# Supply Participation

*Rationale*

## 2.1 Prequalification applications

***Prequalification of existing versus new capacity assets***

2.1.1 In order to participate in the Alberta capacity market, a new capacity asset must meet the requirements specified in this Section 2 of the CMD. Prequalification, among other purposes, is a mechanism to reduce the risk of non-delivery and is intended to provide the AESO with sufficient confidence that a new capacity asset will be in service in time to deliver its obligation volume during the obligation period, or inform the AESO that a capacity market participant plans to implement changes that could affect the future UCAP of an existing capacity asset. As described in subsections 2.1.12 through 2.1.14 below, a capacity asset undergoing retrofits may wish to prequalify in order to exempt all or a portion of the asset's UCAP from the capacity market power screen.

2.1.2 Existing generating assets, including seasonal assets that submit offers in the energy-only market today will automatically qualify to participate in capacity auctions provided the estimated UCAP for the asset is greater than or equal to 1 MW because these assets have demonstrated the ability to provide energy and follow instructions from the AESO System Controller. Automatic prequalification of existing generation will simplify the transition from the energy-only to capacity market. Existing load assets choosing to provide demand response will be required to prequalify as the AESO will require additional information to assess performance based on availability and delivery. Capacity assets under 5 MW of maximum capability do not have to offer in the energy market. However, if a small capacity asset chooses to offer into the energy market it may benefit from having UCAP calculated based on availability factor rather than capacity factor.

2.1.3 An external capacity asset will be required to prequalify to ensure the external asset can meet the eligibility requirements, such as demonstrating the possession of firm transmission to the Alberta border.

***Ineligible assets***

2.1.4 Resources selected for the Renewable Electricity Program (REP) Rounds 1, 2 and 3 are not eligible to participate in the Alberta capacity market as the REP program already provides compensation for the resource's capacity. Eligibility of future REP resources will need to be assessed subject to the contract terms for each round.

2.1.5 The AESO recognizes that energy efficiency is allowed to participate in capacity markets of other jurisdictions. However, the complexities other jurisdictions have faced with determining a capacity value and assessing performance for energy efficiency requires further study with respect to how this resource can be integrated into the Alberta capacity market. While energy efficiency will not be eligible to participate in the initial implementation of the Alberta capacity market it will be eligible for future participation. This is consistent with the AESO's design criteria for pursuing staged implementation where appropriate.

***General prequalification requirements***

2.1.6 A detailed project implementation plan is required as it will be utilized in assessing deliverability prior to commencement of the obligation period, as described in subsection 8.1.1 of Section 8, *Supply Obligations and Performance Assessments*. Advancement through the AESO connection process was considered as a way to track project progress. While this would be feasible for transmission connected projects, it would not be appropriate to other capacity asset projects.

The commercial operation date of the capacity asset must be no later than the start of the obligation period for the capacity auction that the party is seeking prequalification for, regardless of whether the auction is a base auction or a rebalancing auction.

The following list is provided as an example of what may be expected in the project plan submitted to the AESO for prequalification. Note that the list is not intended to be exhaustive.

**Key Milestones of Project Delivery**

(a) **Development Activities** associated with conceptualizing the project, engaging in stakeholder relations, and securing all required approvals and arrangements necessary for proceeding with construction of a facility including:

- Completion of Land Rights and Site Entitlement – Attaining access rights; negotiating and executing lease/purchase agreements or options.
- Completion of Site Analysis – Identifying critical site considerations, such as archeological and heritage sites; conducting geotechnical surveys and studies; evaluating site conditions for constructability.
- Attaining Project Connection (System Access) – Initiating communication with relevant connecting authority; identifying and assessing suitable connection options; developing connection facility application and filing for approval to secure relevant connection agreements.
- Obtaining Environmental Approvals – Identifying and conducting all necessary environmental studies to achieve required approvals.
- Obtaining Other Permits and Approvals – Identifying, applying, and attaining all other necessary permits, and regulatory approvals.

(b) **Construction Activities** associated with building, erecting, constructing, installing, testing, and commissioning of a facility, necessary for attaining commercial operation; including, without limitation:

- Site preparation and access complete.
- Facility equipment delivery, set-up, construction, and erection of facility components.
- Delivery, installation and commissioning of connection facilities and equipment for connecting the generating facility to the electrical system/network.
- Testing and commissioning of a facility in order to measure the ability of a facility can reach and maintain its capacity obligation.
- Compliance with permits, applicable law and notifying relevant stakeholders
- Achieving commercial operation.

The AESO will not request information that is not project-related as part of the prequalification application, such as financial strength of the organization or the previous project development and delivery experience of the capacity market participant. The AESO will rely on a financial security requirement, and the monitoring of the achievement of project milestones to mitigate delivery risk. This approach is intended to facilitate the greatest amount of competition from new assets by reducing administrative burden, while still ensuring that the AESO can effectively vet new project developments. Please refer to the rationale for security requirements in subsection 2.1.13 below.

### *Asset-specific prequalification requirements*

2.1.7 Certain assets, such as aggregated assets, may be made of resources of different fuel-types or technologies. To ensure that these “compound assets” are properly prequalified, the prequalification requirements of all relevant asset-specific categories apply.

2.1.8 Demand response assets may consist of a large single load asset or an aggregated asset consisting of smaller load sites. Demand response will only be eligible to participate on the supply side of the market. Participation of a demand response asset on the demand side of the capacity market is not contemplated. Incorporating volumes into the demand curve can significantly change the demand curve shape during the capacity auction, adding significant complexity to the auction bidding process and clearing. Demand side participants are encouraged to develop demand response products and receive capacity payments for the ability to curtail load during periods of tight supply.

A demand response asset must become a retail or self-retail asset belonging to a valid pool participant to ensure the appropriate metering data is captured and collected for the purposes of performance assessment and settlement.

Demand response can take two forms: firm consumption level ("down to") assets or guaranteed load reduction, ("down by") assets. Allowing these two types of demand response assets to participate is intended to provide flexibility and incent load participation in the capacity market.

Demand response assets must undergo a physical commission test to ensure that these assets can demonstrate:

(a) that a relationship exists between the aggregator / provider of load reduction and the actual resources that will curtail load; and

(b) ability to receive dispatches from the AESO System Controller.

2.1.9 Allowing external capacity assets to participate in the Alberta capacity market provides an additional source of supply, and increases market liquidity and competition. The prequalification requirements for external assets are intended to ensure that the capacity of an external capacity asset is deliverable to Alberta during EEA events and tight supply cushion.

The AESO originally considered distinguishing external named assets from system external assets, which is the custom in US capacity markets. Given the differences in energy scheduling practices, treatment of transmission constraints and the additional complexities validating data submitted for a named external asset, the distinction was removed, but the prequalification requirements remain. The capacity market participant with an external asset will be an importer in to the energy market with a capacity obligation (i.e., an import with a capacity commitment). The importer will be responsible to acquire the capacity needed to meet their capacity obligation.

