	0	214	1	0	0	0	4
2020	0	600	180	94	96	0	3	4	5	2
2021	880	0	198	0	540	2	0	3	0	6
2022	530	0	0	0	35	1	0	0	0	1
Total Existing	851	85	440	112	703	1	1	9	27	11
Average Existing MW	851	85	49	4	64					
Total Planned	1,920	692	707	94	1,265	4	4	12	5	15
Average Planned MW	480	173	59	0	84					

Note: This includes natural gas fired units in Alberta All of these units through 2017 are operating, as well as some in 2018. All of the units starting in 2018 are at least permitted. If CT units did not include a turbine type to identify the type, the following assumptions were made: 15 - 110 MWs were aero and greater than 110 MWs were frame type.

Source: Data downloaded from Ventyx's Energy Velocity Suite and S&P Global in February 2018, cross referenced with the AESO Long Term Adequacy Study

Comparison of Alberta to Rest of Canada

New Natural Gas-Fired Capacity in Alberta and the Rest of Canada, 2008-2017

	Alberta Capacity					Rest of Canada Capacity			
Year	CC	Frame CT	Aero CT	RICE	Cogen	CC	> 110 MW CT	15-110 MW CT	RICE
2008	0	85	90	0	0	1,588	330	0	25
2009	0	0	220	0	0	1,515	0	178	0
2010	0	0	100	0	151	948	0	237	0
2011	0	0	0	0	50	0	0	86	0
2012	0	0	0	1	133	174	393	0	26
2013	0	0	0	0	85	261	0	0	0
2014	0	0	30	74	0	0	0	0	0
2015	851	0	0	37	285	205	0	0	0
2016	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	296	0	0	0
Total	851	85	440	112	703	4,987	723	501	50
Average MW	851	85	49	4	64	453	181	42	10

Source: Data downloaded from Ventyx's Energy Velocity Suite in February 2018.

Note: This includes all recently built, natural gas-fired units in Alberta and the rest of Canada, 2008-2017.

Alberta Oil Sands Business Segments

Alberta Oil Sand Production Companies With Stock Traded on U.S. and Canadian Exchanges

Company	Business Segments Including Oil Sands	Oil sands as a % of Revenues
Canadian Natural Resources Limited	Oil sands mining and upgrading	25%
Cenovus Energy Inc.	Oil sands; deep basin development	45%
Husky Energy Inc.	Upstream: exploration, production, infrastructure and marketing	36%
Imperial Oil Limited	Upstream (production for sale)	31%
Suncor Energy Inc.	Oil sands mining and in situ	40%

Source: 2016 and 2017 annual reports

Resource Adequacy Modeling

Technical Workgroup #2

April 6th, 2018

Technical Workgroup Objective: AESO Resource Adequacy Model

- Through the WG process seeking workgroup members review and provide input 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 target.
  - Through the review feedback and acceptance will be 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 the Resource Adequacy Model (RAM), specifically the outstanding inputs from the 2017 discussion and review preliminary draft results.

Revised Agenda

For Discussion:

- Astrapé, SERVM and the Model Mechanics
- Thermal
  - Maintenance, Forced Outage, Seasonal Derates
- Cogeneration
- Emergency Operations/Ancillary Services
- Draft - Results
  - Reserve Margin
  - Reference Technology
  - Draft Result
  - Sensitivities
- Next Steps

For Information:

- Demand
  - Weather/Economic
- Intertie
- Renewable
  - Wind, Solar, Hydro

Material for Discussion

Astrapé, SERVM and the Model Mechanics

- AESO has procured the Strategic Energy and Risk Valuation Model (SERVM) which is managed by Astrapé Consulting
  - SERVM was developed in 2005
  - Astrapé has extensive experience in resource adequacy modeling, assessing physical reliability metrics as well as capturing economic metrics for regulated utilities, regulators, and independent system operators.
  - Clients include CPUC, ERCOT, SPP, Southern Company, PJM and MISO and FERC
- The tool allows for fast simulation of thousands of iterations of unit performance to identify frequency and magnitude of firm load shed events.
  - Hourly chronological dispatch
  - Stochastic (Monte Carlo) simulation
  - Distribution for load/weather, load growth uncertainty, outages, intermittent renewable output, intertie, and emergency operating procedures

Astrapé, SERVM and the Model Mechanics

- Construction of Scenarios: after a resource mix is defined SERVM runs 7,500 different 8,760 hour simulations
  - 30 Weather years (Load and Renewable profiles)
  - Load forecast error (Distribution of 5 points)
  - Unit outage modeling, capturing frequency and duration (50 iterations)

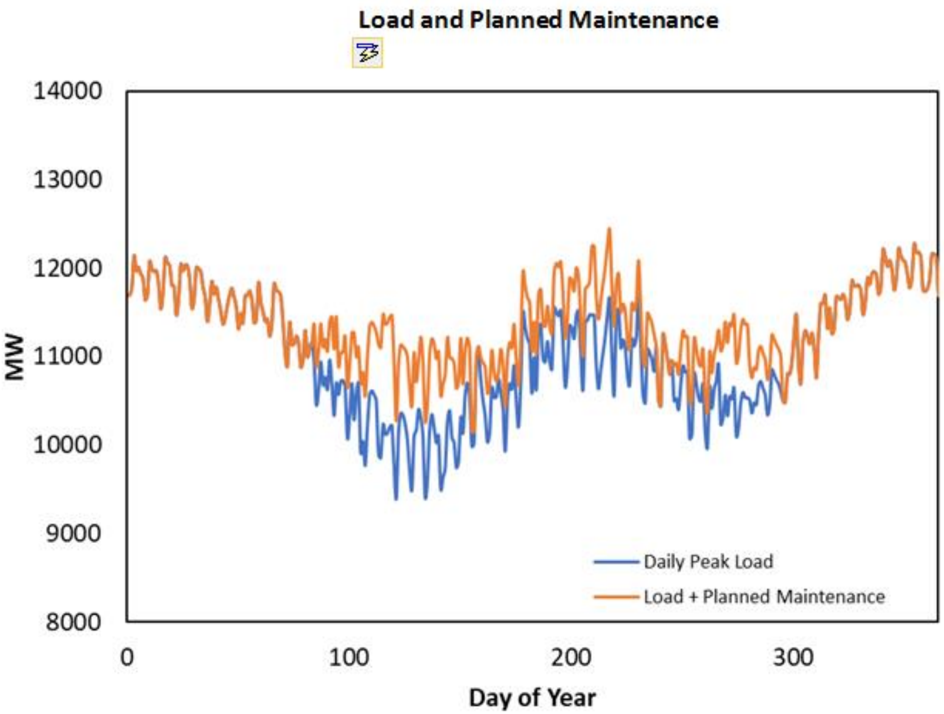
SERVM Framework for Creating Different Scenarios

30 Weather Years (Equal Probability)	x	5 LFE Points (Associated Probabilities)	=	150 Load Scenarios (Associated Probabilities)
150 Load Scenarios (Associated Probabilities)	x	50 Iterations of Unit Performance	=	7,500 Different 8,760 Hour Simulations

Thermal – Planned Maintenance

- The maintenance scheduling algorithm in Resource Adequacy Model (RAM) is to schedule maintenance events such that each event scheduled impacts the lowest load days possible.
- The algorithm is based on daily peak loads, thus placing significant maintenance events in the spring and fall based on lower loads in those periods.
  - Historical Available Capacity (AC) data (2015-2016) was used to analyze planned maintenance.
    - While the maintenance patterns vary from year-to-year for individual generators, the aggregate MWh on maintenance for the entire system is relatively stable thus 2 years is a reasonable proxy for maintenance events
  - For non-coal units that were missing data, a 2% maintenance rate was entered
  - As the outage scheduling algorithm doesn't account for lower cogeneration output in the shoulder season, some maintenance events were manually scheduled and placed in the summer as to not exacerbate reliability issues.

Thermal – Planned Maintenance



	Maintenance Outage Rates used in this initial model			
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%
Other	0.0%	5.9%	2.0%	N/A
SC	0.1%	6.3%	1.3%	3.77%

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

Thermal – Forced Outage

- A distribution of time-to-fail hours (TTF) and time-to-repair (TTR) hours were calculate for each unit to ensure that historical EFOR is captured in the model.
  - The model used historical thermal Energy Trading System (ETS) data from 2012-2017 to identify forced outage and forced derate events
  - Identified planned outage events are excluded
  - Units were referenced to other units in the same unit type if they did not have sufficient historical statistics available
- RAM then randomly draws from these events to simulate the unit forced outage events

Thermal – Forced Outage

- Example – For a unit that has the following TTF and TTR values

$$FOR = \frac{(mean\ time - to - repair)}{((mean\ time - to - repair) + (mean\ time - to - fail))}$$

TTF	TTR
1366	13
2	4
420	40
686	4
42	3
Average: 503	Average: 13

- = 13 / (13 + 503)
- The Forced Outage Rate for this unit would be 2.5%.
- However simulation randomly draws from the distribution

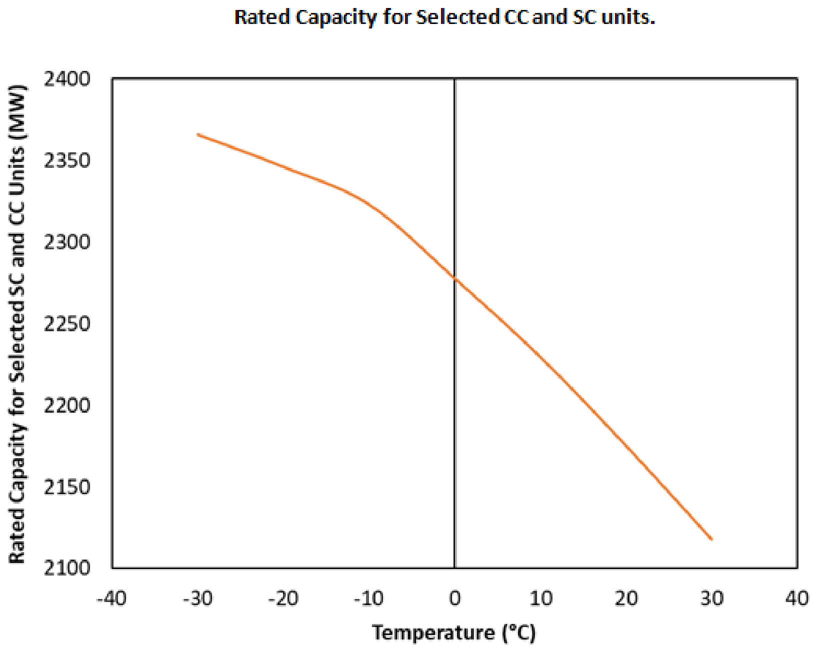
	Forced Outage Rates currently in the model			NERC FOF[2] (2012-2016)
	Minimum	Maximum	Average	All Size
CC	1.0%	9.6%	4.7%	2.6%
Coal	2.4%	19.4%[3]	6.3%	4.7%
Other	3.3%	7.1%	5.1%	N/A
SC	1.0%	10.3%	3.8%	4.1%
	Partial Outage Rates currently in the model			
Coal	0.8%	8.5%	4.2%	N/A

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

3 - The large number is due to a unit facing a significant extended forced outage

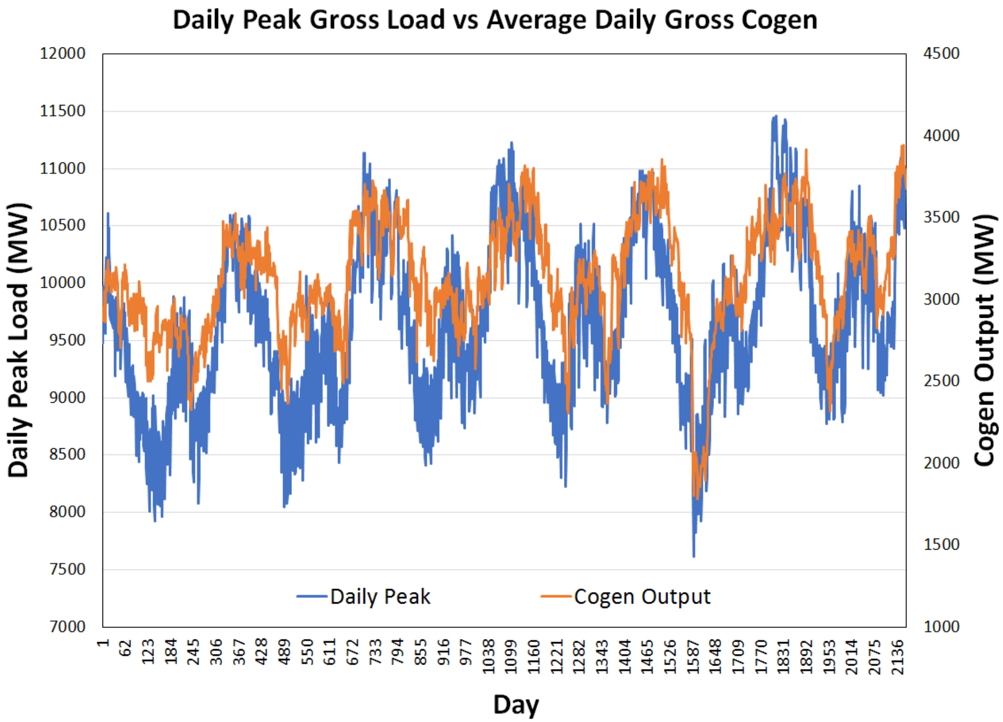
Thermal – Seasonal Derates

- Technology output curves were used to model weather related derates for Combined Cycle and Simple Cycle units
- The technology output curves were calculated using historical ETS Available Capacity data and corresponding weather data to capture ambient temperature derates
- RAM uses the hourly temperature to look up an associated capacity multiplier to determine the output capacity of a unit



