Technical Workgroup Meeting
February 15, 2018

Agenda

Time	Agenda Item	Presenter
9:00 – 9:30	Welcome, Introductions and Housekeeping	Jordan
9:30 – 10:45	UCAP	Ketan
10:45 – 11:00	Break	
11:00 – 12:00	UCAP (Continued)	Ketan
12:00 – 12:30	Lunch	
12:30 – 1:15	Demand Curve	Adam / Nicole
1:15 – 2:00	Load Forecast Methodology	Steven
2:00 – 2:15	Resource Adequacy Modeling	Steven
2:15 – 2:50	CONE	Adam
2:50 – 3:00	**Session Close Out**	**Jordan**

Working Group Three: Technical Working Group

- Scope
  - How parameters of the capacity market are quantitatively determined, including:
    - UCAP calculations for different resource types
      - Capacity value for cogen units, net loads
    - Resource Adequacy modelling
      - Load Forecasting
    - CONE and Net CONE
    - Demand Curve Parameters

Technical Workgroup Workplan

	UCAP	Load Forecast	Resource Adequacy	Net Cone
Today	Draft UCAP calculations by technology type, finalize number of hours and years used in calculation	Final review of load forecast approach and feedback received to date	Resource Adequacy model status update	Discuss Net-CONE calculation process & schedule
April 6	Review calculation details of specific technology types (etc. self-supply, intertie, new assets); Revised capacity factor calculations with AS data	Present final load forecast approach	Presentation of draft resource adequacy model results and outstanding inputs	Present financial assumptions; Present formal reference technology screening results
May 4	Revisit specific issues (appeal process?)		Follow up discussion on draft resource adequacy model results; Present methodology to translating model output to UCAP target	Present Energy & AS offset calculation approach
June 14	Present final calculation process		Present final resource adequacy model results	Present Draft Gross CONE Results

Preliminary UCAP Calculations – by Technology Type

Agenda

- Objectives
- Principles
- Definitions
- Methodology Review
- UCAP Calculations by Technology Type
- Data Issues and Limitations
- Next steps

Objectives

Overarching Objective: Determine a resource neutral approach to evaluate capacity volume that reflects deliverability of energy during periods of tight system conditions

- Take a first look at the Availability Factor (AF)/Capacity Factor (CF) approach for estimating UCAP and examine directional trends
- Examine different sample sizes for the tightest supply cushion hours in each season year and determine an appropriate range

Principles

- Unforced Capacity (UCAP) is the amount of capacity a resource is expected to provide on average, during tight supply and demand conditions
- The reliability value of one MW of UCAP is equivalent across different resource types
- UCAP captures observed operational performance over a defined historical period

Definitions

- Supply Cushion: The amount of excess MW available for dispatch. Sum of available MW minus sum of Dispatched MW
- Capacity Factor Methodology: The ratio of metered volumes (net-to-grid) generation to Maximum Capability (MC)* to determine Unforced Capacity (UCAP) for uncontrollable resources
- Availability Factor Methodology: The ratio of Available Capability (AC) to Maximum Capability (MC) to determine Unforced Capacity (UCAP) for controllable resources
- Modified Capacity Factor for Interties: The ratio of metered volumes to the transfer path rating for each intertie

* In this analysis for some assets Maximum Continuous Rating (MCR) instead of MC was used depending on factors such as meter configuration

Methodology Review

CMD #1 Availability Factors

Availability Factors:

- Thermal
- Gross Cogeneration
- Large Hydro
- Storage

- The Availability Factor captures the availability [Energy + Operating Reserves] of a dispatchable resource during historical periods of tight supply
  - Availability Factors are established by dividing Available Capability (AC) by Maximum Capability (MC)
- The AESO considers the methodology indicative of resources ability to perform under similar conditions in the future

Data availability

- The AESO has access to resource specific, Available Capability (AC) data through participant historical submission into the Energy Trading System (ETS)
- Availability Capability (AC) values that appear in ETS are assumed to be accurate and representative of actual availability during tight supply hours

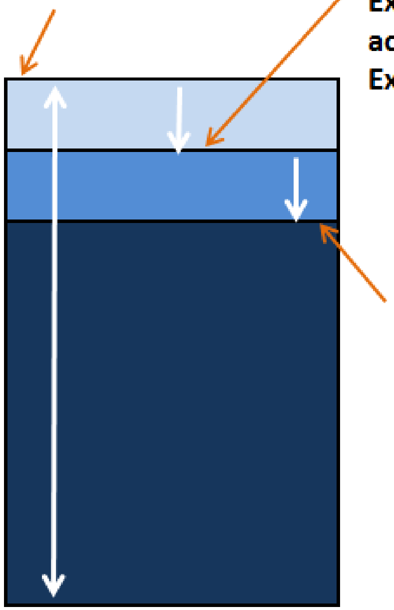
  Alberta is guided by the Must Offer/ Must Comply (MOMC) rule
- Maximum Capability values are relatively stable

CMD #1 UCAP Methodology for Existing Resources

Availability Factor UCAP Methodology

- **Thermal**
- **Gross Cogeneration**
- **Large Hydro**
- **Storage**

Maximum Capability (MC) = 500 MW



Maximum Capability(MC) modified for seasonal ambient limitations. Reflected in Energy Trading System (ETS) as a reduction in resource's Available Capability(AC)
Example: If ambient temperature reduction accounts for 10 MW of the MC.
Ex. 500 MW - 10 MW = 490 MW

Forced & Planned derates also reduce the available Capability(AC) of the unit resulting in a lower availability.
Example: If forced & planned reduction accounts for additional 40 MW.
Ex. 490 MW - 40 MW = 450 MW
UCAP= [AC/MC] x MC
UCAP = [450/500] X 500
UCAP = 450 MW

CMD #1 Capacity Factors

Capacity Factors

- Wind
- Run of River Hydro
- Solar
- Self-Supply
- External Resources (Interties)

- The AESO will use a Capacity Factor methodology to calculate the reliability contribution of variable resources, self-supply and interties*
- Capacity Factors are a statistical approach to determine the ability of a generation resource to provide capacity in periods of highest risk of not meeting load
  - Ratio of electrical energy generated divided by the maximum possible production.
- The amount of energy produced by variable resource is independent from energy market signals, production levels do not increase to respond to tight system conditions (when energy prices are at their peak)
- Self-Supply resources are built to supply on site load and tend to operate independently of system conditions. Modified capacity factor methodology that captures the net energy and operating reserve portion
- The AESO will use modified capacity factors to approximate the level of reliability that the intertie can provide

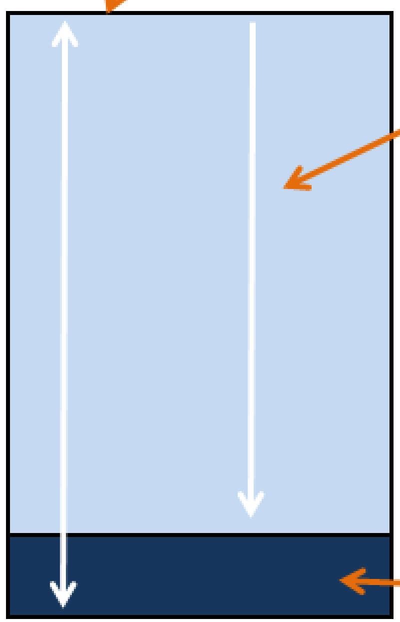
* The UCAP of external resources/interies will be dependent on additional aspects beyond capacity factor (See CMD)

CMD #1 UCAP Methodology for Existing Resources

Capacity Factor UCAP Methodology

- **Wind**
- **Solar**
- **Run of River Hydro**
- **Self- Supply***
- **Intertie***
- **External Resources**

Maximum Capability= 100 MW



In Alberta, the Capacity rating for variable generators is their average capacity factor during 100 tightest supply cushion hours a year.

Example:
Maximum Capability 100 MW
Average energy produced 22 MW
UCAP = Average energy produced / Maximum capability of the resource
UCAP= [22/100] X 100 = 22 MW

***Modified Capacity Factors (energy + *<u>operating reserves)</u>*)**

Public

Workgroup Discussion

Are there any clarifying questions?

Are the technologies assignments to capacity factor and availability factor appropriate?

UCAP Calculations by Technology Type

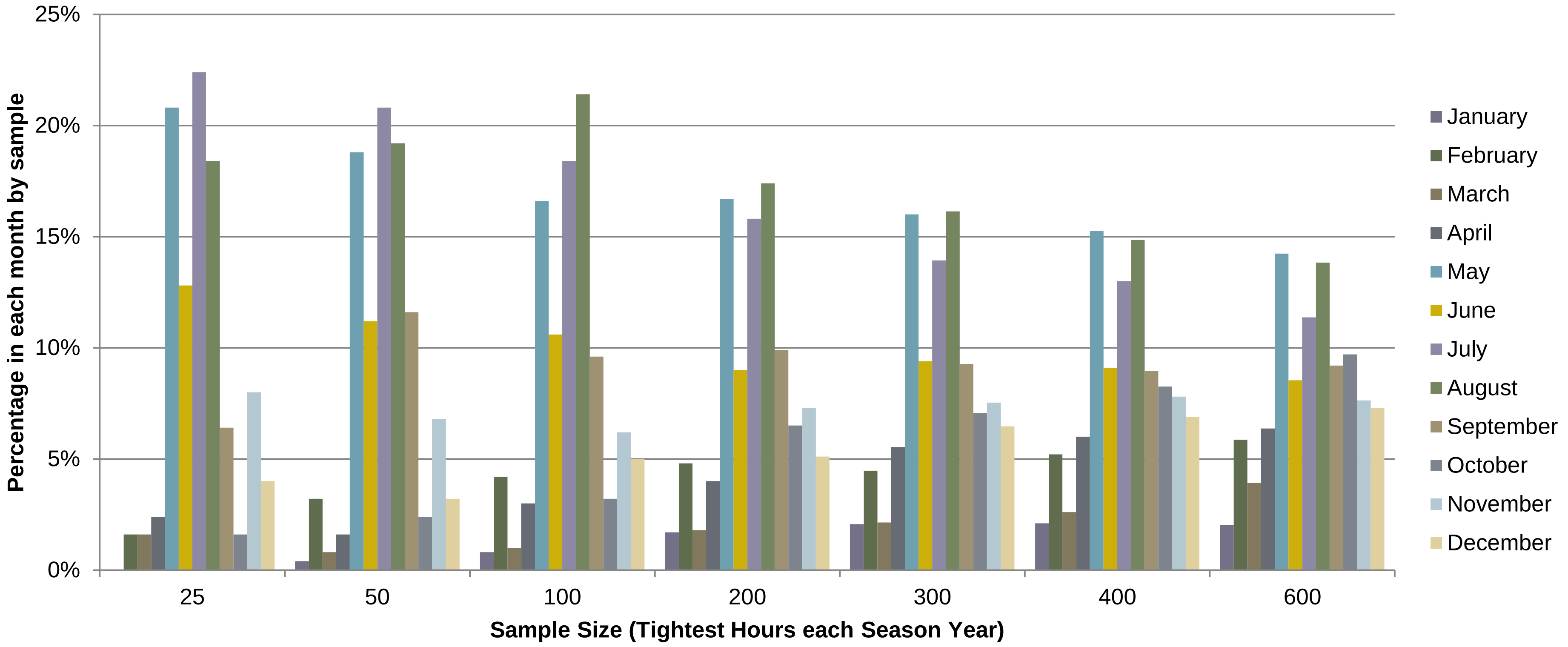
Parameters of the Analysis

- Date Range: November 1st 2012 to October 31st 2017
  - 5 season years each starting on November 1st
- Generally speaking, controllable assets were assigned an availability factor and non-controllable assets were assigned a capacity factor
- Assets currently presented on the Current Supply & Demand (CSD) page were examined for generating assets
- Sensitives were placed on the sample size for the tightest supply cushion hours in each season year
  - These include: 25, 50, 100, 200, 300, 400, & 600 hours
  - These include: 1 to 5 years historical
  - This is what is being referred to as “sample size”
- Preliminary analysis did not include active operating reserves for some capacity factor calculations, further calculations required