2.1.10 Allowing storage assets to participate in the Alberta capacity market increases overall market competition, provided that their reliability value is appropriately reflected. The prequalification requirement to maintain their energy production at the UCAP level for at least 4 hours is intended to ensure sufficient reliability value from the asset. The requirement for a storage asset to demonstrate the ability to sustain energy for at least 4 hours is derived from the historical observation of the average duration of system stress events, i.e. recent emergency energy alert declarations have lasted on average 4 hours. This does not mean that a capacity committed storage asset will not have an obligation beyond 4 hours; the asset will be required to provide its capacity obligation for the entire duration of the delivery event.

**Table 1 – Historical durations of system stress events in Alberta**

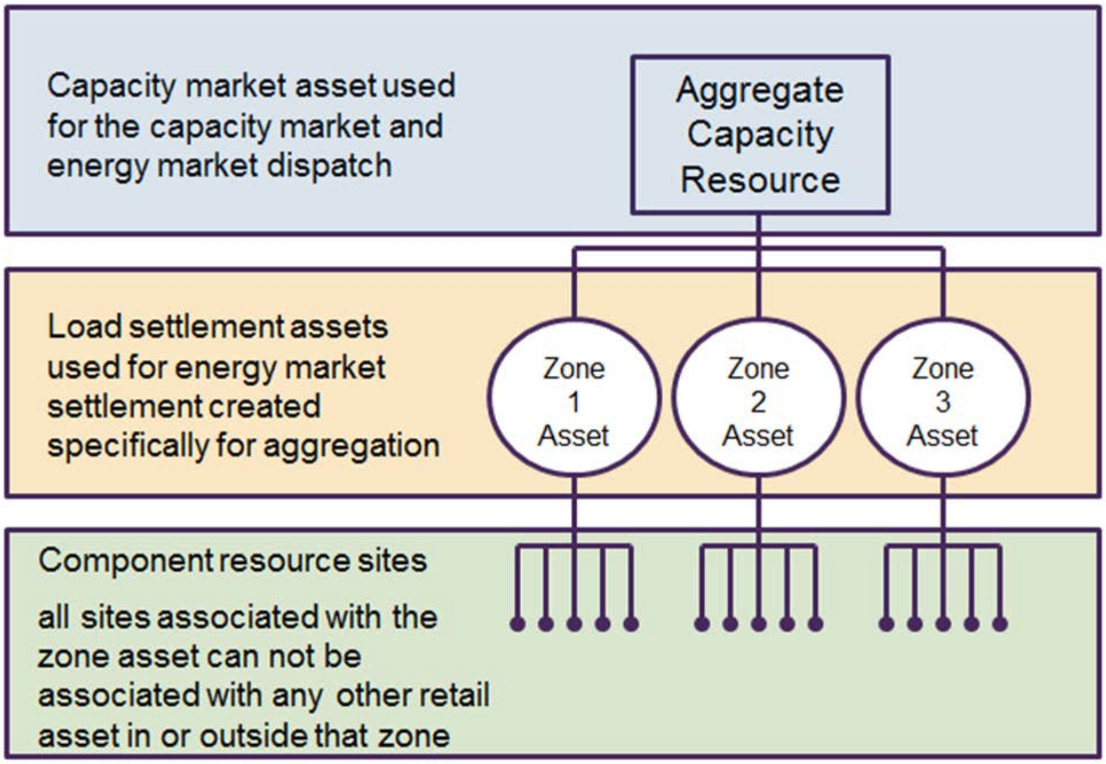
| Year | Month | Day | EEA duration (HH:MM) |
|---|---|---|---|
| 2012 | January | 17 | 2:07 |
| 2012 | January | 18 | 0:27 |
| 2012 | July | 9 | 5:10 |
| 2012 | November | 20 | 1:31 |
| 2013 | May | 4 | 4:28 |
| 2013 | May | 9 | 3:07 |
| 2013 | June | 28 | 8:32 |
| 2013 | June | 29 | 2:43 |
| 2013 | July | 2 | 6:42 |
| 2013 | September | 3 | 3:16 |
| 2013 | September | 4 | 6:03 |
| 2013 | September | 5 | 4:19 |
| 2014 | July | 30 | 6:06 |
| 2017 | July | 26 | 0:08 |
| 2017 | September | 26 | 3:37 |
| Average | | | 3:53 |

2.1.11 The AESO supports the participation of aggregated assets in the Alberta capacity market because it increases overall market competition and provides an opportunity for assets smaller than 1 MW to participate in capacity auctions. Stakeholders have suggested that the maximum UCAP size for aggregated capacity assets should be no greater in size than the single largest contingency (currently 466 MW), in order to prevent reliability issues, potential increases in the operating reserve requirement and any potential impact to capacity auction clearing. The AESO notes that the size of aggregated assets is not related to real time operational risk as each individual component resource of the aggregated asset is operated and dispatched independently (see below). However, the AESO supports initially limiting UCAP size for aggregated capacity assets to be no larger than the single largest existing generation capacity market asset UCAP to ensure that the introduction of aggregated capacity assets does not result in unanticipated capacity market distortions.

The AESO will leverage the existing load settlement processes to ensure accurate and consistent measurement of aggregated demand response capacity assets. This restriction will limit aggregation of individual component resources to the pre-defined load settlement zones. At this time, it is anticipated that most aggregations will be demand response component resources. To be compatible with the AESO's load settlement process, sites must first be aggregated to an asset at the settlement zone level. Two or more zonal assets may be further aggregated into a single capacity asset with a single UCAP. To align with AUC Rule 021: *Settlement System Code Rules*, commercial and retail load participating in the capacity market must be aggregated to a retailer/self-retailer asset. For the purpose of aggregated demand response assets, all sites associated with that demand response asset will be considered individual component resource sites in the demand response program run by that retailer. The sum of the metering for all sites forms the basis of the UCAP, performance measurements (availability and delivery). The retailer is responsible for both energy market and capacity market settlement of the sites associated with the settlement zone asset in the aggregation. In other words, a demand response component site must have the same retailer for the capacity market and the energy market.

Figure 1 provides an illustration of aggregating individual component assets across multiple settlement zones. This example only applies to load and small generation connected on the distribution system and subject to load settlement.

