Singapore Forward Capacity Market

Draft Detailed Design Proposal

PREPARED FOR

Energy Market Authority

Smart Energy, Sustainable Future

PREPARED BY

Sam Newell
Judy Chang
Kathleen Spees
Walter Graf
John Imon Pedtke
Matt Witkin

December 2019

THE Brattle GROUP

Notice

- This report was prepared for the Energy Market Authority of Singapore (EMA), in accordance with The Brattle Group's engagement terms, and is intended to be read and used as a whole and not in parts.
- The report reflects the analyses and opinions of the authors and does not necessarily reflect those of The Brattle Group's clients or other consultants.
- There are no third party beneficiaries with respect to this report, and The Brattle Group does not accept any liability to any third party in respect of the contents of this report or any actions taken or decisions made as a consequence of the information set forth herein.

Table of Contents

I. Introduction

Purpose of This Document

The Energy Market Authority of Singapore (EMA) is proposing a Forward Capacity Market (FCM) to address concerns in the current Singapore Wholesale Electricity Market (SWEM). The EMA has retained The Brattle Group (hereafter "Brattle" or "we"), an international economic consulting firm, to assist in the design of a FCM. This document represents the second public version of a design proposal for the FCM, and it provides stakeholders an opportunity to provide feedback. In particular, we seek feedback on the following design elements that have been further developed since the first draft High Level Design:

- Product Definition
- Administrative Demand Curve
- Supply Resource Qualification and Capacity Ratings
- Forward Capacity Auction
- Settlements and Cost Allocation

Context and Objectives

The SWEM is currently an energy-only market (EOM) with ancillary services. Generation companies are remunerated primarily based on prevailing half-hourly spot prices for energy generated. By design, the EOM provides short-term price signals to guide both operations and investments in generation capacity. However, the concern is that wholesale electricity spot prices may not attract sufficient and timely investment in generation capacity to support resource adequacy i.e., to meet the minimum reserve margin corresponding to the reliability standard.

Other jurisdictions with similar concerns have implemented FCMs to ensure resource adequacy. The concept is to express the demand for capacity in a forward auction, and let suppliers compete to meet that demand at the lowest price. In combination, the real-time wholesale energy and ancillary services markets, and FCM, aim to meet the following objectives:

- Maintain resource adequacy by providing adequate incentives to existing and new resources; and
- Maximize economic efficiency to minimize long-run costs to consumers.

The components of the FCM jointly support these objectives by clearly expressing a demand for the capacity product and encouraging suppliers to compete to offer that product at lowest cost. The product definition in an FCM is simply a megawatt (MW) of capacity supply obligation (CSO) to be available and to offer into the energy market, for a year, subject to penalties for failing to perform. Broadly, the three main components of the market are: (1) a demand curve for capacity, (2) the rules defining how suppliers participate and form a supply curve, and (3) the format of the auction in which supply and demand come together to determine which resources clear the market and the prices at which they are paid.

Demand for capacity expresses how much capacity to buy as a function of price. The FCM demand curve is developed to ensure sufficient capacity is procured to meet the minimum reliability standard. It is designed to avoid procuring substantially more capacity than needed, and to allow prices to rise to attract new resources when necessary. It slopes upward to the left when supply is relatively scarce, and downward to the right in surplus, low-cost conditions.

In order to maximize competition and innovation to meet resource adequacy at least cost, **supply participation** should be open to existing and new resources across a wide range of technologies. Resources can qualify to participate if they pass certain eligibility criteria, and the qualified capacity each resource may offer reflects the marginal resource adequacy value it provides (e.g., derated from nameplate to the extent a resource is unavailable due to outages or intermittency). Each participating resource then provides an offer in terms of dollars per MW of **qualified capacity**, and the **supply curve** is formed by arraying the supply offers in ascending order.

Offers may be capped by the market monitor to mitigate the exercise of market power. Market power is endemic to capacity markets (and to energy markets during tight supply conditions) because available supply typically exceeds demand by small margins, such that even medium-sized suppliers could withhold capacity profitably, unless required to offer competitively. Competitive offers would reflect resources' net avoidable going-forward fixed costs after considering net revenues from selling energy and ancillary services.[1] In the long run, wholesale market revenues should be sufficient to recover the long-run marginal cost of capacity, including fixed costs. However, once certain fixed investment costs have been incurred, competitive market participants should exclude these costs from their offers (as they would be incurred regardless of receiving a CSO, so they are not marginal or additional). Resources' non-avoidable costs will tend to be recovered when higher-cost capacity clears the market.

The auction itself brings together the ascending supply and the descending demand curve in order to clear the market. The auction clears at the point where the supply and demand curves intersect. That clearing point determines which resources clear and accept a CSO—all those with offers at or below the clearing price.

The capacity auction must take place prior to the delivery period. Other jurisdictions vary considerably in how far ahead they conduct the auction. For Singapore, we propose a four-year forward period, corresponding to the lead-time for constructing a new combined cycle gas

1 Net avoidable going-forward fixed costs are net costs that a resource could avoid if it did not have a capacity supply obligation. It is important to note that mothballing or retiring a generation resource may not avoid all fixed costs. For example, a take-or-pay fuel contract may be considered a fixed cost that cannot be avoided by a retirement or mothball decision. In addition, property taxes and some insurance may be unavoidable for plants that mothball. Overall, any costs that are unavoidable would not vary depending on whether the plant stays online, and the capacity payment does not need to cover those costs in order to be willing to stay online.

turbine (CCGT). This enables new generation to compete with existing resources. Such advance commitment also resolves uncertainties regarding the potential retirement of existing supply in time for new generation capacity to replace it. Subsequent to the forward auctions, rebalancing auctions would be held nearer to the delivery year to efficiently address changes in demand requirements or supply availability.

Our initial proposal for each market design element in the FCM is presented in Table 1. Each element is discussed in more detail in the subsequent sections.

Table 1: Overview of FCM Market Design Proposal

Market Design Element	Preliminary Design Straw Proposal	Justification
Product Definition	• 1 MW-year of unforced **capacity supply obligation (CSO)**; "qualified capacity" (QCAP) reflects expected availability, as addressed below. • A CSO entails a requirement to supply energy and/or ancillary services when needed, subject to penalties for being unavailable or otherwise not performing.	• Product definition must correspond to the MW "demand" for resource adequacy. • Product must have clear obligations consistent with reliability objectives.
Administrative Demand Curve	• Demand reflects the **peak load forecast plus required reserve margin** corresponding to the reliability standard (3 Loss of Load Hours). • **Downward-sloping demand curve** with the quantity at the price cap set to the minimum acceptable reliability level, then sloping downward to the right; rest of the curve tuned to achieve acceptable distribution of reliability and price outcomes under an assumed Net Cost of New Entry (CONE).[2] • **Price cap** established between 1.5x and 2x estimated Net CONE; to consider a minimum on the cap set to 0.25× to 1× estimated Gross CONE to protect against Net CONE estimation error. • **Comprehensive review of CONE, energy and ancillary services offset[3], and demand curve parameters** periodically. • Implement **annual updates** based on a formulaic approach. Update Gross CONE based on available public index, energy and ancillary service offset with most recent historical or futures-based market price data, and demand curve parameters with new load forecasts and reliability analysis.	• The objective is to meet the reliability standard. • A downward-sloping demand curve reduces price volatility, and recognizes incremental marginal reliability value at varying reserve margins. • Cap must be high to express higher marginal value at low reserve margins, to mitigate the possibility of underestimating true Net CONE, and to shift the distribution of reserve margin outcomes rightward without paying high prices for excess capacity. • Net CONE parameters need to be adjusted to market conditions. • Demand curve performance needs to be evaluated in relation to design objectives (reliability, price rationality, price stability, and regulatory stability).
Supply Participation	• **Technology-neutral** design to qualify all resources that can contribute to resource adequacy, incl. demand response, imports, storage; both existing and new. • **Qualified MW ratings** account for unplanned and planned outage rates, intermittency, and energy-limits (applicable to storage & demand response). • **Supply curve** aggregates all supply offers in ascending order.	• Technology-neutral approaches will maximize efficiency, competition, and innovation. • "QCAP" is a uniform product, with all MW competing to provide the same marginal reliability value.
Market Power Monitoring and Mitigation	• **Market Power Mitigation** – All existing resources must offer capacity.	• Must-offer requirement and mitigated offers prevent supply-side market power abuse (buyer-

2 Net CONE is an administrative estimate of the long-run marginal cost of capacity ($/kW-year) from a reference resource based on the generation technology most likely to enter the market. It includes capital recovery plus the fixed and variable operating costs of operation for a new resource, net of expected revenues received from the energy and ancillary services markets.

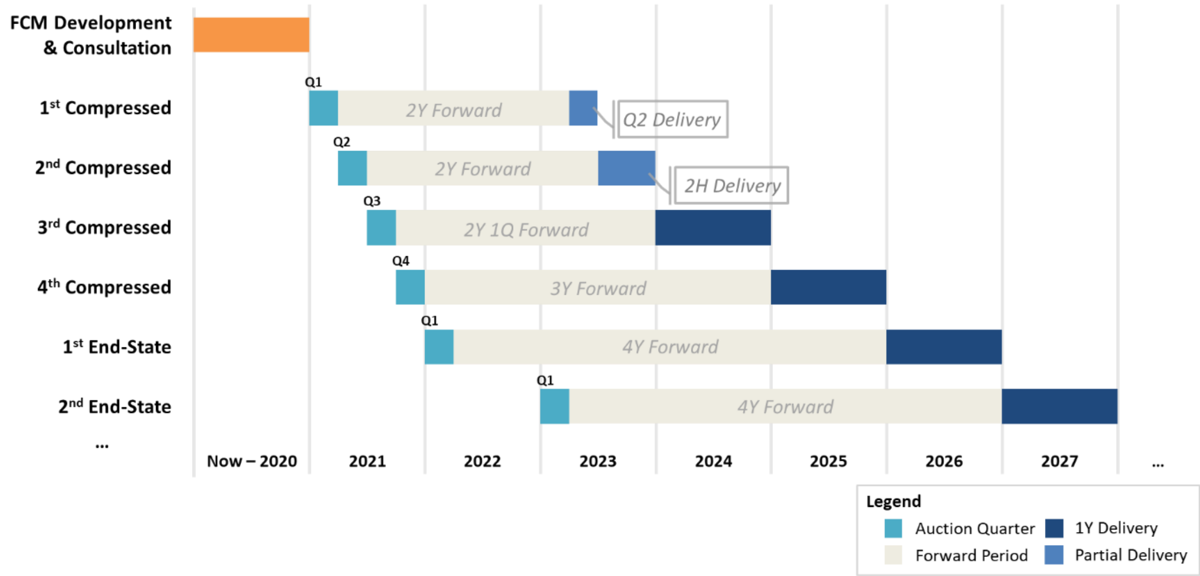
3 The energy and ancillary services (E&AS) offset reflects the expected net revenues (or revenues minus variable costs) that the resource would earn from participating in the E&AS markets.

(Next Round)	– Screen suppliers to detect supply-side market power, and mitigate offer prices of those that fail (to net avoidable going-forward costs).	side market power abuse unlikely in Singapore).
Forward Capacity Auction	• **Uniform price auction** whereby all cleared suppliers earn the same price. • **Single round, sealed bid** auction. • **Four-year forward period**. • Considering options regarding single-year vs. multi-year commitment.	• Uniform price, single-round, sealed-bid auctions maximize competition; has a proven record of delivering efficient market outcomes. • Multi-year price assurance may support new entry, but may have certain disadvantages.
Rebalancing Auctions *(Next Round)*	• **Rebalancing auction(s)** conducted between the base auction and delivery period. • **Supply offers** would include: – Any capacity without an existing supply obligation from base auction. – Excess capacity procured by central buyer in base auction that is not needed due to an updated (lower) load forecast. • **Demand bids** would include: – Any incremental needs by the central buyer to meet updated (higher) load forecast. – Any capacity with a CSO that wishes to buy out of its obligation.	• Provides an opportunity to adjust capacity commitments with demand changes and/or changes in availability.
Bilateral Transactions *(Next Round)*	• Enable buyers and sellers to engage in bilateral exchange of CSOs post-auction.	• Facilitate market participants in managing their own risks and uncertainties.
Supply Obligations and Performance Penalties *(Next Round)*	• Suppliers are obligated to demonstrate availability consistent with their obligations, and face penalties for under-performance. • Penalty rates will be high enough to incentivize performance (but not so high as to impose undue costs that discourage participation).	• An appropriate penalty system will ensure capacity obligations are appropriately fulfilled and supply is available during shortage conditions.
Settlements and Cost Allocation	• Costs allocated to consumers in proportion to their consumption during peak hours on non-holiday weekdays of the year.	• Consumption during these hours drives the need for capacity, and cost allocation should reflect cost causation.
Reforms to Energy, Ancillary Services *(Next Round)*	• Consider conforming changes to the energy and ancillary services (E&AS) markets, including potentially mitigating energy offers more strictly to reflect competitive outcomes.	• Emulates a perfectly competitive market; no need to allow exercise of market power (and associated inefficiencies) since the FCM supports recovery of fixed costs. • Additional ancillary products, if necessary, provide revenues to resources that supply ancillary services needed for reliable operations.

Implementation Timeline

Brattle and EMA have jointly developed a proposed timeline for rapidly developing and implementing the proposed FCM. The first auction is scheduled for Q1 2021 and has a "compressed" two-year forward period and one-quarter delivery period. Both the forward period and delivery period gradually extend over time until reaching the end-state design of a four-year forward period and one-year delivery period, as illustrated in Figure 1. This design allows for the shortest possible implementation timeline and earliest commencement of capacity commitments.

Figure 1: Implementation and Transition Timeline to Full FCM



II. Product Definition

The product definition specifies exactly what each resource in the market is obligated to provide if it clears the auction. Consistent with the concept of "capacity," the product should be 1 MW of capacity supply obligation (CSO) for a year. A CSO requires the resource to offer into the spot energy market (and/or ancillary services markets) when available, subject to penalties for unavailability and non-performance. (Section XI provides more specifics on the obligations and how they relate to Singapore's energy market design.)

We recommend defining the capacity product such that each unit of capacity transacted represents a MW of capacity, normalized for expected unavailability. In reality, all resources are affected by planned and unplanned outages and for other reasons that they cannot always produce at their full capability, so the amount of capacity they qualify to sell will generally be lower than their installed capacity. Thus, each MW of qualified capacity will have the same reliability value per MW as another MW of qualified capacity. The discrepancy between installed capacity and qualified capacity accounts for each resource's outage rates, intermittency, and other factors affecting reliability value, as described in Section IV. The qualified capacity naturally forms the basis for any performance penalties, discussed in detail in Section IX. This creates a uniform product for which all resources can compete and be compensated fairly, and be accounted for appropriately when procuring capacity to meet the reliability objective.

In general, capacity products could be more multi-faceted and varied to specify certain sub-products with specific characteristics (such as fast-start capacity), locational products, seasonal or time-of-day products. We recommend adopting a simpler approach with an annual product with no locational requirement and no additional specifications.

This relatively simple-product proposal is suitable for the supply and demand dynamics in Singapore's electricity market:

- Locational capacity differentiation is not recommended at this time due to limited persistent transmission constraints during peak conditions that would preclude a unified market for capacity. This design choice can be re-evaluated in the future.
- Seasonal capacity product differentiation is unnecessary because load and supply availability do not differ greatly across the year.
- Resources clearing the auction will receive the obligation to supply capacity for a pre-defined period, the "commitment term." A commitment term of one year is consistent with other international jurisdictions; a shorter commitment term would not provide sufficient revenue certainty and a longer commitment term could disadvantage resources that are not able to commit to a longer period.[4]

If certain resource characteristics are absolutely needed to operate the system, one option is to specify the need for them as sub-products in the capacity market. But if those characteristics are merely more valuable or convenient than substitutes (such as fast-start vs. spinning reserves) then we recommend recognizing that value only in the ancillary services markets and/or in capacity ratings, rather than specifying sub-products for capacity. This avoids inefficiently biasing the resource mix and complicating the mechanics for resource qualifications.