Assumptions

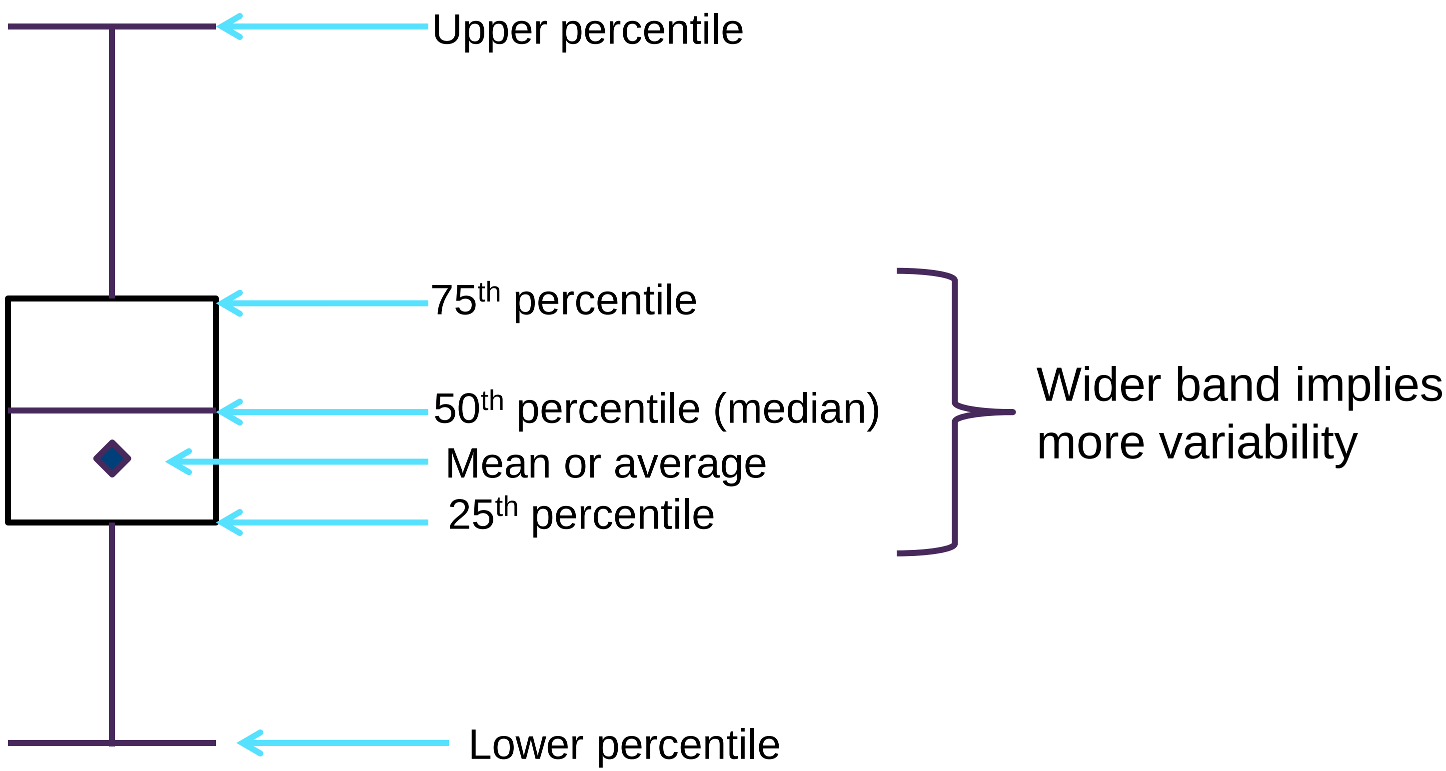
- Used CSD page assets as a basis for asset types and technology type for both availability and capacity factor methodology
  - Alternative was to use metered volume assets instead of CSD assets for capacity factor methodology
- Used Capacity factor methodology for all Cogeneration assets
  - Cogeneration assets typically have net output values
  - Available Capability (AC) was inconsistent in that some were net and some were gross
  - Will require further analysis of mapping meters to AC
  - Self supply assets will have to be identified
- Used mixed methodology for “Other” category. If Available Capability was submitted it was used, if not, metered volumes were used
- Used only metered volumes for capacity factor calculations. Will include AS in future iterations

Supply Cushion Hours by Month

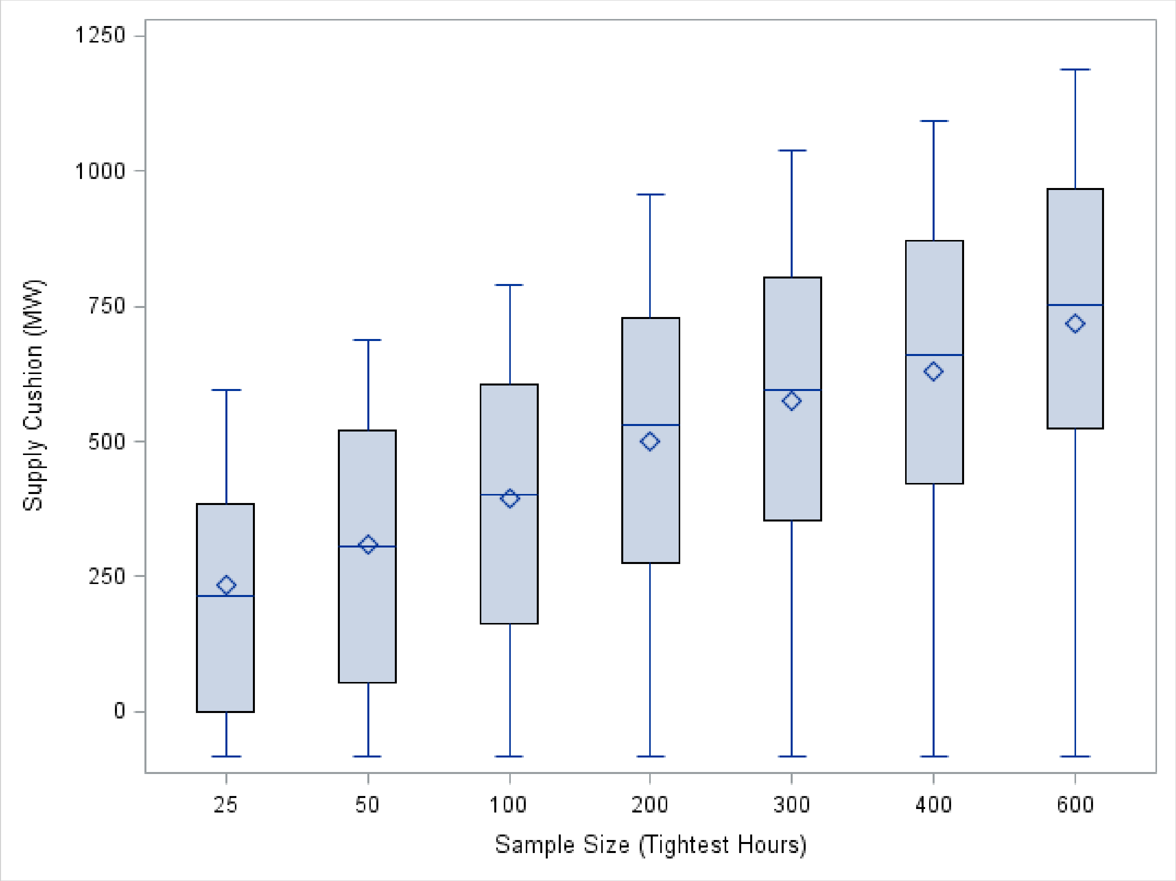


Summer months (May to September) tend to have the highest incidence of tight supply cushion hours and smooths out as sample size increases

Box and Whisker Interpretation



Supply Cushion

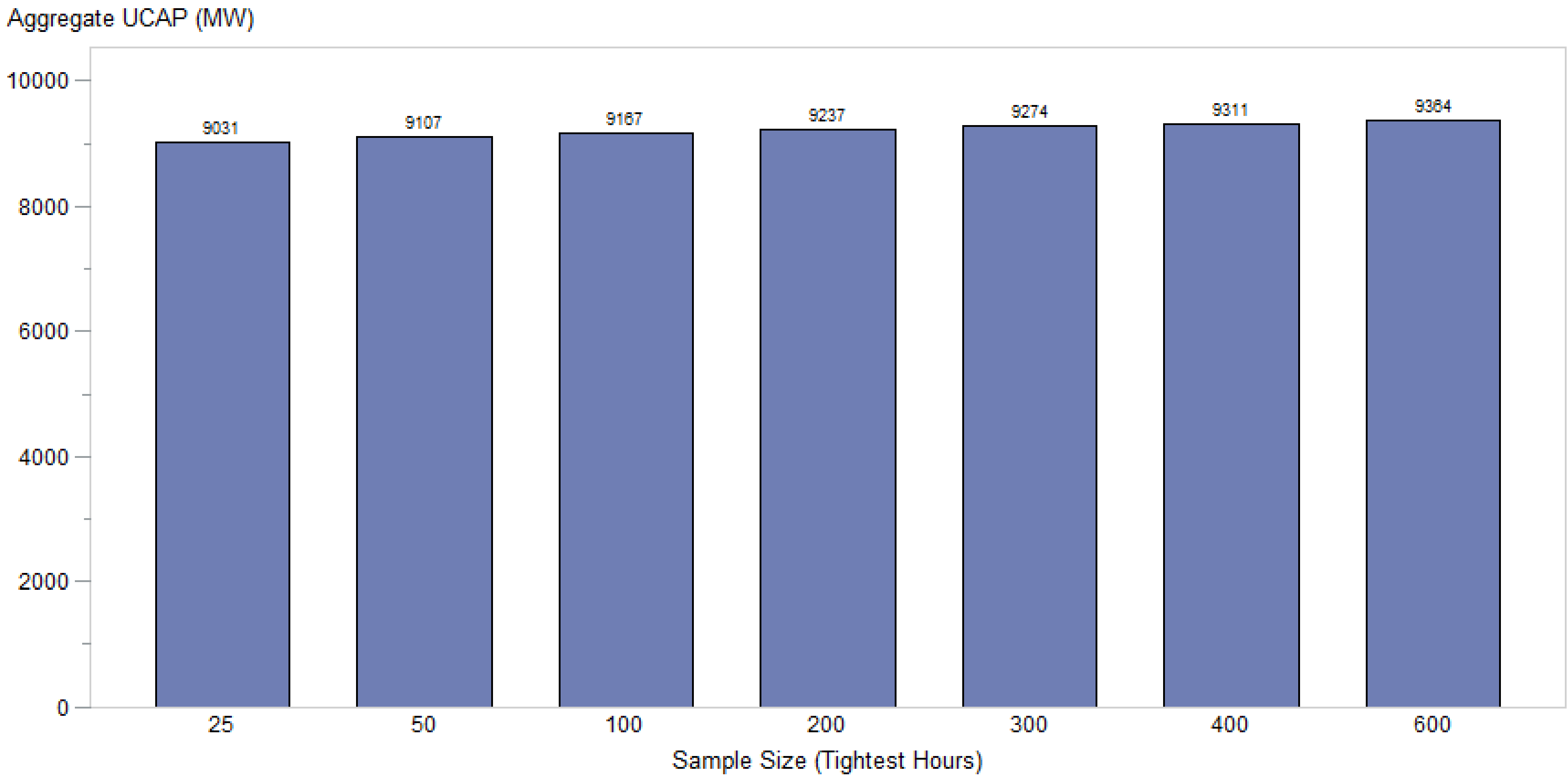


As the sample size increases, average supply cushion increases. At some point, the supply cushion is sufficient such that resource adequacy is not an immediate concern

For this presentation, the threshold is assumed to be at 1000 MW or less, or a little more than 2 large coal plants fully out

A meaningful sample is one that has direct impact to reliability, or less than 400 hours/year

Aggregate UCAP across sample sizes



- As the sample size for tightest supply cushion hours in each season year increases, the aggregate UCAP is stable

Key Findings from sensitivity analysis

- Average Availability factors tend not to vary significantly as sample size increases
- Average Capacity factors are prone to some variation especially for technology types that are limited by the availability of their fuel source (water, wind)
- Using 5 years provides reasonable estimate of future unit performance. This large sample over periods of low supply captures the variability in system conditions over different seasons
- 100 hours (over 5 years) provides a robust estimate of average resource capability, during tight supply and demand conditions. On average the annual spread is approximately 35 days. The statistical error in the UCAP estimate is approximately 2%
- Average UCAPs are reasonable and capture seasonal variation
- Self supply calculations will need additional metering point mapping to assets, denominator to use (MC or MCR) needs to be defined

UCAP Factors – Vary sample size for availability factors

Sample Size	Coal	Combined Cycle	Simple Cycle	Large Hydro	Other
25	73%	73%	83%	83%	41%
50	75%	74%	83%	83%	41%
100	75%	74%	84%	82%	41%
200	76%	73%	84%	81%	40%
300	76%	72%	84%	81%	40%
400	77%	72%	85%	81%	40%
600	78%	71%	85%	81%	40%

Availability factors are stable and don't vary significantly with increased sample size

Availability measures energy plus operating reserve capability

A sample size of a 100 is aligned with the penalty mechanism and is reasonable. As sample sizes get larger, the number of hours that are meaningful decrease.