**Figure 1 –** ***Aggregated capacity asset across load settlement zones***



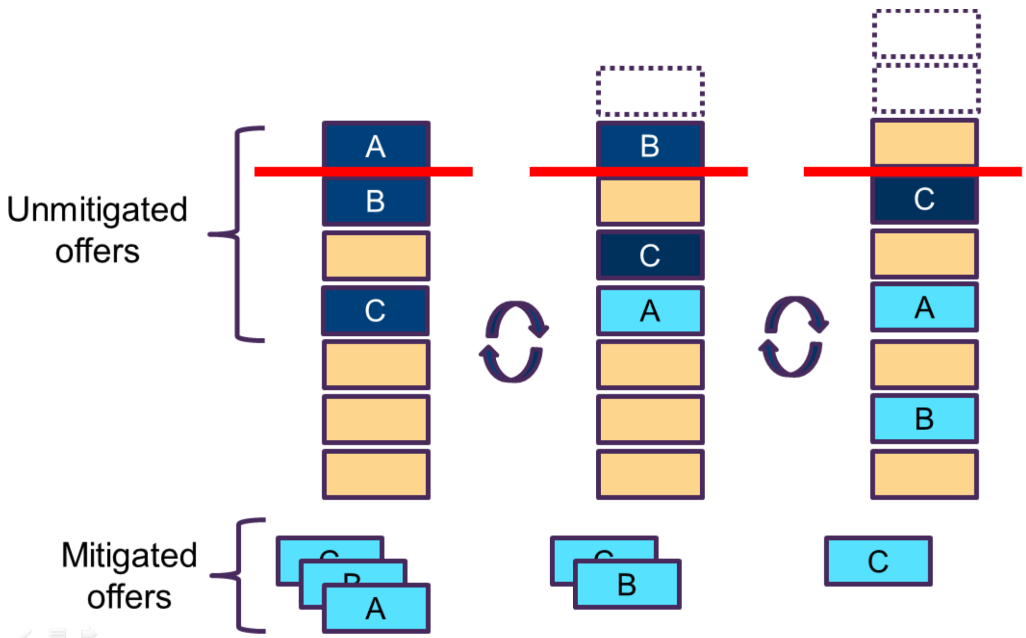

If the individual components of an aggregated capacity asset meet the dispatch requirements in the energy market, the components of an aggregated asset may choose to be dispatched and operated as individual and separate energy market assets. However, the aggregation of generation assets in the energy and ancillary services markets will remain as described in the definition of "aggregated generating facility" in the *Consolidated Authoritative Document Glossary* that will be effective on September 1, 2018, and Section 501.10 of the ISO rules, *Transmission Loss Factors*.

2.1.12 A refurbished capacity asset is considered a new capacity asset to incent asset life extension and potentially increase UCAPs. New capacity assets will not be assessed a default offer cap as described in Section 7, *Capacity Market Monitoring and Mitigation* if the capacity market participant fails the capacity market power screen. In order to determine if modifications to a capacity asset are significant enough for the asset to be considered a new capacity asset, a threshold test was developed using the same approach as North American and United Kingdom (UK) capacity markets. The thresholds levels for refurbished capacity assets in Alberta are based on a volumetric and cost analysis of recent or proposed refurbishments in Canada. Based on a range of different refurbishments across various technologies, the lower range of annualized refurbishment costs are approximately $45/kW-year. Assuming a useful capital life of at least 5 years, this equates to a capital cost of $200/kW. The $200/kW threshold is expected to be low enough to include some coal-to-gas conversions of the existing coal fleet as refurbished assets. The threshold is needed such that it represents a significant capital investment in the facility such that the refurbishment offer process is not abused as a way for units, which are not making material changes or whose cost structure is such that they can be effectively represented even under a standard mitigated offer, from being given an effectively free option to utilize a low risk economic withholding strategy in the market.

2.1.13 As described in the rationale for Section 7*, Market Monitoring and Mitigation*, market power mitigation will be implemented to limit the negative effects of economically withholding capacity volumes. Submitting a refurbishment plan should not facilitate the economic withholding of capacity volumes. A capacity market participant with market power that submits a refurbishment plan that is approved by the AESO is able to offer that capacity volume for the refurbished asset at an unmitigated price. A capacity market participant will be required to indicate as part of the prequalification application, for each refurbished asset, whether the asset will: (a) permanently delist and retire if it fails to receive an obligation; or (b) not permanently delist and submit a mitigated offer for the existing asset to be used in the capacity auction in the event the unmitigated offer does not clear. The one-time use of option (b) is in place to prevent a "free" option that allows participants to submit a prequalification application for refurbishment each year and be permitted to continually have an "opportunistic" higher priced offer in the supply stack while mitigated.

The introduction of this approach for refurbishments will require a multi-stage clearing process for the capacity auction whereby the unmitigated offers for refurbished assets which do not clear are added back into the supply curve at their mitigated price and the market clearing process is run again. This process will continue until all refurbishment assets have cleared the market or offered on a mitigated basis. To simplify the auction clearing process, unmitigated refurbishment offers will be required to be single, inflexible blocks. For example, in the illustration below three participant assets (A, B and C) submitted prequalification applications for refurbished assets and declared option (b).

**Figure 2 – *Multi-stage auction clearing process***




In this example the auction clearing engine iterates twice, each time determining the unmitigated offers that do not clear and replacing them with the mitigated offers. In this example a solution is found when the unmitigated offer from asset "C" clears in the auction.

2.1.14 If a firm subject to capacity market power mitigation enhances a capacity asset to add incremental capacity, the incremental volume will not be mitigated. However, the existing capacity will be subject to the mitigation cap. The rationale for the threshold values for incremental capacity assets are based on a threshold analysis. This analysis included a review of historical uprate volumes in Alberta, documented in the table below. The results indicated two uprate ranges:

(1) in the 3 to 5% (12-19 MW) increase range; and

(2) in the 12 to 15% (44-53 MW) increase range.

**Table 2 - *Summary of Alberta historical uprate maximum capability***

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| **Plants** | **AESO MCR (MW)** | **PPA Comitted Capacity (MW)** | **Increase Capacity (MW)** | **Increase Percentage (%)** | **Note** |
| Battle River 5 | 385 | 368.2 | 16.8 | 4.56% | uprate |
| Genesee 1 | 400 | 381 | 19 | 4.99% | uprate |
| Genesee 2 | 400 | 381 | 19 | 4.99% | uprate |
| Keephills 1 | 395 | 383 | 12 | 3.13% | uprate |
| Keephills 2 | 395 | 383 | 12 | 3.13% | uprate |
| Sheerness 1 | 390 | 378.1 | 11.9 | 3.15% | uprate |
| Sheerness 2 | 390 | 378.1 | 11.9 | 3.15% | uprate |
| Sundance 3 | 368 | 353 | 15 | 4.25% | uprate |
| **Range 1 average** | **390** | **376** | **15** | **3.92%** | |
| **Range 1 min** | **368** | **353** | **12** | **3.13%** | |
| **Range 1 max** | **400** | **383** | **19** | **4.99%** | |
| | | | | | |
| Sundance 4 | 406 | 353 | 53 | 15.01% | uprate |
| Sundance 5 | 406 | 353 | 53 | 15.01% | uprate |
| Sundance 6 | 401 | 357 | 44 | 12.32% | uprate |
| **Range 2 average** | **404** | **354** | **50** | **14.12%** | |
| **Range 2 min** | **401** | **353** | **44** | **12.32%** | |
| **Range 2 max** | **406** | **357** | **53** | **15.01%** | |
| | | | | | |
| Clover bar 1-3 | 243 | 243 | 0 | 0.00% | Refurbish |
| Sundance 1 | 280 | 280 | 0 | 0.00% | no uprate |
| Sundance 2 | 280 | 280 | 0 | 0.00% | no uprate |

Since the smaller uprates require much lower capital additions relative to major uprates, the larger range of uprate volumes will be used to determine the volume addition threshold above which the entire asset will be considered a refurbished asset. The 15% and 40 MW incremental threshold described above is comparable to ISO-NE's New Capacity Eligibility requirements which state that:

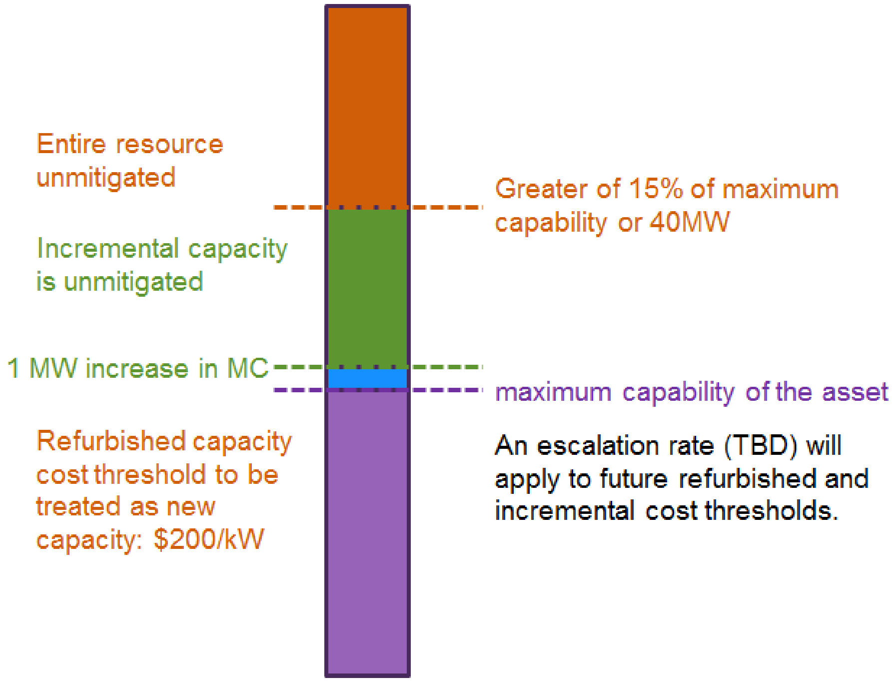
> "Uprate (increase above threshold)—An existing resource can qualify as new if it is proposing an increase in output that is the greater of 20% or 40 MW above the existing qualified capacity".[1]

Based on the AESO's analysis summarized above, the following thresholds will apply in Alberta:

- Assets whose maximum capability is increasing by at least 15 per cent or 40 MW (whichever is greater) or making a capital investment of at least $200/kW (across all installed MWs) may submit an unmitigated offer into the capacity market for the entire UCAP of the asset.
- Assets whose maximum capability is increasing by at least 1 MW and less than the 15 per cent or 40 MW threshold is classified as incremental. The incremental capacity will be unmitigated in the capacity auction.

[1] https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/qualification-process-for-new-generators

**Figure 3 – *Qualification thresholds for refurbished and incremental capacity***




The AESO will consider a 1 MW increase in maximum capability as incremental capacity but it is possible that a 1 MW increase in maximum capability will not cause an increase in UCAP.

### *Security requirement for new capacity assets*

2.1.15 The security requirement for a new capacity asset must balance the tradeoff between creating barriers to entry and ensuring that a capacity market participant is properly incentivize to deliver on its capacity obligation at the start of the obligation period. New capacity assets include assets that are not in service at the time they clear a capacity auction, assets planning to undergo refurbishment before the obligation period, and assets intending on adding incremental capacity before the obligation period. A number of factors may potentially interfere with the new capacity asset's ability to be in service at the beginning of the obligation period. These may include: delays in permitting, failure to secure financing, delays in equipment delivery, delays in construction and equipment installation, issues with installation that lead to a lower than expected capacity rating, and insolvency of the developer. The security requirement is intended to mitigate the risk of non-delivery by: (i) recovering the replacement capacity costs it incurs due to non-delivery through rebalancing; and (ii) creating an additional incentive for capacity assets to physically deliver.

The security requirement for the Alberta capacity market is similar to those utilized in other situations where there is a risk of a supplier meeting a future obligation. For example, construction project performance bonds are normally a percentage of the invested project cost, and are a well-established mechanism for mitigating delivery risk.

As outlined below, the security requirement for the Alberta capacity market will decline through time as project milestones are reached. The quantitative reduction in credit requirement with each completed milestone is intended to reflect the associated reduction in non-delivery risk. Reducing credit requirements as milestones are completed also provides incentive for resources to adhere to development timelines.

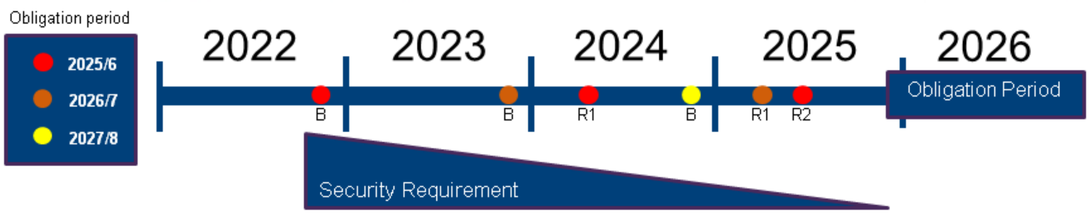
Security requirement for brand new assets = (gross-CONE * 1/CRF) * 5%.

The capital recovery factor (CRF) delineates the number of years over which project investment can be recovered, and consequently how much of the project investment is recovered annually. For brand new assets, the CRF will use 20 years for n. For refurbished and incremental assets, the threshold costs described in this subsection will be used.

The 5% value is based on Surety Association of Canada's guideline for performance bond range from 4% to 10% of invested capital.[2]

The following is intended to provide an example calculation of the security requirement for a brand new 100 MW asset using an estimated gross-CONE of $148/kW:

**Figure 4 – *Declining security requirement***




i. CRF, assuming a 8.2% discount rate = {.082(1 + .082)^20} / {[(1 + .082)^20]-1} = 0.103 or 10.3%

ii. Security requirement = $148/kW *1/CRF = $1437/kw or $1.437m/MW * 5% = $72k/MW

iii. Security requirement rate = $72k/MW / max number of auctions before the delivery year (6) = $12,000/MW

iv. Declining security requirement = security requirement rate * Obligation * number of remaining auctions before the obligation period:

prior to 2025 B (2022) = (.012 * 100 MW) * 6 = 7.2M
prior to 2025 R1(2024) = (.012 * 100 MW) * 4 = 4.8M
prior to 2025 R2 (2025) = (.012 * 100 MW) * 1 = 1.2M
after commercial operation = (.012 * 100 MW) * 0 = 0M

The declining security requirement is contingent on the project meeting its declared project milestones. In the event the project schedule is at risk of delivering in time for the obligation period the financial security will not be returned to the capacity market participant and will be held by the AESO until the project is back on schedule. If the capacity market participant is required to buy back its obligation in a rebalancing auction, the security will be held to guarantee the payment of the rebalancing costs during the obligation period.