III. Administrative Demand Curve

The capacity market demand curve establishes demand for capacity to reflect the willingness to pay at each quantity of capacity. The capacity demand curve is designed to meet a range of objectives (discussed below), with its primary objective being to procure sufficient capacity to meet forecasted peak load plus the reserve margin required to meet the reliability standard. The determinants of a demand curve include:

- **Reliability Standard:** The quantity points of demand curve are established based on the reliability standard needed to maintain reliable operation of the electricity grid. Singapore's reliability standard is a minimum acceptable reliability of 3 Loss of Load Hours (LOLH) measured relative to the applicable load forecast; the demand curve must be designed consistent with meeting this standard even under variable supply/demand conditions.
- **Net Cost of New Entry (Net CONE):** The demand curve pricing points are based on Net CONE, which is the estimated long-run marginal cost of supply or the price needed to attract new resources when they are needed. We recommend a

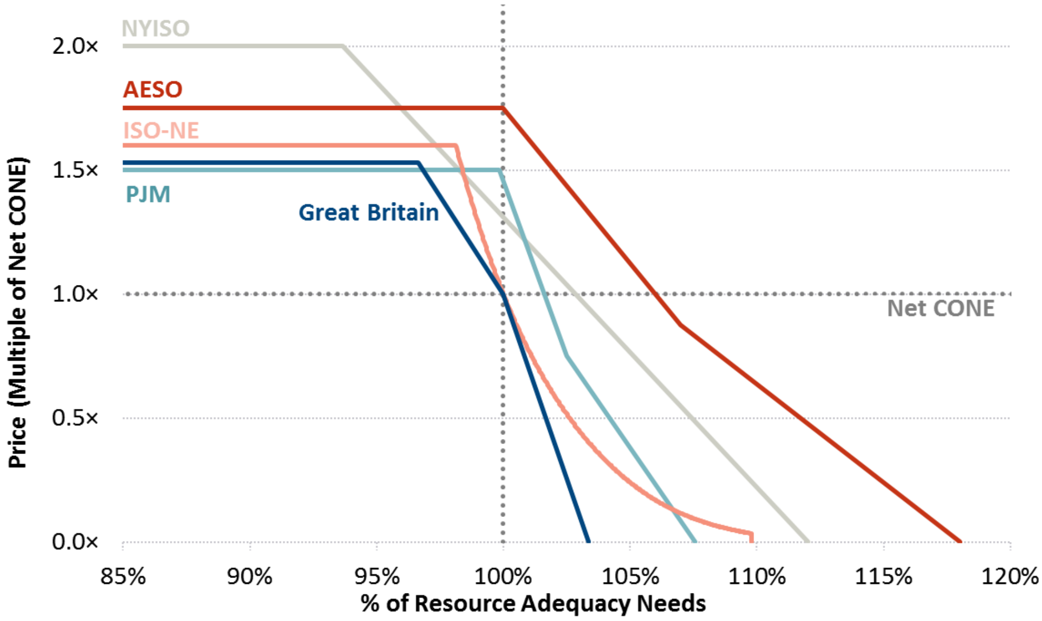
[4] However, the EMA may wish to consider allowing some suppliers to lock-in their clearing price for a period of multiple years to improve investment incentives in the market; this is discussed in more detail in Section VI.C.

transitional Net CONE parameter that takes as a starting point the similar parameter developed for a CCGT for the purposes of vesting contract parameters.

- **Demand Curve Shape:** Most other jurisdictions have developed downward-sloping demand curves because they offer a number of reliability, pricing, and competitive advantages over vertical curves or other alternatives. Downward-sloping curves are indexed to the reliability standard and Net CONE, with carefully specified shape, placement, and parameters such as price cap, quantity at the cap, slope(s), width, and x-intercept. All such choices impact the FCM auction outcomes, including the amount of capacity procured, reliability, consumer cost, and price volatility. To develop a curve that is best suited to Singapore's objectives (see below) and unique circumstances, we recommend proceeding to develop a downward-sloping curve and tailoring the specifics to Singapore's market conditions. We plan to conduct a study of anticipated FCM auction outcomes on reliability and price volatility, in order to evaluate a range of candidate curves.

Figure 2 below illustrates a variety of demand curves used across other markets, illustrating that a range of demand curves can be workable.[5] Each of these curves is tailored to their specific market conditions.

Figure 2: Demand Curves in Other Markets



Sources:
PJM Interconnection, "2021/2022 RPM Base Residual Auction Planning Period Parameters," February 2018.
ISO New England, "Forward Capacity Market (FCA 12) Result Report," May 2018.
New York Independent System Operator, "ICAP Translation of Demand Curve (Summer 2018)," March 2018.
Spees, Kathleen, et al., "Alberta's Capacity Market Demand Curve," Prepared for AESO, January 2019.
McNamara, Fergal, "Capacity Market," United Kingdom Department of Energy & Climate Change, June 25, 2014.

---

5 Although Alberta ultimately decided not to pursue a capacity market, the Alberta Electricity System Operator (AESO) had previously developed a detailed market design. This report thus includes information on their design choices, analysis, and rationale where useful.

A. Principles and Best Practices

The primary objective of a demand curve is to support reliability by appropriately reflecting the reliability requirement, in addition to other objectives described in Table 2 below. Brattle is conducting a study to develop specific demand curve parameters that are consistent with these objectives while balancing trade-offs of reliability, consumer cost, price volatility, and quantity volatility. Some curves will be ruled out based on the inability to meet these objectives (i.e., those that do not meet the primary objective of delivering reliability); however, there will be a range of workable demand curves that align with these objectives. Brattle will inform the tradeoffs between steeper curves (that provide smaller risk of over-procurement, more quantity certainty, and lower consumer costs) and wider curves (that provide lower price volatility and reduced exercise of market power).

Table 2: Overview of Singapore Demand Curve Design Objectives

Design Objective	Description
Primary Design Objective: Deliver Reliability	• The demand curve should attract sufficient supply to meet the reliability standard of 3 LOLH expressed in QCAP terms. This is interpreted as a "minimum acceptable" reliability level
Send Efficient Price Signals	• The demand curve should send efficient price signals to attract entry when the market is short, and discourage entry when the market is long
Minimize Consumer Costs	• The demand curve should ensure reliability but avoid over-procurement relative to target capacity
Mitigate Price Volatility	• The demand curve should reduce price volatility impact from small changes in supply and demand • The demand curve should reduce the impact of lumpy entry/exit on market outcomes
Mitigate Susceptibility to Market Power	• The demand curve should complement market power mitigation mechanisms to limit structural susceptibility to market power
Reflect Singapore's Unique Market	• The demand curve design should account for unique characteristics of Singapore's market (e.g., smaller market size)

The three main approaches to designing a demand curve are described below and illustrated in Figure 3 (note that the figure is schematic; for example, some of the jurisdictions' demand curves that are characterized as "downward-sloping" are actually curved or kinked, even though it appears as a straight line):

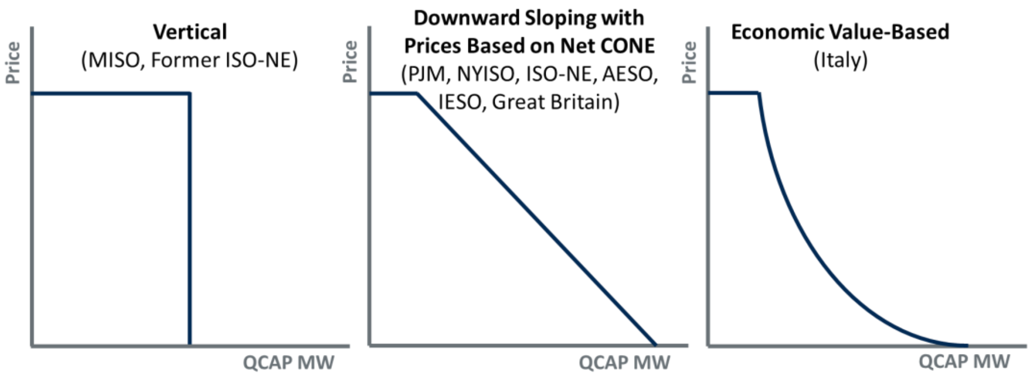
1. **A Vertical Demand Curve** establishes the exact quantity of capacity that is needed based on the reliability standard.[6]
2. **A Downward-Sloping Demand Curve with Prices Based on Net CONE** is designed around the reliability standard and estimated long-run marginal prices at Net CONE.

[6] Although MISO still uses this simple approach, the Independent Market Monitor has recommended implementing a sloped demand curve. This is being considered as part of a suite of issues in the 2020 MISO Integrated Roadmap. See MISO, "Sloped Demand Curve in the Capacity Market (IR084)," 6 November 2019. Available at: https://www.misoenergy.org/stakeholder-engagement/issue-tracking/sloped-demand-curve-in-the-capacity-market/.

3. **A Marginal Economic Value-Based Demand Curve** is based on a probabilistic analysis of marginal system costs at varying reserve margins. At each reserve margin, the analysis estimates the value of lost load, the cost of emergency actions, and production costs. From that cost function, one can derive the demand curve as the marginal change in cost per MW of change in reserve margins. The shape of such a curve is convex to the origin, with diminishing marginal value as reserve margins increase.

None of these approaches will directly set the capacity price; that is done in combination with the supply side as resources represent the marginal cost of meeting demand in the near and long term.

Figure 3: Approaches to Determining Capacity Demand Curve (Adopted or Proposed)



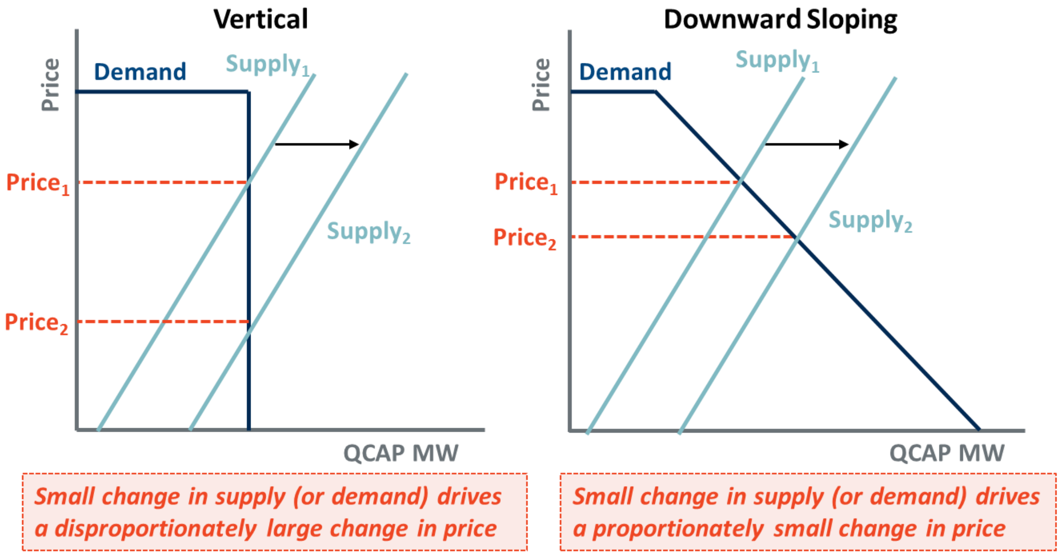
The advantage of a **vertical demand curve** is that it is simple, but that simplicity comes at the expense of greater price volatility and susceptibility to the exercise of market power because small changes in supply or demand quantities can result in significant price swings.[7] It also fails to recognize any marginal value beyond the reliability target. These and other disadvantages of the vertical demand curve drove ISO-NE to switch to a downward-sloping demand curve in 2015.[8]

The **downward-sloping demand curve** with prices tied to Net CONE is most closely aligned with the primary objective of meeting the reliability standard. This design provides price signals that support the reliability standard by increasing prices to reflect the higher reliability value of supply as the reserve margin tightens and decreasing prices when the market has excess supply. In addition, compared to a vertical demand curve design, small changes in supply and demand do not create such large changes in prices and limit price volatility, as illustrated in Figure 4.

7 A vertical curve would also have to be shifted to the right of the minimum reserve margin in order to meet the same reliability outcomes as a downward-sloping demand curve (as some years the auction may clear at the cap and yield unacceptable reliability otherwise).

8 See ISO-NE, "FCM Sloped Demand Curve Key Project." Note that ISO-NE first switched to a linear downward-sloping curve, then transitioned to a convex "relative value-based curve" that is shaped like the economic value-based curve but is fundamentally still a downward-sloping curve indexed to the reliability standard and Net CONE, hence its characterization in as such in Figure 3.

Figure 4: Illustrative Price Clearing Outcome with Change in Supply



The **marginal economic value-based curve** is grounded in economic value and enables the capacity auction to either maximize consumer benefit or to maximize economic efficiency. It can procure the economically optimal quantity of capacity, clearing a higher optimum reserve margin under conditions where the marginal cost of capacity is low (when there is excess supply or there are low-cost sources of new capacity); or it will clear at a lower optimum reserve margin when capacity is scarce. While this may lead to lower consumer costs, it does not necessarily meet traditional reliability standards.

Recommendation for Singapore: we recommend focusing on a downward-sloping demand curve with price points tied to Net CONE. Downward-sloping curves mitigate the price volatility experienced with a vertical demand curve but introduce some quantity uncertainty. The balance between price and quantity certainty can be managed by adjusting the slope and shape of the curve.

B. Reliability Standard

We understand that EMA has established a reliability standard of no more than three expected Loss of Load Hours (LOLH) in the delivery year.[9] This is defined as the minimum acceptable reliability level for the Singapore market, meaning that the quantity procured from the capacity auction needs to be at or above this level as illustrated in Figure 5 below.[10] This quantity will be translated into the equivalent QCAP procurement volume, which is discussed in more detail below in Section IV.

---

9 The reserve margin, corresponding to 3 LOLH, may fluctuate over time as fleet and load characteristics evolve.

10 Figure 4 shows the asymmetrical relationship between the reserve margin and LOLH. As shown in the figure, LOLH outcomes deteriorate at reserve margins below the reliability standard, and improve at reserve margins greater than the reliability standard.

Achieving the reliability standard is the primary design objective that should be incorporated into the demand curve design, and used to establish the quantity points of the demand curve. In particular, the quantity of capacity supply at the price cap is often set to the minimum acceptable reliability level; for Singapore this means the quantity at the cap should be set to 100% of the reliability standard. We recommend this approach in order to ensure that the capacity auction clears all available in-market supply through the demand curve, before resulting in any shortfall relative to the T-4 demand forecast.[11] This will help to align the demand curve with the reliability objective and minimize or eliminate the possibility of any out-of-market interventions.

Figure 5: Illustrative LOLH Curve

C. Net Cost of New Entry

The pricing points on the downward-sloping demand curve will be based on the Net CONE, reflecting the long-run marginal cost of capacity. Net CONE is an administrative estimate of the long-run marginal cost of capacity based on the reference technology most likely to enter the market. Tying pricing points to Net CONE enables the demand curve to adjust as needed to remain consistent with market conditions and the cost of attracting enough supply to meet the reliability standard. The rules will include an approach to establish the follow parameters for developing the Net CONE:

- **Reference Technology** that is the assumed marginal resource type that will be attracted into the market;
- **Gross CONE** reflecting the total annual capital costs, ongoing fixed costs, and financing costs required to bring a resource online, after levelizing these costs over the economic asset life;

11 Note that clearing below the minimum reserve margin in the T-4 base auction is not equivalent to breaching the reliability standard in the delivery year as: (a) in the forward period, the load forecast may decrease or more capacity can be procured in a later rebalancing auction, or (b) the EMA may pursue out-of-market options to secure sufficient capacity.

- **Energy and Ancillary Services (E&AS) Offset** reflecting the expected net revenues (or revenues minus variable costs) that the resource would earn from participating in the E&AS markets; and
- **Approach to Updating Net CONE** over time, including a formulaic approach for updating the parameter for each calendar year and a more comprehensive review of the parameter periodically (as discussed in Section III.E below).

Estimating Net CONE at the present time of market transition poses several challenges given that future market outcomes should not be expected to be similar to recent history. The introduction of a capacity market and any concurrent changes to the energy market could change the estimated value of Net CONE (especially the E&AS offset), the effects of which will not be observed through energy market prices or participant behavior until after a few years' experience with the new market. The market rules may therefore adopt two different approaches to estimating the Net CONE. First, we recommend the market incorporate a Transitional Net CONE parameter to be used in the early years of the FCM auction with a compressed forward period (applicable to delivery years 2023-2025). For delivery year 2026, the Net CONE can be updated in a periodic study using a methodology as prescribed in the market rules. In both cases, the goal of the Net CONE estimate will be the same: to develop an unbiased estimate of the price needed to attract new supply into the market, subject to any limitations of unresolvable estimation uncertainties.

Table 3 below summarizes the approaches adopted in other capacity markets to estimate and update the Net CONE parameter. We discuss the merits of the various approaches in the following subsections as applied in the Singapore context, both during the market transition and in the long term.