UCAP Factors – Vary sample size for capacity factors

Sample Size	Cogeneration	Small Hydro	Wind	BC Intertie	MATL Intertie	SK Intertie
25	29%	56%	9%	21%	17%	31%
50	29%	57%	9%	19%	17%	26%
100	29%	54%	11%	18%	16%	27%
200	29%	50%	13%	17%	15%	25%
300	29%	48%	14%	16%	15%	26%
400	29%	46%	14%	16%	15%	25%
600	29%	44%	15%	17%	15%	24%

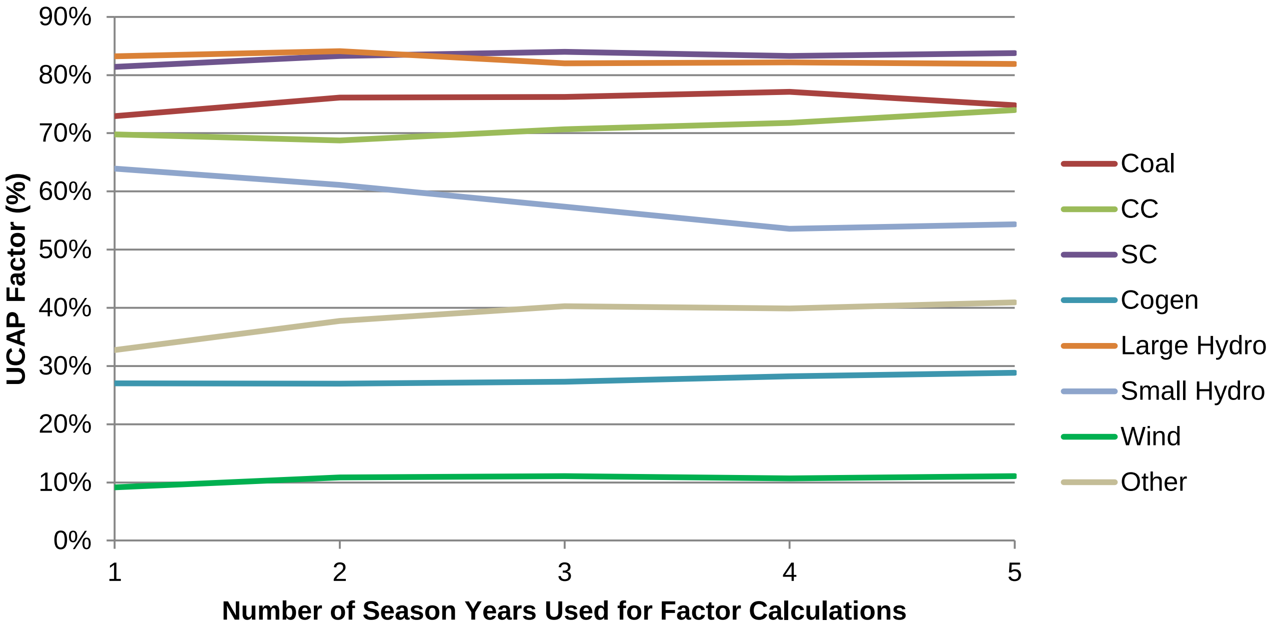
Further refinement required for Intertie and cogeneration factors. Results provided for information.

There is more variability with capacity factor resources like small hydro and wind.

- Should the UCAP for variable generation use the same number of hours as we used for thermal resources?

Currently 100 hours aligns with the penalty mechanism

Varying the Number of Season Years for 100 supply cushion hours/year



UCAP value stabilizes with increasing the number of historical data.

Five years of data smooths out year over year variations and provides a uniform estimate

Varying the number of season years used to calculate AF & CF:

# of Season Years	Coal	CC	SC	Cogen	Large Hydro	Small Hydro	Wind	Other
1	73%	70%	81%	27%	83%	64%	9%	33%
2	76%	69%	83%	27%	84%	61%	11%	38%
3	76%	71%	84%	27%	82%	57%	11%	40%
4	77%	72%	83%	28%	82%	54%	11%	40%
5	75%	74%	84%	29%	82%	54%	11%	41%

Round table feedback - UCAP Calculations

Is 100 hours acceptable for Capacity and Availability factor methodology?

Is 5 years historical data acceptable?

Any further considerations?

Data Issues & Limitations

More mapping needs to be done at the asset level for self supply

- For behind the fence generation assets, alignment is not observed between metered volumes and maximum capability(MC)

MC data

- Metered volumes can exceed MC resulting in high factors
  - Example: UOC1 had a capacity factor of 3 in 2013 - MC data was not updated to reflect the level of metered volumes

Metered Volume Data

- To truly understand the metered volumes, single line diagrams would need to be examined, especially for cogeneration and other assets
- Example: Joffrey (JOF1) and Dow Hydrocarbon (DOWG) have metered volumes based on the difference between MWs in and MWs out of each respective site

AC Data for long lead time assets

- Assets that have long lead times may reflect AC’s that are different than operational availability

Next steps

- Refine calculations
  - Include active reserves for specific capacity factor resources
  - Begin mapping revenue meters to assets for self supply calculations. Self supply will need to be explicitly identified for the auction.
  - Refine intertie calculations
- Incorporate feedback where appropriate
- Working through mapping issues prior to releasing asset specific UCAP calculations
  - Will be provided as available, targeting to provide for full all assets by March 22

Load Forecast Methodology & Resource Adequacy Modeling Update

February 15, 2018

CMD Technical Work Group

Technical Workgroup Objective: AESO Load Forecast & Resource Adequacy Model

- Through the WG process seeking workgroup members review and 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

Load Forecast Methodology

February 15, 2018

CMD Technical Work Group

Agenda

- Review load forecast methodology
  - Further material provided in *Capacity Market Load Forecast* document
    - Minor additions to the November 2017 version
- Review SAM 3.0 feedback
  - Customer sector energy models
  - Energy efficiency, demand response, price responsive load, and distributed generation
  - Use of third party economic forecasts

Methodology for capacity market load forecast - inputs

- The AESO utilizes four key input variables to forecast load
  - A blended index of population, employment, and real GDP
    - The RHA, RLEMA, and RQTOA variables from the Conference Board of Canada (CBoC)
  - Temperature across the province
    - An average of temperature from Calgary, Edmonton, Lethbridge, and Fort McMurray
  - Many calendar effects
    - Day of the week, hour of the day, month, daylight, DST etc.
  - Other independent variables
    - Oilsands production
    - Indicator variables

Methodology for capacity market load forecast – model specification

- After a data cleaning procedure, the data is run through a iterative diagnose procedure
  - Many different model specifications are attempted with the goal of minimizing hourly mean absolute per cent error (MAPE) during a one year hold-out period, by iterating through:
    - Lagged temperatures configurations
      - Polynomial degree
    - Groupings of calendar effects
      - Grouping economic and calendar effects together
    - Groupings of holiday effects
    - Independent variables
  - Specification with the lowest MAPE during the one year hold-out is chosen

Methodology for capacity market load forecast – managing uncertainty

- To manage economic and weather uncertainty during the forecast horizon, the AESO will
  - take a probabilistic approach with respect to temperature
    - With 30+ years of temperature data, a large range of possible temperature outcomes are contemplated throughout the forecast horizon
  - Use economic scenarios to capture the possibility of recessions or large economic expansions not contemplated in the economic outlook
  - The outcome is over 100 load profiles based on different combinations of temperature and economic outcomes

SAM 3.0 feedback

- Feedback from SAM 3.0 on the proposed load forecast methodology and process indicated that there are three key areas of interest:
  - The move from the sector level energy models to an hourly aggregated load model
  - How the AESO will incorporate energy efficiency (EE), demand response (DR), distributed generation (DERs), and price responsive load (PRL)
  - The risk of relying 3rd party vendors for economic forecasts
    - It was suggested that the AESO run the load forecast model on vintage CBoC forecasts

SAM 3.0 feedback – the move from the sector level models

- For the 2017 Long-term Outlook (LTO) the AESO moved away from the sector level models, to an hourly AIL model
  - A decision to rely on this forecast model was made following a review of the AESO's 2016 LTO Reference Case load forecast and the near-term load growth of that scenario following the significant drop in oil price in 2015
- This review indicated that the sector level energy models had many undesirable features
  - The sector models are yearly energy models. As a result they have very few degrees of freedom, and have to utilize data from back as far as the 1980's
    - Load in Alberta has materially changed since the 1980s
    - Few degrees of freedom, and picking up on outdated relationships, created very strong relationships between load and the economic driver variables
      - This created a large risk of over-forecasting based on optimistic economic outlooks

SAM 3.0 feedback – EE, DR, DERs, PRL

- In the interest of being transparent, the AESO proposed that EE and DR will be contemplated through post model adjustments
  - For EE, If the data is available, bottom up modelling of equipment replacement can be netted from the forecast load.
  - If EE data is not available, it may be necessary to estimate the impact using alternate techniques such as examining similar programs in other jurisdictions
  - For first auction, the AESO is not currently planning to make an explicit EE assumption
    - EE uncertainty will be captured through the varied load profiles
  - If demand response providers are able to provide the AESO with data of their capabilities and drivers, post-model adjustments can be made to ensure the impacts are accounted for
    - Any demand response present in historic data will be picked up by the many parameters in load forecast model

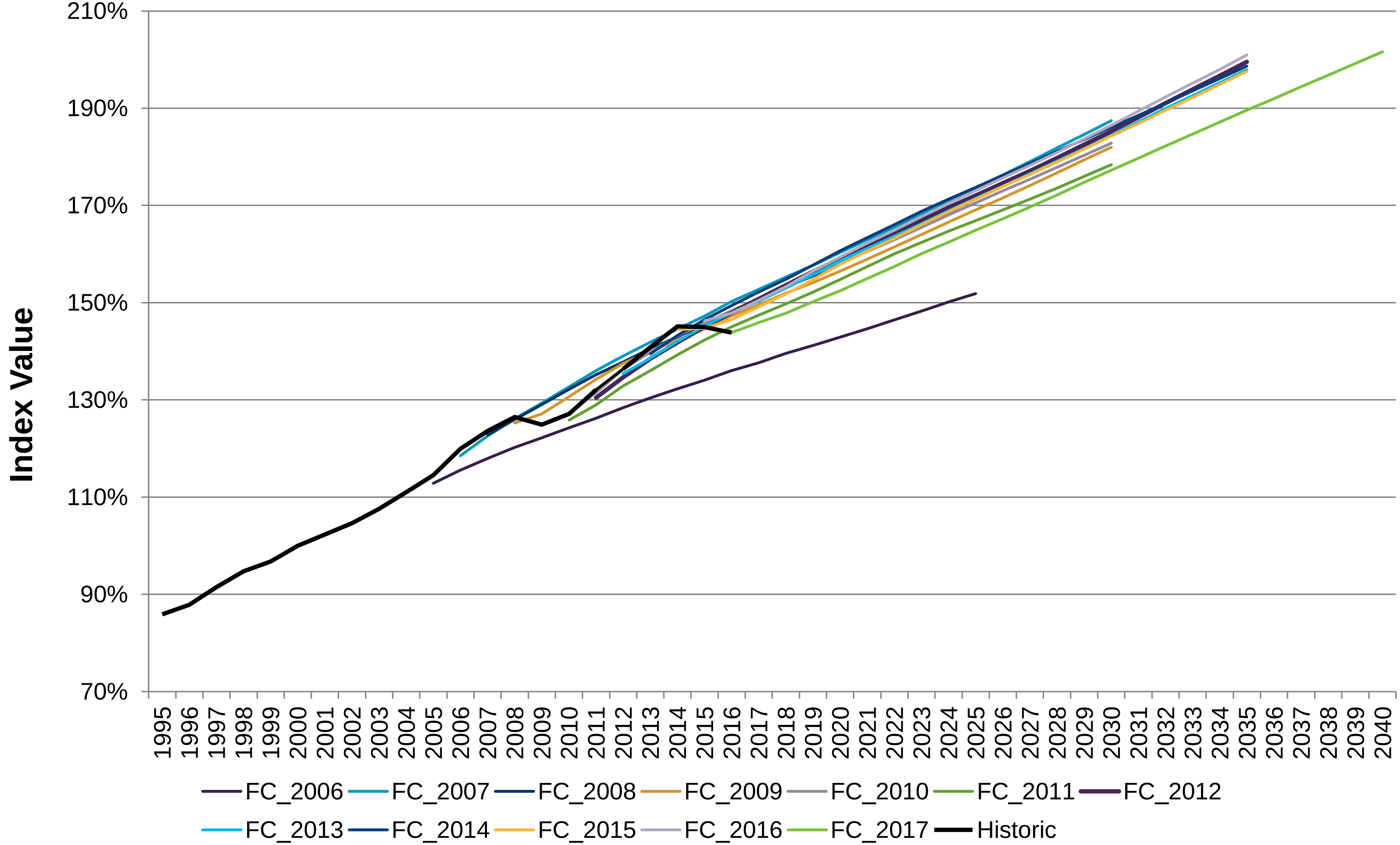
SAM 3.0 feedback – EE, DR, DERs, PRL

- The Capacity Market Load Forecast model is an hourly model, therefore all previous PRL activity in the training period will be picked up in the estimated parameters
  - Hold-out hourly minimal (less than 1.5%) implying PRLs impacts to price or tariff are picked up through the various indicator variables.
    - For example: Absent PRL in the past, the parameter on HE 18 would be larger than it is estimated to be when PRL is included in the historic data
- Due to current data constraints, load served behind-the-meter (BTM) by micro generation (<5 MW) is currently unavailable to the AESO
  - If this data becomes available the AESO will incorporate it into the aggregate load number used in the forecast
    - If the data does not become available, and if BTM load served by microgeneration grows, the AESO will contemplate grossing up Alberta Internal Load (AIL) to include this impact
    - It's unlikely this adjustment will be made for the first auction