Refurbished assets will use the $200/kW cost threshold described in section 2.1.12 above instead of 1/CRF as the life extension of a refurbished asset is not expected to last 20 years. Incremental capacity will use a $100/kW cost threshold derived from an AESO analysis of historical cost of capacity uprates in Alberta and jurisdictional comparisons. The AESO developed its security requirement proposal in consideration of Alberta's unique needs, and after reviewing the credit rules used in the PJM, ISO New England (ISO-NE), and UK capacity markets. Table 4 below summarizes the capacity market credit requirements in these other markets. Looking at other capacity markets, ISO-NE and the UK have comparable credit requirements. The PJM credit requirement is much higher, which may stem from a more conservative approach to credit risk,

[2] http://www.surety-canada.com/en/surety_resources/contract-surety/performance-bonds.html

and the fact that PJM will increase a market participant's unsecured credit limit if they earn net revenues in PJM's markets.[3]

**Table 3 – *Capacity market credit requirements for new resources***

| Component | PJM[4] | ISO-NE[5] | UK[6] |
|---|---|---|---|
| **Applicability** | New capacity only | New capacity only | New capacity only |
| **Credit Requirement (After Clearing a Forward Auction)** | ~50% Annual net-CONE | 8.3% Annual Clearing Price | £10,000/MW<br>(~12% Annual net-CONE) |
| **Adjustment of Credit Requirement Over Time** | Increases with each forward auction cleared for separate delivery years | Increases with each forward auction cleared for separate delivery years | Increases with each forward auction cleared for separate delivery years |
| **Unsecured Credit Limit** | Increases with credit rating, net worth, and historical net revenues across all PJM markets<br>Maximum: $50 million per market participant | Increases with credit rating, and net worth<br>Maximum: $50 million per market participant | N/A |
| **Acceptable Forms of Secured Credit** | Cash<br>Letter of Credit | Cash<br>Letter of Credit<br>Mutual Fund Shares | Cash<br>Letter of Credit |

The AESO's proposed capacity market security requirement for new capacity assets aligns with its existing credit policy which specifies limits on unsecured credit, and the acceptable forms of secured credit for participants across the AESO's markets. At this time, the AESO does not believe that any change is required to its current guidelines on unsecured credit or acceptable forms of secured credit.

### *Prequalification of a new capacity asset*

2.1.16 An application is required to properly assess a new capacity asset against the eligibility criteria for prequalification.

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[3] Unsecured credit limits in U.S. markets were tightened by the Federal Energy Regulatory Commission (FERC) following the 2008 financial crisis when U.S. RTOs faced severe credit stresses. In Order 741 and its subsequent modification, the FERC limited unsecured credit to $50 million per market participant. In both U.S. markets, unsecured credit limits increase with the credit rating of the market participant and its net worth up to the $50 million limit. PJM also allows a market participant's historical net revenues across PJM's markets to count toward its unsecured credit limit for the purposes of its capacity market credit requirement. These differences across markets may be explained by differences in volatility. Generally, a more volatile market will require higher credit requirements.

[4] Credit Overview and Supplement to the PJM Credit Policy, October 6, 2017.

[5] Exhibit IA, ISO New England Financial Assurance Policy, June 1, 2017.

[6] Applicant's Credit Cover Process, July 6, 2015. Government Response to the March 2016 consultation on further reforms to the Capacity Market, 2016.

2.1.17 Prequalification is intended to: (i) ensure that a new capacity asset meets the minimum standards for a capacity asset; and (ii) verify that a proposed project prequalification package contains all of the supporting information necessary to assess delivery progress, apply the appropriate security requirements, and determine the form of capacity asset in order to apply the correct UCAP, availability, and performance methodologies to the asset.

2.1.18 A prequalified asset will be assigned a UCAP for the upcoming auction. If the UCAP for that asset is less than 1 MW the asset is not qualified to participate in the upcoming auction. However, it will remain prequalified for future auctions given that improvement in performance can increase UCAP above the minimum sizing requirement.

***Prequalification for subsequent auctions***

2.1.19 Prequalification of an asset is a one-time step, unless circumstances surrounding the asset change. Allowing prequalified resources to remain eligible for future auctions until delisted, modified, or deemed ineligible by the AESO gives the AESO certainty on resources that will participate in the auction and in determining supply adequacy. This approach also reduces the administrative burden of prequalifying resources each year for every base auction and rebalancing auction.

The modifications mentioned above include changes in self-supply status, refurbishment, and the addition of incremental capacity. A capacity market participant with incremental capacity must submit an incremental capacity prequalification application to the AESO prior to the auction in order for that incremental capacity to be included in the UCAP determination.

## 2.2 Self-supply designations

The concept of self-supply, a best practice found in other capacity markets, was leveraged to accommodate existing cogeneration and other sites in Alberta where load is served by onsite generation. Such sites account for approximately 2,000 MW of generation. This also recognizes the unique nature of Alberta's system.

2.2.1 Sites must be able to physically deliver capacity to the rest of the grid in order to meet the criteria that capacity contributes to reliability and is a physical product. The rationale for requiring certain sites to self-supply is as follows:

(a) The City of Medicine Hat is a site with onsite generation that is net metered at the connection to the Alberta Interconnected Electricity (AIES) system, and cannot physically flow their gross generation volumes due to system connection limitations. They must therefore self-supply. This includes generation not owned by the City of Medicine Hat located within the city limits.

(b) Sites that do not have revenue quality metering at the generator terminus cannot be measured accurately for the purposes of capacity market settlement.

(c) The Alberta capacity market is a physical market. The original criteria and assumptions for the design of the capacity market state that “a capacity obligation is a forward obligation on capacity suppliers that requires the capacity sold in the market to be available to provide energy production or reduced consumption when needed.” Based on this statement, sites with onsite generation that are net-metered and cannot physically flow their gross generation volumes to the grid due to system connection limitations must self-supply because they cannot physically deliver additional MWs to the system greater than that based on physical transmission limitations. Not all sites under this configuration are cogeneration sites and some manage their load with their own generation investments.

2.2.2 A site may choose to self-supply capacity provided they have a bi-directional net-interval meter at the connection point to the system. The bi-directional meter is necessary to accurately measure the net-to-grid energy in order to ensure delivery. Alberta's market does not have integrated utilities acting as load serving entities, as found in other capacity markets, but over 20% of the internal load is served by onsite generation. The capacity market design for Alberta must include consideration for this form of participant. Self-supply provides the market with a methodology to deal with behind-the-fence (BTF)[7] locations with limited transmission capability. In addition, the ability to self-supply allows cogeneration sites that are tied to a host customer's load to be exempt from offering all of its capacity into the AESO-operated capacity market.

2.2.3 The 4 year requirement is intended to align with the proposed timing of the approval of the demand curve parameters to increase market certainty with respect to the demand curve. If the demand curve review cycle is shorter or longer than 4 years, the AESO will adjust this requirement accordingly. Self-supply volumes are not included in the procurement volume and therefore, the choice of whether or not to self-supply will impact the procurement volume. Stakeholders have suggested that the 4 year requirement is too restrictive and does not align with changes in operation and market conditions. In response to this feedback, the AESO will permit self-suppliers and capacity market participants to submit a change in self-supply status inside of the 4 years provided the self-supplier participant can demonstrate a physical change to the operation of the site. This allows reasonable certainty to be incorporated into the capacity market while ensuring that the capacity market structure does not negatively interfere with the business decisions of self-suppliers

2.2.4 *Stakeholder concerns related to self-supply*

An independent load and generator may pay, and are paid differently, from sites that are combined load and generation. Using a simple settlement example for the capacity market, it can be demonstrated that a site that is self-supplied will be allocated less of the reserve margin than a similar load without the ability to self-supply.