Cogeneration

- Cogeneration units in Alberta exhibit widely ranging generation and availability patterns (2012-2017)
- Strong correlation between daily peak gross load and daily average gross cogeneration output, allowing the model to draw an output from the cogeneration fleet based the daily peak load
- Astrapé has used a similar approach to model private use networks (PUNS) generation in ERCOT[4]



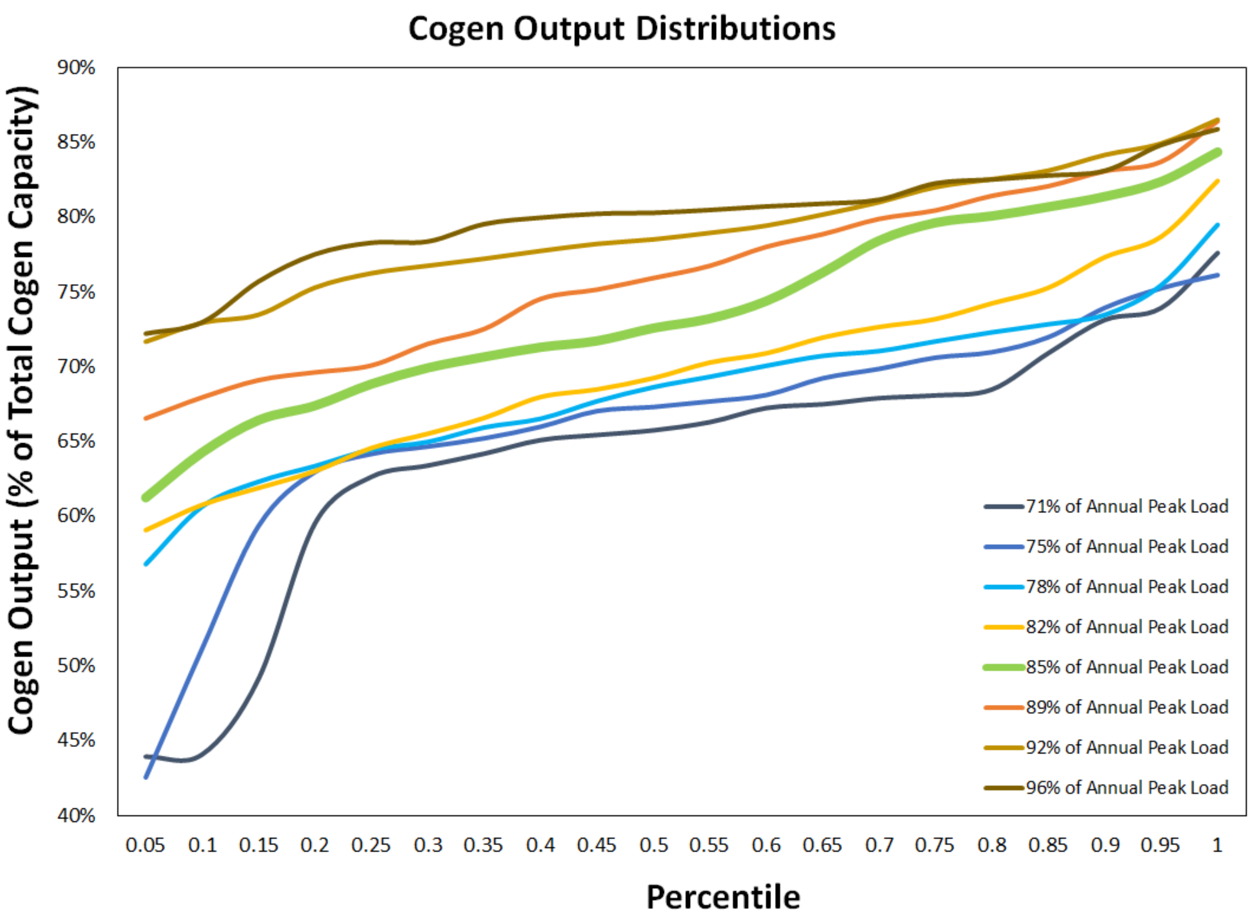
4 - http://files.brattle.com/files/6098_estimating_the_economically_optimal_reserve_margin_in_ercot_revised.pdf

Cogeneration

- Aggregation was performed by adding the historical availability capacity (AC) from generators then normalized by the installed capacity at each hour
- The daily peak load and daily peak available capacity were calculated for the aggregate. This was grouped into a number of normalized load levels each with a distribution of the cogeneration availability
- The model then randomly draws cogeneration multipliers for each day

Cogeneration

- An example, when daily peak load is 85-89% of annual peak load, the model will draw a multiplier of 61% to 84% (the green line)
- The drawn value is multiplied by the installed capacity of approximately 5,000 MW to determine the daily generation of the cogeneration fleet



Emergency Response/Ancillary Services

- Emergency operations modeling plays a significant role in evaluating loss of load events
  - BAL-002-WECC-AB1-2[5] and System Controller Procedures[6] outline our current guidelines
- AESO will model EEA1 and EEA2 hours by measuring how often RAM dispatches contingency reserves
  - Supplemental Reserves (Quick Start)
  - Spinning Reserves (Spinning Reserves)
- Firm Load shed will begin once contingency reserves are depleted, but regulating reserves will be maintained even during load shed events
  - Reserves are calculated as a percentage of load and then allocated to an eligible resource units capacity and then only activated once all remaining in-merit energy is dispatched, representing an EEA event
    - Spinning Reserves (2.5% of Gross Load)
    - Supplemental Reserves (2.5% of Gross Load)
    - Regulating Reserve (1.5% of Gross Load)

5 - https://www.aeso.ca/assets/documents/BAL-002-WECC-AB1-2.pdf

6 - http://ets.aeso.ca/ets_web/ip/Market/Reports/HelpTextServlet?service=EnergyAlertsInfo

Reserve Margin

- NERC defines RM as Percentage of additional capacity over load
  - Reserve Margin (%) = (Capacity – Load)/Load X 100
  - Generally measured over Peak Load
- Other regions generally include nameplate capacity for thermal resources and derated intermittent resource values according to expected resource adequacy benefit.
- RAM results are displayed with an ICAP figure then a capacity credit is applied to calculate a reserve margin to evaluate results

Unit Type	ICAP	Capacity Credit/RM defintion
C - Cogeneration	5,067	1.00
F - Coal, CC and Other	7,479	1.00
H - Hydro	894	0.79
R - Wind	3,056	0.11
T - Simple Cycle	916	1.00
Sum	17,412	14,504
Peak Load (2021-2022)	12,235	12,235
Reserve Margin	42.3%	18.5%

Generation Additions - Reference Unit

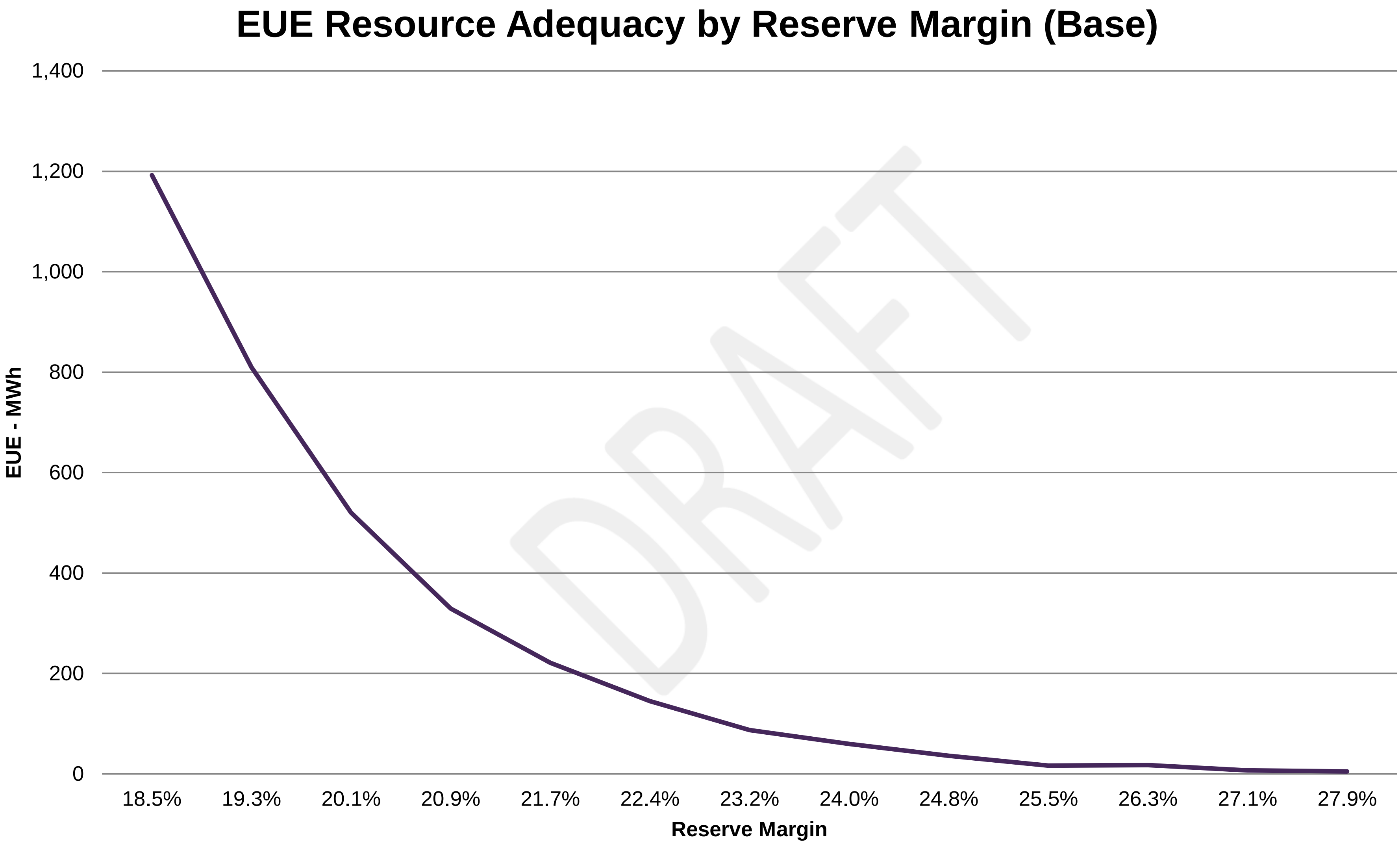
- For resource adequacy modeling a reference unit is selected to allow the model to evaluate different reserve margin levels
- Resource adequacy intention is to align with the reference technology selected to calculate cost of new entry
- Current assumed generic expansion unit characteristics
  - Nameplate Capacity – 47.5 MW
  - Fuel/Technology – SC gas
  - Forced Outage Rate of 3%