SAM 3.0 feedback – reliance on vendor forecasts

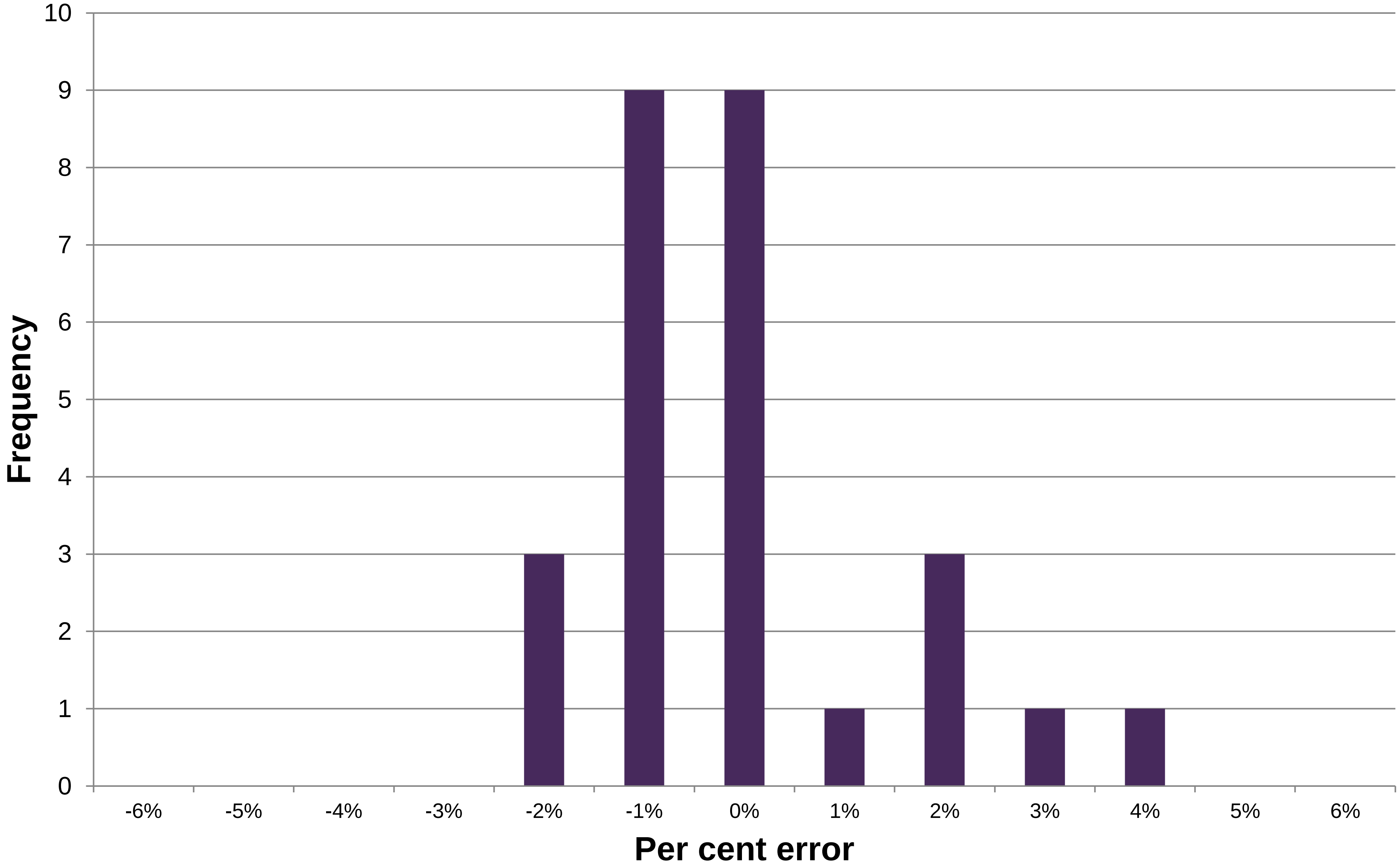
- To evaluate this concern, the AESO undertook an analysis of historic forecast errors from the CBoC and Canadian Association of Petroleum Producers (CAPP) on the variables that are inputs into the load forecast
  - These historic errors were ran as sensitivities through the capacity market load forecast model to quantify the impact of vendor errors on predicted load
- CBoC forecasts from 2004 to current were gathered to analyze the forecast errors on the derived index
- CAPP forecasts from 2010 to current were used (data limitations)

Weighted index based on CBoC forecasts



“FC_20XX” refers to the Conference Board forecast from that year

Distribution of errors up to 3 years out (excluding FC 2006)



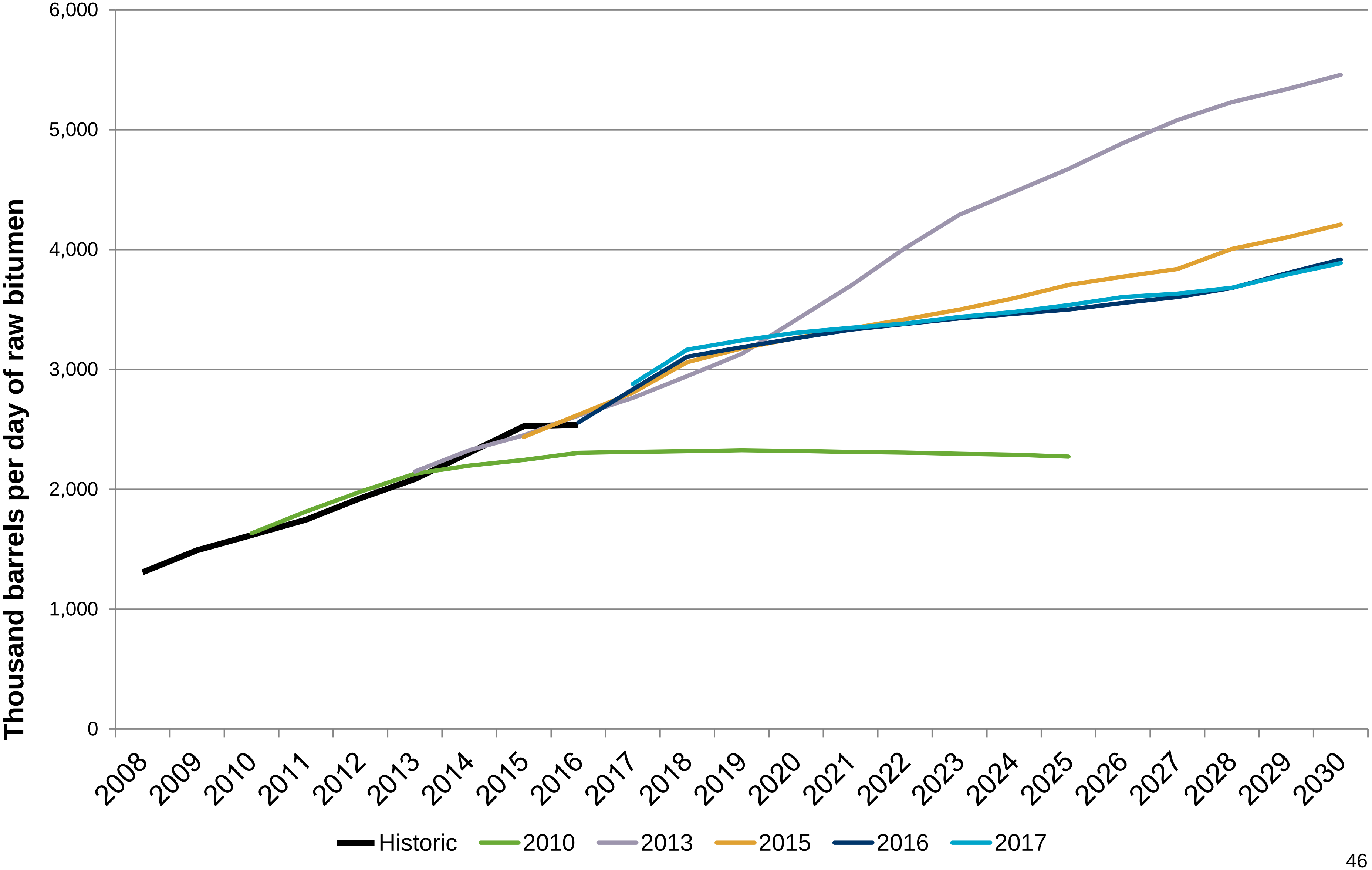
Impact to load forecast

- The current run of the capacity market load forecast finds that for a 1% increase in the economic index, load increases by 71 MW during winter peak conditions
- The CBoC error analysis found that 3 years out, the largest errors were -2.8% and 3.4%
  - This translates to under-forecasting during peak load times in 2021 by 200 MW or over-forecasting by 238 MW
- One year out the largest errors are -1.4% and 1.1%
  - This translates to under-forecasting during peak load times in 2021 by 101 MW or over-forecasting by 79 MW respectively

Vendor error analysis

- The AESO uses oilsands production as an input into the capacity market load forecast model
  - The current run utilized the 2017 CAPP forecast
- Analysis of four different CAPP forecasts showed that between one and three years out, forecast errors can range from -3.6% to 3.9%

Previous CAPP forecasts



Impact to load forecast

- The current run of the capacity market load forecast finds that for a 1% increase in oilsands production, load increases by 17 MW during 2021 winter peak conditions
- The CAPP error analysis found that 3 years out, the largest errors were -3.6% and 3.9%
  - This translates to under-forecasting during peak load times in 2021 by 63 MW or over-forecasting by 68 MW
- Due to the small sample size, errors did not vary largely between one and three years out

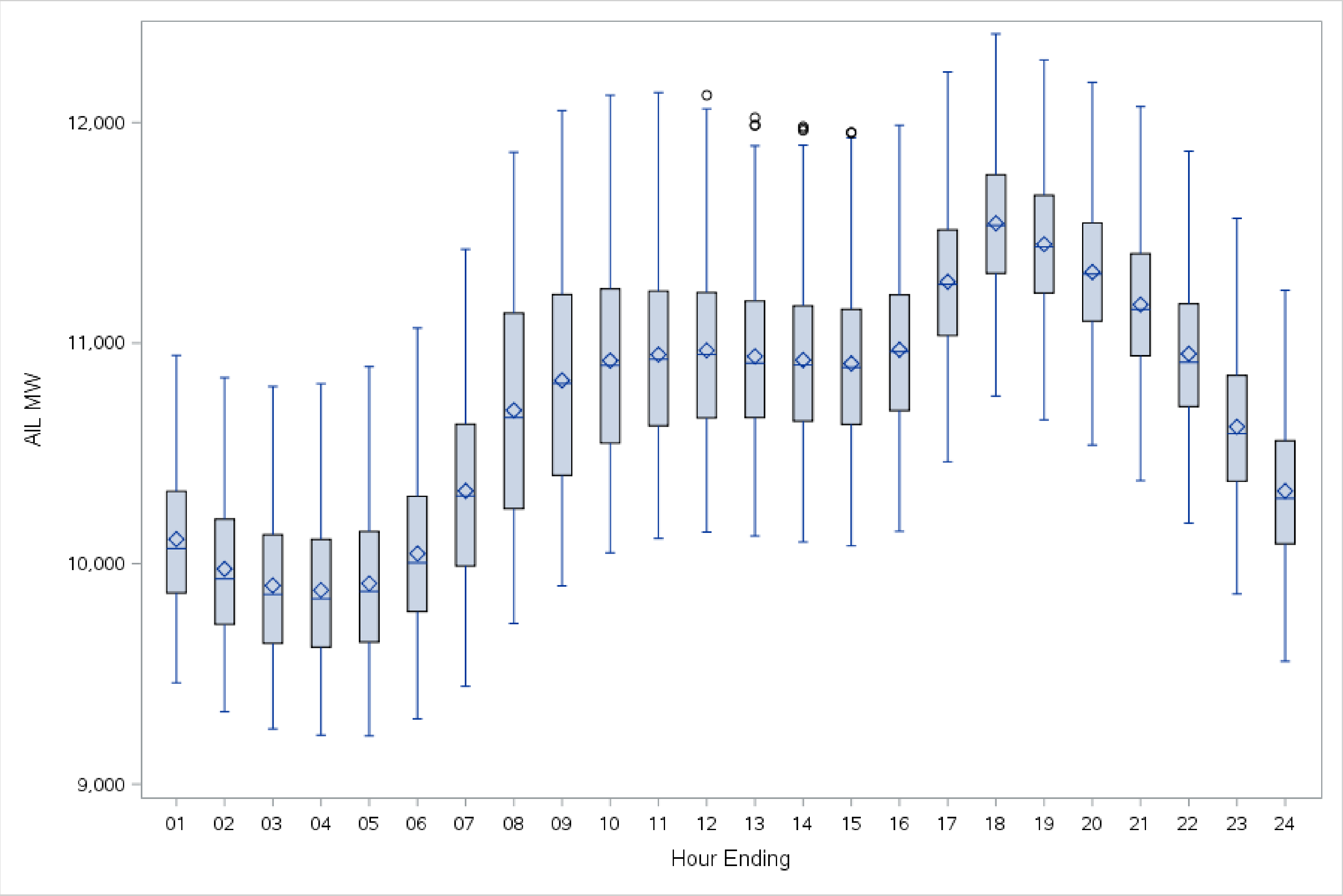
Worst case scenario

- If the CBoC and CAPP *both* over-forecast in line with the *worst* currently observed three-year-out errors, the input errors would translate to 306 MW of load forecast error
  – One year out the worst case would be 147 MW
- The highest possible under-forecast three years out would translate to 263 MW
  – One year out this translates to 164 MW
- The current model run has a hold-out mean absolute error of 125 MW or 1.33%
  – If the direction of model error aligned with CAPP and CBoC error, the totals then for three year errors would be
    - 431 MW over-forecast
    - 388 MW under-forecast

