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

The AESO is requesting written feedback from the Capacity Market Design Working Group (DWG) members about the content of the first draft Comprehensive Market Design (CMD 1) and about the working group session in which CMD 1 was discussed. This draft comment matrix is provided in advance to help working group members prepare for their upcoming session. Following the working group session, the AESO will post a **final comment matrix** one (1) day after the session. This final comment matrix should be completed by working group members within four (4) business days. The final feedback matrix is intended for working group members to provide written feedback about CMD 1 or the content of their working group session that is within the scope of their working group.

The AESO will post all comment matrices and any other feedback received from working group members on www.aeso.ca and on the Capacity Market SharePoint site. **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: Janene Taylor **Organization: TransCanada Energy Ltd. (TCE)**

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CMD Key Design Questions	Comments and / or Recommendations
1. UCAP: Can you support using Availability factor for dispatchable resources? Does the approach meet the intent of a resource neutral approach to capacity volume that reflects the deliverability of energy during periods of tight system conditions?	**UCAP Determination** TCE agrees that the UCAP of a capacity resource should reflect that resource's ability to deliver energy during periods of tight system conditions, or in hours in which capacity is most required to ensure sufficient reliability. Unlike other jurisdictions, Alberta experiences periods of tight supply at all load levels and in all months of the year. This is in part due to Alberta's high load factor and the small size of the Alberta system relative to the size of Alberta's largest generators. Therefore, the capacity product the AESO is purchasing is fundamentally different than the summer availability product that is procured in many other capacity markets. Therefore, TCE supports a resource's UCAP being calculated as the average available capacity for that resource in the 100 hours with the lowest supply cushion (100 tightest hours) on an annual basis over a five-year rolling period. TCE further supports the assessment of penalties within the 100 tightest hours during the delivery year as this ensures that the capacity product the AESO procures is the same product that the AESO assess for performance. **Availability Factor vs. Capacity Factor for Net-to-Grid Facilities** TCE supports the use of an availability factor for dispatchable resources, however, has concerns that the characterization of all net-to-grid facilities as non-dispatchable may not be correct. TCE understands the AESO intends to work with resource owners in the determination of their UCAP volumes and supports that availability factor be used for net-to-grid resources where there has historically been un-dispatched capacity available for dispatch. In these instances, net-to-grid resources should not be treated differently than any other dispatchable thermal asset. If a capacity factor is used for net-to-grid resources that have historically had un-dispatched capacity available, the UCAP determination may create an incentive for net-to-grid resources to offer all available capacity in the energy market at a price of zero dollars. The UCAP determination should not create an incentive for resources to offer their capacity in the energy market at zero dollars when these resources would otherwise not behave as price-takers.

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	<u>Determination of UCAP for Net-to-Grid Facilities</u> Given the nature of net-to-grid and/or co-generation facilities there could be changes at a site (addition of load, change in configuration etc.) that would impact the determination of UCAP on a go forward basis. In cases where there a step-change in UCAP, a five-year rolling average may no longer be appropriate. Rather, the resource owner should have an opportunity to inform the AESO of the change to its UCAP. The penalty structure will ensure that all resources have an incentive to maximize their capacity market revenue while minimizing their penalty exposure. Therefore, TCE is of the view that resource owners who are facing changes to their site will be incented to propose a UCAP that accurately reflects the ability of that resource to deliver capacity during periods of tight system conditions (100 tightest hours). **<u>Dispute Resolution Process</u>** A dispute resolution process is required if resource owners and the AESO disagree on the UCAP determination for a capacity resource. Such a process will be particularly important in the first few auctions given that historical data is based on a capacity resource's operation in an energy-only market and may not necessarily be indicative of future capacity market performance. **<u>Outage Exemptions</u>** The AESO has proposed that there will not be penalty exemptions for planned maintenance outages. TCE recognizes that exempting capacity providers from receiving penalties when they are on a planned maintenance outage dilutes the incentive to ensure maintenance outages are timed in manner that minimizes their impact on reliability. However, in the absence of an appropriate mechanism in which resource owners earn incentives when they perform above their UCAP (an ability that is enabled due to good maintenance practice) the lack of an exemption is overly punitive. In Alberta capacity providers face a unique risk when taking planned maintenance outages as Alberta can experience periods of tight supply at all load levels and in all months of the year making it far more difficult to schedule planned maintenance. Although under the proposed penalty framework capacity providers can manage their penalty exposure within a delivery year if they provide capacity in excess of their obligation, capacity providers do not have the opportunity to manage their penalty exposure on a year over year basis. In years where planned maintenance is required capacity providers that deliver less than their capacity obligation during the assessment period will be assessed penalties. However, in years where the resource provides capacity in excess of its obligation it does not earn the incentives required to mitigate the penalties assed in maintenance years.