Table 3: Approaches to Estimating Net CONE in Other Capacity Markets

	PJM	New England	New York	Ontario *(Proposed)*	Great Britain	Alberta *(Cancelled)*
Reference Tech	Frame 2x1 Gas Combustion Turbine (CT)	Frame CT	Frame CT	Aero CT, Frame CT, CCGT, Battery storage	CCGT	Aero CT, Frame CT, CCGT
Gross CONE	Capital, fixed & financing costs, level nominal	Bottom-up engineering costs, level real	Bottom-up engineering costs, level real	Capital, fixed & financing costs	Bottom-up engineering costs	Capital, fixed & financing costs, level nominal
E&AS Offset	Three-year historical average simulated	Forward looking prices derived from simulation of future energy market revenues	Simulation of revenues using rolling three-year historical locational energy and reserve price average, with adjustment	Forward looking market methodology	Forward looking multi-year dispatch simulation	Forward looking approach, dispatches reference technologies against a forecast of hourly market prices
Annual Net CONE Updates	CONE: based on weighted index E&AS: three-year rolling average	CONE: escalating cost components and revenues offsets according to indices E&AS: annual updates to reflect futures prices	CONE: updates based on single state-wide technology specific escalation factor	CONE: updated based on weighted average of public indices E&AS: annual update	CONE: updated regularly based on electricity prices	CONE: prior to each subsequent capacity auction based on applicable cost indices
Periodic Reviews	Full CONE study and methodology review every four years	Full re-evaluation of Net CONE every three years	Full review of reference resource, Gross CONE and demand curve every four years	Full review every three years	Net CONE and reference technology annually reviewed	Update estimated CONE values every four to five years

Sources: PJM: Review of PJM 's Variable Resource Requirement Curve; New England: ISO NE Filing of CONE; New York: NYISO Order Accepting Tariff Filing; Ontario: IESO Incremental Capacity Auction High-Level Design; Great Britain: Setting Capacity Market Parameters; Alberta: AESO Calculation of Demand Curve Parameters

Reference Technology

Net CONE is the estimate of the long-run marginal cost of capacity, or the average capacity price that should prevail in a long-run equilibrium condition when market entry is needed to support the reliability standard. The reference technology used as the basis for estimating Net CONE should therefore be a resource that is most likely to be attracted into the merchant capacity market. We anticipate that a wide variety of resource types will be likely to participate and clear in Singapore's capacity auction including existing and new gas-fired generation plants, solar photovoltaics, battery storage, demand response, and others. By definition, all of these cleared resources can be considered an economic portion of the resource mix, but some resource types would be more appropriate than others to adopt as the reference technology for estimating the administrative Net CONE.

The most appropriate resource type to select as the reference technology should:

- **Be economic to build when new capacity is needed.** The reference technology should be one that developers are likely to build when new supply is needed in the market. The determination of which technologies are likely to be economic in the long-run equilibrium can be determined by estimating the Net CONE across multiple technologies and identifying the least cost, and supplementing this with evidence of commercial interest through recent developments and proposed projects.
- **Be feasible to develop given anticipated technical limitations and regulations.** The reference technology should be a technically feasible and proven technology, ideally as demonstrated through widespread adoption and development. The technology cannot be prohibited through any legal means, such as environmental regulations that might prevent the development of power plants without proper emissions controls.
- **Be possible to build in relatively large quantities at uniform cost.** The reference technology should be a resource type that could be developed in large quantities at relatively similar prices. This criterion rules out certain resource types that may be limited in their total available quantity, such as unique projects that face idiosyncratic circumstances (e.g., demand response, and cogeneration projects), and thus would not be appropriate to adopt as a reference technology.
- **Be possible to estimate costs with relatively low uncertainty.** The Net CONE of the reference technology should be possible to estimate with as much accuracy as possible. This criterion introduces a preference to use the costs of a better-known technology type with more available data on costs and anticipated revenues. However, even for well-known technologies it may be challenging to calculate the parameter within +/-20% accuracy.

Other markets have applied these or similar criteria with differing emphasis depending on their unique circumstances, and have ultimately chosen either CCGT or open-cycle plants as the most appropriate reference technologies (as summarized in Table 3). The Ontario market operator has also proposed to consider battery storage alongside other options as the potential reference technology; batteries may become a more relevant resource type to consider in regions that are aiming to phase out fossil fuel plants as part of their supply mix.

In Singapore, we recommend applying these principles to select the reference technology for both the transitional Net CONE parameter, as well as re-evaluating the reference technology in periodic reviews (see Section III.E below). In both cases, this evaluation should consider the best available data on resource costs, recent and anticipated net market revenues, recent project developments, and proposed developments.

Gross CONE

The Gross CONE parameter should reflect the annualized costs associated with building and maintaining the reference technology. The development of the Gross CONE in other markets is typically calculated through an independent bottom-up engineering cost study accounting for the following components:

- **Overnight capital expenditures** necessary to construct the plant including project development, permitting, engineering, procurement, construction, labor, materials, major equipment, transmission interconnection, gas pipeline interconnection, backup or onsite fuel storage (if relevant), the expected value of contingencies, taxes, capitalized inventories, working capital, and interest during construction.
- **Annual fixed operations and maintenance costs** necessary to maintain the plant on an ongoing basis over the asset's life including labor, asset management, regular maintenance, major overhauls, the firm/fixed portion of any fuel contracts (excluding any variable fuel costs), property tax, and insurance. These costs would exclude any variable costs that are anticipated to be incurred on an incremental basis as a function of how often the plant runs (such as start-up and variable running costs).
- **Financing costs** necessary to serve debt and equity. The financing cost analysis would consider the after-tax weighted-average cost of capital (ATWACC) consistent with attracting merchant power investments in Singapore, the relevant tax rate that would be applied to any earnings, and the asset's anticipated economic life.

Bringing this to the Singapore context, the Gross CONE parameter is essentially the same number as the long-run marginal cost parameter developed for the purposes of setting vesting contract prices.[12] That vesting parameter analysis has been developed for a different purpose, but is similar enough and recent enough that we recommend considering whether it would be appropriate to adopt the same or a slightly adjusted parameter for the purposes of establishing the transitional Net CONE parameter for the capacity auction. This approach would have a number of advantages including expedience, simplicity, transparency, and familiarity to market participants, but limits the selection of the reference technology to only consider a CCGT. For the initial auctions, we recommend using this vesting price parameter for Gross CONE, as suggested by several stakeholders. In periodic future reviews, we would recommend developing a comprehensive bottom-up engineering cost study (of multiple potential reference technologies) in order to ensure that the parameter can evolve with market conditions.

Energy and Ancillary Services Offset

The E&AS offset is a parameter used to calculate Gross CONE and reflects the expected net revenues (or revenues minus variable costs) that the reference resource would earn from participating in the E&AS markets. There is no single, commonly accepted approach for estimating the E&AS revenue offset given the unique issues of data availability, market context, and underlying uncertainties that affect each market region. However, there are some useful

12 These parameters are developed by the EMA to calculate the vesting contract level and vesting payments to gencos with vesting contracts. See EMA, "Review of the Long Run Marginal Cost Parameters for Setting the Vesting Contract Price for 2019 and 2020," 26 November 2018. Available at: https://www.ema.gov.sg/cmsmedia/Final%20Determination%20Paper_Review%20of%20Vesting%20Parameters%20for%202019%20and%202020.pdf

underlying principles that can be used to develop a reasonable approach for any market. To the extent possible, the approach should:

- Be an accurate representation of expected net revenues for the reference technology (considering expected average revenues across weather-driven and other uncertainties);
- Be simple, replicable, and transparent, using trusted and reliable sources and procedures;
- Reflect future market conditions and/or market equilibrium conditions as currently perceived; and
- Be validated against the historical net revenues earned by representative existing units that are similar to the reference technology.

These principles should be interpreted as an ideal to strive toward. However, data limitations, uncertainty surrounding the market outlook, and trade-offs among these principles make it challenging to achieve all of these outcomes simultaneously. Key choices and considerations include the following:

- **Observed Net Revenues vs. Simulated Dispatch:** Estimated E&AS margins can be derived from those of representative existing resources historically observed in the marketplace. This approach can be simple and straightforward, but requires a sample of representative generating resources, is backward looking, and tends to be more volatile compared to forward-looking approaches. Alternatively, E&AS margins can be estimated based on a simulated dispatch of the particular reference technologies. This approach allows reference resources to be dispatched against either historical or future prices, and the method of dispatch simulation can take different levels of complexity. Both backward- and forward-looking approaches using a simulated dispatch can be further validated by comparing to the observed outcomes for representative existing plants.
- **Historical vs. Future Market Prices:** E&AS margins can be estimated based on historical or future market prices for E&AS. Historical prices can be readily observed but can be volatile and do not capture expectations about the future. Futures-market-based prices are observable, and when based on liquid futures markets, provide a reasonable reflection of market participants' expectations for near-term (and weather-normalized) changes in market fundamentals. Near-term futures (1-year forward) can be used as a proxy for longer-term futures as they will account for some, but not all, of the changes in market conditions going forward. Forecasts of future prices derived from market simulation models can explicitly incorporate expectations about the future, but developing price forecasts through market simulation models (1) requires agreement on reasonable simulation assumptions, (2) can be very sensitive to modelling inputs and assumptions, and (3) are often less transparent to market participants.

Each of these approaches offers advantages and disadvantages that usually depends more on local context, such as data availability and current market conditions, than underlying principles. For example, historical approaches may provide simpler, more transparent, and more replicable means of estimating the E&AS revenue offset, even if a forward-looking methodology is otherwise desirable. In practice, most approaches utilized in other regions with capacity markets apply a blend of forward- and backward-looking features. Therefore, there is not a consensus on the best practices approach to estimating E&AS, as illustrated by the variety of approaches adopted in other markets as summarized in Table 4.

Table 4: Method to Estimate E&AS Offset in Other Jurisdictions

Market	E&AS Methodology
PJM	• Three-year average of simulated E&AS values based on virtual dispatch against historical hourly prices • Calculated zonally to get a zone-specific Net CONE
ISO-NE	• Simulate future energy revenues over 20 years using a market pricing model to develop a price forecast and using a dispatch model to estimate revenues
NYISO	• Simulation of revenues using rolling three-year historical market prices and reserve prices, fuel and emission prices, and variable operations and maintenance costs
IESO *(Proposed)*	• Forward-looking market methodology to estimate E&AS offset reflecting the expected market fundamentals that will affect revenues available to the reference resource
AESO *(Cancelled)*	• Forward-looking methodology, assuming a stand-alone resource which assesses options to maximize its offset • Would initially exclude ancillary service revenues

For the Singapore market context, we recommend proceeding with an analysis to assess the likely E&AS offset that would be produced from both historical data and future simulations to inform the most appropriate number to use for the transitional Net CONE estimate.

In the long term, we recommend annual formulaic updates to Net CONE in addition to conducting a full Net CONE study every few years based on updated data. This study would result in a recommended E&AS offset estimate and methodology for performing annual formulaic updates to reflect evolving supply/demand conditions. See Section III.E for further discussion on demand curve review and updates.

D. Demand Curve Parameters

Long-term performance of the capacity market relative to the objectives is ultimately determined by how all aspects of the demand curve design jointly support reliability by supporting prices that attract entry when needed. No individual aspects of the demand curve will determine performance alone. Below in Figure 6 we illustrate the key design parameters, including price cap, quantity at the cap, width and steepness, and shape, each of which has different design considerations:

- **Price cap** defines Singapore's maximum willingness to pay for in-market supply and is often set at a multiple of Net CONE. During tight supply conditions as LOLH increases above target, the reliability value of additional resources exceeds the long-run marginal cost. As a result, market operators should be willing to pay substantially above Net CONE to procure supply under these tight market conditions. This also allows for high price outcomes that can offset low prices during surplus market conditions such that investors can earn Net CONE on average over the long run. In other markets, the demand curve price caps range from 1.5× Net CONE to around 2× Net CONE.[13] High price caps are generally associated with less out-of-market intervention, and less reliability risk from underestimating Net CONE, but also tend to result in higher price volatility and are more susceptible to exercise of market power. We recommend Singapore's demand curve have a price cap in the range of 1.5× to 2× Net CONE. We will also consider a backstop minimum price cap of 0.25× to 1× Gross CONE to prevent estimation error from artificially collapsing the price cap and the entire demand curve, should the estimated E&AS offset be close to estimated Gross CONE.

- **Quantity at the cap** determines the level of supply at which prices reach the cap. This quantity should be greater than or equal to the minimum acceptable reliability in order to ensure all in-market supply is procured before any out-of-market backstop procurements are considered. Across some (but not all) other markets, the quantity at the cap is set to the minimum acceptable quantity.[14] We recommend setting the quantity at the cap equal to Singapore's minimum acceptable quantity corresponding to 3 LOLH, given that this reliability standard is a minimum that should be met each year.
- **Demand curve width and steepness** affect performance metrics such as average reliability outcomes, price volatility, opportunity for the exercise of market power, and consumer costs. Wider and flatter curves generally mitigate the opportunity to exercise market power and lead to outcomes with lower price volatility, but also may lead to more over-procurement of supply and produce higher quantity uncertainty, which could lead to higher consumer costs. Tighter and steeper curves generally reverse these trade-offs. In a small market such as Singapore, a relatively wider curve may be needed so that entry or exit of one resource does not introduce extreme price volatility or susceptibility to market power.
- **Demand curve shape** ranges in complexity from vertical curves (MISO) to downward-sloping straight-line curves (NYISO), to two-part convex kinked curves (PJM, AESO), to smoothed multi-point curves (ISO-NE), and to two-part concave curves (Great Britain, prior PJM). Vertical curves are simple to implement, but they suffer from extremely high price volatility and susceptibility to exercise of market power. Straight-line curves are also relatively simple to implement while typically resulting in good price volatility outcomes. Convex curves are slightly more complicated to implement but are more consistent with diminishing reliability value of incremental supply. Concave curves help to mitigate price volatility but may understate the value of reliability at high reserve margins. We recommend testing straight-line, two-part convex, and two-part concave curves for Singapore's

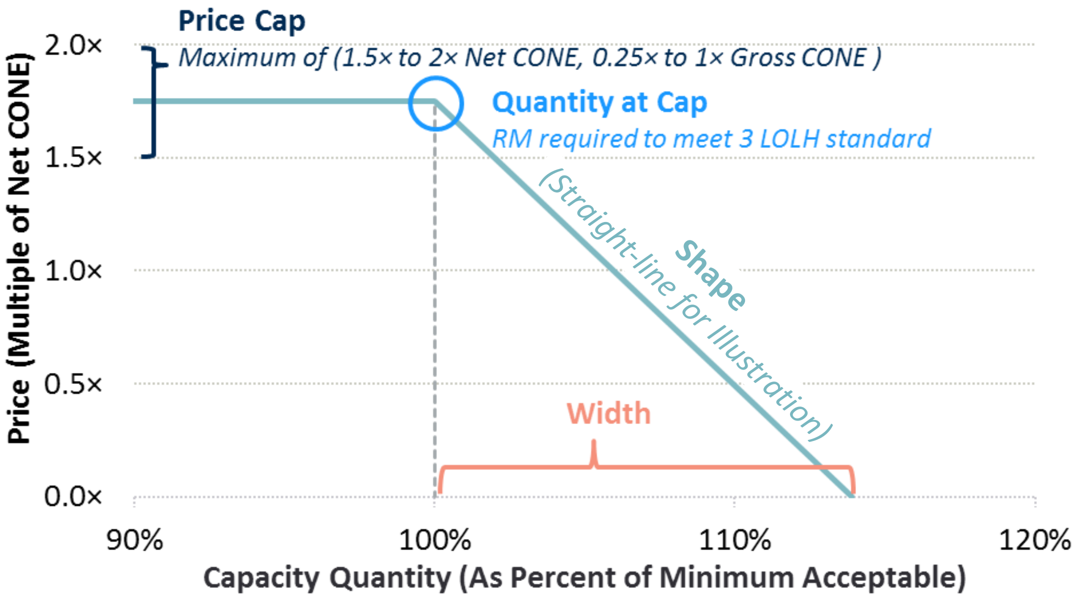
---

[13] PJM's price cap is set as the maximum of 1.5× Net CONE or 1× Gross CONE. ISO-NE's price cap is set as the maximum of 1.6× Net CONE or 1× Gross CONE. NYISO's price cap is set to 2× Net CONE, AESO's proposed curve had a price cap set to 1.75× Net CONE or 0.5x Gross CONE, and Great Britain's price cap is set to 1.53× Net CONE. See Figure 2 for sources.

[14] The quantity at the cap ranges from 97-100% of the reliability requirement or minimum acceptable reliability in other markets. NYISO's demand curve is the exception and has a very low quantity at the cap, set to around 92% of the reliability requirement. See Figure 2 for sources.

capacity market, with the specific shape and parameters developed based on a study of the potential clearing outcomes in this market.

Figure 6: Illustration of Key Demand Curve Parameters



Some stakeholders have expressed the importance of including a price floor on the demand curve. However, this is inconsistent with efficient operation of the capacity market. Beyond a certain reserve margin, the incremental reliability value of additional capacity is negligible. The demand curve should express this value. Artificially limiting downward movement in the price could inefficiently retain capacity that is not needed, increasing consumer costs.