Draft – Results

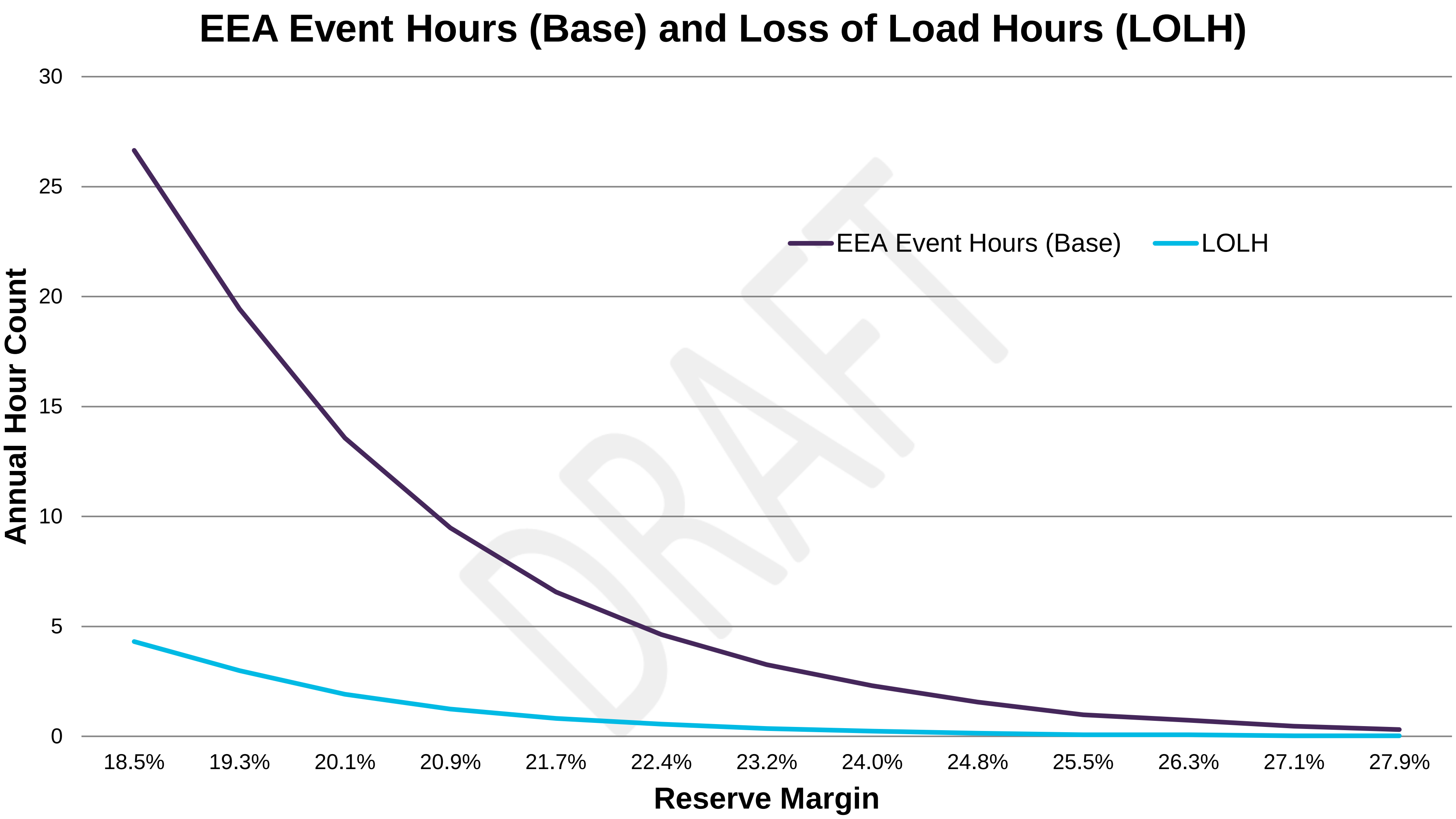
- The base case was run for the time reference period Nov 2021 – Oct 2022
- It consisted of thousands of annual simulations which consisted of combinations of load shapes, economic forecast error, and generation performance draws
- The resource adequacy metrics were aggregated into single values by calculating the weighed average of all cases

Reserve Margin (%)	EUE (MWh)	LOLE Capacity (Events per Year)	LOLH Capacity (Hours)
18.5%	1,192	1.83	4.31
19.3%	810	1.32	2.99
20.1%	521	0.89	1.92
20.9%	329	0.60	1.24
21.7%	221	0.40	0.82
22.4%	145	0.29	0.56
23.2%	87	0.19	0.35
24.0%	60	0.13	0.24
24.8%	36	0.08	0.14
25.5%	17	0.05	0.08
26.3%	18	0.04	0.07
27.1%	7	0.02	0.03
27.9%	5	0.02	0.02
28.6%	4	0.01	0.01
29.4%	2	0.01	0.01

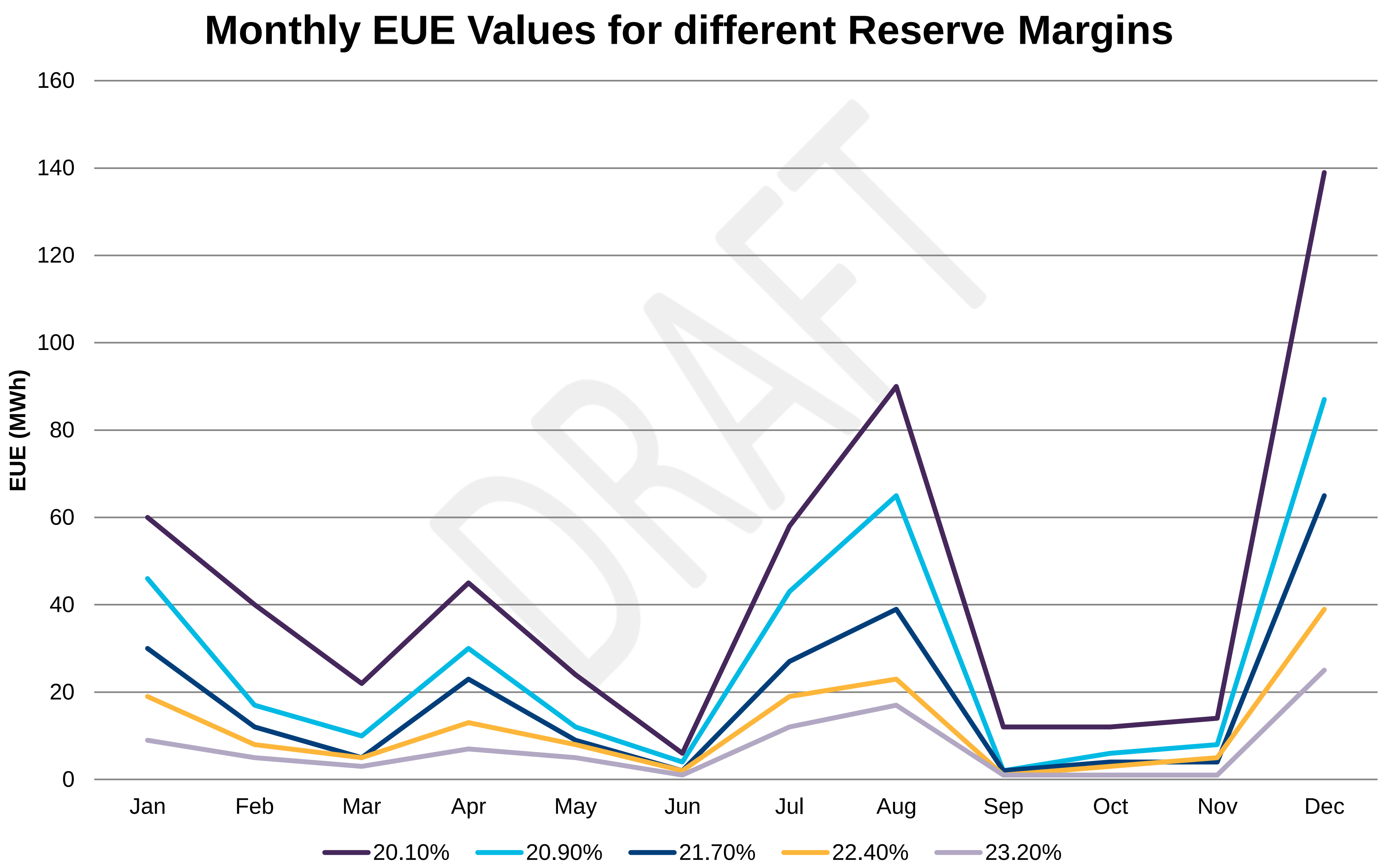
Draft – Results



Draft – Results



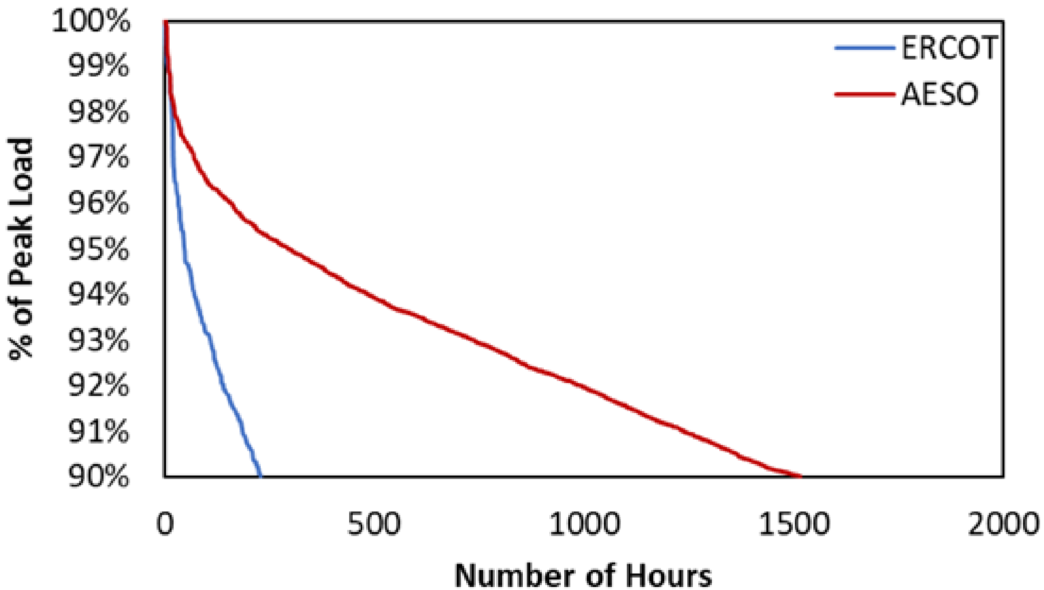
Draft – Results Monthly



Draft – Results Monthly

- Resource adequacy problems are more distributed throughout the year for AESO than for utilities with a higher degree of seasonality and more load responsiveness to weather conditions.

- Given the high AESO load factor and transmission availability risk, the level of reserves is required may be higher than other systems across the industry.



Next Steps

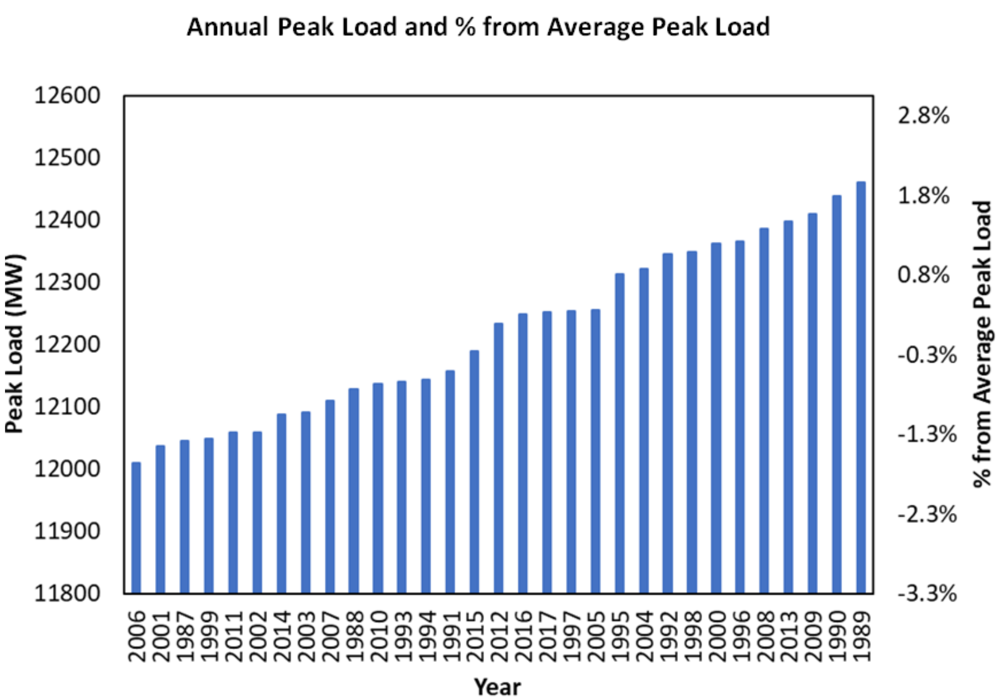
- Seek and respond to feedback on:
  - Set of inputs currently in the model
  - Methodology used to calculate inputs and results
  - Additional inputs or uncertainties AESO should consider
- AESO will continue to validate model and perform additional sensitivities to assist with calibration
- Continue to align with other streams of the capacity market design (UCAP, Demand Curve, etc)