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	A planned maintenance, taken at the wrong time, will not only result in significant penalties but it will also reduce the UCAP for that resource for the following five years. This impact can and should be mitigated with the opportunity to earn incentives when performing above their capacity obligation. The system should be designed to incentivize, and resource owners should be rewarded for, good maintenance practices. **<u>Force Majeure</u>** An appropriate force majeure exemption is required for both the determination of UCAP and for the assessment of penalties. Disruptions in supply that are out of the capacity providers (similar to a lack of transmission) such as the need to evacuate a facility due to forest fires or flooding, or in circumstances such as those outlined in Section 18(4) of the *Transmission Regulation,* should be considered legitimate exemptions from penalties. Likewise, the AESO should consider that disruptions in gas supply for thermal resources who have purchased firm supply should be exempt from being assessed penalties. **<u>Asset Substitution</u>** Capacity providers will be assessed availability penalties when the average capacity availability across the 100 tightest hours within a delivery year is below their UCAP obligation. Therefore, a capacity provider is not incented to sell additional capacity to another provider who is short as they will need to ensure they overdeliver that capacity to improve their own average. The lack of a liquid market for asset substitution increases penalty risk for capacity resources and is best mitigated through the introduction of incentive payments for over-delivery.
2. Payment Adjustment Mechanism: Can you support using a 60/40 performance/ availability framework? Does the approach achieve the intent of higher adjustments to performance periods?	**<u>Penalty Framework</u>** In its Recommendation Paper[1] the AESO recognized (after interviewing generation developers, investors and lenders, and financial advisors) that the merchant nature of the Alberta market made it unattractive to investors. In response, the AESO proposed a capacity market to encourage investment through the provision of a stable revenue stream. TCE is supportive of the objective but submits that the penalty framework proposed undermines the stability of the capacity market revenue due to the lack of incentive payments and because it is not revenue neutral. A penalty framework that allows capacity resources to earn over-

[1] AESO, Alberta's Wholesale Electricity Market Recommendation, page 2.

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	performance incentives allows capacity providers to better manage unavailability risk and provides a stronger incentive to resource owners to increase availability/reliability. Further, a revenue neutral penalty framework should promote investment in more reliable resources and at the same time reduce the penalty risk premium applied to capacity offers resulting in higher reliability at a lower cost to consumers. TCE is concerned that performance framework, specifically the: • weighting of assessment hours, • the calculation of the performance and unitability adjustment mechanism including, and • lack of incentive payments is not consistent with the objective of providing a stable revenue stream. **Weighting of Assessment Hours** Energy Emergency Alert (EEA) performance penalties are likely to be assessed over very few hours. This creates significant risk that a capacity provider could lose a significant portion of its capacity payment by not meeting its delivery obligations in a single event. Given the infrequency of EEA events there is a very real possibility that a capacity resource will not have the ability within a delivery year to earn back its capacity payment through incentive payments. This high risk will translate directly to higher priced capacity offers and higher costs for consumers. This higher cost to consumers will not result in higher reliability, but simply reflect the high-risk market design and risk-adverse generators. Therefore, to provide a stable investment framework, and low cost capacity for consumers, TCE suggests that the AESO weight EEA hours and unavailability hours equally. **Performance and Unavailability Payment Adjustment Mechanism** The design of the payment adjustment formulas[2] suggest that it is the AESO's intent is that a capacity resource could lose up to 78% of their annual capacity market revenue during EEA hours and up to 52% of their annual capacity revenue during the 100 tightest hours. However, TCE is concerned that the inclusion of "expected EEA hours" in the Performance Payment Adjustment formula could create significant uncertainty and undue penalty risk if the number of EEA hours used in the formula is not fixed for the delivery year. For example, suppose the AESO expects three EEA hours within a delivery year and sets the per MWh penalty

[2] the unavailability payment adjustment rate is designed as 40% * 1.3 and the non-performance payment adjustment rate is designed as 60% * 1.3,