Managing risk

- The current run of the capacity market load forecast has a range of ~925 MW for 2021 winter peak
  - Ranges from 11,733 MW to 12,656 MW with a median of 12,185 MW
- This range is produced by using 30+ weather years to capture temperature uncertainty, and by using economic scenarios determined by previously observed economic booms and busts
- Therefore, in the reliability study, extreme events where the input forecasts contain large errors are captured as possible scenarios
- However, because these scenarios are extremely rare, they lie on the tails of the load forecast distribution

2021 December 20th-27th (peak load conditions) forecast distribution within each hour



Mean value

Interquartile range, mid line is the median

Represents the upper/lower fence, 1.5 * the interquartile range

Represents outliers outside the upper or lower fence

Risk Management

- As the box and whisker plot demonstrates, the load values during winter peak converge around their median as the mean and median are very close, with a small inner quartile range
- This means that like the distribution of errors from the CBoC, the outlier events are only represented with a small probability
  - Therefore in expectation, the correct load values are contemplated
  - The Monte Carlo simulations in the reliability study reflect the risks of over- or under-forecasting, and weight them accordingly

Workgroup Discussion

- Are there any outstanding concerns with the load forecast methodology?

Resource Adequacy Modeling update

Technical Working Group

February 15th, 2018

Resource Adequacy

- The AESO has completed the validation process to select a resource adequacy modeling tool.
  - The recommended solution was to procure the Strategic Energy and Risk Valuation Model (SERVM) which is managed by Astrapé Consulting.
  - SERVM will be used to evaluate the resource adequacy of the Alberta system and its interconnected areas in terms of resource adequacy metrics.
- The AESO is currently implementing the software solution and developing a preliminary resource adequacy model.
  - Implement Resource Adequacy system by Q1 2018
  - Astrapé is also providing consulting services on an initial physical reliability assessment.

Next Steps

- Physical resource adequacy study and model development
  - The AESO is currently working with Astrapé to prepare an initial assessment to evaluate system resource adequacy in parallel with the implementation of the software.
  - The AESO will review the calibration of inputs of this assessment and run sensitives to further refine and develop the model.
  - The AESO will present initial results during the next session (April 6th) of the Technical Working Group for review and received feed back

Workgroup Discussion

- What specific information should be provided to the workgroup to ensure the required level of transparency and detail to test the reasonableness of the resource adequacy model results?

Cost of New Entry Development Process

February 15, 2018

Feedback from SAM 3.0 Process

- Stakeholders were generally supportive of the calculation approach suggested by the AESO in the SAM 3.0 Process
- Support for the use of an independent advisor with experience in Alberta
- Stakeholders stressed the importance of an Alberta specific focus as it relates to financing, capital costs, and macroeconomic assumptions
- Support for reference technology selection criteria based on
  - Lowest Gross CONE
  - Lowest Net CONE
  - Development history in Alberta
  - Fastest deployment
- Support for a forward looking rather than historical energy & ancillary service offset
  - Mixed opinions on preference for a forward curve vs. forecast/simulation

Cost of New Entry Process

- AESO has contracted with advisors that have significant experience in capacity market consultation, electricity financing, and power plant construction in Alberta
- Advisors will develop a CONE report including
  - gross CONE estimates for several natural-gas fired technologies
  - reference technology recommendation
  - recommendation for an CONE update process
- Technical Working Group will be updated at each meeting as the consulting work progresses
- Feedback will be requested from Technical Working Group members

Consultant Engagement

AESO has engaged Brattle to work with Sargent & Lundy to develop Gross CONE calculations including:

- Financing costs: After Tax Weighted Average Cost of Capital
- Recommendation of Reference Plant
- Plant capital costs: Capital costs including EPC & owners development costs for reference plant
- Recommended approaches to updating annual Gross CONE

Alberta Specific Experience

- Brattle Group has significant experience in Alberta and a strong understanding of the developing Capacity Market
  - Significant expertise in cost of capital and capital structure proceedings in Alberta and other jurisdictions in Canada
- Sargent & Lundy has participated in numerous thermal generation projects in Alberta including combined cycle, simple cycle, and cogeneration projects over the past 20 years

Schedule

- February – Discuss Gross CONE & Net CONE process & schedule for working group
- April – Review financial assumptions and reference technology screen
- May – Review approach to Energy & Ancillary Service Offset calculation
- Jun – Present draft Gross CONE results and gather feedback from the technical working group
- Q3 – Final consultation on Gross CONE & Net CONE

Workgroup Discussion

- Are there any concerns with the intended Gross CONE estimation approach?
- Is there an aspect missing from our considerations or plan in Net CONE estimation?

Demand Curve Updates

February 15, 2018

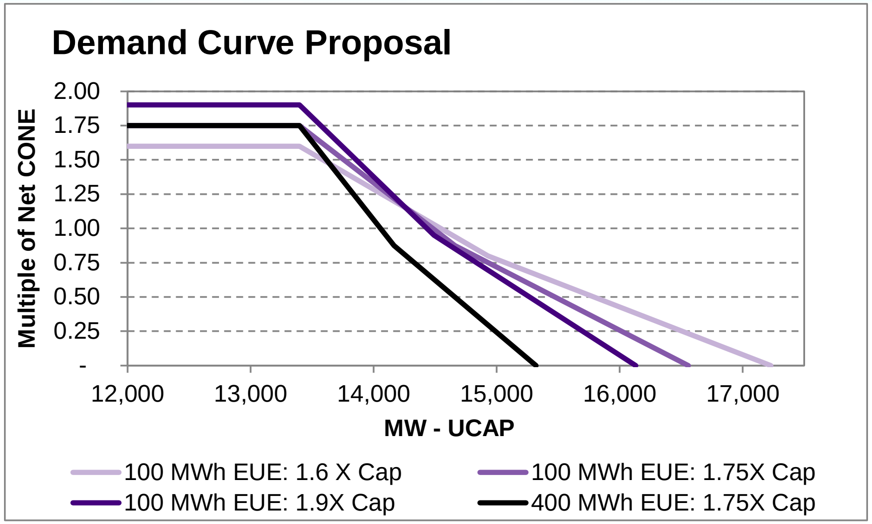
Technical Working Group Process

- Throughout the Technical Working Group process, we will explore the demand curve analysis within the context of new resource adequacy modeling results
- Will be revisit decisions relating to the demand curve shape and parameters
  - Gather feedback from the working group on the trade-offs between demand curve parameters

Feedback Received from SAM 3.0 Process

- Stakeholders generally accept a downward sloping convex demand curve
- Many stakeholders felt that the demand curves presented in the SAM3.0 process were too wide
  - Opinions ranged on width from foot-to-cap, between 4,000 MW to effectively 0 MW
- Some participants preferred a much steeper curve, with a lower price cap, and significant bid mitigation for large portfolios

Evolution of Candidate Curves



	100 MWh EUE			400 MWh EUE
Price Cap	1.9X Net CONE	1.75X Net CONE	1.6X Net CONE	1.75X Net CONE
Width (Cap-to-Foot)	2,734 MW	3,163 MW	3,833 MW	1,924 MW

- Subsequent to the SAM3.0 process, the AESO has revised the resource adequacy standard working assumption from 100 MWh EUE to 400 MWh EUE, which shifted the demand curve inward
- The change reduces the width of the demand curve significantly

Questions for the Technical Work Group

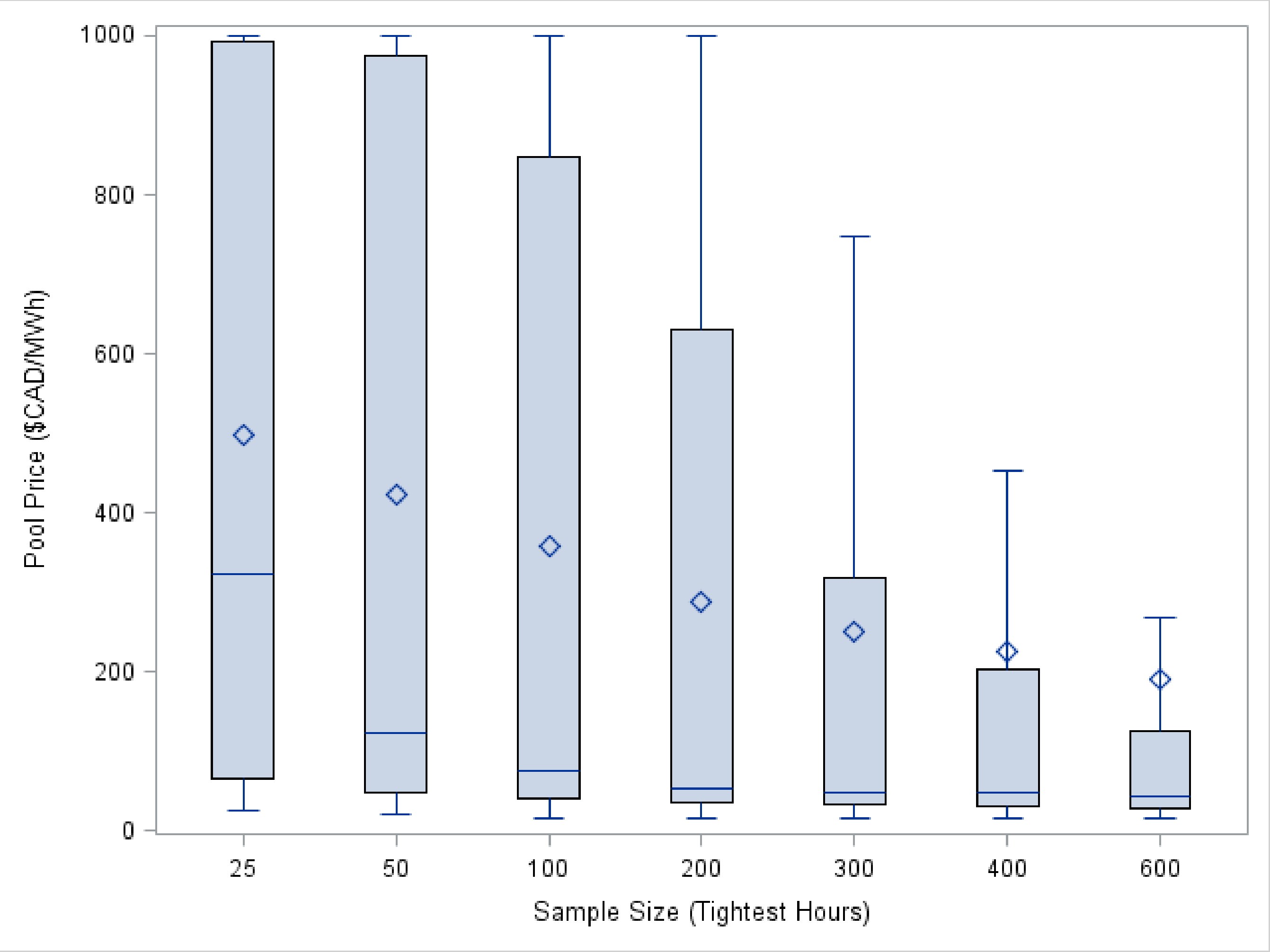
- Does the reduced width of the 400 MWh EUE curve, compared to the 100 MWh EUE curve address stakeholder concerns regarding over-procurement?
- Is the concern of over-procurement related to elasticity/slope or to the target procurement level?