To take these concepts and develop specific demand curve parameters to fit Singapore's unique market, Brattle is conducting a full demand curve study using a probabilistic simulation methodology. This approach has been used across several markets such as PJM, MISO, and AESO when designing capacity market demand curves and/or conducting periodic reviews of the demand curve performance.[15] The probabilistic approach uses a Monte Carlo model to simulate a distribution of market clearing outcomes, price distributions, and expected reliability under long run equilibrium conditions with a variety of potential demand curves.

E. Demand Curve Review and Updates

Singapore's capacity market rules will need to incorporate a process for updating and reviewing demand curve parameters. These periodic reviews provide the opportunity to evaluate the performance of the demand curve relative to the design principles and make any changes necessary to improve its design. These reviews are important to ensure the demand curve is adjusting to the market's changing needs and cost of supply. These updates can be conducted in two timeframes:

---

15 Examples include: Spees, Kathleen, et al., "Alberta's Capacity Market Demand Curve," Prepared for AESO, January 2019. Newell, Samuel, et al., "Fourth Review of PJM's Variable Resource Requirement Curve," Prepared for PJM, April 19, 2018.

- **Annual formulaic updates** that require minimal administrative effort but are necessary to maintain consistency with market demand and supply costs over time. The annual updates normally focus on updating demand curve quantity points based on new load forecasts and reliability analysis, as well as updating Gross CONE and E&AS offset with the most recent market data to get a more accurate Net CONE. These updates ensure the pricing points on the administrative demand curve maintain consistency with market conditions and the auction procures sufficient capacity while avoiding significant over-procurement. We recommend Gross CONE updates to be based on the most recently available public index and E&AS updates to be based on either recent historical or futures-based market price data, as applied using a formulaic updating approach.
- **Periodic comprehensive reviews** to address longer-term trends and fundamental shifts to technology. These comprehensive reviews are a detailed evaluation of demand curve parameters and methodologies used to calculate Gross CONE and E&AS offset. Often, they review:
  - *Reference technology.* Evaluate which technologies are economic to build when new merchant supply is needed. Account for changes in policy regulations and technology cost trends.
  - *Gross CONE.* Evaluate change in costs of technology, labor, and land, as well as updates to tax rates and deductions and policy incentives and regulations to more closely align with observed and anticipated market conditions. Assess methodology used to calculate Gross CONE (i.e., using level-real or level-nominal approach to calculate annualized costs).
  - *E&AS Offset Methodology.* Evaluate forward- or backward-looking methodology and whether to use simulated or actual market data. Review changes in fuel prices, energy and ancillary service prices, generation resource mix, and policy regulations.
  - *Demand Curve Parameters.* Evaluate performance relative to the reliability standard and whether the standard needs to be updated. Determine whether the shape of the demand curve, width, price cap, or any set of price and quantity points of the demand curve need to be adjusted based on any observed or anticipated challenges to the market.

Details on comprehensive periodic reviews of reference technology, Gross CONE and E&AS Offset estimates, and demand curve parameters will be determined at later stages of the design process. The practices in other markets are shown in Table 5 below.

Table 5: Capacity Market Comprehensive Review Cycles in Other Jurisdictions

	PJM	ISO-NE	NYISO	Great Britain
Frequency	4 years	3 years	4 years	5 years
Scope	CONE estimate, E&AS offset methodology, demand curve	CONE estimate, E&AS offset, resource type mitigation levels	CONE estimate, demand curve performance	Assess market performance relative to objectives, review market objectives

Sources and Notes:

PJM's major reviews were initially on a three-year cycle and included a broader scope. See, for example, Pfeifenberger, J., Newel, S., Spees, K., Hajos, A., Madjarov, K., *Second Performance Assessment of PJM's Reliability Pricing Model*, August 26, 2011.

Great Britain's Energy Act of 2013 calls for a comprehensive review of the market 5 years from passage of the Act.

F. Recommendations for Singapore

Recommendations and Next Steps

Reliability Standard

- Maintain Singapore reliability standard (currently defined as 3 LOLH). This quantity will be translated into the equivalent QCAP procurement volume (used to set the minimum quantity points on the demand curve)

Net Cost of New Entry

- Estimate a transitional Net CONE parameter based on currently available data to apply over the 2023-2025 delivery years (with auctions to be conducted in a compressed forward period in initial years)

Demand Curve Parameters

- Price cap to be in the range of 1.5× to 2× Net CONE
- Consider minimum on price cap in the range of 0.25× to 1× Gross CONE
- Quantity at the price cap set at the 3 LOLH minimum acceptable reliability level
- Downward-sloping shape with specific parameters to be established using a probabilistic simulation methodology that achieves the reliability standard

Next Steps

- Conduct a full demand curve study using a probabilistic simulation methodology
- Determine frequency and scope for demand curve review and updates

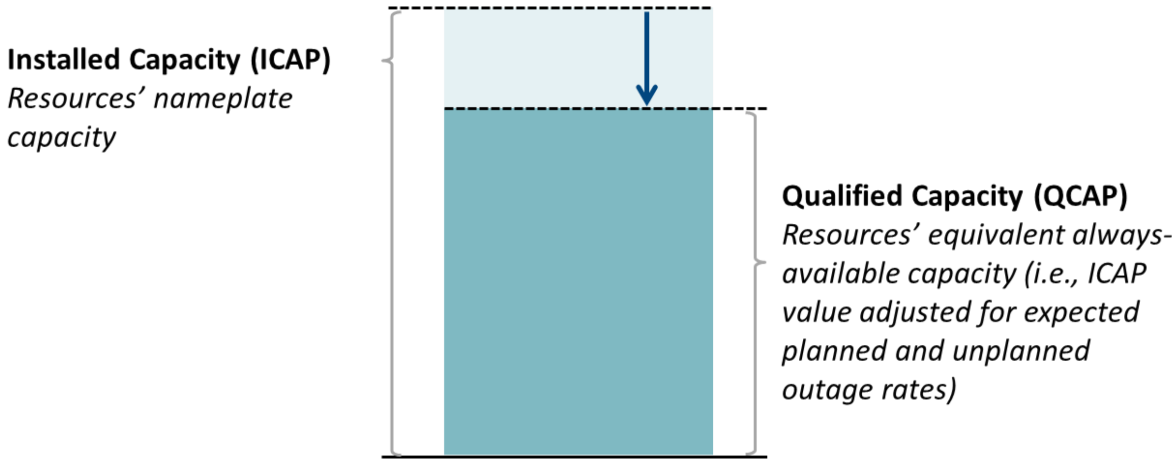
IV. Supply Resource Qualification and Capacity Ratings

A resource qualification process is needed to validate that supply resources participating in the FCM will be online and able to operate in the delivery year. As part of this process, the capacity value or rating for each resource is also determined. This rating gives the MW quantity each resource is qualified to offer into the auction, given its demonstrated availability and any operating limitation. This is needed both to ensure that resources are compensated fairly and consistently with their value, and to ensure sufficient capacity is procured in the auction to meet resource adequacy requirements.

The FCM will use a technology-neutral design to qualify all existing and planned resources that can contribute to resource adequacy, including conventional thermal resources, demand response, imports, solar, and storage. Some stakeholders have provided feedback that a technology or resource neutral approach favors resources with lower avoidable going-forward costs, indirectly discriminating against newer resources with higher unavoidable fixed costs. However, efficiency will be maximized and consumer costs minimized when all resources are treated fairly and can compete to offer the same capacity product to support system reliability.

There are two primary approaches to determine capacity ratings. The first reflects the maximum output of a given resource, or a resource's installed capacity (ICAP). The second discounts the resource's ICAP to reflect the capacity that it is expected to be able to provide during potential shortages, which we hereafter refer to as the "qualified capacity" (QCAP) approach. The differences between ICAP and QCAP are captured in Figure 7. While the ICAP approach is the most straightforward and simple, the QCAP approach offers superior reliability and economic benefits.

Figure 7: Schematic of Resource ICAP and QCAP



We recommend adopting a QCAP approach, where resources' ICAP is discounted to account for their historical reliability value including all planned and unplanned outages. This provides better assurance that the FCM achieves the desired reliability level, creates a level playing field across resource types based on their reliability value, rewards better performing resources appropriately, and ensures fair and equitable treatment. Including planned outages in this calculation accurately reflects the effect of maintenance outages on capacity value of a resource and provides proper incentives for resources to efficiently plan their maintenance schedules.

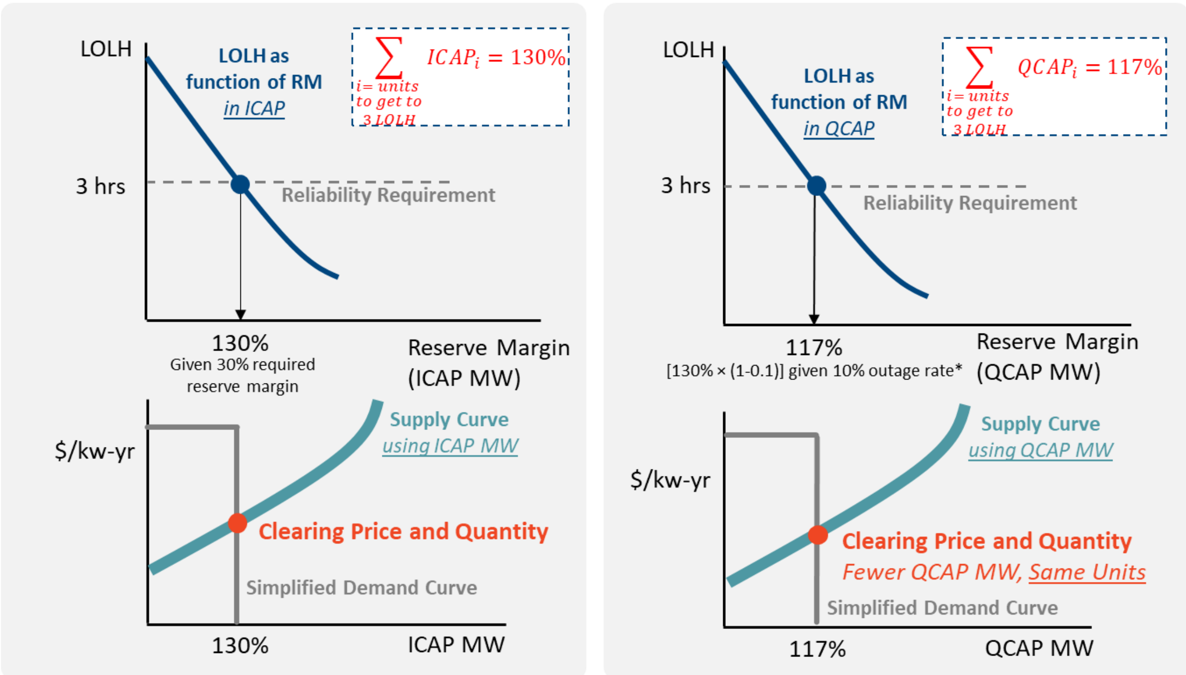
A. Principles and Best Practices

An accurate and robust resource qualification system is necessary to efficiently procure sufficient capacity and ensure reliability. Most markets rely on an approach similar to the QCAP approach that we discuss here, which discounts a resource's nameplate capacity, or ICAP, to reflect its expected marginal contribution to system reliability. The difference between the ICAP and QCAP approaches does not directly impact the amount of cleared capacity and system reliability. Under both approaches, the market seeks to procure enough capacity to achieve the reliability requirement and reserve margin calculated in a loss of load hours (LOLH) study.

An ICAP based reliability requirement appears higher on a MW basis since the capacity counted under a QCAP approach reflect MW of always-available capacity. However, the reliability requirement in both ICAP and QCAP approaches describe the same underlying level of reliability established in the LOLH study. This is captured in Figure 8, which shows two examples of the same level of capacity being procured to meet the same LOLH of three hours, yet different ways of accounting for the procured capacity.

Figure 8: ICAP vs QCAP Illustrative Reserve Margin

Panel A: ICAP Approach *Panel B: QCAP Approach*



Notes: In this figure we make the simple assumption that all resources have a 10% outage rate, so there is no "merit order" switching between ICAP and QCAP approach. Below we discuss the more complex cases where the fleet differs from expected, and when resources vary from each other.

The two approaches differ in how well they solicit actual resources for meeting the need when (1) actual resources' reliability characteristics differ from those modeled in the LOLH study; and (2) their characteristics differ from each other. For example, suppose the market clears a set of resources that have an average outage rate that is higher than that assumed in conducting the LOLH study. In this example, the ICAP approach may not achieve the desired level of reliability, as it clears the same amount of ICAP capacity as required by the LOLH study, but the capacity that it cleared is more prone to outages than the capacity assumed in the LOLH study. Additionally, under an ICAP approach, the auction may be more likely to clear capacity that has these outage risks since that might be the cheapest available capacity. These concerns are mitigated under a QCAP approach, where the reserve margin is set to reflect the necessary capacity to achieve the LOLH target, and the auction offers reflect the marginal capacity value of the resource. Since the QCAP approach removes any assumptions regarding potential outage rates, it procures exactly the needed amount of capacity from the auction, without any potential for under or over procurement.

In addition to impacting the reliability requirement, capacity ratings also affect penalty mechanisms. Under ICAP, there is no direct link between the committed MW and the expected performance, although resources may differ greatly in realized performance during peak demand. One approach to address this is to introduce strict availability or performance penalties for *any* under-performance relative to ICAP, but these penalties will be large on average and thus introduce substantial risk to suppliers. Alternatively, under a QCAP approach, resources can be compared against their established expected performance rate. If a resource under performs relative to its committed capacity in a given year, it can be penalized based on its realized performance (but the average size of these penalties would be smaller than under the parallel approach in an ICAP setting). Additionally, resources have an incentive to perform to earn a higher expected performance rating in future years, increasing their possible capacity commitment and associated payments.

This discussion primarily concerns traditional thermal resources. However, all jurisdictions, whether they employ an ICAP or QCAP approach, recognize that intermittent and other non-traditional resources are not always available and could be discounted differently than traditional thermal resources to reflect the lower marginal reliability value of such resources. The similarities and differences between ICAP and QCAP capacity rating approaches are captured in Table 6.

Table 6: Summary of ICAP and QCAP Design Elements

Design Element	ICAP	QCAP
Capacity for Thermal Resources	Maximum rated output of the supply resource, i.e., nameplate capacity	Maximum output rating adjusted for expected outages that reduce resources' resource adequacy value
Capacity for Intermittent or Use-Limited Resources	For resources whose nameplate capability may be materially different from their reliability value (e.g., wind, solar, storage, hydro), special accounting rules are often (but not always) employed	Similar to ICAP, different approaches are required to estimate QCAP MW. Guiding principle is that 1 MW of QCAP should provide equivalent reliability value across resource types
Reliability Requirement	Traditional reserve margin standard consistent with reliability requirement, expressed in ICAP MW terms	Same reliability requirement, but expressed in lower QCAP MW terms based on the fleet mix and associated outage rates modelled in the LOLH study
Penalty Structures	Penalties for non-performance would need to be substantially larger than under a QCAP mechanism to create a more level playing field across resource types and provide similarly large incentives for improving reliability performance	Resources are held accountable for realized availability in two ways: 1. In-year penalties need not be as large to create a level playing field 2. Annual QCAP updates based on historical availability (rewarding high-availability resources with higher QCAP ratings)

Approaches in Other Jurisdictions

PJM, MISO, NYISO, and Alberta all rely upon an "unforced capacity" (UCAP) methodology, which is very similar to the QCAP approach discussed here in that it accounts for expected performance during potential shortage events, except it does not consider planned outages. Ireland and the UK use a derating factor to achieve a similar impact and capture resources marginal reliability contributions. ISO-NE differs from other capacity markets in that it operates on an ICAP basis. PJM, MISO, and NYISO all rely upon an estimate of equivalent forced outage rate demand (EFORd) to account for unplanned outages to qualify UCAP for traditional resources. While the underlying principles are similar across these three markets (i.e., UCAP is the function of a resource's ICAP rating and EFORd), the details in the calculation of EFORd differ slightly. We provide below a short summary of the methodology applied in each of these jurisdictions.