To demonstrate the payment difference when comparing gross settlement to net settlement, Table 5 below provides a simple system with four cogeneration sites (I1 through I4), 1 pure load site (I5) and one new entrant pure generator (A1). This example assumes a reserve margin requirement of 15% as the additional amount to procure in the capacity market to ensure reliability. The internal load of this system is 44 MW, adding an additional 15% brings the procurement target for this system to 50.6 MW of capacity less 18 MW of self-supply equaling 32.6 MW. The volume of self-supply is calculated as the difference between the sites gross load and its net load. The size of the resource procured to serve this sample of load portfolio is calculated as difference of the necessary amount for the gross load minus the sum of the generators' UCAP.

Once the capacity market clears, the load will be allocated the cost of the capacity procured. The cost allocation formula used here is the total payment to all capacity assets multiplied by the load of the site divided by the total load of all sites. The illustrative example includes both a gross load and a net load calculation. The payments that generators receive in this illustrative example assume a capacity market price of $40/MW (over a particular obligation period). The capacity payment is simply the capacity obligation multiplied by capacity market price. The example includes both a gross generation and a net generation calculation. The results of the example show that by allowing netting of the generation out of the load: (i) the rest of the load on the system (pure load represented by I5) will pay more than it would if netting were not allowed; and (ii) the loads that have cogeneration sites would pay less if short of generation, or the generators would be paid more if long on generation. Currently in Alberta 20% of the gross load is self-supplied.

[7] The AESO 2017 *Long-Term Outlook* defines BTF as "industrial load served in whole, or in part by onsite generation built on the host's site."

**Table 4 - *Gross vs net settlement for self-supply***

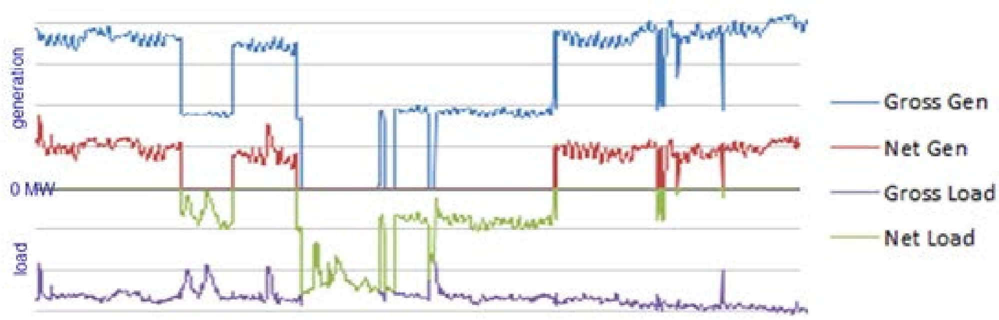
| | Net | | Gross | | cost allocation | | | | payments | | totals | | Volume of |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| sites | net load | net gen | gross load | gross gen | net | $ | gross | $ | net | gross | sum net | sum gross | Self-supply |
| I1 | 2 | 0 | 5 | 3 | 2.507692 | $ 100 | 5.75 | $ 230 | $ - | $ 120 | $ (100) | $ (110) | 3 |
| I2 | 0 | 3 | 3 | 6 | 0 | $ - | 3.45 | $ 138 | $ 120 | $ 240 | $ 120 | $ 102 | 3 |
| I3 | 4 | 0 | 8 | 4 | 5.015385 | $ 201 | 9.2 | $ 368 | $ - | $ 160 | $ (201) | $ (208) | 4 |
| I4 | 0 | 3 | 8 | 11 | 0 | $ - | 9.2 | $ 368 | $ 120 | $ 440 | $ 120 | $ 72 | 8 |
| I5 | 20 | 0 | 20 | 0 | 25.07692 | $ 1,003 | 23 | $ 920 | $ - | $ - | $ (1,003) | $ (920) | 0 |
| Sum: | 26 | 6 | 44 | 24 | 32.6 | $ 1,304 | 50.6 | $ 2,024 | $ 240 | 960 | $ (1,064) | $ (1,064) | 18 |
| A1 | 0 | 26.6 | 0 | 26.6 | | | | | $1,064 | $1,064 | $1,064 | $1,064 | |
| Sum: | | 32.6 | 44 | 50.6 | 32.6 | $ 1,304 | 50.6 | $ 2,024 | $ 1,304 | $ 2,024 | 0 | | |
| | amount to procure: | | 32.6 | 26.6 | | | | | | | | | |

In this example, the difference between the gross and net calculation, an additional 2.08 MW, is allocated to the pure load at a cost of $83 ($1003 to $920). This is because the netted load is not carrying their reserve requirement under the same level of reliability criteria as the rest of the system. The rationale submitted by the cogeneration owners for this acceptable difference is that cogeneration provides a reliability benefit due to the fact that the load and generation are tightly coupled. When looking in aggregate at Alberta industrial systems there is a correlation between the load and generation. In Figure 4 below, it is apparent that as the generation at the site drops the load drops too. This correlation makes sense as, by definition, the electricity is a by-product of the steam used in the industrial process. If no steam is generated, then no generation output is provided and no industrial process is supported by the cogeneration. Historical analysis of industrial system designation sites from 2012 to 2017 showed the reduction in generation was roughly 500 MW greater than the decrease in load. This is partially due to the fact that some industrial system designation sites are not cogeneration sites.

*Determination of self-supply capacity*

Self-supply volume is the difference between a site's gross load and net load. Depending on when that difference is measured the value can change dramatically. No reliability risks exist if it can be assured that in the event of generation failure during a performance event the load will be at its net-load volume levels. However, examination of historical individual net site behavior has not demonstrated this in all cases. Loads are not always reduced when the generation is down and we find net loads increase to gross load levels in some instances. In the example graph below, when the generation at the site (blue line) goes to or approaches zero, the net load at the site (green line) increases. The gross load at the site (purple line) remains relatively constant. Further analysis indicates 7 of the 15 current industrial system designation sites demonstrate a high correlation of their load and generation.

**Figure 5 – *Net and gross measurements at a self-supply site***



Due to this observation, the AESO proposed four options to industry for mitigating this risk in the form of the following question.

***How should the AESO determine how much capacity to procure for self-supplied load? Four options are listed below:***

1. *The AESO does not procure capacity for the netted-out load and requires the net load to be curtailed during delivery events if not meeting their delivery obligation.*
2. *The AESO does not procure capacity for the self-supplied load, but charges the load at the value of lost load plus the curtailed loads capacity payment (liquidated damages) if they rely on the system under shortage events.*
3. *The AESO procures some capacity based on a probabilistic assessment of each self-supplier's dependence on the system's capacity market.*
4. *Apply the cost allocation formula to net load only. If a self-supplier takes capacity in a prior year they pay for it in the future year*.