UCAP Appendix

Appendix

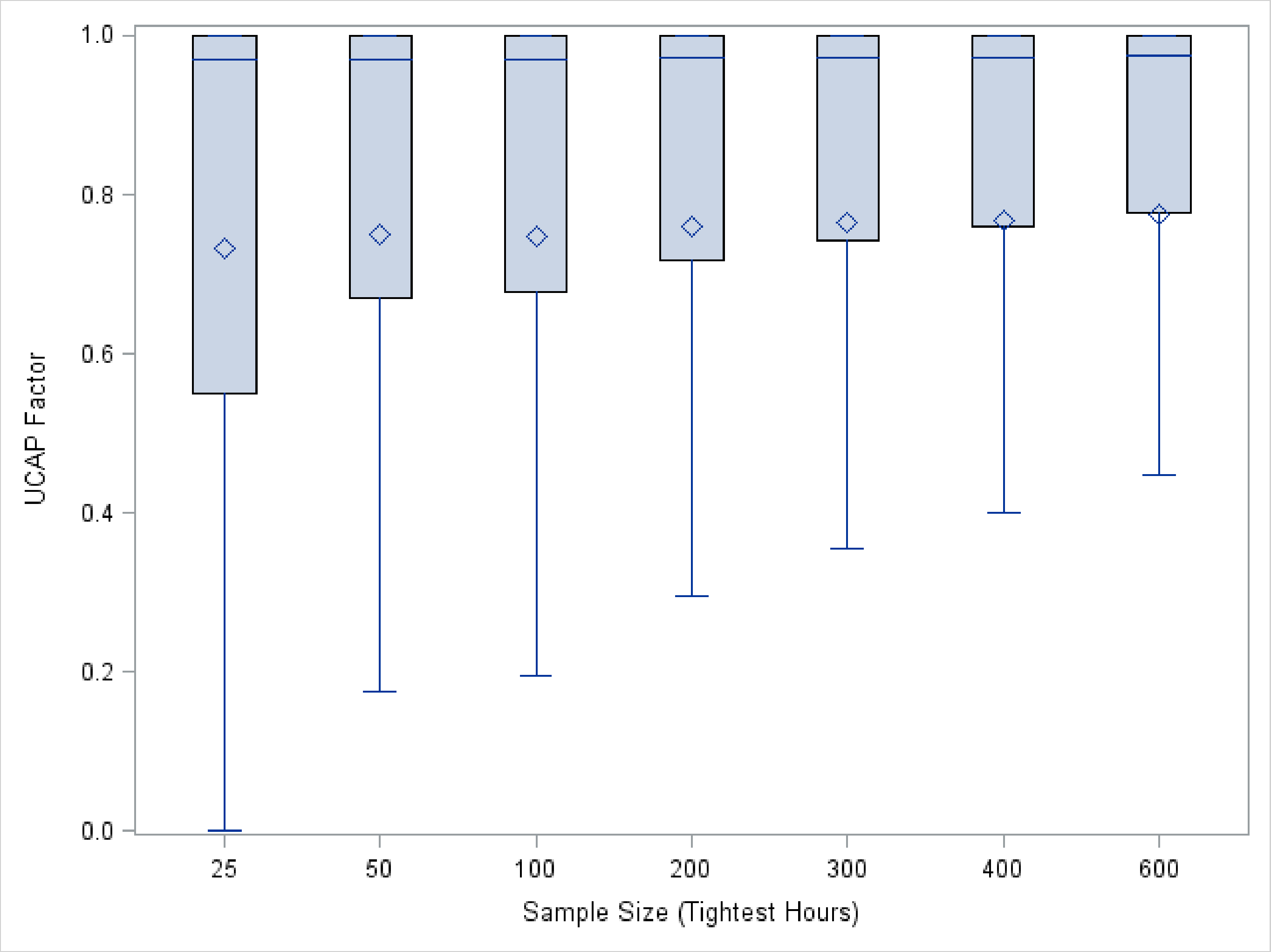
- Box and whisker plot for price
- Box and whisker plots by technology

Pool Price



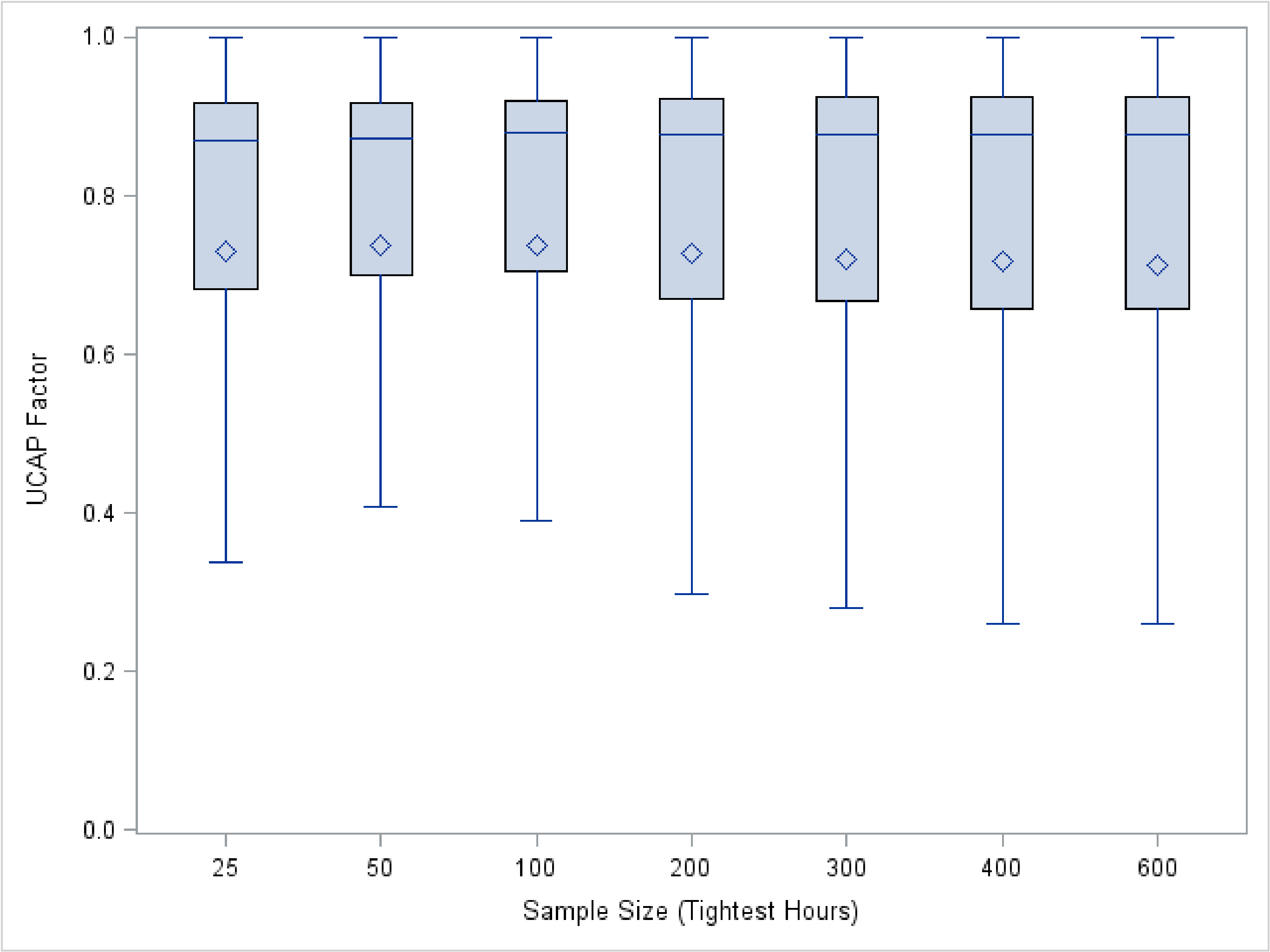
As the sample size increases, average pool price decreases

Coal

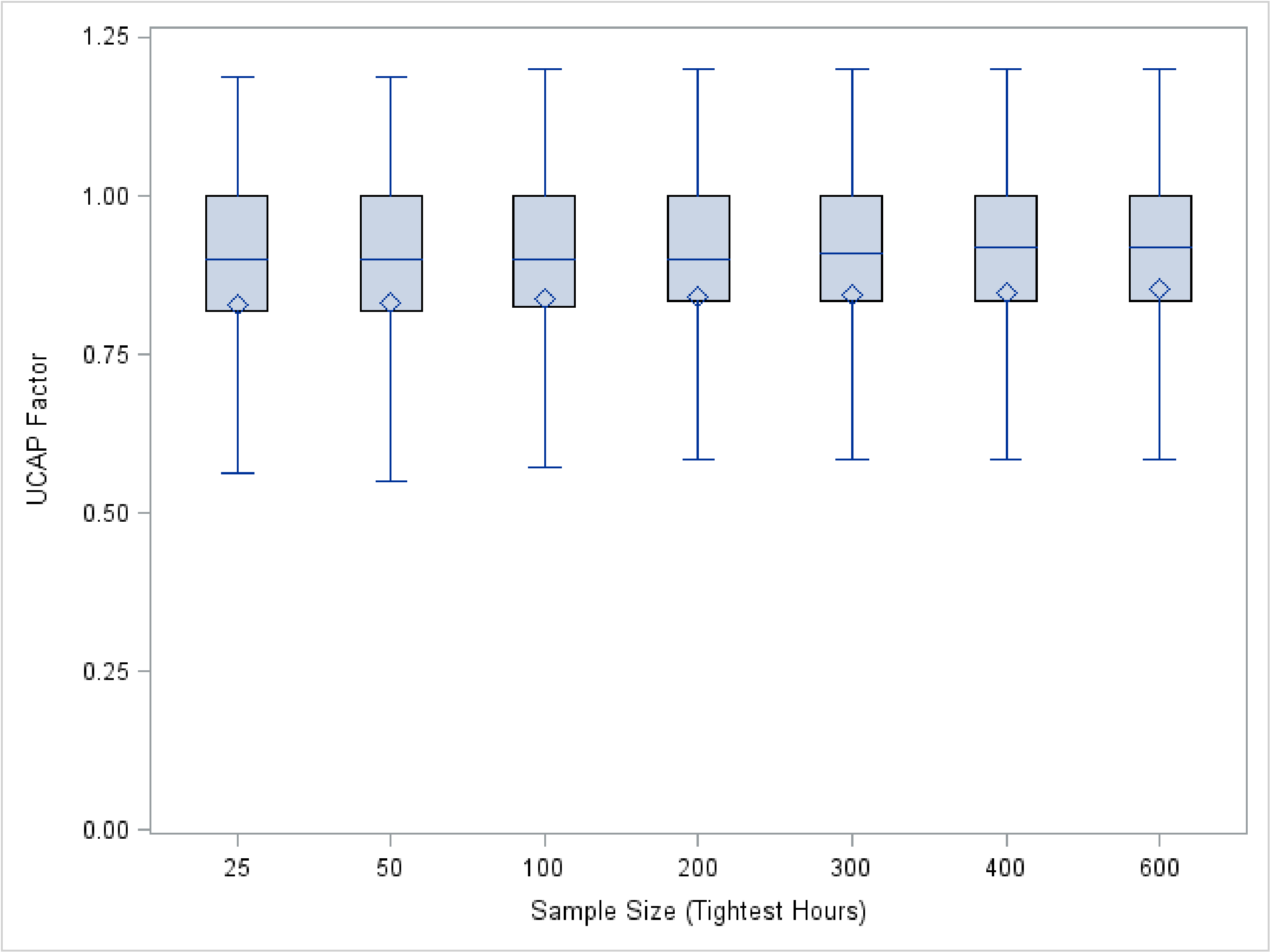


UCAP Factor
1.0
0.8
0.6
0.4
0.2
0.0
25
50
100
200
300
400
600
Sample Size (Tightest Hours)