PJM uses an annual EFORd value for conventional resources calculated based on forced outage data from October through September of the previous year.[16] The EFORd is finalized for all resources at least one month prior to the third incremental auction in PJM (roughly three months before the start of the delivery period).[17] If a resource has less than twelve months of available service data, a class-average EFORd is applied for that resource. This EFORd calculation includes outages that are deemed outside management control events, including events related to transmission/distribution, acts of nature, fuel quality, and unforeseen regulatory action among others.[18]

NYISO uses a seasonal EFORd, calculated separately for its summer and winter auctions based on a rolling annual average of resource availability. For the winter capability period, the EFORd considers the average outages over the twelve-month periods ending in January, February, March, April, May, and June from the prior year (i.e., the average of those six twelve-month periods). The summer EFORd is calculated similarly, considering the six twelve-month periods ending July, August, September, October, and November.[19] For new generating resources, NYISO relies upon NERC class averages (if NERC averages are unavailable, NYISO estimates EFORd based on the class average of same type resources). Outages that are considered outside of management control events are counted as forced outages, similar to PJM.[20]

---

16 See PJM, PJM Manual 18: PJM Capacity Market, Section 4.2.5 (p. 68), January 1, 2019.

17 See PJM, Reliability Assurance Agreement among Load Serving Entities in the PJM Region, Schedule 5, Section B, September 17, 2010. For overview of PJM incremental auction schedule, see PJM, RPM 101 Overview of Reliability Pricing Model, slide 53, April 18. 2017.

18 Prior to the introduction of capacity performance in PJM during the 2018/2019 delivery year, the EFORd calculation excluded such events. For a more complete description of outside management control events, see PJM eGADS OMC ("Outside Management Control") Guidelines.

19 NYISO, Manual 4 Installed Capacity Manual, pp. 50-51, March 2019.

20 *Ibid*, p. 58.

MISO relies on the three-year average EFORd to calculate UCAP.[21] Unlike PJM and NYISO, outages that are considered outside of management control are excluded from MISO's derating calculations, which is referred to in MISO as the XEFORd. In instances when the resource has fewer than three years of available outage data, MISO will use all the data that is available unless a resource has less than twelve months of available data in which case they will use a class average XEFORd based on fuel type and size.

AESO created its own resource qualification methodology to best meet system needs during periods of system stress.[22] For conventional resources, AESO uses an availability factor, which captures the availability of a resource during the tightest 250 supply cushion hours in each year, over a five-year period, for a total of 1,250 hours. This availability factor is applied to a resource's capacity to calculate an availability factor UCAP, or "AF UCAP."[23] Unlike in the other markets surveyed above, all outages, included planned outages and physical delists, count against availability.[24] When a resource has fewer than 300 hours of available historical data, AESO uses a class average to fill in the remaining hours.[25]

Ireland specifies derating percentages according to technology class (i.e., gas turbine, hydro, solar) in its capacity market accounting for planned and unplanned outages.[26] For some resource types, there are curves that specify a derating factor based on the nameplate capacity of the resource.[27] The individual percentages and curves are derived using a model that repeatedly simulates the probability of scarcity in the I-SEM and Great Britain market.[28] All resources of that type use the same derate no matter the age or condition of the resource. If a new resource joins the market for which there is not a specified derate, that resource uses a system-wide curve.

Great Britain has very similar scheme to Ireland. In Great Britain, generators are derated based on derating factors for each resource type.[29] The derating factors are calculated based on fleet availability during the seven preceding Core Winter Periods.[30]

---

21 MISO, Business Practices Manual 11: Resource Adequacy, Appendix H, pp. 131-139, February 20, 2019. Available from: https://www.misoenergy.org/legal/business-practice-manuals/.

22 Note that the summaries regarding AESO reflect the most recent proposal before the capacity market design was cancelled.

23 AESO, Alberta Electric System Operator Application for Approval of the First Set of ISO Rules to Establish and Operate the Capacity Market, p. 77, January 31, 2019. Available via the AUC eFiling System: http://www.auc.ab.ca/pages/apply-or-access-applications.aspx.

24 *Ibid,* p. 79.

25 *Ibid,* p. 79.

26 SEM-O, Capacity Market: The Quick Guide to Understanding Qualification, April 3, 2019, Pages 3–4.

27 SEM-O, Capacity Market – Final Auction Information Pack, August 3, 2018, Pages 14 – 16.

28 Capacity Requirement and De-Rating Factor Methodology Detailed Design: Decision Paper, SEM-16-082, December 8, 2016, Page 21.

29 National Grid, Capacity Market Auction Guidelines, July 19, 2018, Pages 5 – 6.

30 Informal Consolidated Version of the Capacity Market Rules, Rule 2.3.5, July 26, 2019.

ISO-NE differs from the markets described above in that it relies on an ICAP based capacity rating approach. This means that ISO-NE does not consider a resource's unplanned or planned outages in its procurement of capacity. Intermittent resources are adjusted to account for their intermittent nature. Additionally, a resource's capacity commitment can be reduced to account for failure to perform in prior years.[31]

B. Recommendations for Singapore

After considering the system conditions in Singapore, we recommend that the Singapore FCM rely upon a QCAP approach, where resources' capacity is rated based on its expected ability to generate during potential shortage events. A resource's ICAP would be discounted by its expected unplanned outage rate (UOR) and its planned outage rate (POR), as described in the equation below:

$$QCAP = ICAP \times (1 - UOR) \times (1 - POR)$$

We propose that this approach is applied only to existing conventional dispatchable resources with sufficient historical operational data to estimate the necessary parameters. Non-dispatchable resources, new resources, and other resources without sufficient historical operational data will require a different approach, which will be developed in later versions of the design proposal.

Rationale for Adopting the QCAP Approach

We recommend adopting a QCAP approach for capacity ratings. A QCAP approach provides three primary advantages over ICAP, including: (1) *uniformity and interchangeability,* with 1 MW of QCAP contributing the same expected reliability value regardless of resource type, age, or other characteristics, which provides greater assurance of meeting reliability objectives especially if procured resources differ from those assumed in the LOLH study; (2) *fairness,* in that suppliers are rewarded in proportion to expected reliability value; and (3) *more economic asset selection,* in that the auction will be more likely to procure the resources that provide the most reliability value at the lowest price, and this also has the beneficial effect of incentivizing and rewarding reliability improvements in the fleet. We understand that various stakeholders have recognized these advantages and support the proposed approach.

We do acknowledge that the ICAP capacity rating approach provides some advantages, including: (1) it is most consistent with the historical reliability requirement and reserve margin measures; and (2) it will require less administrative overhead. These trade-offs are captured in Table 7.

[31] CRA, A Case Study in Capacity Market Design and Considerations for Alberta, March 30, 2017, Page 83.

Table 7: Advantages and Disadvantages of QCAP and ICAP Systems

	ICAP	QCAP
Advantages	• Most consistent with historical reliability standard measures • Simpler to calculate resources' capacity ratings (but availability ratings and calculations may still be required for penalty assessments, so administrative savings are minimal)	• Uniformity among resources provides better assurance that the capacity auction will achieve the desired reliability level • Most level playing field among resource types, with payments proportional to reliability value (which incentivizes and rewards cost-effective reliability enhancements) • More likely to procure better-performing resources • More compatible with future treatment of intermittent and energy-limited resources
Disadvantages	• Adverse selection of resources that under-spend on maintenance and fuel security and thus perform poorly • No protection from procuring a fleet with higher EFORd than assumed in the LOLH model, resulting in poor reliability • If playing field is levelized through higher penalties for non-performance, the magnitude of these greater payment adjustments would be less transparent to the market than a simple QCAP-based price • Favors traditional resources over intermittent and energy-limited resources that presumably will be derated for their unavailability during peaks	• Different from historical approach • Potentially increased administrative effort

To highlight a key advantage of the QCAP approach, we have included a simple illustrative example in Table 8. In this example, a reliability study determined it would need a 130% ICAP reserve margin or a 117% QCAP reserve margin to reach achieve the target reliability of 3 LOLH given a 10% average fleet outage rate. If the 10% outage rate assumption was correct in the study and reflects the cleared capacity, using an ICAP or QCAP approach both yield the expected 3 LOLH reliability standard. However, if the assumed outage rate is incorrect, the two approaches yield very different results. Under the ICAP approach, the auction still procures capacity to achieve a 130% ICAP reserve margin although the performance of the capacity procured differ from what was expected. This means that if the outage rate is much higher than anticipated and the system will be less reliable, evidenced by the 20% outage rate which yields a LOLH of 10. Alternatively, if the outage rate is lower, the market over procures capacity, and consumers overpay for a level of reliability that might not be necessary. By contrast, the QCAP approach is able to procure the desired level of capacity as determined by the reliability study, since a QCAP approach procures capacity that reflects its actual marginal reliability contribution.

Table 8: ICAP vs QCAP Performance with Variable Outage Assumptions

	Cleared Resource Actual Outage Rate	QCAP (% of Peak Load)	ICAP (% of Peak Load)	LOLH	
ICAP Methodology	10%	117%	130%	3	Uncertainty yields variable reliability under ICAP method; increases cost if higher ICAP needed to avoid exceeding 3 LOLH
	20%	104%	130%	10	
	0%	130%	130%	~0	
QCAP Methodology	10%	117%	130%	3	Uncertainty yields consistent reliability under QCAP methodology
	20%	117%	146%	3	
	0%	117%	117%	3	

This example highlights how a QCAP approach yields consistent reliability no matter the underlying makeup of the fleet. It also shows how an ICAP approach can lead to variable reliability, which leads to higher costs if it clears additional capacity above the target reliability level, and if it necessitates increasing the target capacity to ensure the reliability standard is not breached even when the resources cleared in the capacity market differ substantially from those expected and modelled in the LOLH study.

Finally, the QCAP approach achieves the most economic asset selection and ensures that resources clear in the fairest manner. Since capacity bids under a QCAP approach reflect each resource's marginal reliability value, it is possible to clearly and efficiently rank resources by their ability to contribute to reliability. This might not be true under the ICAP approach, where resources with a higher outage probability may be able to offer at a lower price and, therefore outcompete resources that could provide more reliable capacity at lower cost. This is captured in the 20% outage scenario above, where resources that were less reliable than expected cleared and caused a lower reliability outcome.

Account For Unplanned and Planned Outages in Determining QCAP

If adopting a QCAP approach to capacity ratings, we recommend accounting for all unplanned and planned outages to accurately capture a resource's marginal reliability value. While most markets simply rely on an UOR to derate from ICAP, we recommend that the Singapore market also account for resources' POR to capture the full range of outages that may impact a resource's ability to provide capacity when needed. Whereas other markets with more seasonal demand variation, such as PJM and ISO-NE, are able to plan all of their maintenance in shoulder months, additional maintenance scheduled in any month can impact reliability in Singapore due to its relatively consistent peak load profile throughout the year. By accounting for all types of outages, the QCAP approach incentivizes resources to maximize their overall resource adequacy value by optimally managing maintenance decisions while also not jeopardizing overall system reliability.

We recommend using an annual UOR and POR to determine QCAP in Singapore, as opposed to focusing on estimating availability for one particular time period during the year, because it appears that shortages in Singapore are equally likely to occur in any time of the year. This follows from the fact that the annual load duration curve in Singapore is relatively flat compared to other jurisdictions, and that the primary drivers of resource shortages are unplanned or forced outages, not peak load.

The POR will be defined as the share of hours across the delivery year during which the resource will be unavailable due to planned maintenance outages, based on maintenance schedules. The UOR will be based on historical data for a "test period" of several years, aligned with the probability that the resource was not available due to unplanned outages or unplanned derates.

Estimating the UOR requires a precise definition of what constitutes an unplanned outage or unplanned derate. The North American Electric Reliability Council (NERC) defines an unplanned, or "forced," outage as the removal from service availability of a generation for emergency reasons or being unavailable due an unanticipated failure.[32] Different jurisdictions have different views on what types of outages are considered unanticipated. To increase the likelihood that QCAP capacity is available, we recommend a conservative approach that includes all unplanned outages. This is consistent with the PJM and NYISO definition that includes outages that are deemed outside management control events, including events related to transmission/distribution, acts of nature, fuel quality, and unforeseen regulatory action.

In addition, estimating the UOR requires determining when a resource would have been needed if it was available based on historical data. In a market with clear price signals, this can be accomplished by observing the hours when the market price is higher than the variable cost of the resource. If the resource experienced an unplanned or planned outage or derate in an hour when the price was higher than its operating costs, it can be assumed that the resource would have been needed at its full capacity if it had been available.

Recommendations and Next Steps

Capacity Rating Approach

- Adopt a QCAP based capacity rating approach, where the reliability requirement and capacity qualification are conducted on a QCAP basis
- Consider all outages, including unplanned and planned, in QCAP calculations to get most accurate measurement of marginal reliability value

Next Steps

- Establish qualification and credit requirements for all resource types, including treatment of embedded generation, solar, storage, and demand response
- Develop resource QCAP rating approach for non-dispatchable resources
- Develop UOR and POR estimation methodology for resources, including resources with little historical operational data
- Develop approach for resources undertaking refurbishments
- Develop the penalty framework

32 North American Electric Reliability Council, "Glossary of Terms used in NERC Reliability Standards," Updated May 13, 2019. Accessed here: https://www.nerc.com/files/glossary_of_terms.pdf

V. Market Power Monitoring and Mitigation (Next Round)

All capacity markets are considered structurally uncompetitive at least some of the time because residual supply tends to be small (with little excess beyond peak load plus reserve margin) relative to the size of some suppliers. Singapore is no different, with several suppliers being large enough to be pivotal or become pivotal as excess capacity diminishes. Large participants could have the incentive and ability to increase the price by inefficiently withholding capacity. Withholding could occur physically, by not offering or prematurely retiring a resource. Withholding could also occur economically, by offering a resource at a price above the cost of providing capacity with the intention of not clearing the auction.

The FCM can protect against both physical and economic withholding, though market power monitoring and mitigation by the market monitor.

To address physical withholding, all existing resources should be required to offer. Resources that wish to retire, mothball, or export their capacity would need to receive a must-offer requirement exemption prior to the auction in order to do so. The decision to grant a must-offer requirement exemption would be reviewed by the market monitor to test for potential market power abuse.

To prevent economic withholding, the market monitor will cap ("mitigate") the auction offer prices of market participants that are deemed likely to have both the *incentive* and *ability* to exercise market power. To determine which capacity suppliers should have their offers capped, the market monitor will employ a market power screen to test each supplier. There are many different types of market power screens used in other jurisdictions, such as the three-pivotal supplier test, the single-pivotal supplier test, the conduct and impact test, or an incentive test.[33]

[33] PJM uses a Market Structure test based on a three-pivotal supplier test. If the required capacity cannot be met with the output of the two largest suppliers, plus the output of the supplier being tested, then all three are jointly pivotal. These three suppliers would be able to manipulate prices by jointly withholding output. See PJM Tariff Attachment DD: Reliability Pricing Model, Section 6.3. We have previously raised the concern that this test is too stringent as it would mitigate even very small suppliers; see Reitzes et al., "Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets," September 2007.

NYISO uses similar monitoring and mitigation measures, based on a single pivotal supplier test. Of particular interest are several measures that are specifically applied only to market-internal import-constrained capacity zones, particularly New York City which has a high concentration of both supply and demand. These factors tend to increase the risk and impact of market power exercise relative to larger and more structurally-competitive capacity zones. See NYISO Tariff Attachment H: Market Power Mitigation Measures, Section 23.2.1.

MISO's monitoring and mitigation measures are quite different from those in PJM and NYISO, partly because of the region's traditionally-regulated market structure in which the vast majority of

Each of these screens has advantages and disadvantages, and can result in a larger (or smaller) share of suppliers being mitigated. The appropriate market screen for the FCM will depend on the objectives of regulators and the market administrator in Singapore, as well as the market concentration, shape of the demand and supply curves, and other factors that can affect the likelihood of market power abuse. Details will be determined at later stages of the design process.

Suppliers with market power typically need not have their offers mitigated if offers are below pre-defined thresholds. Defining a "no-review" threshold can reduce the administrative burden of mitigation and can limit the risk of over-mitigating. Such thresholds can represent a reasonably low estimate of the net avoidable going-forward costs of providing capacity, either generically or by resource type. The specific levels will be determined in subsequent design phases.

Resources that fail the market power screen and exceed the no-review threshold would be subject to possible mitigation. The identities of capacity suppliers whose offer prices have been mitigated would remain confidential. To enforce that their offers are competitive and reasonably reflect net avoidable going-forward costs, the market monitor would provide the resources with two options:

1. Submit a pre-determined default offer cap (typically the same as the review threshold).
2. Request a resource-specific offer cap and provide cost and revenue data to support the request. The data will be reviewed and used to calculate a resource-specific offer cap, consistent with the net avoidable going-forward cost of that resource.

Auction results should also be reviewed *ex-post* to detect anti-competitive behavior. This review should comprise a thorough analysis of supplier bidding behavior and market outcomes. If market power is found to still be a concern after the *ex-ante* mitigation, the EMA may wish to adjust the market power screens and/or pursue administrative action against offending parties.