Option 1 is a true form of opting out of the market and would not compromise reliability. However, there are very few self-suppliers that could utilize this option, and the cost of mandating this on all sites would be prohibitive. Options 2 and 4, which are variations on a similar theme, provide a financial incentive for self-suppliers to make sure assets manage their consumption during delivery events. The most important difference is that Option 2 sets a maximum load obligation that is assessed during delivery assessment periods, whereas the Option 4 cost allocation method is tied to cost allocation periods. Option 3 is a combination of Option 4 plus an additional premium, equal to some fraction of the system reserve margin percentage, placed on the self-supplied load to cover the risk of the load exceeding typical net levels during delivery events. This was seen by some stakeholders as incurring a double cost allocation and by the AESO as a highly administrative calculation requiring actuarial science to determine the right premium.

Option 4 was seen by a majority of the working group as the simplest method to manage self-supply as it is consistent with the current energy market treatment of generator station service load and net-measured sites. Some members felt this mechanism did not adequately address the reliability issue. The reliability concern comes from two places: (i) the method of cost allocation may not provide proper incentives for self-supplied load to not consume during system stress events if there is no alignment of delivery events and the times where costs are allocated; and (ii) the net load is highly variable, and most sites can incur non-coincident peaks in the hundreds of MW even though net loads are mostly in the tens of MW range.

With the high variability of net loads combined with the fact that these loads are large, the treatment of self-supply must ensure that appropriate incentives are in place to discourage self-supply loads from consuming during the capacity delivery assessment periods. To not do so could present a reliability risk.

*Weighted energy cost allocation and self-supply*

Generation used for self-supply can participate in the capacity market only on a net-to-grid basis, while the load it supplies will be subject to capacity market cost allocation based only on net-to-grid consumption. Concerns have been identified with the potential for self-supply loads to increase consumption due to onsite generation being off-line under the weighted energy methodology for cost allocation.

The weighted energy methodology for cost allocation reasonably and fairly apportions capacity market cost to loads that operate in a predictable and consistent manner. The methodology can also be compatible with creating incentives to ensure that self-supplied loads have sufficient incentive to curtail during conditions when onsite generation is reduced. For example, to provide an incentive for self-curtailment, a rate could potentially be designed whereby additional costs are allocated to loads when net-to-grid consumption is significantly higher than average under defined conditions. The additional cost allocation would not impact loads that operate with a "normal" load profile that do not exhibit periods of intermittent high consumption. The additional cost allocation would be expected to account for a small percentage of the total cost of the capacity market. A market participant could avoid incurring the additional cost allocation by avoiding intermittent periods of high consumption. This is the incentive the rate design is intended to provide. Additional details will be developed by the AESO and subject to further consultation.

## 2.3 Delisting

2.3.1 For market transparency purposes, prequalified capacity assets that cannot participate in the Alberta capacity, energy and ancillary services markets for physical or economic reasons are required to temporarily or permanently delist from the Alberta capacity market. For clarity, “participation” refers to supply participation in the Alberta capacity, energy and ancillary services markets (i.e., providing energy production or demand response). A load that applies, prequalifies and obtains a capacity obligation to provide demand response is considered a supply of capacity The capacity market participant will have a must offer requirement in the energy market if the asset is committed to provide 5 MW or more in the capacity market in accordance with Section 10, *Roadmap for Changes in the Energy and Ancillary Services Markets* and a must offer in the capacity market in accordance with Section 5, *Base Auction*. As such, these demand response assets will be required to delist should they choose to no longer offer demand response. When a load delists it does not mean the load must no longer consume electricity or lose the ability to self-curtail their consumption. Self-suppliers that are net load and choose not to provide demand response are not considered to be participating capacity supply.

2.3.2 Capacity assets that are currently on extended mothball outages under Section 306.7 of the ISO rules, *Mothball Outage Reporting* (“Section 306.7”) will be required to submit a temporary or permanent delist bid during prequalification for the first obligation period in order to remain offline. This will increase market information and transparency and will also facilitate the transition from Section 306.7, which will be amended to align with the delisting process.

***AESO review of impacts to the reliability of the interconnected electric system***

2.3.3 - 2.3.4

The AESO may review delisting submissions for reliability impacts and supply adequacy issues to ensure the safe, reliable and economic operation of the AIES.

***Temporary delist request for economic reasons***

2.3.5 Temporary delisting bids for economic reasons may be submitted during the prequalification period associated with the second rebalancing auction. The economic delist bid may be submitted after the asset has participated in both the base auction and the first rebalancing auction. It is only after participating in the base and first rebalancing auctions that a firm will be able to determine that the capacity asset has not earned sufficient revenue to remain economic. This notice period is in line with the notice period in Section 306.7.

The AESO acknowledges stakeholder feedback surrounding the requirement for a capacity market participant to offer into the base and first rebalancing auction even when it plans to temporarily delist its asset for economic reasons for the upcoming obligation period. As long as the offer reflects the net avoidable costs of temporary economic delist, the requirement that a temporary economic delisting request can only be submitted before the second rebalancing auction should not take away the opportunity for a capacity market participant to make arrangements to prepare, even in advance of the base auction, to temporarily delist the asset for the upcoming obligation period.

In addition, the requirement to submit a temporary economic delist request during the pre-auction period for the second rebalancing auction should not have an undue impact on the market outcome. If the offer clears in the base auction or first rebalancing auction for the upcoming obligation period, there is no economic reason for the capacity asset to delist for the upcoming obligation period. If the offer does not clear, the temporary economic delist request for the upcoming obligation period may be submitted before the last rebalancing auction relevant to the subsequent obligation period. As such, allowing economic delist bids for the second rebalancing auction only does not restrict an asset from economically delisting for more than one obligation period.

2.3.6 In order to verify that the temporary economic delist request is not for the purpose of removing an asset from the market in order to increase capacity or energy prices to benefit the firm's portfolio, the AESO requires a firm to submit net avoidable cost data as described in subsection 7.1.9 of Section 7, *Capacity Market Monitoring and Mitigation* and an attestation from a corporate officer of the firm. If the capacity asset will be available in the energy and ancillary services markets for a portion of the obligation period, the net avoidable cost submission associated with the temporary economic delist request must reflect that fact. For example; labor costs are not avoidable while participating in the energy market.

2.3.7 Allowing a temporarily economically delisted capacity asset to participate in the energy and ancillary services markets for a portion of the obligation period allows flexibility to capture energy market opportunities. However, a temporary economic delist request suggests a capacity asset is intended to be mothballed due to economic reasons. Participating in the energy and ancillary services market for a prolonged period would not be consistent with the intent of temporary economic delisting. Therefore, a 5 month limit on the duration of participation in the energy and ancillary services markets will be placed on such assets.