Additional Material for Information

Demand – Weather Uncertainty

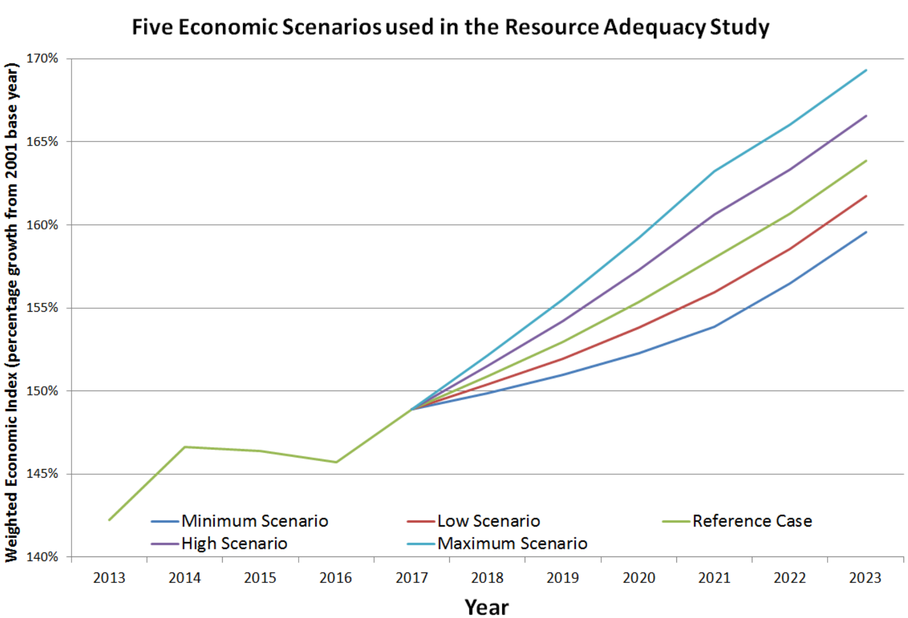
aeso ALBERTA ELECTRIC SYSTEM OPERATOR

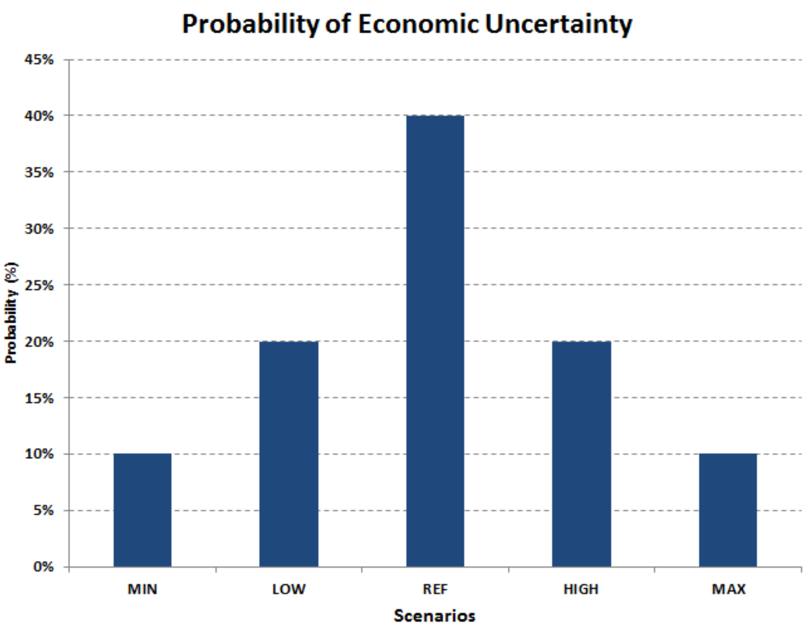
- The Resource Adequacy Model (RAM) takes into account weather uncertainties by using hourly load forecasts based on historical weather patterns
  - Our current study has hourly load forecasts for Nov 2021 - Oct 2022 based on weather patterns from 1987-2017
  - The annual peak load and percent difference from the average peak load value for each historical weather year is shown here
  - Equal probability was assigned to each load profile



Demand – Economic Uncertainty

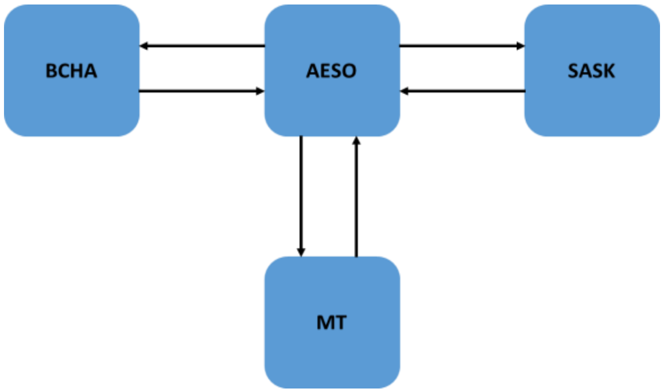
- Economics will impact load growth
- The RAM will consider economic uncertainties using a probabilistic approach
- The AESO load forecast currently uses the Conference Board of Canada's economic data
- Range is informed by historic high and low growth rates, and probability weighting assumes forecast uncertainty is normally distributed.





Intertie

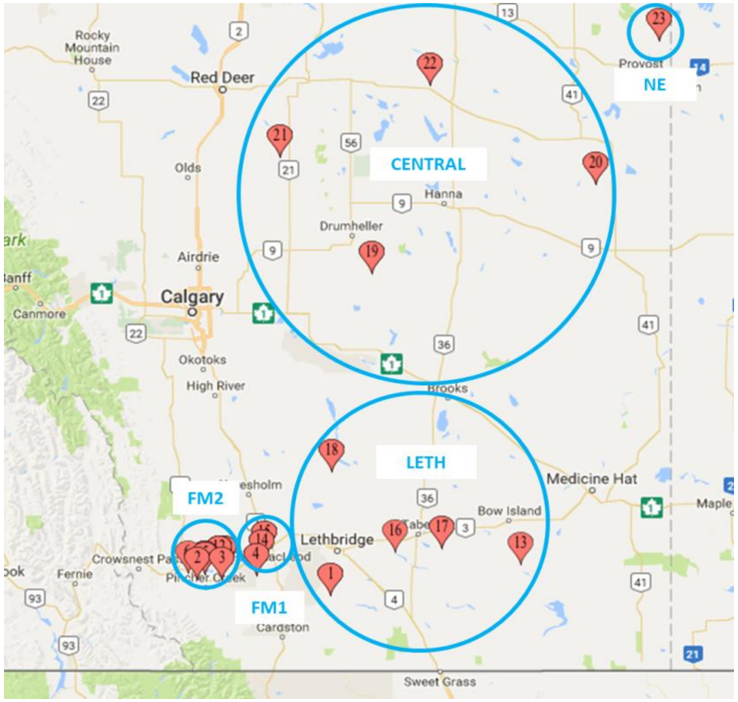
- Interties are modeled as pseudo units because the transmission capability was identified as the binding market support constraint rather than the generation availability from neighboring markets
- Historical ATC data was analyzed and a tie-line availability distribution was created subject to transfer constraints
- The model draws the same percentile for each intertie to allow for high and low availability to occur in all regions simultaneously
- Due to the nature of this modelling being focused on the physical resource adequacy assessment, imports were set to occur after the dispatch of AESO's last resource



Percentile of Capacity Limit In (%)	BCHA -> AESO (MW)	MT -> AESO (MW)	SASK -> AESO (MW)
0	0	0	0
10	635.0	0	0
20	750.0	0	0
30	750.0	47.8	0
40	750.0	90.1	0
50	750.0	174.0	0
60	750.0	182.0	30.4
70	750.0	190.6	41.0
80	750.0	200.7	68.0
90	750.0	210.0	100.0
100	780.0	225.0	152.5

Renewable – Wind

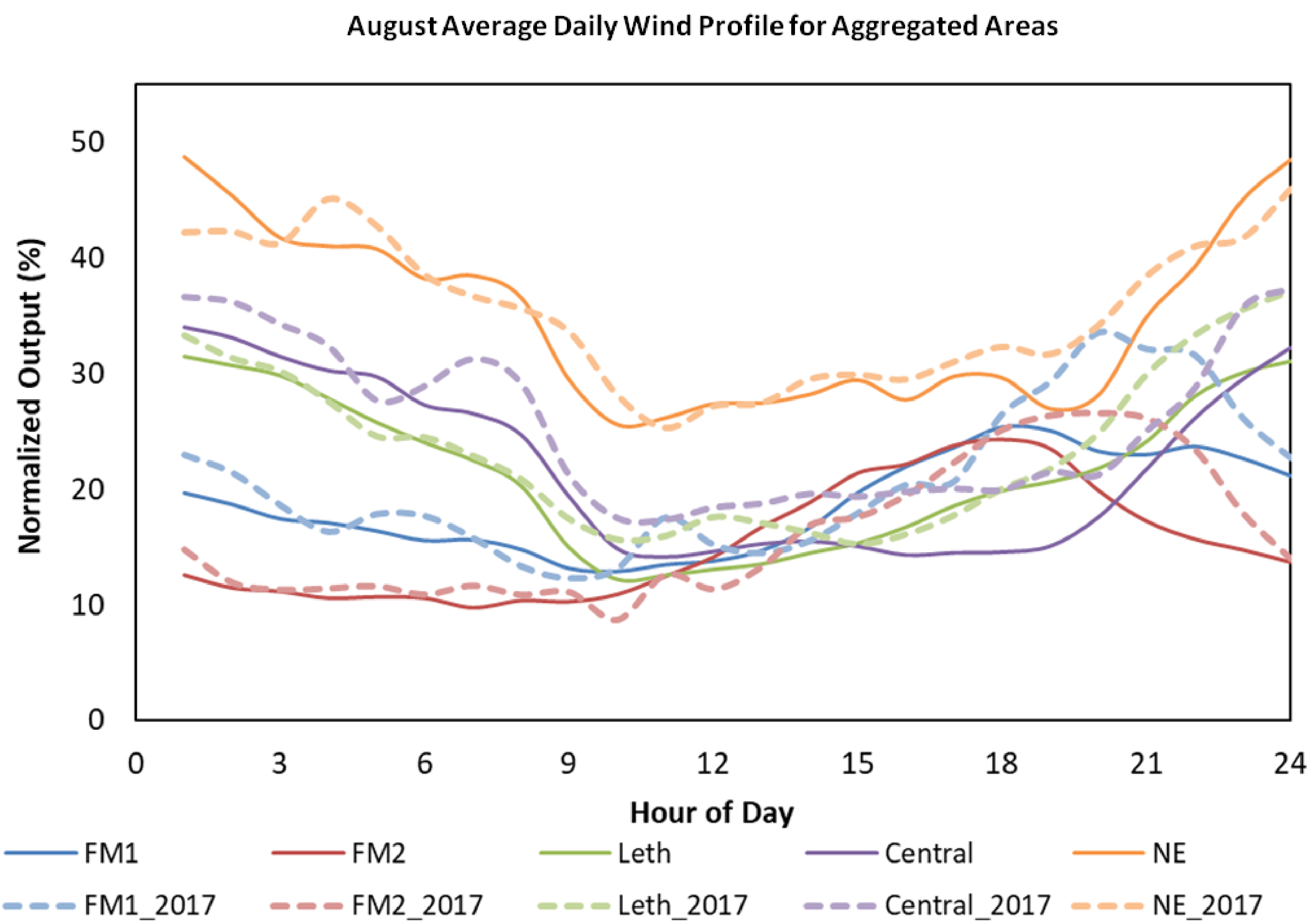
- Simulated wind shapes were developed using historical metered output from existing sites from 2005-2017
  - The data was initially normalized by dividing each hourly output by the maximum output of the site
  - The shapes were then aggregated by geographic locations according to wind output correlations
  - Aggregated profiles were assigned to each existing and future wind farms