Rules to mitigate against the exercise of buyer-side market power (the ability and incentive to profitably depress the market price) are not applicable in Singapore.

supply and demand are represented by vertically-integrated, cost-of-service-regulated utilities that have balanced positions and so have little incentive to manipulate capacity auction prices. In that context, and to minimize its interference in the auction, MISO imposes mitigation measures only if it determines that exercise of market power could increase auction clearing prices by an impact threshold of at least 10% of the Cost of New Entry (CONE). In that case, must-offer or offer-cap mitigation measures may be applied. See MISO Tariff Module D, Section 64.2.1(e).

VI. Forward Capacity Auction

We recommend that the FCM have a four-year forward auction. The auction should have a uniform clearing price paid to all resources, conducted as a single-round auction, with sealed bids. This auction structure can maximize reliability at the lowest possible societal cost, and has a strong performance record in other capacity market contexts.

A. Auction Design

We recommend a single-round, sealed-bid, uniform clearing price auction. This is the auction structure that is most likely to achieve efficiency and deliver the targeted reliability at the lowest cost. In this section we review the alternatives and provide justifications for the recommended approach to each design element.

Pay all Cleared Resources a Uniform Price

In a uniform price auction construct, all cleared suppliers receive the same price per MW of capacity. This incents suppliers to offer at cost—the absolute minimum price they are willing to accept to provide capacity, that is, at their net avoidable going-forward costs—except in cases of market power.[34] As a result, the clearing price in the auction should reflect the marginal cost of capacity, which is most likely to ensure least-cost procurement of capacity and to provide efficient long-term signals for investment and consumption.

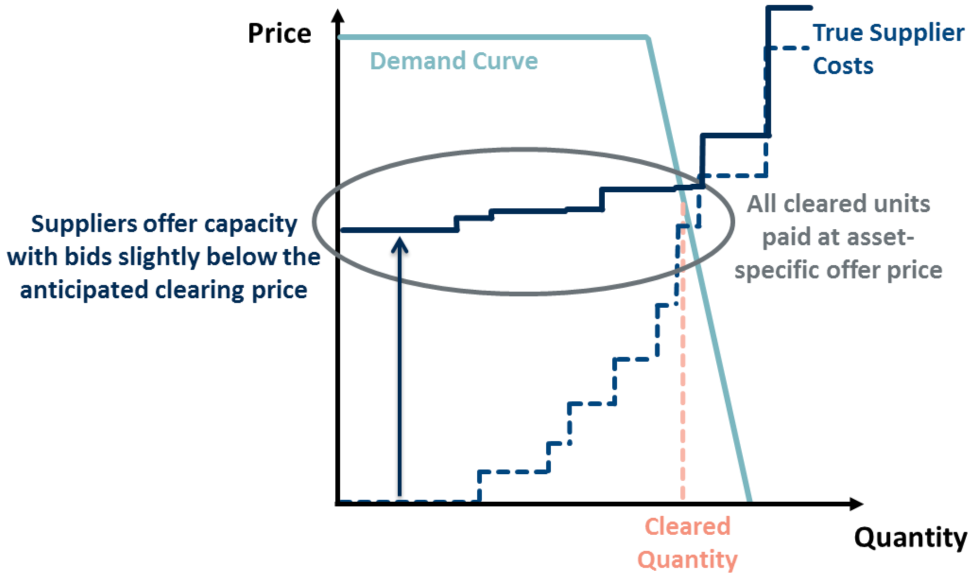
There are two primary alternatives to this approach: "pay-as-bid," in which cleared resources are paid according to the price they offered capacity into the market, and differentiation between new and existing resources, which allows prices to separate between new and existing resources if the marginal new resource has a higher offer price than the marginal existing resource. We explore each of these alternatives below.

Pay-as-bid. In an alternative pay-as-bid approach, all cleared suppliers are paid their bid price. This approach is not used in any centralized wholesale energy or capacity market, but it is used in other contexts, most commonly in decentralized commodity markets. We see no substantial benefits over uniform price auctions in any centralized market context.

---

[34] Competitive offers at net avoidable going-forward costs would include: (a) capital and fixed costs incurred in the immediate year, minus (b) energy/ancillary margins expected in the immediate year, minus (c) future net capacity and ancillary margins expected for the remainder of the asset life. If the capacity obligation exposes suppliers to non-performance risk, the rational offer price would not drop below the expected penalty size.

Figure 9: Supplier Offer Behavior in Pay-As-Bid Auction



Under a pay-as-bid construct, suppliers have the incentive to bid at the price of the most expensive offer they expect to be accepted (that is, at the expected clearing price), as illustrated in Figure 9. Thus, the auction does not elicit information about suppliers' marginal costs (as in a uniform price auction), but rather about suppliers' expectations of the clearing price.

Theoretically, these two approaches could produce the same prices if suppliers accurately estimate the marginal cost of capacity. However, in practice, the pay-as-bid construct will likely not achieve the efficient price signals achieved by uniform pricing. The pay-as-bid construct invites sellers to offer above their costs, and uncertainty over the clearing price is likely to result in inefficient results. If low-cost resources offer too high (due to incorrect beliefs about the auction clearing price) and fail to clear, they may exit or fail to enter while higher-cost resources with lower offers enter instead. This issue of distorted merit order is illustrated in Figure 10. In addition, suppliers with a larger generation portfolio are likely to have more information about the potential clearing price, and would be at an advantage compared to smaller suppliers who risk guessing the clearing price wrong and inefficiently fail to clear their resource. Finally, monitoring for the abuse of market power is inherently difficult in this construct, where offers reflect participant beliefs rather than private costs.

Figure 10: Example of Distorted Merit Order in Pay-as-Bid Auctions

Differentiated payments for new and existing capacity. In a second alternative to uniform pricing, the clearing price could be differentiated between new and existing resources to reflect the marginal offer under each resource type. It is often believed that differentiating payments will save consumers money overall, based on the implicit assumption that existing suppliers have lower net avoidable going-forward costs than new resources, and therefore do not "need" the same high capacity payments necessary to attract new resources.

However, these arguments are flawed. There are three key reasons that uniform pricing for new and existing resources is best:

- With any market-oriented approach, all-in prices are expected to reflect long-run marginal costs in the long run. Thus, differentiation would achieve no net gain for consumers in the long run.
- Paying all resources the same price for the same product, regardless of how it is produced, is consistent with current principles and practice in the energy market and best practices in other commodity markets, including all other capacity markets.
- Uniform clearing will minimize societal costs, which minimizes consumer costs in the long run. Allowing the market to express demand for the capacity product, and treating all suppliers of that product the same, will allow the market to find the least cost resource mix. If the price for existing resources is not allowed to rise to the same prices facing new resources, the market will not accommodate efficient upgrades to existing resources or provide incentives for efficient retirement decisions. From a societal perspective, price differentiation is inefficient because it reduces competition, can induce inefficient high-cost investments in new resources, and often leads to inefficient retirement of lower-cost existing resources.

We conducted quantitative analysis comparing auction outcomes and consumer costs between a uniform-price FCM and one that differentiates payments between new and existing resources.[35] This quantitative analysis suggests that consumer costs are similar under either method over a 20-year horizon. Initial consumer savings (a wealth transfer from existing generators to consumers) are likely offset by long-term higher prices. This reflects the fact that new entrants must offer at very high prices to recover capital costs rapidly in initial years (the period when they are still considered "new," assumed to be five years in our analysis).

Use a Single-Round, Sealed-Bid Auction

Single-Round Auction. We recommend that the FCM auction be conducted in a single round. Multi-round auctions are used to allow resources to amend offers during the auction clearing process. However, such auctions can be more complex to administer and increase the risk of participants engaging in gaming behavior. The advantages and disadvantages of each approach are outlined below in Table 9.

[35] Our model assumes that under the alternative approach where new and existing resources clear separately, new entrants must recover most of their capital costs during the years they are considered to be "new" resources in the auction. Thereafter, lower "existing" capacity payments are assumed to cover only their ongoing fixed O&M costs, and their only capital recovery will derive from net E&AS revenues. This affects how new suppliers offer into the auction because it compresses the amount of time during which they can recover capital costs. In our base case, we assume that resources offer at prices consistent with recovering capital costs over just five years instead of over the 25-year economic life of the plant.

Supply offers in our analysis are assumed to reflect avoidable going-forward fixed costs, net of expected E&AS revenues. We assume that new resources are efficient enough to earn net revenues in the energy market. Solar resources' net energy revenues are calculated based on an assumed capacity factor over the year, while the net revenue for new CCGTs is an input assumption to the model. Existing thermal resources are assumed to be on the margin, making a negligible profit in the energy market. Demand increases annually according to EMA projections and at a consistent rate after the projections end, and the demand curve has been simplified to be a vertical curve.

Table 9: Comparison of Single-Round and Multi-Round Auction Formats

Format	Advantages	Disadvantages
Single Round	• Simplicity helps prevent design flaws. • Less exposure to the exercise of gaming, market power, and collusion. • Lower implementation, transaction, and overhead costs (both for the market administrator and market participants). • Easier to implement in a zonal framework (N/A in Singapore) or any other structure that would add complexity to the types of constraints reflected in the auction (e.g., flexibility requirements, seasonal requirements, dynamic effective load carrying capability ratings that depend on penetration levels, or clean energy requirements). So far these are N/A in Singapore but that could change in the future.	• *Theoretically:* No price discovery during the auction. • *In practice:* We do not view price discovery as particularly valuable or important in capacity auctions. Price discovery is useful in other contexts (such as leases on an oil reservoir) when the true value of the contract is the same across all bidders, but the bidders all have different information on the "common value" (e.g., the amount of oil in the ground). Thus, a more accurate price is achieved by allowing bidders to pool information via multiple rounds (this avoids under-bidding to avoid "the winner's curse"). In the capacity market, this logic does not apply since there is no "common value" aspect of the capacity market contract. • *In theory:* The other theoretical benefit of multi-round auctions is related to products that have a "contingent value" such as spectrum auctions, where the value of a radio broadcast right in one area is higher if also receiving the same spectrum in a neighboring area. • *In practice:* This benefit also does not apply in capacity auction contexts since there is only one product being cleared.
Multi-Round ("Descending Clock")	• Price discovery in early rounds may help marginal suppliers decide what to bid. This is likely to be minor or not applicable in the context of a capacity market, where price discovery is not likely to be efficiency improving (as most bidders' costs are private costs and little information about private value can be gleaned from other bidders' behavior, as discussed above). • Similar result as single-round auction in higher price ranges where bids must be pre-approved by the market monitor, at least for existing resources. • Better clearing with multi-product auctions (though not as efficient as if those multi-product auctions can be simultaneously co-optimized).	• More complicated if using zonal capacity product (N/A in Singapore). • More exposure to the exercise of market power, gaming, and collusion (as price discovery may allow participants to infer when they are pivotal and change their offers accordingly).

We believe it is best to use the standard single round approach for two reasons:

- This approach helps limit exercise of market power. The descending clock approach could allow participants to infer when they are pivotal and exercise market power when they would not have risked doing so in the single round format.
- The primary theoretical advantage of descending clock auctions, which is that bidders can learn information about other participant's cost of providing the good being auctioned, and that "crowdsourcing" this information may lead to better bids,

is largely not applicable in capacity markets. In capacity markets, most of the costs each participant would incur to provide the capacity product are privately known and not highly correlated across participants.

Across other capacity markets, only ISO-NE and UK use a multi-round, descending clock approach. We are of the view that the benefits of a multi-round design in these capacity auctions are overstated. The theoretical benefits of multi-round auctions are much more applicable in other types of products, as described above. Further, the way that ISO-NE implements the multi-round auction make the outcome similar to a single-round auction in any case (as any medium- or high-price offers for existing resources are capped in advance, market participants are not able to change their offer prices as information is gleaned over rounds of the auction).

Sealed-Bid Auction. Market participants in the FCM will submit sealed bids. In a sealed bid auction, the offers of the participants are not revealed to the other participants during the auction. The additional information made available to participants via open bidding may introduce greater opportunities for gaming. This shortcoming has led all existing capacity auctions to use the sealed bid approach.

B. Offer Format and Auction Clearing (Next Round)

Our initial proposal is that resources can submit multiple offer segments (e.g., a maximum of five to ten offer segments), which can each be rationable (can partially clear) or non-rationable ("lumpy"). Higher priced segments will not clear unless lower-priced segments clear first. Lumpy resources can be guaranteed all-or-nothing clearing. Allowing multiple offer segments will allow suppliers to represent a range of potential underlying cost structures of their supply resources. Suppliers may be able to offer additional capacity at a higher marginal cost, for example via inlet chilling or refurbishment, at incremental cost, or adding higher-cost demand response to a portfolio. It is also consistent with best practices in other jurisdictions. Allowing both rationable and non-rationable offers allows efficient clearing of discrete units of capacity that may affect how suppliers make investment and/or operations and maintenance decisions in the forward and delivery periods.

The mechanism for auction clearing and price setting will need to be developed further as we continue to design the FCM. There are different approaches to auction clearing, such as maximizing social surplus, minimizing consumer costs, or based on a set of heuristics. These approaches generally approximate the intersection of supply and demand but accommodate the complexities introduced by lumpy and segmented resource offers. This will include the development of procedures for tie-breaking cases. Auction clearing procedures will be transparent and shared with all market participants.

C. Commitment Term

The default delivery period for all resources will be a single year (after a few shorter delivery periods during a transition to the "end-state" market). It may be beneficial, however, to allow some resources to "lock-in" the clearing price for multiple years after they are initially cleared in the auction. The potential advantage to this approach is that it reduces revenue uncertainty and may help reduce financing costs for capital-intensive new resources or refurbishments to existing resources. This may lower clearing prices in the FCM and/or reduce the risk of failing to attract sufficient new resources when needed. In addition, it may facilitate greater competition by attracting investments that would not have otherwise participated in the capacity market.

However, even if improving revenue certainty can allow suppliers to offer lower prices, this does not necessarily translate to lower overall costs to consumers. Most importantly, providing price certainty does not eliminate risk, but rather merely shifts risk from suppliers to consumers. This risk manifests as the potential for paying above-market prices to locked-in capacity in subsequent years. Whether the efficiency of market clearing outcomes is improved depends on whether suppliers or buyers are better able to manage or absorb the risk. Other potential disadvantages are described in the table below.

Table 10: Advantages and Disadvantages of Multi-Year Price Lock-Ins

Advantages	Disadvantages
• Revenue certainty may be beneficial to lower financing costs, thereby lowering supply offers and market clearing prices. • Encourages greater participation in the FCM, which can help to improve resource adequacy and mitigate against under-supply conditions when significant new capacity is needed.	• Risk of locking-in expensive supply, increasing costs in subsequent years when capacity prices are lower. • Discriminates against existing resources and may distort the incentives for generation owners. With the option for a lock-in on new resources, generation owners may have less incentive to invest in maintaining existing resources and more incentive to build new resources, even if maintaining existing resources is the lower-cost option for providing capacity to the market. • Special provisions to incentivize new investment could be distortionary if they reduce investors' incentives to carefully assess future market conditions. In particular, lock-ins diminish the importance of future market conditions (supply and demand outlook, technology costs, etc.) and increase the importance of current market conditions for suppliers making investment decisions.

Several other jurisdictions with capacity markets allow new and refurbished resources to lock-in prices in this way, as described in Table 11.

Table 11: Price Lock-ins in Other Jurisdictions

Jurisdiction	Eligibility	Term	Rationale
ISO-NE	New & refurbished	Up to 7 years	Smaller markets with lower investor confidence and/or shorter history of capacity market; deemed necessary to provide revenue stability to attract sufficient investment
Great Britain	New & refurbished	Up to 15 years for new; up to 3 for refurbished	
Ireland	New & refurbished	Up to 10 years	
IESO	New & refurbished*	?	
PJM	No Lock-In*	-	Significant investor confidence. Not deemed necessary to attract new investments
NYISO	No Lock-In	-	Most investments supported by long-term contracting (by traditional utilities); not necessary to attract new investments
MISO	No Lock-In	-	

Notes: Ontario suspended design and implementation of the FCM so details of the multi-year lock-in were not finalized. PJM does have a very narrowly defined price lock-in for the purpose of supporting prices in small, transmission constrained zones where a large new resource could suppress capacity prices for a sustained period. It is almost never triggered and sufficiently different in scope and design that we do not consider it here.