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	accordingly. Next suppose that during the delivery year six EEA hours occur. In this case, capacity providers would be penalized at double the rate intended as they would receive the same dollar/MWh penalty calculated on the expectation of three EEA hours. Therefore, TCE recommends that the AESO set the number of EEA hours in the denominator to be equal to the number of EEA hours the reliability model predicts will occur at the maximum number of EUE hours permitted (i.e. 800 MWh). In addition, EEA hours should not be included in the both the performance and unavailability assessment. Capacity providers should not be penalized twice for not performing in EEA hours. Finally, capacity providers should not face penalties that are not a function of the clearing price they receive. If a capacity provider participates in the base auction it should not be at risk for being penalized at a different clearing price should the re-balancing auction clear at something different. The suggestion that the penalty should be a function of a higher re-balancing price as this it is a more accurate reflection of the value of the capacity ignores the fact that capacity providers are not being paid the more recent market valuation. As such, the reference to the maximum of the base auction and re-balancing auction clearing price should be removed and penalties should be a function of the clearing price received. **<u>Incentive payments</u>** TCE supports the opportunity to earn inventive payments during the availability assessment hours. TCE recognizes that incentive payments must be less than one times capacity market revenue to ensure that it is always more profitable to participate in the capacity market than to simply receive incentives. As discussed above the intent of the capacity market is to create a stable revenue stream. The unique risks associated with planning maintenance in Alberta and the lack of a liquid market for asset substitution creates the need for a revenue neutral performance framework and likewise the need for incentives. Currently the design of the unavailability payment adjustment allows capacity resources to average their availability within a delivery year, but not across delivery years. Given that the UCAP is set as the average of a five year period the expectation is that in some years the capacity provider will deliver less than the average and in some years, deliver more than the average. The current design will penalize capacity providers in years where they under deliver but not allow them to earn incentives in years where they over deliver. This guarantees that a capacity provider will pay penalties and receive less than the clearing price even if it delivers on average what it sold. This will lead to higher capacity prices as capacity providers include the risk of penalties in their offers. In addition, to send efficient real-time signals during periods of system stress non-committed capacity resources should be eligible to receive incentive payments. This ensures that all resources maximize their availability and or production when the system needs it most.

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	Given the concerns with the AESO proposal described above TCE support the performance framework the CWG has proposed. The CWG penalty framework proposal is simple and: • sends strong incentives to deliver during EEA hours, • retains the incentive to sell the forward capacity commitment as incentives are less than the clearing price, • allows units to manage the annual variation in UCAP by earning incentives in years with higher availability, and • refunds customers if the overall system delivery of capacity falls short of the commitment.
3. Payment Adjustment Mechanism: Can you support a monthly cap at 300%? Does the approach achieve the intent of reasonably limiting adjustment payments?	TCE supports smoothing out the payment of penalties over time. TCE requests that the AESO confirm that the cap is a cap on the penalty itself and does not simply reflect the amount the AESO will claw back in a month, with any remaining penalty exposure carrying over into the following month.
4. Payment Adjustment Mechanism: Can you support a 1.3x annual revenue/ rebalancing assessment limit? Does the approach achieve the intent of ensuring capacity resources are available for the obligation period?	TCE agrees that penalties must be greater than the capacity market clearing price to ensure that capacity providers are not indifferent between not receiving the capacity payment and receiving a penalty. However, TCE also supports phasing in penalties slowly to allow capacity resources and the AESO to gain experience with the new market. Existing capacity markets are only now starting to introduce performance frameworks after operating for many years. Further, given the recent implementation in other capacity markets, there is not yet any evidence available that demonstrates that the performance frameworks will have the desired effect on market participant behavior and reliability. Alberta is in the midst of a significant electricity market transition. Once the capacity market is in place capacity providers will respond to differently to the different price signals begin sent. One such example is the determination of UCAP. Given that market participant behavior will adjust to the new market design TCE submits it may be difficult to determine a capacity resources UCAP using historical data from an energy market and it is inappropriate to penalize capacity providers on that basis. The AESO has also stated it does not have sufficient time to hold a re-balancing auction as it will be holding three base auctions within a very short time-frame. The re-balancing auction is an important risk mitigation tool for capacity market providers as they gather more relevant and timely information about their capacity resource prior to the delivery period. In addition, given the compressed time-frame, market participants will not have the opportunity to learn from one auction to the next, and they will have participated in three base auctions before the first delivery year. This creates significant risk for potential capacity providers as they are making commitments regarding their resources for multiple years in advance without an opportunity to learn from experience. Finally, Alberta has historically enjoyed a healthy reserve margins and a very high-level of reliability indicating that the performance framework may be an attempt to resolve a problem that does not exist.