2.3.8 In the event of potential or eminent supply shock or sustained supply tightness caused by unplanned events, the AESO may permit a temporarily economically delisted capacity asset to delay the start of the outage or return to the energy market before the end of their outage term. Should these types of events occur, energy prices are expected to increase and the economic assumptions that went into the delisting decision may have changed to where the asset may not have delisted with foresight of these events.

2.3.9 From a marginal cost perspective, a capacity market participant would offer into the capacity auction at the net-avoidable costs of such asset. It is those costs the capacity market participant needs to recover in order to operate profitably in that obligation period. If the market clears above the asset's net-avoidable costs it will be economic for the capacity asset to remain active.

2.3.10 A capacity asset may not temporarily economically delist for more than two consecutive obligation periods in order to facilitate the optimal use of the existing transmission system and prevent price distortion caused by the uncertainty with respect to the duration and timing of a delisted capacity asset's return to operation.

The requirement to submit a temporary economic delist request for each of the two periods separately is to prevent potential supply condition changes in the market from one obligation period to another and distortion of investment signals as a result of the uncertainty about the capacity delisting duration and the timing of its return to operation.

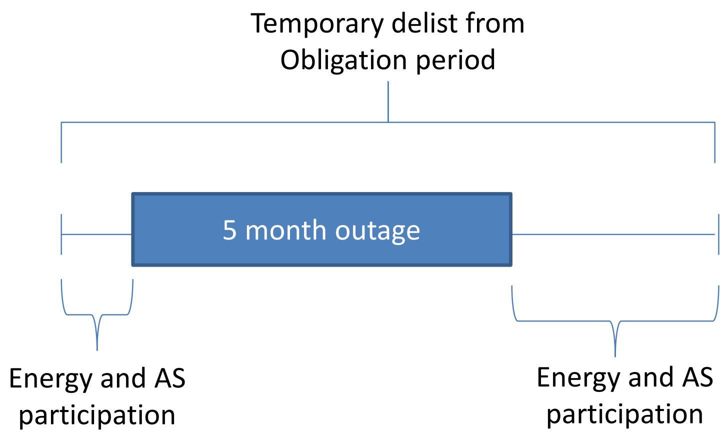
### *Temporary delist request for physical reasons*

2.3.11 A capacity market participant is able to temporarily delist an asset if it is physically unable to operate. A 5 consecutive month period was chosen because this duration is greater than the average duration of a planned maintenance outage in Alberta, which is 2 to 3 months per year. Additionally, 5 months is short enough to enable seasonal assets to participate, and long enough to ensure the seasonal asset provides adequate value for reliability. A 5 consecutive month period is intended to preserve incentives to plan regular maintenance in periods of lower system risk while recognizing that longer than typical outages really mean a unit is unavailable and not expected to provide sufficient reliability.

The obligations related to temporary physical delisting apply to all capacity asset types. For example, if an aggregate demand response asset loses individual component resources and those components cannot be replaced to maintain its capacity obligation, then the capacity market participant would be expected to delist due to a physical operational restriction thereby reducing performance risk.

2.3.12 Physical delisting presumes that an asset will not be physically operational for at least 5 continuous months of the obligation period. The AESO will approve physical delisting bids without the requirement for an economic review. If a capacity market participant wishes to delist a capacity asset for a period greater than 5 months but less than 12 months, the capacity asset is delisted from the capacity market for the entire obligation period. When the asset returns to service it will be required to participate in the energy market. For example, a capacity asset that physically shuts down January 1 of a calendar year (the third month of the obligation period) and starts up again 5 months later, would be delisted from the capacity market for the entire obligation period but will be required to participate in the energy market from November 1 until December 31 and from June 1 to October 31 of that obligation period. In other words, a capacity asset that has received approval to temporarily delist due to physical reasons may participate in the energy and ancillary services markets during the period that the asset is physically capable of providing energy (able to function) assuming that period is less than or equal to 7 months of the obligation period, as shown below.

**Figure 6 –** ***Physical delisting participation in the energy and ancillary services markets***




The asset will not receive a capacity obligation for the obligation period but will be able to participate in the energy and ancillary services markets.

2.3.13 In the event of potential or eminent supply shock or sustained supply tightness caused by unplanned events, the AESO may permit a temporarily physical delisted capacity asset to delay the start of the outage or return to the energy market before the end of their outage term. Should these types of events occur, energy prices are expected to increase and the economic assumptions that went into the delisting decision may have changed to where the asset may not have delisted with foresight of these events. In addition, resources which may be able to enhance reliability should be made available.

2.3.14 The restriction of up to two consecutive obligation periods is applied to temporary physical delisting to facilitate the optimal use of the existing transmission system, as well as ensure that the capacity market price signal is an effective investment signal.

### *Permanent delist notifications*

2.3.15 Because a permanent delisting decision is a long-term one and is likely not dependent on the price outcome of a single obligation period, permanent delisting notifications are allowed to be submitted during the base or first rebalancing auctions prequalification processes. Permanent delisting notifications may not be permitted during the last rebalancing auction in order to mitigate the potential risk of the market not having sufficient time to react to permanent change in supply conditions.

The asset retirement date does not need to occur at the start of the obligation period. A capacity market participant that is currently participating in the energy market and is intending to permanently delist, if the asset has a must offer requirement in the energy or ancillary services markets, must participate in the energy market until to the physical retirement of the asset. If the retirement start date is greater than 7 months into the period, the asset may still receive a UCAP and be required to offer into the capacity market.

Permanent asset delisting is an irreversible process and once the application is received by the AESO the asset will be required to retire on the declared retirement date. A capacity market participant should consider temporary delisting if it would like to return the asset back to operation at a future period. This approach ensures the market has clear information in order to provide effective and accurate investment signals.

2.3.16 The same rationale for temporary physical delist in section 2.3.11 applies to permanent delisting as well.

2.3.17 Demand response and external capacity assets may permanently delist. If the capacity market participant chooses to return to the capacity market they must prequalify as a new asset. This requirement is to recognize the physical difference between generating assets and external assets and loads. Generating assets in Alberta which permanently delist are physically dismantling while the other asset types may physically still exist (e.g. loads still consuming, wires still available to deliver energy from external sources) and may be able to return to the market at a future date.

2.3.18 The AESO will not review permanent delisting notifications for acceptability of financial data and cost information. The AESO, in response to multiple stakeholders, agrees that a legal owner of a capacity asset is entitled to make their own judgement about the economic viability of their assets and whether to retire them permanently.

## 2.4 Physical bilateral transactions

2.4.1 Physical bilateral transactions will not be permitted in the Alberta capacity market. Physical bilateral transactions take place outside of the centralized capacity market. If permitted, buyers and sellers would find each other (i.e., self-matching) and report their matched commitments to the centralized market (i.e., the AESO) prior to a capacity auction. Contract prices are not reported, but remain private information between the buyer and seller. This practice negatively impacts the size of the centralized market by potentially reducing liquidity, thereby making the market less competitive.

Prohibiting capacity assets and load to arrange for capacity outside of the market through physical bilateral arrangements promotes liquidity and competition in the market. The design requires the capacity market to achieve the desired reliability objectives through a real and measurable supply adequacy product that still respects the unique aspects of Alberta's electricity system.