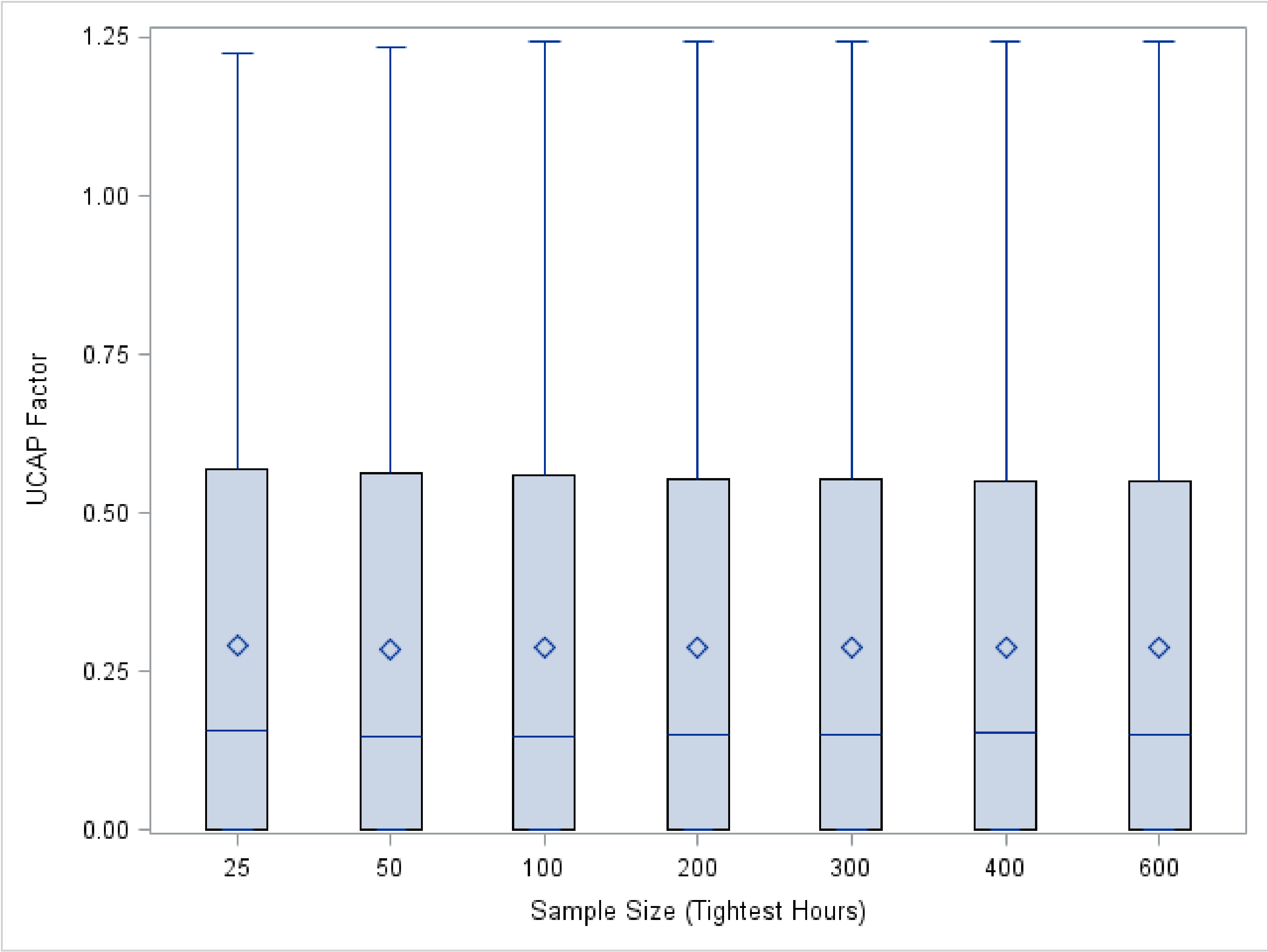
Combined Cycle



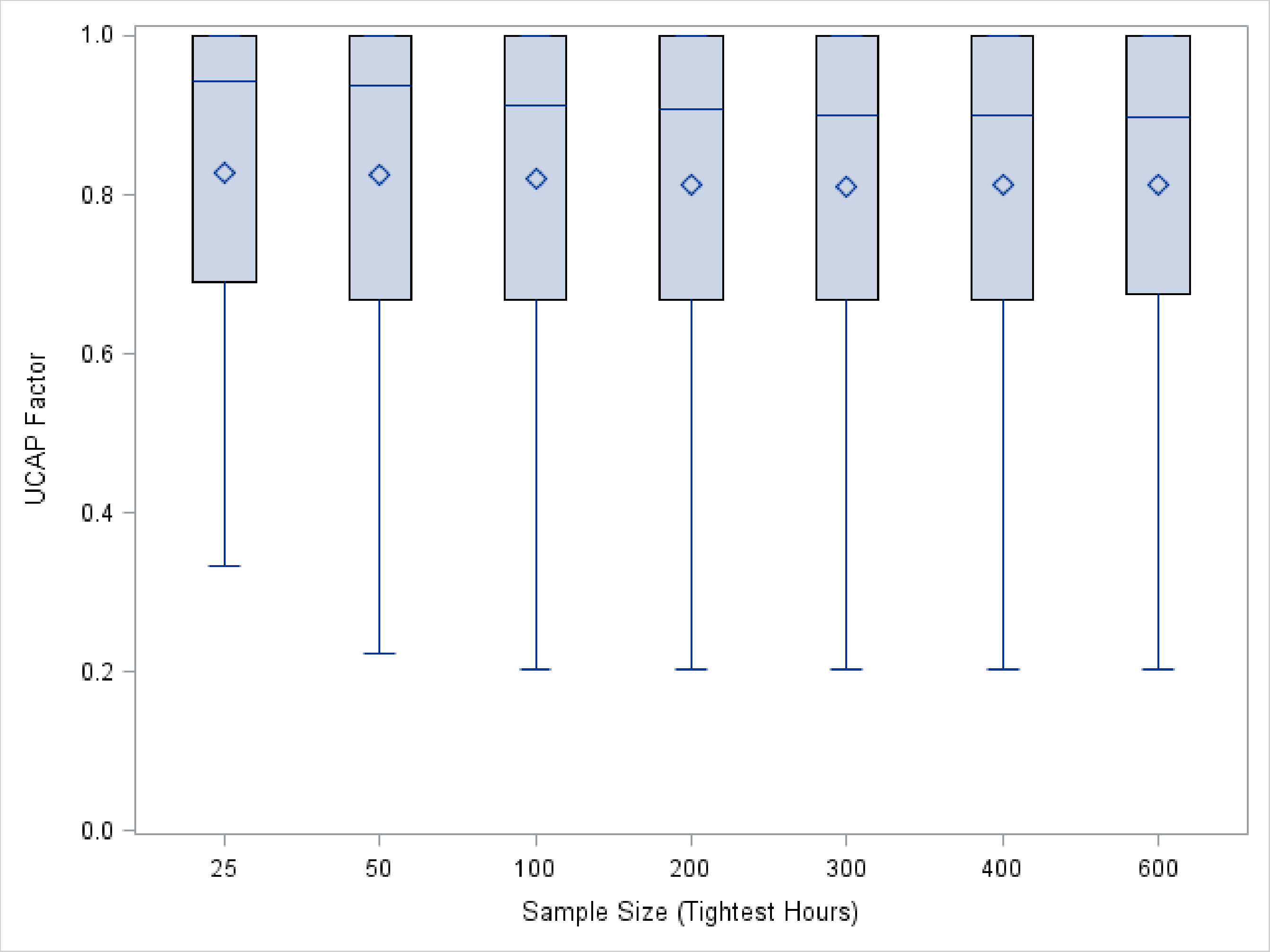
Simple Cycle



Cogeneration

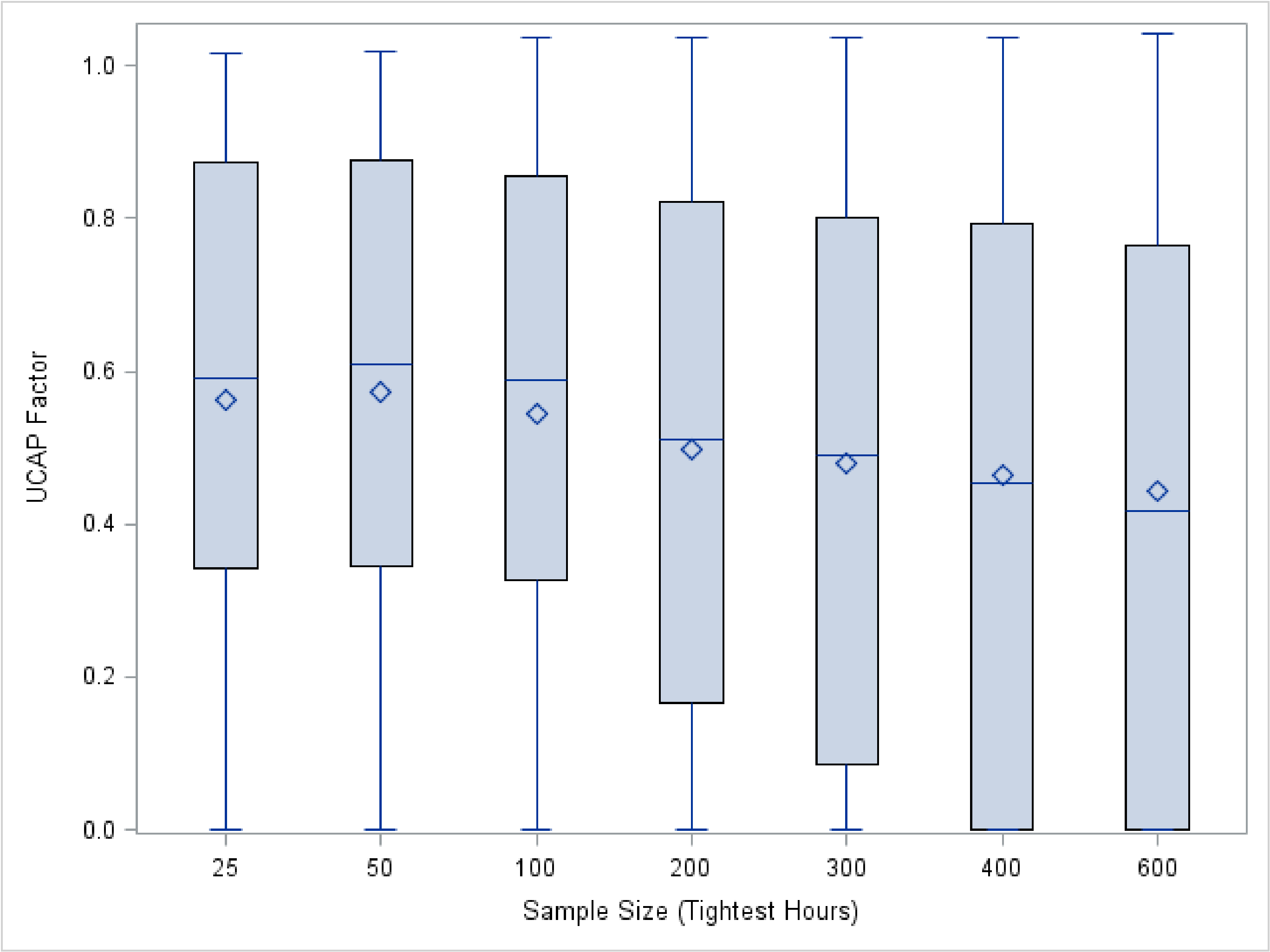


Large Hydro



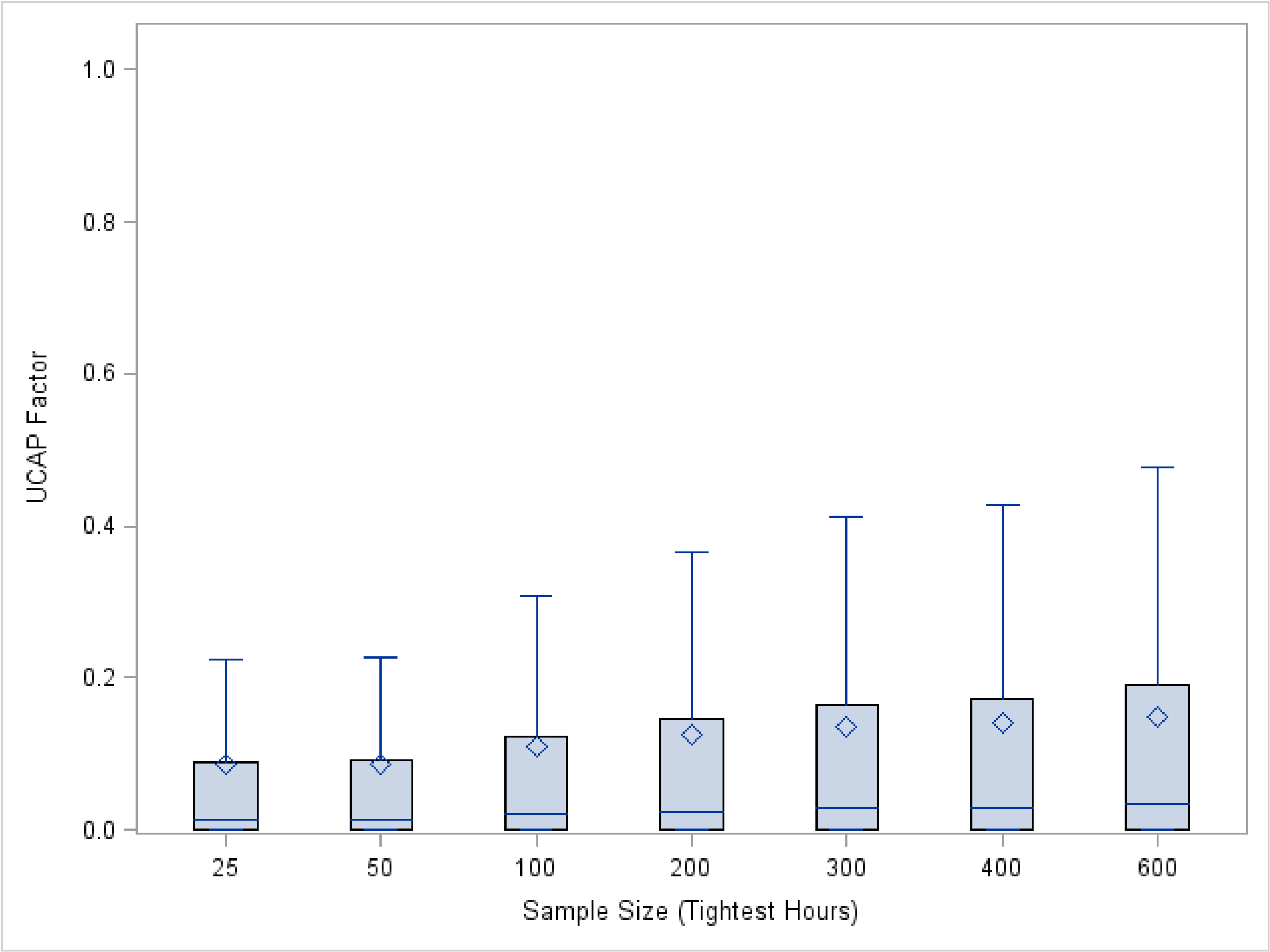
1.0
0.8
0.6
0.4
0.2
0.0
UCAP Factor
25
50
100
200
300
400
600
Sample Size (Tightest Hours)