Renewable – Wind

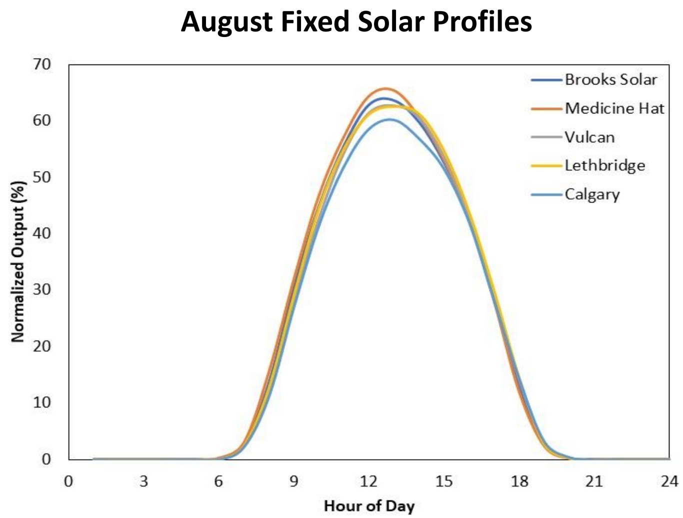
- Simulating wind data for Central (2005-2010) and NE (2005-2015)
  - Random days from available years (2011-2016 for Central and 2016 for NE) were selected by month
  - The selected daily profiles were then scaled such that the correlations with the reference Fort Macleod (FM1) wind profiles from the available years were maintained
- Simulating wind data for the period of 1987 to 2004 for all areas
  - The profile selection was based on a correlation between the forecast daily peak load and wind output to align with weather
  - For example, the forecast daily peak load of Jan. 3, 1987 was compared with all forecast daily peak loads from Jan. 1 to Jan. 5 of 2005 to 2016 (60 data points – 5 days in each year for 12 years). The wind profile of the closest matching peak load day was selected
  - Hours 24 to 1 (the seams) were interpolated from hour 23 and 2 to avoid a drastic hourly change in output

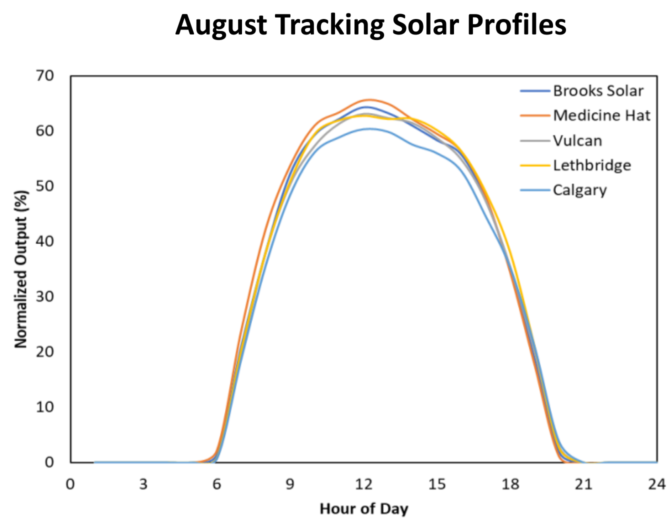
Renewable – Wind



Renewable – Solar

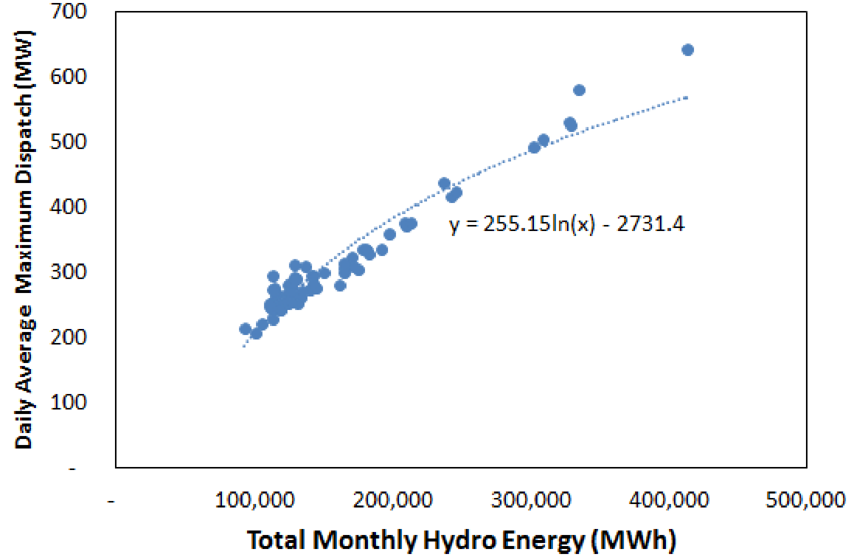
- Simulated solar shapes were developed using the NREL National Solar Radiation Database (NSRDB) Data Viewer and System Advisory Model (SAM) to generate the hourly solar profiles for 1998 to 2016
- Solar profiles for 1987 to 1997 and 2017 used the same daily peak load look-up technique as creating wind profiles for 1987 to 2004
- Ten profiles were created using the inputs and assigned to our existing asset and would be assigned to future assets.
  - 5 geographic locations
  - 2 technology (fixed & tracking solar PV)

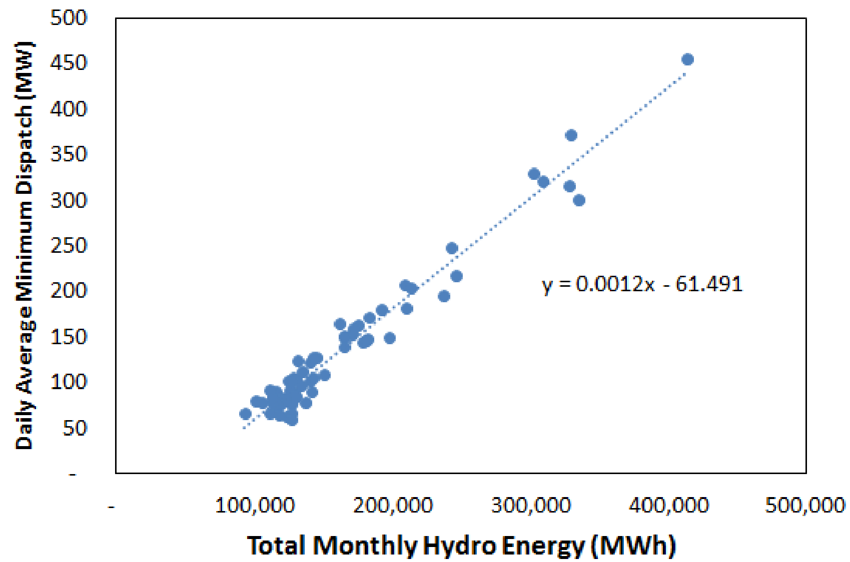




Renewable – Hydro

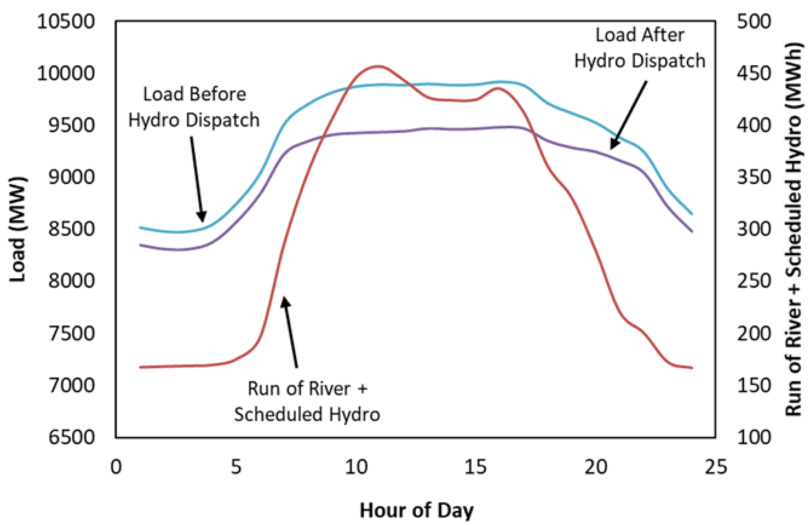
- Actual hourly hydro data was analyzed from 2012 to 2017 and an aggregated profile was created
- The minimum and maximum daily dispatch levels and monthly maximum dispatch levels can be defined as a function of the total monthly hydro energy
- Curve fit equations applied to historical monthly energy 2001-2017
- For years without monthly energy availability (1987-2001), data from the year that most closely matched average annual snowfall (2001-2017) was used

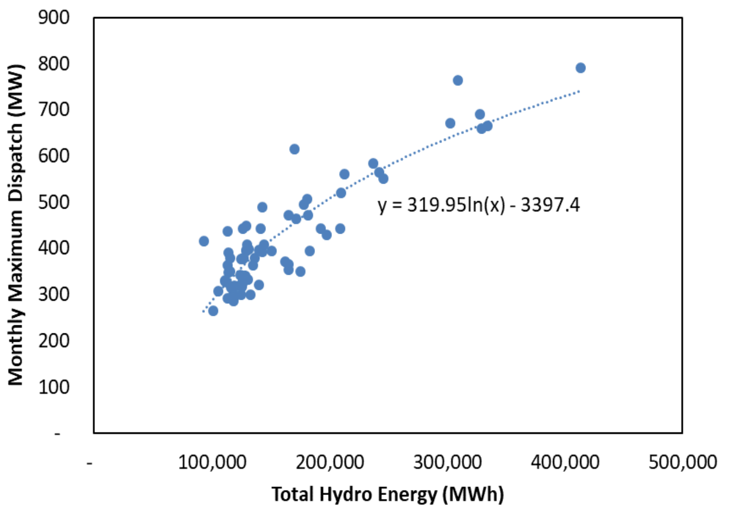




Renewable – Hydro

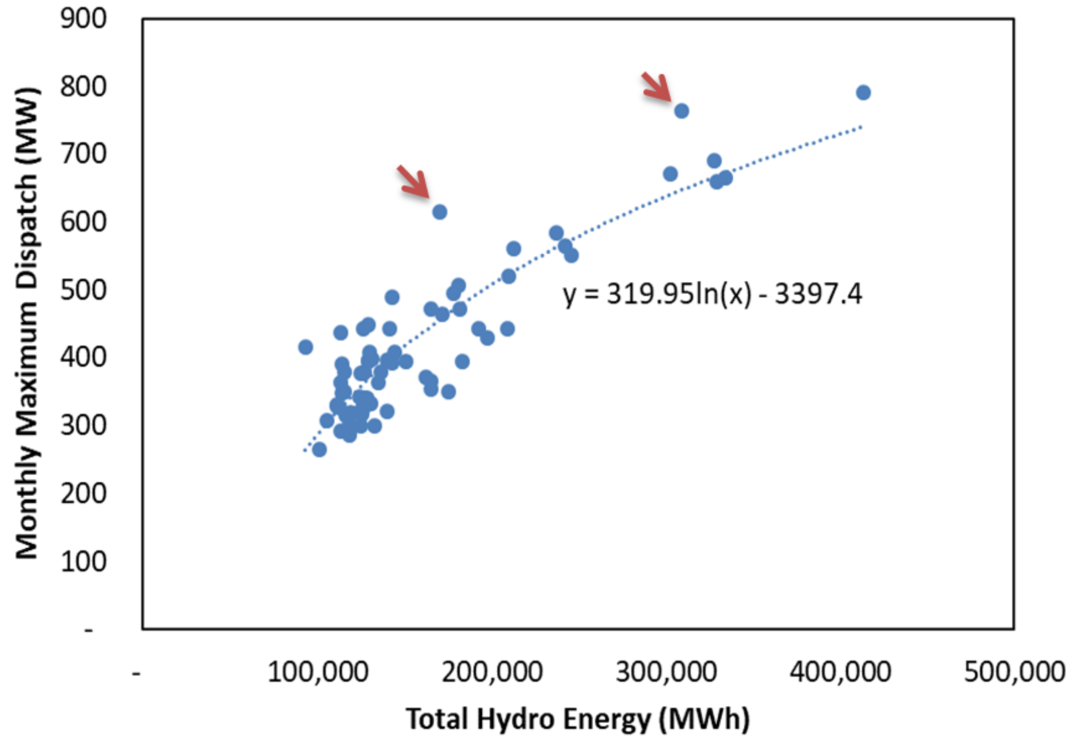
- RAM optimally schedules the hourly hydro energy based on each day's hourly load shape while respecting daily and monthly dispatch constraints
- The following values are identified and used to constrain the dispatch logic
  - Average daily minimum
  - Maximum dispatch levels
  - Total monthly energy
  - Monthly maximum dispatch levels
- After minimum weekly flows are taken into account, the remainder of the month's energy is scheduled as peak shaving respecting the totally monthly hydro constraint





Renewable – Scarcity Hydro

- While dispatch data is highly correlated with monthly energy, some deviation was identified historically which is expected to reflect scarcity dispatch hydro capability
- An scarcity hydro block of 150 MW was modelled based on the historical observed deviation from the fitted curve subject to the maximum system hydro capability



- The emergency hydro is only used to prevent firm load shed
- It allows hydro to borrow “energy” from the future dispatch (up to 7 days forward) of scheduled hydro but for only a limited period (duration of 10 hours)

Appendix

Draft – Results Monthly

Monthly EUE (MWh)