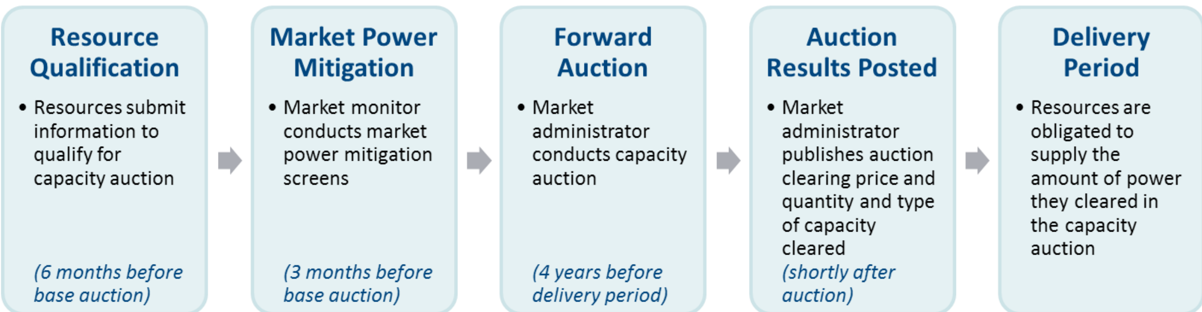
Notably, in other jurisdictions that have a multi-year lock-in provision, existing resources are never included. These resources have already entered the market and made large, irreversible investments. A price lock-in is not needed to attract them to the market, and a single-year term is sufficient for existing resources to recover avoidable going-forward costs if they clear the capacity market. Furthermore, allowing existing resources to lock in prices for multiple years may artificially delay economic retirements and hinder investment in new resources. Finally, it could substantially reduce the liquidity in subsequent auctions, increasing market power concerns.

Thus, we recommend that EMA discuss with stakeholders the advantages and disadvantages of allowing price lock-ins for new resources and capital-intensive refurbishments.

D. Auction Timelines

The FCM market rules will establish the timing of events leading up to the auction, immediately after the auction, and for the period between the auction and the delivery period. These procedures are illustrated in Figure 11.

Figure 11: Preliminary Timeline for Base Forward Auction



Pre-auction: During the pre-auction period, the market administrator will need time to qualify resources, and the market monitor will need time to implement market power mitigation procedures (see Section V on market power mitigation). Other jurisdictions begin these processes five to nine months before the auction. The responsible institutions in Singapore will need to assess how much time is required to conduct these functions, and establish the timelines appropriately.

Post-auction: After each auction, the results should be published in a timely manner, usually within a few weeks. The published auction results should, at a minimum, include information on the clearing price, how much capacity cleared, and what types of resources cleared. The lag time allows the market monitor to assess auction performance to check for ex-post signs of market power abuse or other inefficiencies, then to publish the results of that assessment. On longer time scales, the overall performance of the FCM should also be assessed, likely by an independent third party, after every few years (perhaps more frequently at the beginning of FCM implementation).

Forward period: The forward period refers to the time between the auction and the start of the delivery period. We recommend a four-year forward period, consistent with the expected lead-time needed to incorporate planned new CCGTs in Singapore. A shorter forward period may limit the types of resources that could make their development contingent on clearing the FCM. A longer forward period would increase the uncertainties that exist between the base auction and delivery of capacity. This would increase risks for suppliers by introducing more uncertainty regarding the status of their resource so far in the future; it would increase risks for consumers of over-procuring capacity based on larger errors in such long-term forecasts.

E. Recommendations for Singapore

Recommendations and Next Steps
Capacity Auction Design • Adopt a uniform-price, single-round, sealed-bid auction design
Commitment Term • Adopt a one-year commitment term (delivery period)
Next Steps • Determine whether multi-year price lock-ins will be available, and how they should be designed • Develop design of offer format and auction clearing

VII. Rebalancing Auctions (Next Round)

Rebalancing auctions are designed to address the uncertainty (both demand-side and supply-side) between when the base auction occurs and when the delivery period starts. On the demand side, the load forecast may change, which will affect how much capacity the EMA wishes to procure. On the supply side, resources' availability may also change, necessitating a mechanism to allow resources with a capacity supply obligation (CSO) to buy out of previously committed positions. The rebalancing auction is a voluntary market that can be used to transfer CSOs between qualified suppliers at a new clearing price.

Our recommendation is to conduct one or more rebalancing auctions between the base auction and the delivery period, with the last rebalancing auction about 12 months prior to delivery. The timing of the rebalancing auctions and base auctions (for different delivery years) can be staggered to prevent having to conduct multiple auctions in a short time period. Details will be developed at a later time.

Preliminarily, the FCM market rules should establish the format and participation model of the rebalancing auctions:

- **Auction Format and Demand Curve:** Our proposal is that the same auction format apply as in the base auctions. In addition, while auction parameters (primarily the load forecast) may be updated, we recommend that the demand curve shape in the rebalancing auction otherwise be unchanged from the forward auction. Any systematic discrepancies in auction format or curve shape and position have the potential to create incentives for suppliers to arbitrage between these auctions to capture the value differential between these curves.
- **Auction Clearing Mechanism:** There are two possible clearing mechanisms in rebalancing auctions: gross clearing and net clearing. Under the gross clearing mechanism, all supply and demand in the market are represented in the auction. The demand curve shape is the same as in the base auction, providing for a clear way of seeing the effect of updated auction parameters on the administrative demand curve. Under the net clearing mechanism, only supply and demand that is incremental to the base auction is represented. This means that buy-out bids appear on the buy side, as expected. Our initial proposal is to implement the same clearing approach as in the base auction (gross clearing), and combine it with a settlement on a net basis (i.e., only the incremental cleared quantities would be settled at the rebalancing auction price). This allows market participants that do not wish to change their position to be unaffected by the rebalancing price.
- **Supply Resources Offers and Bids:** During the rebalancing auctions, market participants may want (or need) to change their capacity commitments because of changes in resources' availability or performance rating. To allow for these types of adjustments, the initial proposal is that market participants will be allowed to submit the following types of offers and bids:
  - **Incremental Sell Offers:** Enable suppliers to offer in additional capacity that has been made available or capacity that requires a shorter lead time (for example, demand response and imports);
  - **Buy-Out Bids:** Enable suppliers to buy out of their committed positions (for financial reasons or because they are no longer able to provide the capacity); or
  - **Do Nothing:** Enable capacity suppliers who do not wish to change their supply to participate as a price taker on the supply side during the rebalancing auctions. This will not incur any settlement as a result of the auction; the capacity price of their previously committed positions will remain unchanged.

VIII. Bilateral Transactions (Next Round)

Gencos, other market participants, and independent retailers may wish to transact CSOs for a variety of reasons outside of the centralized capacity auctions, both before the base auction, during the forward period, and potentially during the delivery period. These transactions may be used to hedge capacity costs or to assign a CSO to another qualified supplier in cases of unexpected inability to provide capacity during the delivery year. The market should enable these bilateral transactions.

We are exploring the development of a simple mechanism to track the bilateral exchange of CSOs from the auction. For simplicity, we do not advise facilitating and tracking financial bilateral transactions. Market participants can transact financially on their own. What the market administrator must do is track when one entity assumes the physical obligations of another.

Outside of the capacity auction, large loads or retailers may want to enter into bilateral transactions with capacity suppliers that lock in capacity prices even before the base auction. EMA could provide information for market participants to form their view on supply/demand conditions and market prices.

IX. Supply Obligations and Performance Assessments (Next Round)

Suppliers receiving a CSO will be subject to obligations that require them to participate in the energy and/or ancillary services markets. In addition, they may have other obligations such as participating in performance testing and data collection activities necessary to calculate qualified capacity levels. Specific offer and testing requirements for capacity resources, which may vary by resource type, will be developed through subsequent consultations.

Performance assessments measure compliance with obligations, and associated penalties determine how compliance will be incentivized. The combined incentives from energy market prices and potential capacity market penalties encourage efficient operations and investment.

A. Obligations on Capacity Resources

Obligations on the capacity product procured during the capacity auction has to be properly defined. As a starting point, best practices in other jurisdictions with a day-ahead energy market is to enforce a must-offer requirement to ensure the full available capacity of committed resources. These obligations accomplish two objectives:

- Ensure availability during shortage conditions; and

- Mitigate the potential for exercise of market power.

As several stakeholders have emphasized, in the SWEM, the absence of a day-ahead market precludes strict must-offer requirements, as resources are self-committed. As a result, they may not be available in the short timeframes required by the real-time market, for example if they have longer start-up times (some conventional generation) or notice periods (some demand response). Instead, we recommend accomplishing the two objectives listed above through alternative mechanisms. To ensure availability during shortage conditions, we recommend obligating all resources that are available to offer in the real-time market. Resources that are not available in the real-time market must be available for emergency, out-of-market commitment by the system operator.

We also propose conducting periodic ex-post review of suppliers' operational behavior to ensure their pattern of self-commitment is consistent with competitive behavior. These and other mechanisms to mitigate market power in the SWEM, will be discussed in more detail Section XI.

B. Penalties for Resource Unavailability

Incentives for resource performance during shortage conditions can come both from the energy market and from the capacity market. We recommend energy market prices reflect marginal system costs, including scarcity and the costs of administrative actions during shortage conditions, up to the energy market price cap.

Capacity performance incentives and penalties are important to encourage performance and solidify the value of the capacity product:

- **Availability and Performance Incentives.** Several markets have established penalty and/or incentive mechanisms that measure suppliers' availability during pre-defined hours of the year and/or performance during shortage conditions. The purpose of an availability mechanism is to reward sellers for maintaining availability for dispatch to the system operator, especially during times when the resource is most likely to be needed for supply adequacy. As a starting point, we suggest applying availability-based penalties to incentivize reliability of resources that have been committed through the capacity auction. Performance penalty mechanisms encourage strong in-year performance from resources and readiness to respond to dispatch instructions. These availability and/or performance penalties would account for planned maintenance and unplanned outages included in the QCAP determination, but would penalize resources for performance below their QCAP amount.
- **Penalty Rate.** The total size of potential penalties needs to be large enough to encourage delivery of the promised capacity, but should not be so burdensome as to reflect a cost far beyond the value of the underlying capacity. The penalty payment can be developed considering a few options such as:
  - Tying the penalty rate to the original capacity price (e.g., a penalty rate at 1.2 to 1.5 times the capacity price), which caps the overall magnitude of the penalty payment and associated risk at some reasonable fraction of the potential reward;

- Imposing a floor on the penalty rate that would apply in circumstances when capacity market prices are low;
- Imposing a minimum penalty at some factor above the clearing price in the last incremental auction before delivery, which would ensure that deficient suppliers have an incentive to procure replacement capacity; or
- Setting the penalty at the capacity auction price cap or some factor above it, again creating incentives to secure replacement capacity if any is available.

X. Settlements and Cost Allocation

The costs of procuring capacity in the FCM should be allocated to consumers in a manner that sends fair and efficient price signals for them to reduce load and mitigate the need for capacity to maintain reliability.

Accordingly, we recommend capacity costs be allocated to consumers or retailers that serve end-users in proportion to actual MWh consumption during peak hours on all non-holiday weekdays of the year. We elaborate on and justify this recommendation below.

A. Principles and Best Practices

A key principle of cost allocation that underlies our recommendation is that the allocation of costs should be aligned with the drivers of those costs. This ensures that the market can send accurate price signals so consumers can respond efficiently. The capacity market is intended to ensure sufficient resources are available to serve load during shortage or near-shortage conditions, which generally align with times that the load on the system is the greatest.[36] Thus, costs should be allocated in a way that reflects consumption during those peak periods: consumers that consume more during those periods and contribute more to the peak demand level should contribute more to capacity cost recovery. By aligning the price signal with the peak period, consumers have an incentive to reduce consumption during the system's peak, which should allow the market to efficiently reduce the need for additional capacity in the future and, in turn, reduce the overall capacity cost of the system.

The precise definition of the peak period used to determine capacity cost allocation varies across jurisdictions, generally reflecting underlying characteristics of each market:

- In markets where the annual load factor is high (i.e., a non-peaky load profile where the average load is close to the annual peak load), a **wide peak period approach** is most efficient. Under this approach, the peak period can be pre-defined to include a wide range of hours throughout the year. This "ex-ante" approach allows consumers to plan

[36] The alignment is not perfect due to planned and unplanned maintenance outages, variation in output from variable renewable energy, and other factors.

to reduce their consumption broadly over many peak hours. This incentive aligns with value since such markets are vulnerable over a broad range of hours when loads are close to their maximum, and random generator outages can cause shortages.

- In markets where annual load factor is lower, it is likely more efficient to adopt a **narrow peak period approach**, where consumers are charged based on their consumption during only a few of the highest realized load hours during the year. Since it is only possible to determine when these peak load hours occurred after the fact, it is necessary to select these hours on an ex-post basis, and they are used to allocate capacity costs for the *following* delivery year. With the price signal concentrated in a few high-consumption hours, consumers have a strong incentive to anticipate when these highest load hours will occur and reduce their consumption during those periods. These strong price signals will likely lead to stronger demand reductions in those hours, efficiently reducing capacity costs.

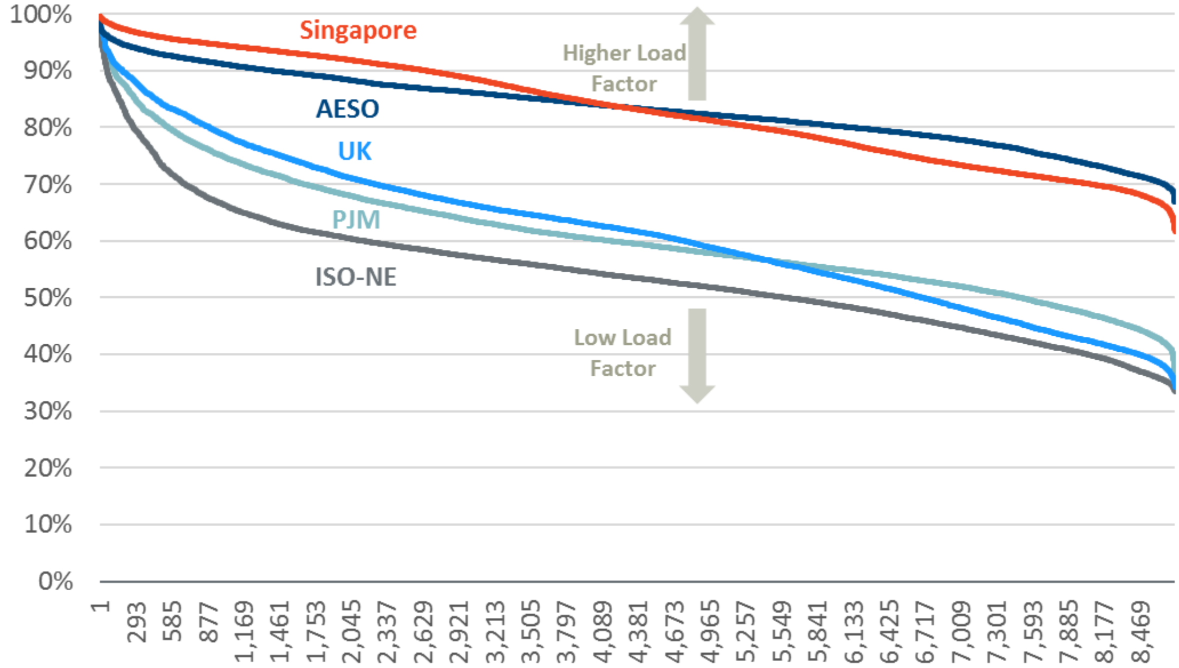
Selecting the peak period for cost allocation purposes can have significant impacts on market efficiency. For example, consider a market with a relatively flat annual load profile but where capacity costs are allocated on an ex-post basis across only the highest few peak hours in the year. Consumers would aim to reduce their consumption in just those highest hours but might not considerably reduce the need for capacity absent an incentive to reduce consumption during other high consumption periods. Conversely, if a market had very pronounced peak loads but costs were allocated according to consumption over many hours, then capacity costs would likely stay relatively unchanged, as consumers would broadly reduce their consumption, but not focus those efforts in the most important, highest load hours. It is important that the cost allocation approach reflects the actual drivers of the costs so that price signals incentivize efficient behavior from the consumers.

None of the cost allocation approaches presented here runs any risk of under-recovery. In each delivery year, *actual* capacity costs are fully allocated according to the methods described above. Thus, even if consumers reduce their consumption during the relevant peaks, the total costs allocated will still be sufficient. In the medium and long run, load reduction during the peaks will reduce capacity needs and system costs for all consumers.

Approaches in Other Jurisdictions

As discussed above, markets with higher load factors should find it beneficial to allocate costs using a broader, ex-ante peak period definition, whereas markets with a lower load factors and more pronounced peaks should adopt a narrower, ex-post peak period definition. This pattern is generally confirmed in our review of other jurisdictions. Alberta (designated as "AESO" in the graph) relies on ex-ante, wide peak period definitions corresponding to its high load factor, as shown in Figure 12. PJM and ISO-NE rely on ex-post, narrow peak period definitions and have the lowest load factors. The UK has a load factor more similar to PJM but still determined that a wide peak period definition was most appropriate for reasons we have not been able to confirm.