Small Hydro



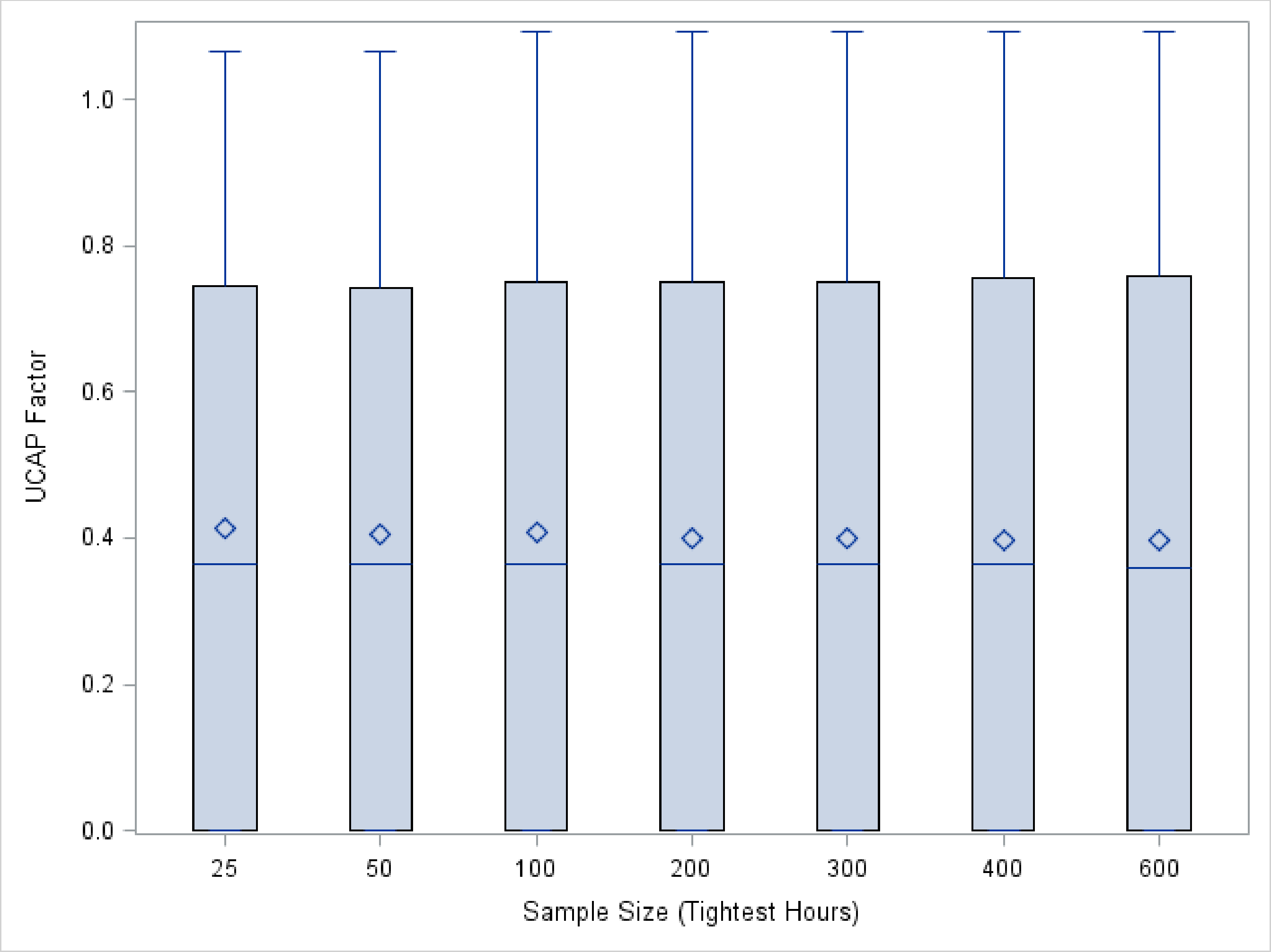
UCAP Factor
1.0
0.8
0.6
0.4
0.2
0.0
25
50
100
200
300
400
600
Sample Size (Tightest Hours)

Wind



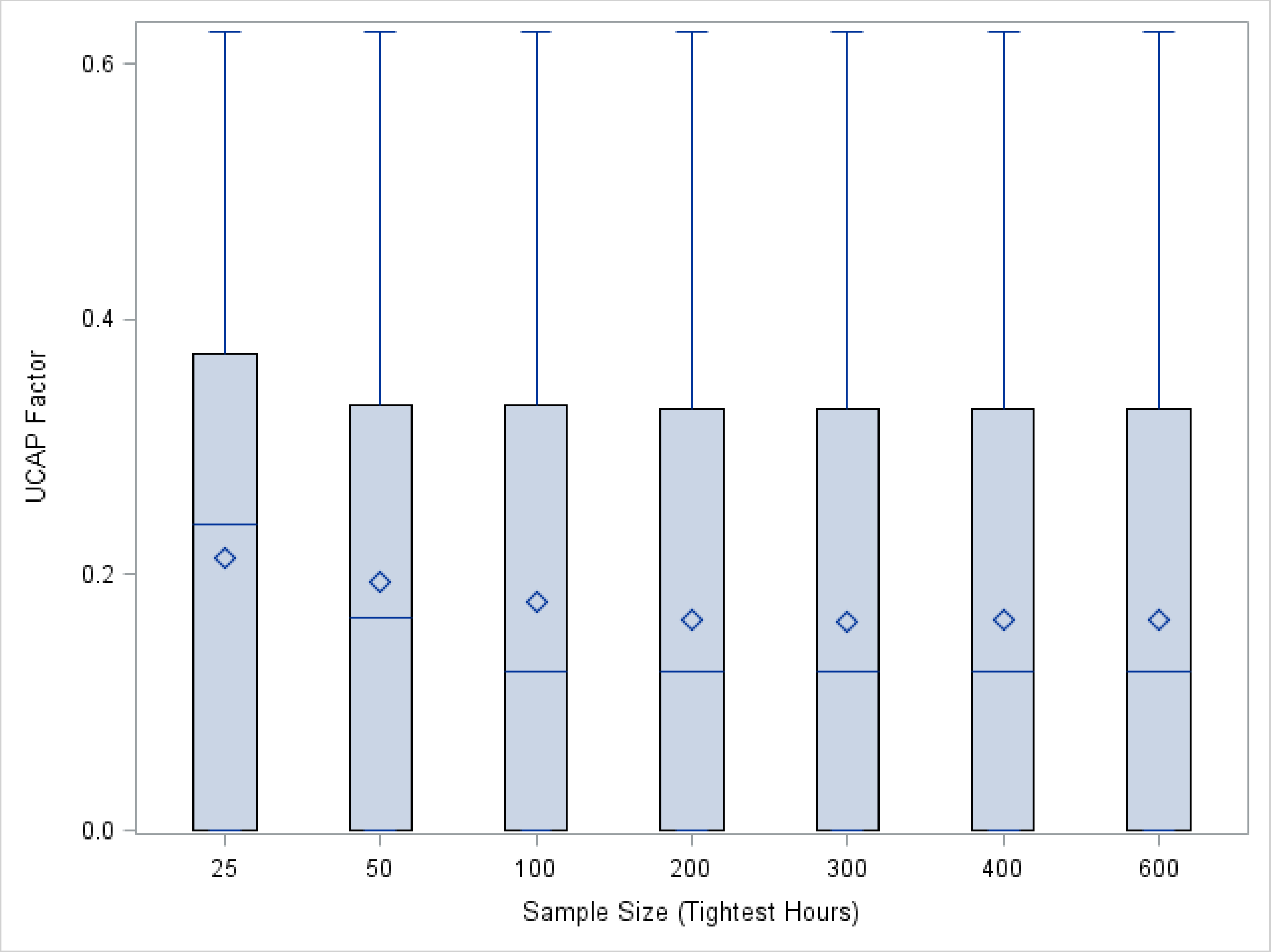
UCAP Factor
1.0
0.8
0.6
0.4
0.2
0.0
25
50
100
200
300
400
600
Sample Size (Tightest Hours)

Other

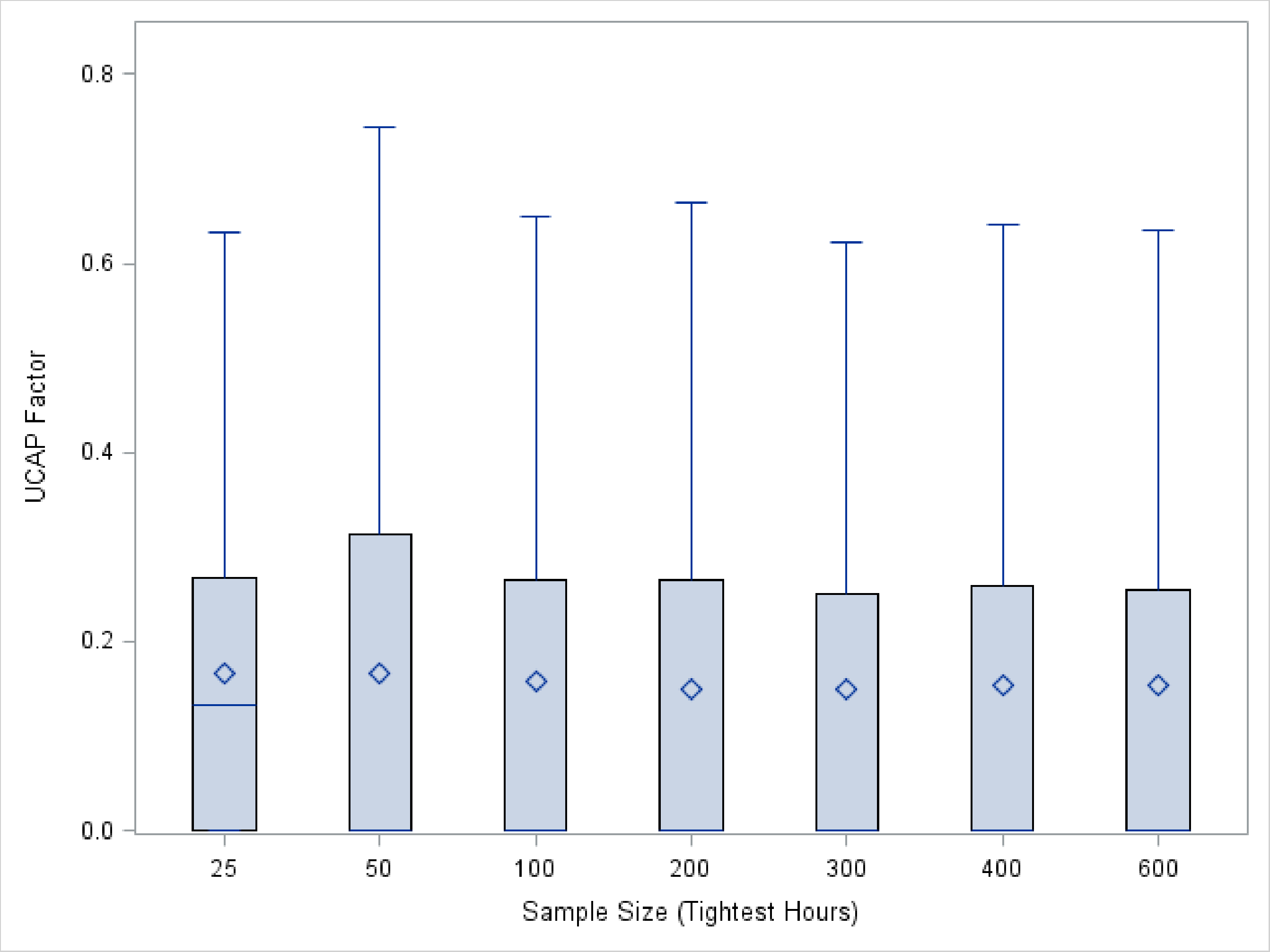


UCAP Factor
1.0
0.8
0.6
0.4
0.2
0.0
25
50
100
200
300
400
600
Sample Size (Tightest Hours)

BC Intertie


0.6
0.4
0.2
0.0
UCAP Factor
25
50
100
200
300
400
600
Sample Size (Tightest Hours)

MATL Intertie



Saskatchewan Intertie