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

Name: The Cogeneration Working Group **Organization:** The CWG, as represented by Power Advisory LLC, is comprised of the following members: (1) TransCanada; (2) Suncor; (3) Cenovus; (4) Canadian Natural (CNRL); (5) Dow (6) Imperial; (7) MEG Energy; (8) Husky; (9) Nova Chemicals Corporation; (10) Syncrude; (11) Lafarge; and (12) InterPipeline.

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?	The CWG supports the availability factor approach and the use of 100 tightest hours over 5 years as the data range. Given that the AESO is procuring capacity to meet a specific reliability goal, it is ideal to assess UCAP during the hours that matter most for reliability. Further, given the AESO's intention to assess penalties during EEA events and the 100 tightest hours of supply cushion, setting UCAP in this manner aligns the product being sold with the product being measured and assessed for penalties, allowing generators confidence that they are able to deliver on their obligations. It is important that the number of hours be high enough that it remains relatively stable from year to year. The AESO materials demonstrate that UCAP by asset class are largely stable between 25 hours and 600 hours, however, that assessment was not done for individual assets. Individual assets will have varying UCAPs from year to year and this is a key rationale for incentive payments within the availability adjustment payments. The CWG notes that in recent years due to a significant over supply of capacity the 100 tightest supply cushion hours have included hours with a supply cushion as high as 800MWs. The goal should not be to sustain a significantly oversupplied market in the long run and accordingly, that this noted issue of supply cushion as high as 800MW being included in the UCAP and penalty assessments should only be a short term transitional issue in years of oversupply. Given that historical data did not incent generators to respond to the 100 tightest hours, the CWG believes a UCAP adjustment process is appropriate for the first several auctions. Participants should have the opportunity to demonstrate that the UCAP for their asset is understated for a specific reason (maintenance, long-lead time behavior, etc) and re-state the UCAP as a result. The CWG notes that participants would be at risk to deliver against this revised UCAP. It should also be noted that revising a single unit's UCAP **should not alter the total system need for capacity but rather impact only that unit** if the adequacy modeling appropriately captures the reliability of units in the system. It would be beneficial for the AESO to provide an analysis or additional materials that highlight how the AESO will translate the UCAP as calculated per the 100 tightest hours into a demand curves. Significant concern that the large de-rates associated with this methodology will create over-supply was raised. The CWG's understanding of the process is that this will not be the case but information on the process would be helpful to ensure this is true.

2. UCAP: Can you support the UCAP calculation being based on 5 years of historical data?	The CWG 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. Net-to-grid facilities are not always price-takers in all blocks. Accordingly, net-to-grid facilities will often have un-dispatched energy available in low priced hours. This is no different than a thermal asset that has priced one or more of its energy offer blocks higher up the merit order. Assessing UCAP for net-to-grid facilities based on a capacity factor may create the incentive for net-to-grid facilities to become price-takers on all blocks in all hours to ensure higher revenue in the capacity market, distorting the efficiency of the merit order, as some net-to-grid block may have high variable costs or high opportunity costs. Creating more price-taking offer blocks should not be the goal of the UCAP formula. Instead, the UCAP formula should be designed to accurately reflect the expectation of that asset to deliver during the tightest supply cushion hours of the delivery year. In the case of net-to-grid facilities, this requires consideration of the un-dispatched blocks that were available for dispatch in real-time had the energy price risen to the level of those un-dispatched offers. The CWG understands from the market design working group session that the AESO intends to develop a process for determining UCAP for new net-to-grid facilities with CMD 2.0. Without the benefit of actual operational history, the CWG submits that this process will, by its nature, be more arbitrary. Given this the CWG would suggest that a net-to-grid facility should be able to state its own UCAP in the first year. The penalty structure will incent the net-to-grid facility not to sell more capacity than it is able to deliver and the net-to-grid facility is incented to sell as much as it is able to deliver in order to maximize its capacity market revenue. The net-to-grid facility is in the best position to know its capabilities moving into the first year 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 new renewable facilities, for example. In the second year, the UCAP can begin to reflect historical data in the same way the AESO has proposed for other new resources, eventually becoming fully reflective of its own historical data after five years. Lastly, the CWG expects there to 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, the CWG expects disputes will be rare for existing resources, but this process will be important for new resources in the first five years who receive a UCAP that is more arbitrary than the standard formulaic calculation. It is also 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.	To the extent that there are data issues, the CWG suggests that the AESO determine what data is needed and begin to collect that data this year. If the AESO begins to collect the relevant data by November 2018 then five years of data will be available for the 2023 auction. This means that the AESO can use the most accurate data to do the calculations in an ideal manner beginning in the 2023/24 delivery year and that the AESO would only use sub-optimal calculations as a transitional mechanism in the first couple of auctions. The CWG supports including planned outages in the UCAP calculation as maintenance is a significant challenge to ensuring supply adequacy in Alberta. The system must carry sufficient capacity to allow maintenance to occur, and units with lesser maintenance requirements should be rewarded and incented.
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.	The CWG considers that the demand curve has improved from the versions presented in 2017; however, the design continues to bias the Alberta market to a significant over-supply of capacity, with the associated impact of depressed energy prices. This has two main impacts: (1) the capacity market will become the primary driver of investment decisions; and (2) Alberta customers will face materially higher prices than necessary. The CMD 1.0 continues to show the demand curve intersection with the target procurement level priced at 1.5 x net-CONE. This results in an unacceptable bias towards over procurement. It is tantamount that the demand curve intersects the assumed target at net-CONE. Only in that circumstance will the market converge to the desired level of reliability; that is exactly what target means. Every demand curve that intersects the target above net-CONE will inherently converge to persistent over-supply, just like every demand curve that intersects the target below net-CONE would converge to persistent under-supply. The capacity market is unlikely to provide the same incentive for efficient, flexible generation as a healthy energy market and accordingly, the CWG is concerned that the bias to oversupply, in addition to being costly, will not result in the type of responsive generation expected to be required to support wind integration. The CWG supports the current proposal to clear on the demand curve. Given the expectation that many existing resources will price most or all of their offer blocks at or around $0, as they will be price takers, it is important to price on the demand curve and allow capacity prices to be paid to generators.