Reserve Margin (%)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
18.5%	153	85	46	121	63	14	155	179	19	18	41	298
19.3%	99	54	29	69	35	8	106	147	7	17	30	208
20.1%	60	40	22	45	24	6	58	90	12	12	14	139
20.9%	46	17	10	30	12	4	43	65	2	6	8	87
21.7%	30	12	5	23	9	2	27	39	2	4	4	65
22.4%	19	8	5	13	8	2	19	23	1	3	5	39
23.2%	9	5	3	7	5	1	12	17	1	1	1	25
24.0%	8	3	2	5	2	0	7	12	1	1	1	17
24.8%	4	1	1	2	3	0	4	10	0	0	1	11
25.5%	2	1	0	1	1	0	2	4	0	1	0	5
26.3%	2	1	0	2	4	0	1	2	0	0	0	6
27.1%	1	0	0	1	0	0	1	2	0	0	0	2
27.9%	0	1	0	0	0	0	1	2	0	0	0	1
28.6%	0	0	0	0	0	0	0	0	0	0	0	2
29.4%	0	0	0	0	0	0	0	0	0	0	0	0

UCAP Calculation Methodology

Technical Workgroup #2

April 6th, 2018

Agenda

- Summarizing Feedback from TWG #1
- More details on how assets are classified between Availability Factor (AF) & Capacity Factor(CF)
    - Used Metered Volumes vs Dispatch Levels to assess whether assets were true to their dispatch levels
- Further information on calculation considerations
    - Denominators for Capacity Factor
    - Inclusion of ancillary services
    - Weighted average Availability Capability for use in Availability Factors
    - Calculation approach for assets that have mothballed
- Supply cushion Analysis
    - Selection of Supply cushion (mid hour, top hour, weighted)
    - Applying supply cushion size constraint to 100 tightest hours
- Asset Specific Information – Impacts to UCAP (Appendix)

Feedback on proposed UCAP calculation

- Generally, half the members agreed on using 100 hours and 5 years historical data. The other half were conditional yes's, neutral or no's. Additional asks from the conditional yes's were:
  - Ensure alignment to resource adequacy
  - Asset specific information to determine variation in UCAP
  - Removal of planned outages
  - Analysis of MW and supply cushion thresholds, resulting in less than 100 hours for some years

- For those that were not supportive suggested:
  - Future not reflective of past
  - Use more hours instead of 100
  - Alignment to resource adequacy
  - AESO does not have enough data
  - Asset specific analysis required before decision

The AESO will be continuing with the proposed AF & CF approach, work for future CMDs will be focused on defining and refining details of the AF & CF approach

Classification of assets between AF & CF approach

Are dispatches reflective of metered volumes?

Y

Availability factor

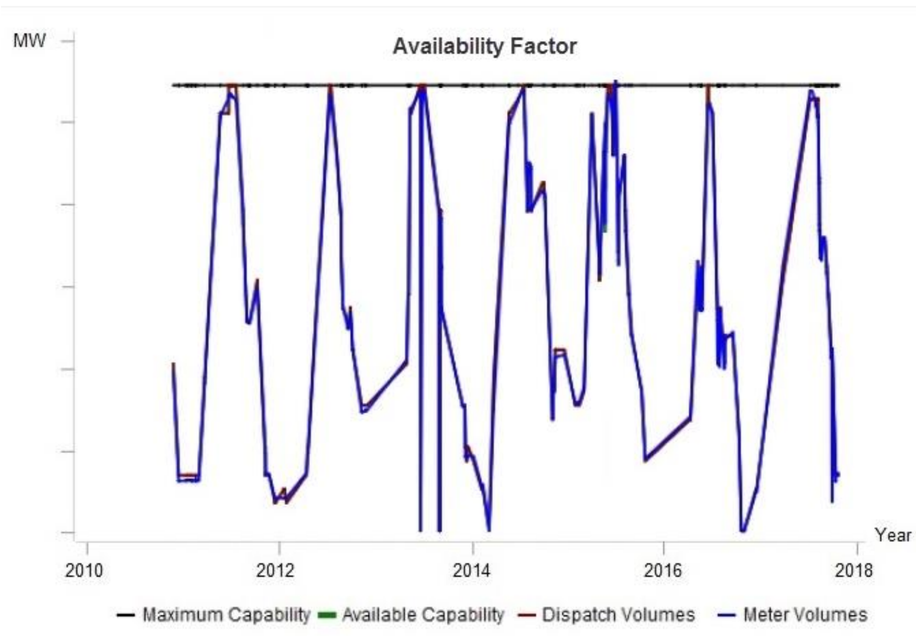
= Weighted Available Capability/ Maximum Capability

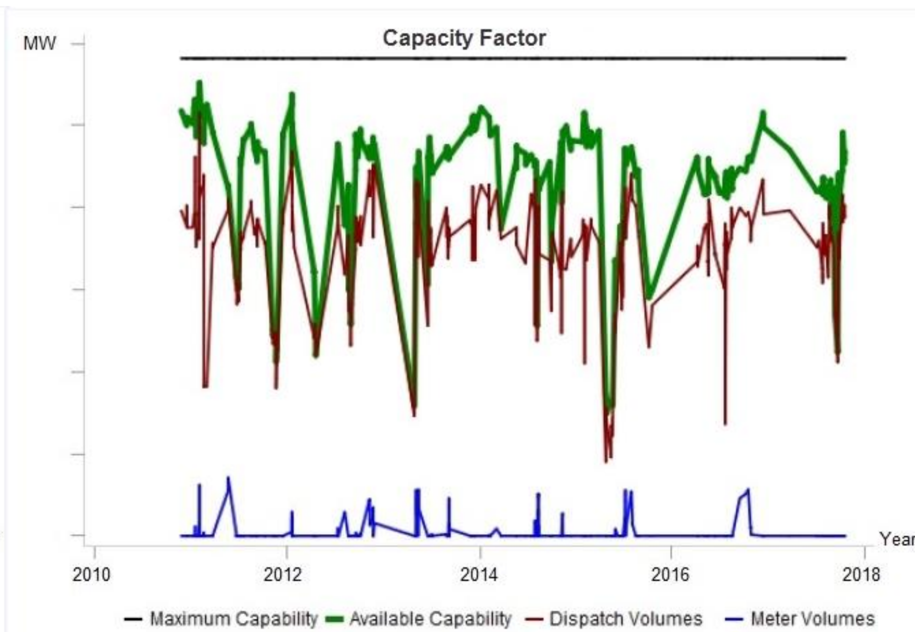
N

Capacity factor =

Metered Volumes / Maximum Capability

UCAP = Performance factor time MC (Current or Future)





Classification of assets

Are dispatches reflective of metered volumes?

Y

Availability factor

= Weighted Available Capability/ Maximum Capability

N

Capacity factor =

Metered Volumes/ Maximum Capability

UCAP = Performance factor times MC (Current or Future)

All coal and hydro,

Most combined cycle, Most Simple Cycle,

[Cogen] BCR2, BCRK, CNR5, FH1, JOF1, MEG1, PW01, RL1, SCL1, TC01, TLM2, UOA1, MKRC

Most 'Other'

[CC] MEDHAT ,FNG1,

[SC] ANC1,

[Cogen] SHELL, DOWG, EC04, IMPOIL, MKR1, NX02, PR1, SUNCOR, TC02, HMT1, CL01, UOC1

[Other] GPEC, WEY1

All Wind

Exception: There are five assets that don't meet either criteria, AESO continues to work through these

Further information on calculation considerations

AESO will be using:

1) Maximum Capability of individual assets for the denominator of capacity factor calculation, instead of maximum metered volumes. Metered volumes are prone to significant variation and not a reasonable reflection of assets capability

2) For Inclusion of ancillary services volumes for capacity factor resources, AESO will be using Metered Volumes plus dispatched and/or directives

3) Weighted average Available Capability over the hour will be used to represent the assets availability as this is an accurate representation of the availability of an asset

Accounting for Mothballing of asset in UCAP calculation

Available Capability during a mothball outage is not indicative of a generators ability to produce capacity.

- Mothball methodology
  - Exclude the tight supply cushion hours when the asset is mothballed
  - Take the simple average over all of the remaining hours (e.g. If an asset had 82 mothballed hours in 2016/17, the average would be taken over 412 hours)
  - If below a statistically significant value, use a combination of existing data to establish a UCAP.

	Year 1	Year 2	Year 3	Year 4	Year 5	
Hours	100	100	100	100	12	82
Normal Op	Normal Op	Normal Op	Normal Op	Normal Op	Normal Op	Mothball

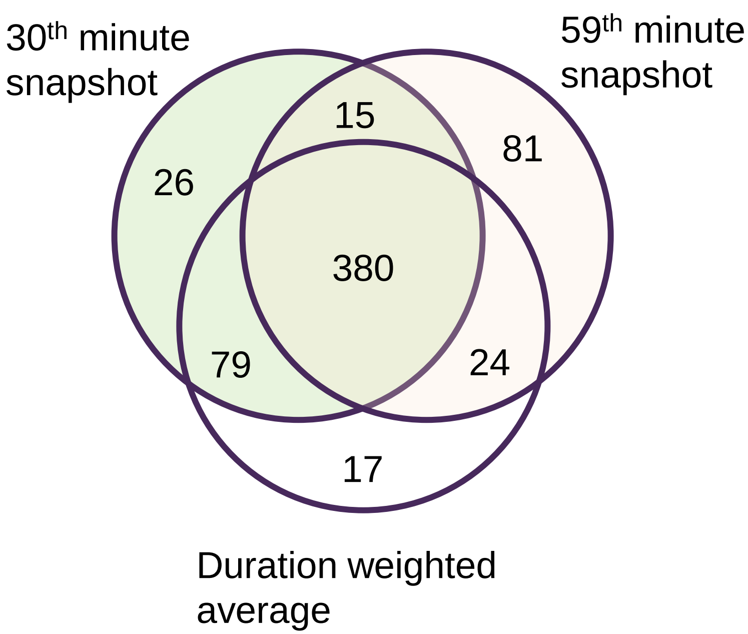
Other options considered, but discarded:

1. Replace mothballed time with group average
   - Discarded because distort assets actual performance

Supply Cushion Analysis

- Selection of hourly supply cushion value
  - Mid hour – Snapshot at 30th minute of hour
  - End of hour – Snapshot at 59th minute of the hour
  - Weighted average – duration weighted average within the hour
- Use of additional constraints
  - Compared 100 hours base case to a frontier scenario

Selection of Supply Cushion hours



- Duration-weighted average is gold standard calculation methodology
  - Requires high-quality data
  - Implementation requires IT resources
  - Representative of true supply cushion
- Mid-hour snapshot could proxy duration-weighted average
  - Over 90% common observations
  - Already in production
  - Can act as a reasonable proxy to duration weighted average calculation

AESO will be using the duration weighted average going forward

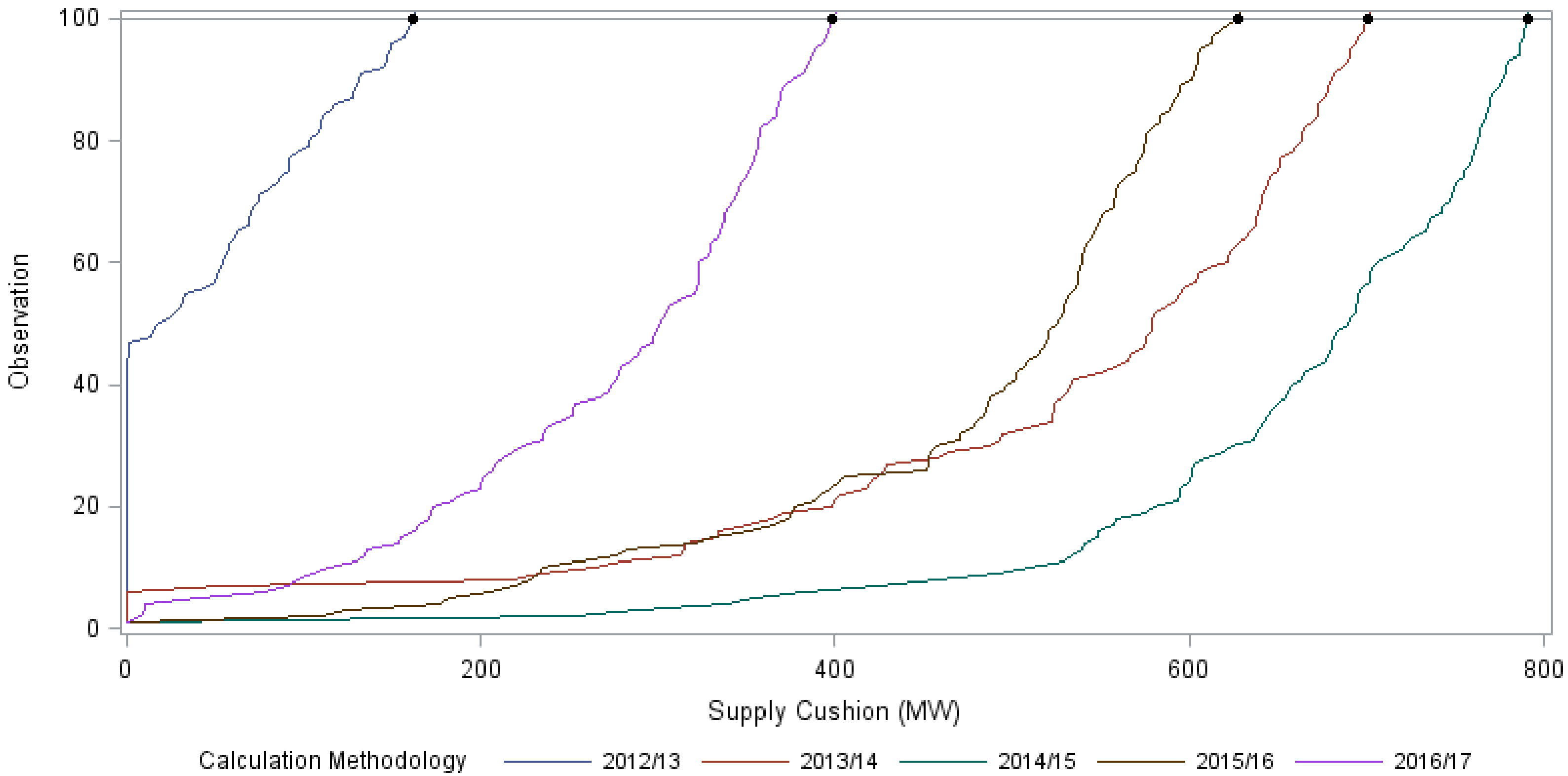
Applying constraints to 100 tightest hours