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	Therefore, TCE submits the risks of getting the performance framework incorrect outweighs the potential benefits and recommends that the performance framework be phased in. TCE suggests that the AESO simply calculate the penalties that would have been assessed in the first three delivery years and provide this information to the resource owners who can then adjust their participation in future auctions accordingly. This option also provides the AESO with a valuable opportunity to learn how the framework will function, what behavior it will incentivize, and to recommend revisions to the framework should it not produce the expected and desired results without creating undue risks for capacity resource owners.
5. Market Power Mitigation: Can you support setting a market power screen as a fixed percentage of aggregate UCAP requirement for the auction? Does the approach meet the needs of mitigating supplier market power?	Only market participants with a portfolio large enough to abuse market power in the capacity market should be mitigated. Although TCE would support a market power screen, TCE does not support fixing the percentage for the screen. Rather, TCE is of the view that it will be necessary to revise the screen when significant changes to the demand curve are made. The screeb should be a function of an analysis of the ability of a single market participant to raise prices significantly on an annual basis.
6. Market Power Mitigation: Is a price cap of 50% of net CONE appropriate to mitigate the offers of suppliers with market power?	The purpose of market power mitigation is to ensure that market participants with market power are not able to set prices significantly above competitive market outcomes for extended periods of time. Net-CONE is considered the long-run competitive market outcome and therefore existing market participants should not be mitigated below this level. In other markets the offer cap for existing and mitigated resources is often below net-CONE, however, in other markets new entrants set price in every year. This is not a reasonable expectation for Alberta due to its small size. It can be expected that Alberta will have many years in which no new capacity is purchased and existing resources will set price. Given that the AESO is recommending a one year term, this implies that after entering, a new resource may not receive a payment greater than 0.5 times net-CONE or risk not clearing. The capacity market design should provide new entrants with confidence that upon entering they can continue to expect the price of capacity to be set at a level that allows them to recover a fair return on their fixed costs.
7. Market Power Mitigation: Do you think there is sufficient support that mitigation of buyer side market power is not initially required in the capacity market?	TCE agrees there is no need for a “no minimum offer price requirements for capacity resource suppliers due to net-short capacity positions or out-of-market payments.”
8. Delisting: Are there some circumstances where the delist bid of an asset does not clear but the asset continues to participate in the energy market?	If a resource delists from the capacity market it should be eligible to participate in the energy market in the same way that resources that are not qualified to participate in the capacity market may participate in the energy market.

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9. Delisting: Should a resource be able to delist from the capacity market but be eligible to participate in the energy and ancillary services market? For example: a. An asset of a non-mitigated supplier fails to clear, should it be allowed to continue energy market participation? b. For long outage requirements that are for a substantial portion of the year?	If a resource delists from the capacity market it should be eligible to participate in the energy market in the same way that resources that are not qualified to participate in the capacity market may participate in the energy market.
10. Transition to Capacity Market: Is a rebalancing auction for first obligation period 2021/22 required and practical?	The first auction will take place over a year in advance of the first delivery year and as discussed above the re-balancing auction is an important risk mitigation tool for capacity providers. Due to the pace of implementation and the issues that arise due to the transition itself (changes in incentives and offer behavior) the first auction is most susceptible to unforeseen and unintended outcomes. It is important to provide market participants the option to sell out of their capacity obligation if they consider themselves overcommitted when reaching the 3-months prior to the delivery year. In the absence of a re-balancing auction TCE submits it is even more important that penalties should not be assessed in the first few auctions.

General Comments

Retirements

Resources should not be required to demonstrate to the AESO that the net going-forward costs of maintaining the resource exceeds revenues that can be earned in the capacity market in order to retire. Resources should be entitled to the opportunity to earn a fair rate of return on their assets, not simply enough to cover maintenance, and resources should be able to retire for reasons outside of the electricity industry (i.e. a self-supplier is retiring its load and wants to shut down the whole facility) without the AESO's approval.

The AESO has proposed a three year forward period and if resource owners are required to announce a retirement three months prior to a base auction the market will respond to the decrease in supply and new resources will be developed. Furthermore, if a capacity resource owner does not have market power the retirement of a capacity resource will not impact capacity market outcomes.

TCE accepts that more stringent rules may be required for capacity providers that wish to mothball a resource. Like retirements, mothballing a resource does raise prices, however, unlike the decision to retire, the decision to mothball will discourage new entry. New entrants may be hesitant to invest as they are aware that a mothballed resource will return.