	Based on the revised demand curve shape, the cost of oversupply to the market is reduced relative to previous iterations but still significant. Based on the same approach highlighted in previous CWG submissions on the cost of the rightward shift in the demand curve, the current recommendation is estimated to result in higher costs in the range of $60 to $75M per annum. There are more effective and market 'friendly' ways to ensure adequacy in the face of uncertainty instead of simply purchasing excess capacity. The CWG is concerned that the AESO has not yet provided analysis or rationale supporting the move to over-procurement as opposed to other measures to address the apparent concern that the capacity market will not be able to consistently deliver enough capacity without a 'cushion' of about 500 MW over the true target. Lastly, the CWG considers that it is important for all parameters to be well reasoned and justified. At the moment, it is difficult to support individual parameters of the demand curve as the AESO has not explained its logic in selecting those parameters. The CWG requests that the AESO explain, in detail, its rationale for selecting each individual demand curve parameter (i.e. an EUE of 400 at target, the price cap at the maximum of 1.75 x net-CONE or 0.5 x gross-CONE, the inflection point is set at 0.875 x net-CONE, the foot is 13 per cent above the target capacity volume, the price at the target capacity level is 1.5 x net-CONE, etc.)
5. Load Forecast: Can you support the proposed approach to forecast load? Are there any outstanding comments or concerns with the proposed approach?	The CWG is concerned that the AESO has not analyzed all possible options prior to making its decision. The CWG requests that the AESO 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 CWG and other working market participants can become comfortable with the AESO's reasoning in choosing AIL modeling. It is not clear that the purported accuracy benefit of forecasting AIL and then adjusting AIL to a proxy of AIES is superior to directly forecasting AIES (even if an AIL forecast itself is more accurate). The CWG further suggests that the AESO should run historical years through its model for calibration to ensure the model works as intended.

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<td>6. CONE: Can you support the intended Gross CONE estimation approach?</td>
<td rowspan="3">The CWG supports the approach for estimating Gross CONE and Net CONE, and reiterates the importance of appropriate governance. The CWG has submitted a number of specific suggestions for how the governance structure in Alberta needs to be adjusted as a part of its submission to the Department of Energy on November 24. This submission can be found in Appendix 8 of the SAM 3.0 comments.

These specific suggestions stem from the fact that the AESO's mandate will change significantly as it takes on an active role in determining resource adequacy and the appropriate price signals for capacity and therefore, indirectly, for the energy component of the market. The commercial implications of their new mandate results in the AESO directly influencing the economic outcome for, and the decisions of, generation and load in Alberta, as well as imports and exports. Through the new governance model, it is important that market participants have direct input into key capacity market parameters including Gross CONE, Net CONE, the demand curve shape, and the load forecasting that will be used to set the procurement target.

Gross CONE must be set with relevant Alberta-specific data on construction costs, debt costs, equity costs and all other relevant cost factors. 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, net-penalties will impact the net-CONE calculation. Accordingly, the CWG suggests that it is simpler to design the penalty scheme such that net-penalties are zero on an expected basis to remove one extra step from the net-CONE calculation. It is also vital that the net-CONE calculation reflect the expected UCAP of a new asset. Seasonal de-rates and forced outage rates will not accurately reflect the expected capacity value of a new asset – expected performance during the 100 key hours should be based on actual experience of similar assets.</td>
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<td>7. CONE: What are the important considerations AESO needs to take into account when selecting the Energy and Ancillary Service offset estimation methodology?</td>
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<td>8. CONE: Are there any issues or gaps in our considerations or plan in Net CONE estimation?</td>
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General Comments: Any comments on relevant scope areas of the CMD that are not addressed above