- Evaluation set identifies historical hours used to calculate UCAP
  - Set must restricted to tightest supply-cushion hours
  - Set must be large enough to be representative

Two options were compared.

- 100 tightest hours/year
- Frontier
  - Three constraints on supply-cushion data define the frontier:
    1. 100 tightest hours
    2. 500 MW threshold – aligned with no-look scarcity test
    3. 30 minimum tightest hours – textbook statistical standard

Effect of Constraints on Evaluation Set



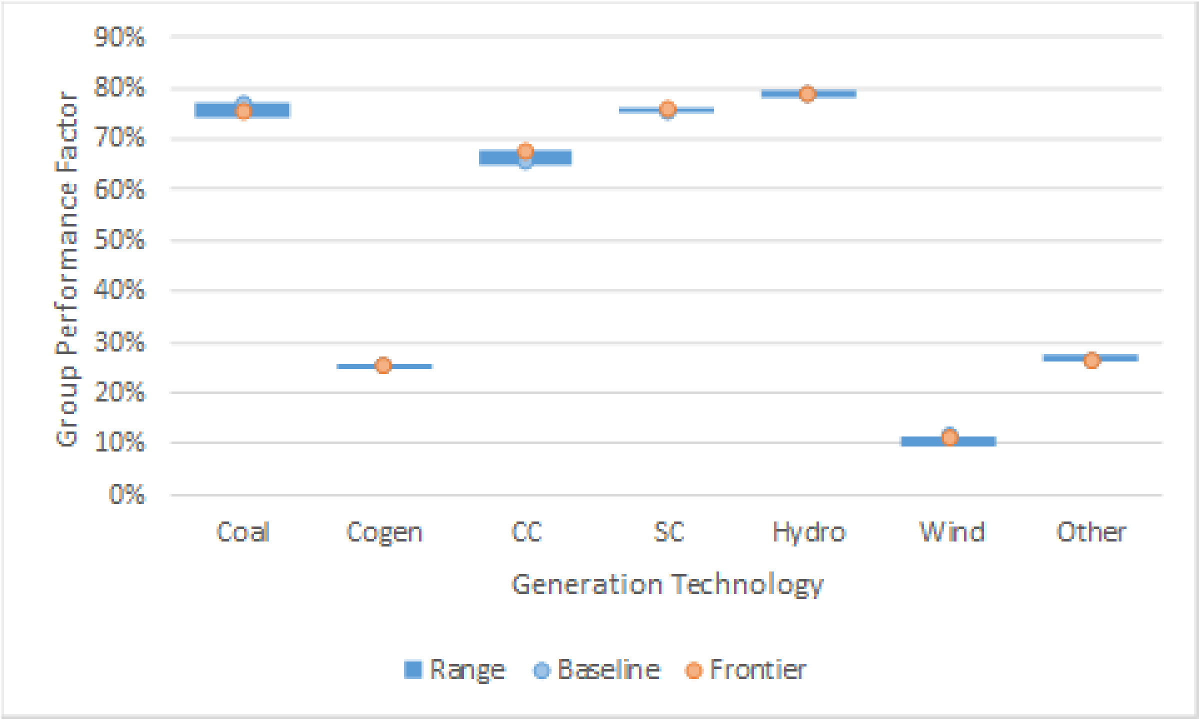
100 observations per capacity interval

Selecting the Evaluation Set

- Options
  - Leave at 100 tightest hours per year
  - Impose 500 MW supply cushion threshold and also minimum sample n>= 30 per year

	100 hours	**500 MW and at least 30 tightest hours**
Advantage	Simpler to implement and explain	Targets specific hours where reliability is a concern. Will eliminate hours in which there was adequate supply
Disadvantage	May include hours where supply cushion is considered "healthy"	Smaller sample size in high supply cushion years Potential that the number of hours used changes year-to-year

Minimal change in mean performance factor by class across two options



System level changes are less than 100 MW

Independence of days drops to approximate 10 in 2014/2015

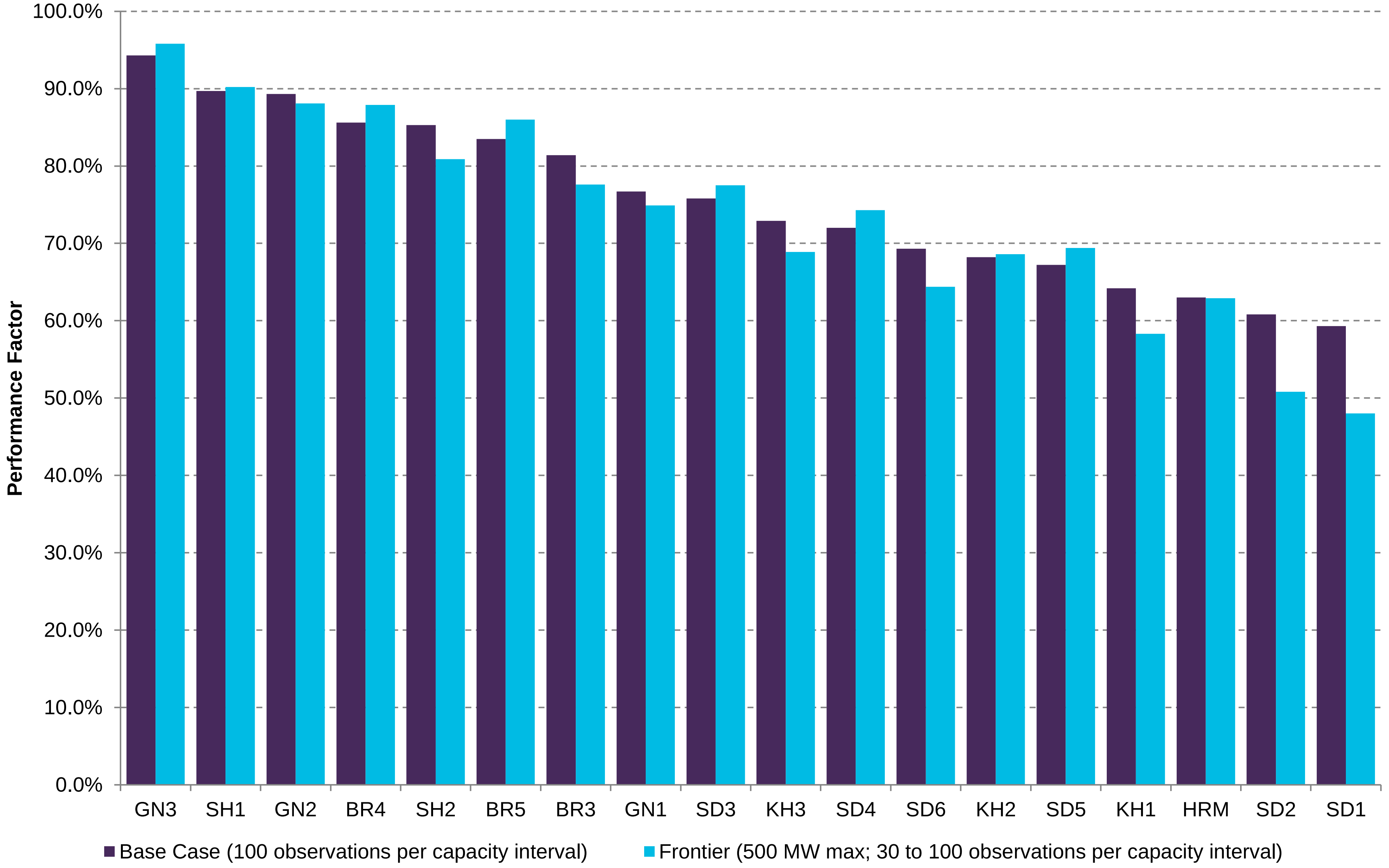
Applying principles of UCAP

	100 hours	SC cushion at most 500 MW and Tightest hours at least 30
Reliability value	Similar/Less	Similar/More
Consistency across resources	Yes	Yes
Complexity	Less	More – Penalty mechanism also has to be adjusted
Statistical independence	More	Less
Consistency across assets y/y	More	Less

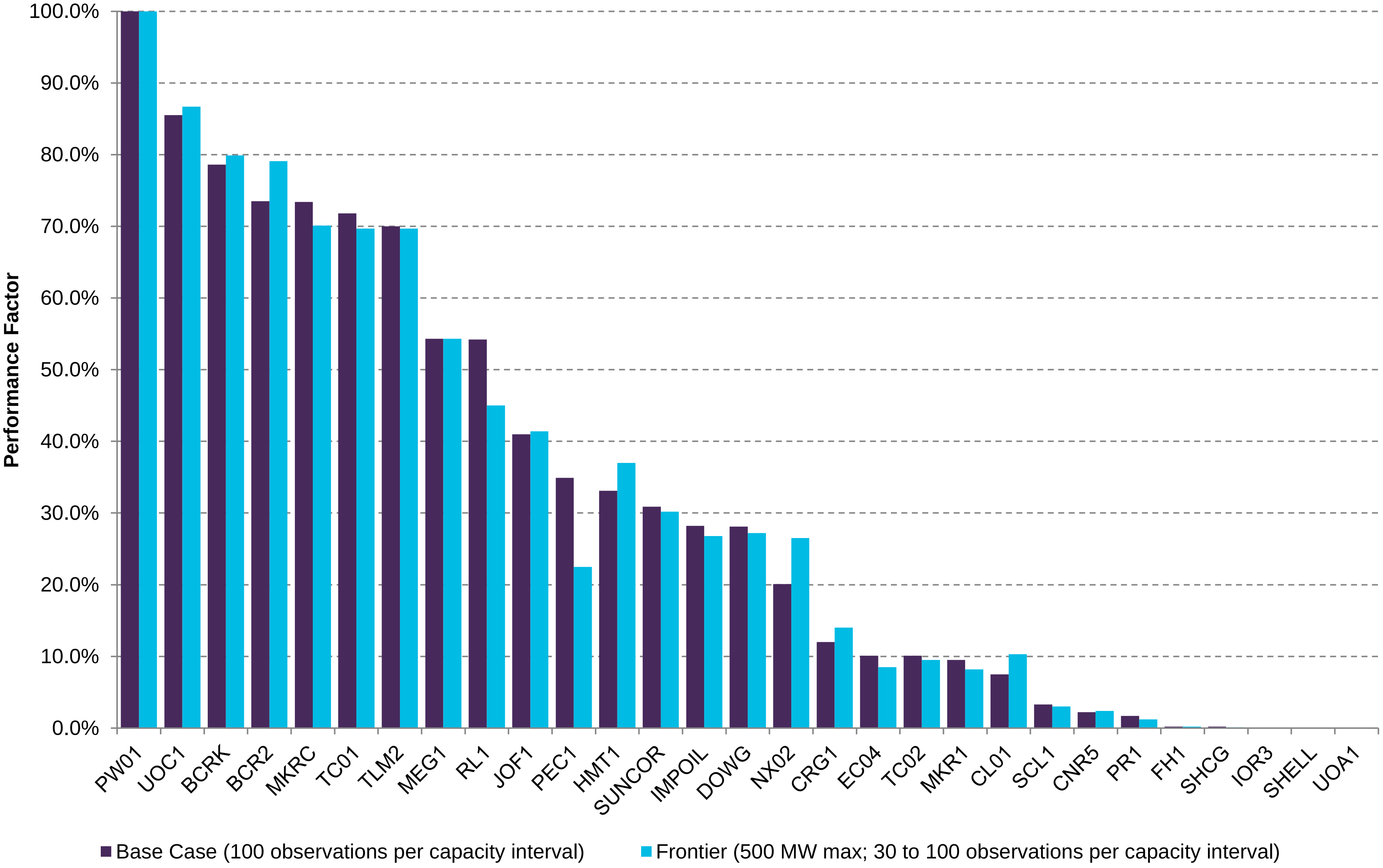
Given that the 100 hours provides more asset level stability, draws from a fixed sample maintaining independence and is simpler, the AESO’s position is to use the 100 tightest hours.

