Comprehensive Market Design Stakeholder Comment Matrix
Technical Working Group – *FINAL*

Please complete this matrix by February 27, 2018, and upload it to the “Feedback” folder on the CMD SharePoint site. The AESO will post all comment matrices received from working group members on www.aeso.ca. **Please note that the names of the parties submitting each completed comment matrix will be included in this posting.** The AESO does not intend to respond to individual submissions. If you have any questions about this comment matrix, please email capacitymarket@aeso.ca

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Date: February 27, 2018

CMD Key Design Questions	Comments and / or Recommendations
1. UCAP: Can you support the availability factor/capacity factor over the 100 hours of smallest supply cushion being used to calculate the UCAP?	MEG supports the availability factor approach and further supports the use of 100 tightest hours over 5 years. MEG does not support the use of a capacity factor to calculate net-to-grid/self-supplied assets and notes that an availability factor is better suited for these assets. It is important that the number of hours be high enough to remain relatively stable from year to year and to represent an accurate UCAP. Thermal generation asset capacities obviously vary with ambient temperature, which can be up to 30% difference between summer and winter for natural gas turbines. Given that the supply cushion can occur at any time of the year, UCAP performance during winter will be higher than in the summer. CMD1.0 suggest that penalties, rebalancing and future UCAP adjustments are contemplated, even if caused by randomly distributed scarcity events. This risk to generators should be recognized and should be discussed and solution incorporated into CMD2.0. Some solutions could include allowing generation operators the option to adjust their UCAP to reflect future expectations. This is an important consideration for cogeneration assets that support industrial loads behind the fence. Cogen site may wish to reduce their net to grid UCAP based on expected increases in site consumption (and therefore less export). Also, industrial sites may dictate when and for how long associated cogeneration may be off line. There could be non-repeatable events that should not warrant long term UCAP derating. Risk management with industrial site considerations and capacity market penalties may require cogeneration operators to off less UCAP. Penalties should be offset with incentives in the capacity system. This will motivate overperformance during scarcity and provide generation with opportunity to maintain capacity payment revenue and avoid the ‘missing money problem’ the capacity market is designed to avoid. Given that historical data did not incent generators to respond to the 100 tightest hours, a UCAP adjustment process may be appropriate for the first several auctions and should be considered.
2. UCAP: Can you support the UCAP calculation being	MEG can support a UCAP based on 5 years of historical data, and recommends a process be created and allowed to adjust

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based on 5 years of historical data?	UCAP values to best represent expected performance in the future. A net-to-grid facility, for example, is in the best position to know its capabilities for the capacity market and due to the uniqueness of each facility. The AESO will not be able to use an average of similar facilities in the same manner as UCAP has been proposed for other generation types There should be some form of UCAP dispute resolution process in the case where the generator disagrees with the UCAP determined by the AESO. Due to the formulaic nature of the UCAP calculation, disputes may be rare for existing resources, but a process will be important for the initial years. It is important to recognize the need for a dispute process during the transition period as historical data will not reflect the new market incentives.
3. UCAP: Are there risks with including planned outages in the availability factor data used to calculate UCAP? If so please describe.	MEG supports including planned outages in the UCAP calculation as maintenance outages are a significant challenge to ensuring supply adequacy in Alberta. Scarcity in summer is likely due to outages and not increase in demand. Cogeneration facilities may have outages caused by the associated industrial process. A UCAP dispute and adjustment process described above would ensure the most efficient power market and lower cost for consumers
4. Demand Curve: Do you have any feedback on the material presented in the CMD 1? Note: AESO and the WG will revisit the shape of the demand curve once draft outputs from the Resource Adequacy model are available.	MEG supports the current proposal to clear the capacity market on the demand curve. The CMD1 has the demand curve intersection with the target procurement level priced at 1.5 x net-CONE. This may result in a bias towards over procurement. Over procurement is risk to an inefficient market and may result in creating a ‘missing money’ problem the market is intended to avoid. Consideration of the target at 1.0 x net-CONE may be more appropriate and should be reviewed together with forecasted load variability.
5. Load Forecast: Can you support the proposed approach to forecast load? Are there any outstanding comments or concerns with the proposed approach?	MEG agrees with the Cogen Working Group members that the AESO should evaluate AIES modelling in addition to AIL modeling or, if this work has already been completed, to share the results with the working group members such that the market participants can become comfortable with the AESO’s reasoning in choosing AIL modeling.

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	Also, each cogeneration site should be modelled for its appropriate load when generation is offline. It is not appropriate to assume load will exist without on-site cogeneration. At SAGD facilities, steam is the heat product of cogeneration, and site power loads will be reduced if the steam and water balance is disrupted. Also, Fort McMurray facilities do not have adequate import transmission capacity to supply all loads without local generation. AIL models need to incorporate transmission capacities.
6. CONE: Can you support the intended Gross CONE estimation approach?	MEG supports the intended approach for estimating Gross CONE. Gross CONE must be set with relevant Alberta-specific data on permitting, construction costs, debt costs, equity costs and all other relevant cost factors including ambient conditions. Relying on surveys from other jurisdictions may be appropriate for some items such as turbine costs, but overall Gross CONE must reflect actual Alberta conditions. Regarding Net-CONE, the penalty system proposed should impact the net-CONE calculation. A penalty and incentive system is suggested as an alternate solution. It is also vital that the net-CONE calculation reflect the expected UCAP of a new asset. Seasonal de-rates and forced outage rates need to be considered for a new asset.
7. CONE: What are the important considerations AESO needs to take into account when selecting the Energy and Ancillary Service offset estimation methodology?	
8. CONE: Are there any issues or gaps in our considerations or plan in Net CONE estimation?	

General Comments: Any comments on relevant scope areas of the CMD that are not addressed above