<u>Term</u>

Alberta is expected to require around 8 GW (AESO LTO of 5.7 GW of new + 2.4 GW of coal conversions) of new generation over the next 10 years. For the market design to be sustainable, it must incent developers to invest the billions of dollars required to build these plants. As such, it is necessary for the AESO to consider what criteria developers will consider as they make these decisions whether to invest. TCE has invested a significant amount of capital into the Alberta power market since the advent of deregulation and until recently was the largest market participant in Alberta's energy-only market. TCE has also made significant investments in Canadian power generation capacity since the early 1990's, building over 3300 MW itself as well as investing in the eight unit 6400 MW Bruce nuclear facility. As an Independent Power Producer with experience developing projects across North America, TCE wishes to share the criteria it considers when determining whether it will invest in a geographic region, market design and project.

Although there are many considerations the most significant are:

1. an opportunity for a fair return on and of capital;
2. the ability to finance; and
3. a stable regulatory and policy regime.

Return on and of capital and ability to finance

For TCE, in many cases, the first and second criteria are often inherently linked. In its paper, Alberta's Wholesale Electricity Market Transition Recommendation, the AESO recognized (after interviewing generation developers, investors and lenders, and financial advisors) that the merchant nature of the Alberta market made it unattractive to investors. The AESO itself also concluded that there is limited capital available for investments in merchant power plants which have significant revenue uncertainty, and capital that is available is at a much higher cost.[3] Financing projects today generally requires the stability of long-term power contracts. Although developers retain the option of financing these projects on balance sheet, investors and rating agencies generally dislike merchant assets as much, if not more than, banks.

Stable Regulatory and Policy Regime

The third criterion is one of the greatest risks developers face. The last thing an investor wants to see when making the decision to invest is policy uncertainty on the horizon. Given that the AESO is setting the Gross CONE such that the recovery will occur over 20-25 years for the reference technology to recover its investment, developers will be extremely sensitive to any perceived risks of legislative or regulatory changes that would jeopardize a power plant investment.

It is TCE's view that the volatility and uncertainty of the long-term revenue profile for a power plant operating in a capacity market with a one-year contract term will not be significantly different from the energy-only market. Providing only a single year of revenue certainty provides essentially the same risk profile as a purely merchant investment. Merchant power plant investments require high returns and more expensive financing costs in order to balance the volatility of revenue. Investment grade developers are typically unwilling to take the risk associated with merchant

[3] AESO, Alberta's Wholesale Electricity Market Recommendation, page 2.

plants, and thus this type of market structure is likely to attract only those investors with high risk tolerance and associated return requirements. It is TCE's view that providing short term capacity contracts will result in more expensive generation costs and developers that are not investment grade.

Furthermore, efficient baseload combined cycle gas plants, large-scale zero-emitting options such as hydro, nuclear, and utility-scale storage projects are very difficult if not impossible to develop under the proposed market structure. Private developers are less likely to make long lead time, multi-billion dollar developments for a one-year capacity contract payment. This fact, combined with the fact that policy makers have determined that renewable resources require out-of-market payments and long-term contracts to ensure development indicates that the capacity market will be severely limited in its size.

In conclusion, TCE does not support the obligation period, or the capacity contract term being limited to one year, rather TCE supports the contract term being greater than seven years. In fact, TCE sees no rationale for the contract term being inconsistent with that which is being offered to renewable resources participating in the Renewable Energy Program (REP). The successful parties in the REP were able to provide low-cost resources due to their ability to secure contracts with 20-year revenue certainty, thereby minimizing financing risk and associated cost premiums. Technology improvements will contribute to lowering capital costs, but the security of off-take is the largest driver to lower costs and should be a primary tenet of the new capacity market.

Rebalancing Auctions

TCE suggests that capacity resources should not be required to participate in the re-rebalancing auctions unless they experience a significant change in their UCAP. It is not efficient to require a resource whose UCAP declined to participate in the 18-month rebalancing auction to only then have the UCAP for the same resource increase prior to the final re-balancing auction. It should be optional for resources to participate in the first re-balancing auction and capacity providers should only be required to participate in the last re-balancing auction if the change in their UCAP is sufficiently large.

Subsidized Resources

TCE agrees that REP 1 resources that are receiving an indexed REC should not be eligible to participate in the capacity market. To the extent that future rounds of REP also use an indexed REC it will become necessary for the AESO to not only account for that volume when setting the reliability target, it will also have to account for the price impact of these resources. Capacity and energy market prices for non-subsidized resources should not to suppressed due to the integration of otherwise uneconomic supply.