Appendix

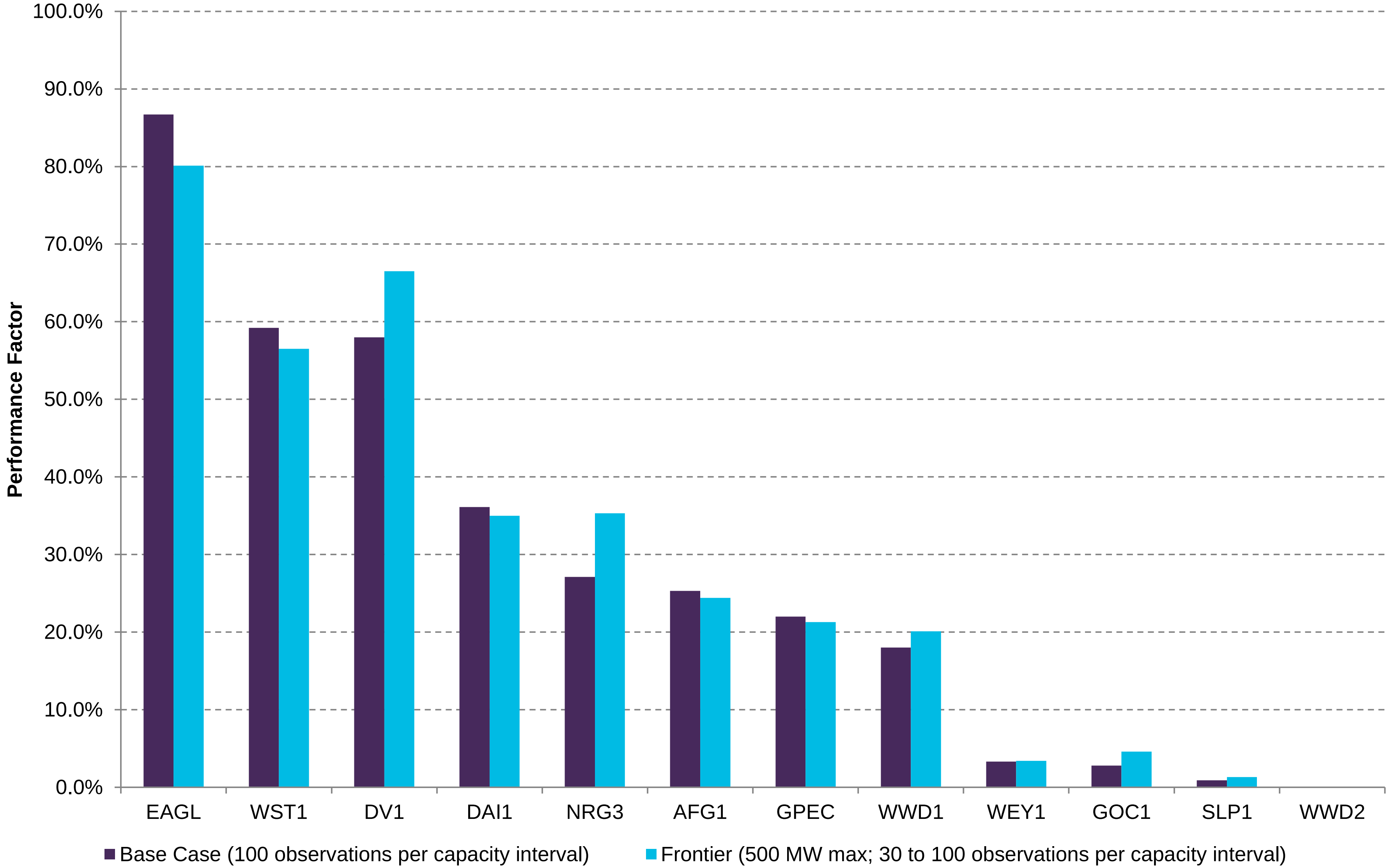
Preliminary Asset Specific Statistics - Coal



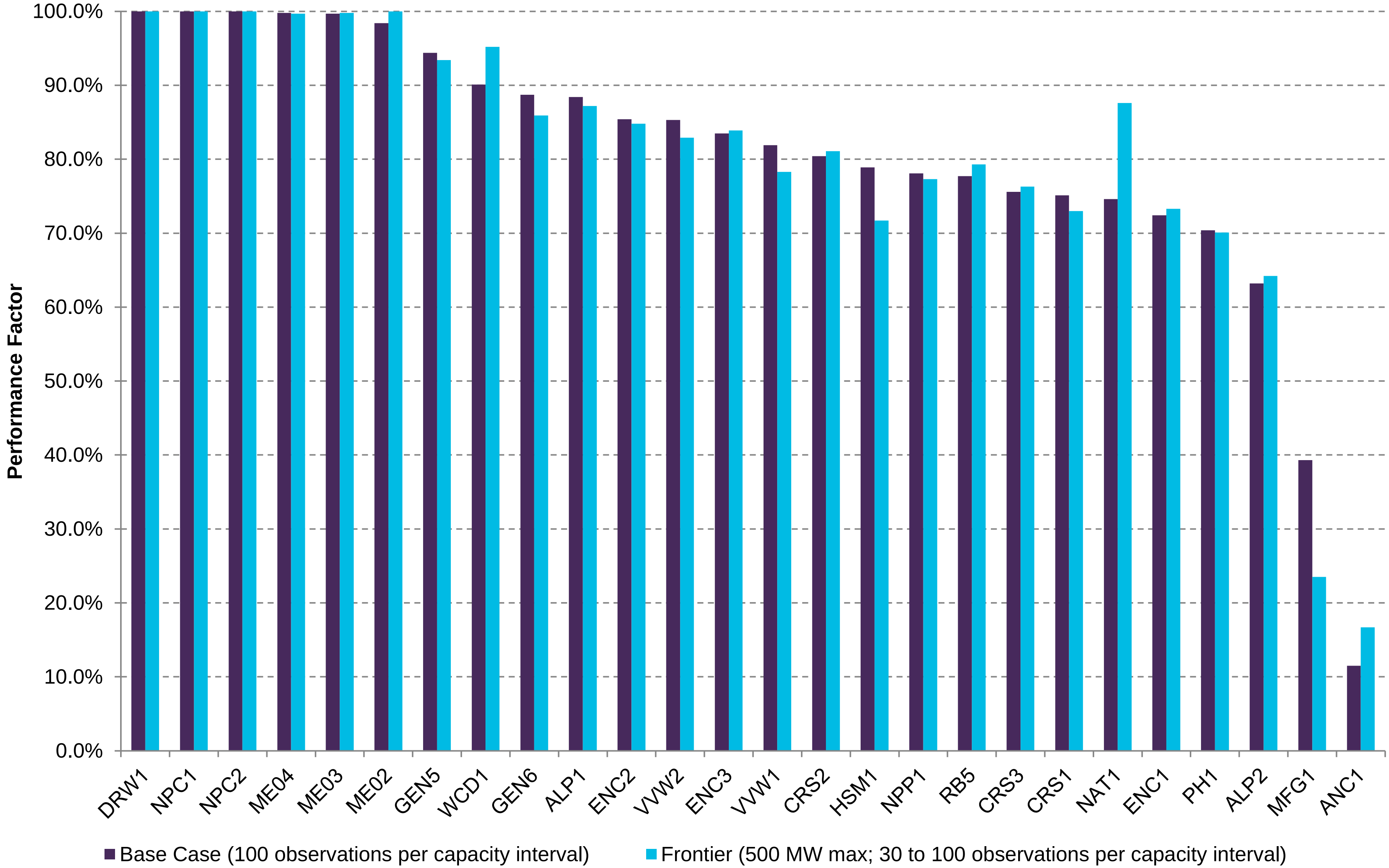
Preliminary Asset Specific Statistics - Cogen



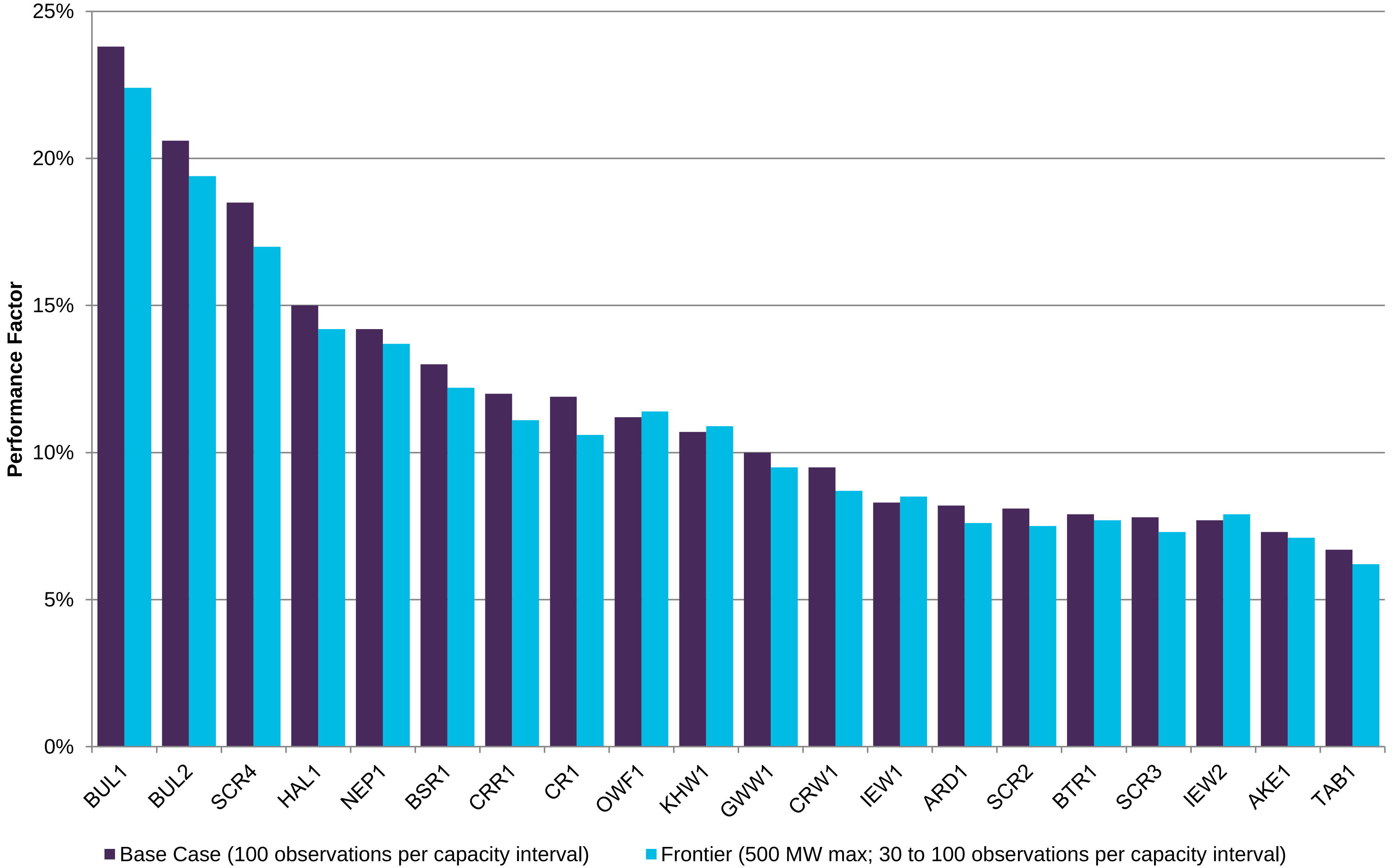
Preliminary Asset Specific Statistics - Other



Preliminary Asset Specific Statistics - SC



Preliminary Asset Specific Statistics - Wind



Preliminary Asset Specific Statistics - CC