Figure 12: Load Duration Curves across Markets



Sources and notes: The Singapore, AESO, PJM, and ISO-NE load duration curves reflect 2018 load. UK load duration curve reflects 2015 load (latest we could find publicly available). AESO, PJM, ISO-NE data from Ventyx Velocity Suite. UK load data from European Network of Transmission System Operators for Electricity. Singapore load data provided by EMA.

Alberta's (AESO's) proposed approach allocates costs according to MWh consumption during a broad range of hours in peak and mid-peak blocks.[37] These blocks were determined by an analysis of the distribution of expected unserved energy (EUE) as follows:

- The peak blocks represent the very highest load hours throughout the year in August through October, for hours ending 16:00 – 18:00 (HE16–HE18) and November through February HE18–HE19; these hours receive the highest cost allocation (on a per-MWh basis); and
- The mid-peak block represents the other hours with non-negligible EUE potential throughout the year (HE8–HE23 excluding the already designated peak hours);[38] these hours receive a lower cost allocation.

By choosing to allocate costs on a wide range of hours, the AESO would be able to incentivize load reduction during peak times throughout the year, which is valuable given their very flat load duration curve.

---

37 Although the AESO capacity market was recently cancelled, their proposal materials offer another legitimate point of reference.
AESO, *Tariff Design for Capacity Market and Bulk and Regional Transmission Cost Allocation*, March 2019.

38 AESO considered hours with unserved energy contribution greater than 0.0007% per hour across months. The period they chose had a lower bound of about 10 observations of a given month-hour exceeding the 0.0007% EUE cutoff.

The U.K. also relies on a broad peak period definition, even though its load duration curve is not quite as flat as that of Alberta.[39] The U.K. defines its peak periods, or "periods of high demand," from hour ending 17:00 – 19:00 on any workday between November and February. Consumers are charged based on their volumetric (MWh) consumption during these periods, similar to Alberta's approach.

PJM, which has a relatively much lower load factor, and thus higher peak demand, relies on a narrow peak period definition, where costs are allocated based on *actual* consumption during the five highest coincident peak hours in the year.[40] The effect of this approach is that capacity costs are allocated according to consumption during very few (five) hours in each year. Each consumer's peak load contribution (PLC) is calculated as its consumption during the (five) coincident peaks and each retailer who serves load has an obligation that reflects the sum of the PLCs across all its consumers. Because these periods are determined after the delivery year, they are used to allocate capacity costs for the *next* delivery year. This necessitates an additional step of tracking consumers as they can potentially switch between retailers from one year to the next.

ISO-NE allocates capacity costs using a single coincident peak methodology.[41] Similar to PJM, ISO-NE has relatively very high peak loads such that it seeks to focus capacity price signals on just the highest load hour of the year. Relying on this narrow peak methodology, capacity cost allocations are based upon consumption during the annual system-wide coincident peak load for the prior year.

B. Recommendations for Singapore

We recommend that costs of Singapore's FCM be allocated to consumers or retailers in proportion to actual consumption during peak hours on non-holiday weekdays of the year. In this section we step through each component of this recommendation.

Costs Allocated in Proportion to Actual Consumption

As outlined above, capacity costs should be allocated in a way that reflects the cost drivers. Since the load duration curve in Singapore is relatively flat, as shown in Figure 12, we propose to adopt an ex-ante, "wide peak" approach where the costs are allocated across a broad set of pre-established hours. This has the advantage of spreading the cost allocation across many hours that contribute to incurring capacity costs, and gives consumers a defined set of hours during which they receive an incentive to reduce their load. To reflect prevailing supply/demand conditions, some hours could be allocated higher costs per kWh.

Allocating costs to a very narrow set of hours defined after the delivery year, as in PJM and ISO-NE, would not be appropriate for Singapore. This coincident-peak allocation approach would send a price signal that is too concentrated given the flat load duration curve of the Singapore system.

---

39 EMR Settlement Limited, *G12 – Supplier Capacity Market Demand Forecast*, June 2018.

40 PJM, *Manual 18: PJM Capacity Market*, Section 7 (pp. 149-155), January 2019.

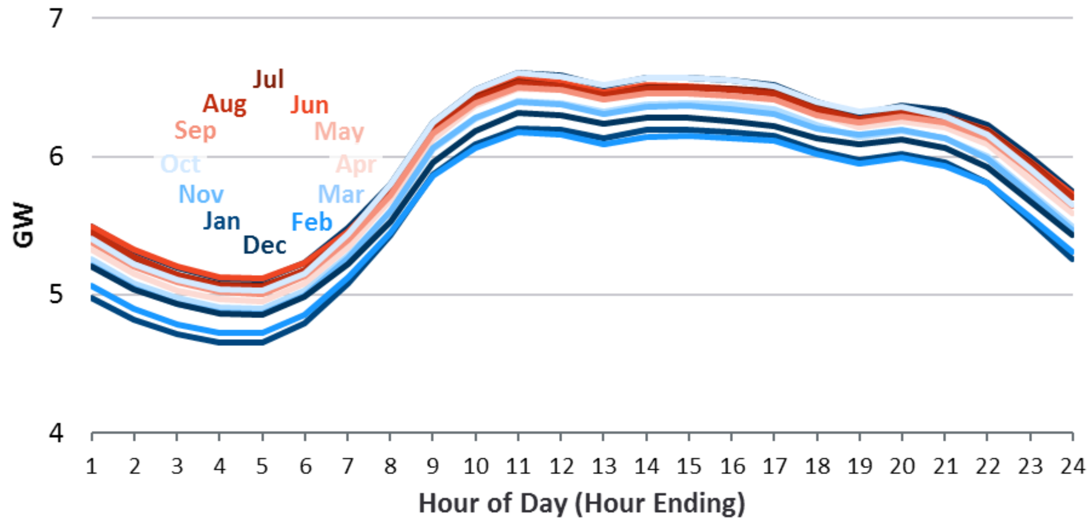
41 ISO-NE, Demand-Side Settlement – FCM Charges, October 2018.

Regarding the mechanics of cost allocation, we recommend establishing a volumetric rate (S$/MWh) that applies to all consumption during the peak period, described below. The rate would be calculated to recover the appropriate capacity costs over the expected volume of consumption. Monthly (or quarterly) true-ups could be used to continually adjust the rate going forward if there is slight under-collection or over-collection in preceding months. Details will be developed at a later time.

COSTS ALLOCATED TO PEAK HOURS

We propose to use a constant set of hours throughout the year to define the peak period. As shown in Figure 13, the daily load profile is almost identical across months such that the highest load hours remain fairly constant. Additionally, using a consistent set of hours will help to keep the peak period definition simple, although it may not perfectly capture intra-day granularity such as the dip during the midday lunch hour.

Figure 13: Representative Daily Load Profile across Months

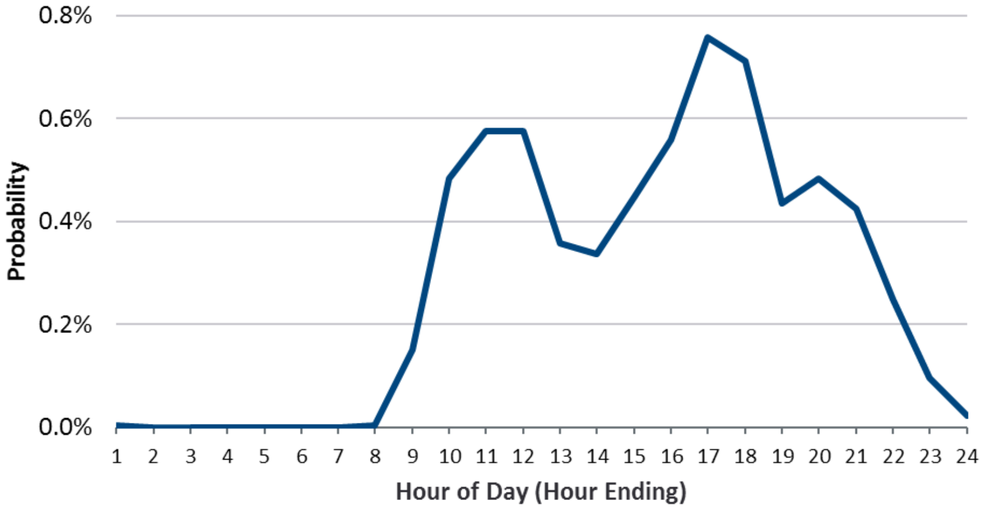


Sources and notes: Representative daily load profiles reflect average monthly-hourly load during 2014-2018. Singapore load data provided by EMA. Note axis does not begin at zero.

The threshold to determine the exact definition of peak hours within the day is somewhat subjective, but should reflect the marginal reliability cost associated with incremental electricity usage, or inversely, the reliability value to the system of conserving a marginal MW. As shown in Figure 14, this probability is highest in the late morning through evening, when average system load is highest across all days. Based on a preliminary analysis, one reasonable definition of peak load could be HE10–HE21. This would capture all hours with an average probability of shortage conditions exceeding 0.3%.

An alternative approach, is to define a "peak" and "mid-peak" period, as proposed in Alberta; the peak period would have higher per-MWh costs allocated to it to reflect the higher value of consumption/conservation during those hours. The disadvantage of such a solution is that it likely only marginally improves the efficiency of the price signals, while somewhat adding to the complexity of both the cost allocation design and the price patterns to which consumers would be expected to respond.

Figure 14: Average Probability of Shortage Conditions by Hour of Day

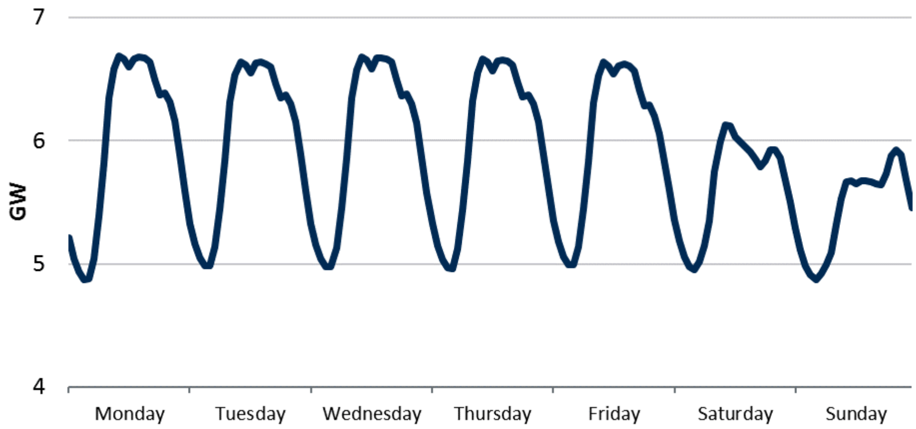


Sources and notes: Figure reports average probability of shortage conditions in EMA reliability analysis for 2030. To calculate the average probability of shortage conditions, we count the number of intervals with load-shed events in each hour of the day, divided by the total number of intervals represented by each hour. Data provided by EMA.

Costs Allocated Only to Non-Holiday Weekdays

We propose to allocate capacity costs to reflect consumption during peak hours only on non-holiday weekdays.[42] The data show that load on weekends is significantly lower and does not present risk of shortage events. As shown in Figure 15, the weekends have much lower average loads than weekdays.

Figure 15: Representative Weekly Load Profile



Sources and notes: Representative weekly load profile reflects average hourly load during 2014-2018 across days of the week. Note axis does not begin at zero. Data provided by EMA.

Weekends have considerably lower average load as well as daily peak load. This is further captured in Figure 16 and Figure 17, where we observe that Saturday and Sunday have

42 We have heretofore only analyzed weekday vs. weekend load, as load on holidays in Singapore follows a similar pattern to that observed on weekends (as we have observed in other markets), and as such should also be excluded from the definition of peak hours for cost allocation purposes.

significantly lower load throughout the peak period and do not contain a single observation in the top five percent of load throughout the year. Thus, we conclude that consumption on weekends is very unlikely to contribute to potential shortage conditions, and thus should not be considered for the purposes of cost allocation.

Figure 16: Average Load in Each Hour and Day of Week (GW)

	Hour Ending																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Monday	5.2	5.0	4.9	4.9	4.9	5.0	5.4	5.8	6.3	6.6	6.7	6.7	6.6	6.7	6.7	6.7	6.6	6.5	6.4	6.4	6.3	6.2	5.9	5.6
Tuesday	5.3	5.2	5.0	5.0	5.0	5.1	5.5	5.8	6.3	6.5	6.6	6.6	6.5	6.6	6.6	6.6	6.6	6.5	6.4	6.4	6.3	6.2	5.9	5.6
Wednesday	5.3	5.2	5.0	5.0	5.0	5.1	5.5	5.9	6.4	6.6	6.7	6.7	6.6	6.7	6.7	6.7	6.6	6.5	6.4	6.4	6.3	6.1	5.9	5.6
Thursday	5.3	5.1	5.0	5.0	5.0	5.1	5.4	5.8	6.3	6.6	6.7	6.6	6.6	6.6	6.7	6.6	6.6	6.5	6.4	6.4	6.3	6.1	5.9	5.6
Friday	5.4	5.2	5.1	5.0	5.0	5.1	5.4	5.8	6.3	6.5	6.6	6.6	6.5	6.6	6.6	6.6	6.6	6.4	6.3	6.3	6.2	6.1	5.8	5.6
Saturday	5.4	5.2	5.1	5.0	5.0	5.0	5.1	5.4	5.7	6.0	6.1	6.1	6.0	6.0	5.9	5.9	5.9	5.8	5.8	5.9	5.9	5.9	5.7	5.5
Sunday	5.3	5.1	5.0	4.9	4.9	4.9	5.0	5.1	5.3	5.5	5.7	5.7	5.6	5.7	5.7	5.7	5.6	5.6	5.7	5.9	5.9	5.9	5.7	5.5

Sources and notes: Table reports average load in 2018 across each day-of-week and hour. Darker red shading indicates higher load. Data provided by EMA.

Figure 17: Distribution of Hours in Top 5% of Load

	Hour Ending																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Monday	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	4%	3%	2%	3%	3%	3%	3%	1%	0%	0%	0%	0%	0%	0%
Tuesday	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	3%	3%	2%	3%	3%	3%	3%	1%	0%	0%	0%	0%	0%	0%
Wednesday	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	3%	2%	1%	2%	3%	3%	2%	0%	0%	0%	0%	0%	0%	0%
Thursday	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	2%	1%	3%	3%	3%	2%	0%	0%	0%	0%	0%	0%	0%
Friday	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	3%	2%	1%	2%	3%	3%	2%	0%	0%	0%	0%	0%	0%	0%
Saturday	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Sunday	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Sources and notes: For each day-of-week and hour in 2018, we report the fraction of half-hour observations that fall in that period and are in the top 5% of highest system load observations. Data provided by EMA.

Costs Allocated in Every Month of the Year

Singapore experiences relatively small variations in load patterns across the year. As a result, shortage events could occur in any month and, therefore, load in all months drives capacity costs. This relatively consistent monthly load pattern is captured in Figure 13.

Since load is relatively even across months, the supply cushion, which represents the difference between load and the available capacity to serve that load, is very similar during peak hours of each day throughout the year. As a result, we expect that the effect of a marginal unit of consumption on reliability during on-peak, weekday hours should be relatively similar throughout the year. Following the principle of cost causation, this implies that costs should be equally distributed across all months of the year.

Recommendations and Next Steps
Cost Allocation Approach • Define the peak period as certain hours on all non-holiday weekdays of the year • Determine S$/MWh rate to allocate capacity costs volumetrically to energy consumed during defined peak period
Next Steps • Finalize peak period definition • Design mechanics of settlements, including monthly (or quarterly) true-up when consumption during peak is higher or lower than expected (leading to differential between capacity costs and costs collected) • Define rules concerning pass-through of capacity charges to consumers.

XI. Reforms to Energy/Ancillary Services (Next Round)

The introduction of an FCM can be complemented by changes to the existing energy and ancillary services markets to ensure the combined markets function efficiently.

First, because a FCM provides for recovery of fixed costs, resources' energy offers can potentially be mitigated to their short-run marginal costs. This emulates a perfectly competitive energy market and allows the market to always clear the resources with the lowest costs. We have noted industry feedback regarding this recommendation and will be reviewing it in subsequent design phases.

Second, alternative or additional ancillary services may be warranted if operations assessments indicate that some system needs are not currently met reliably. For example, if ramping supply is found to be in short supply during certain conditions, a flexible ramp product could be introduced to provide a revenue stream to suppliers that can provide valuable ramping.

BOSTON
NEW YORK
SAN FRANCISCO

WASHINGTON
TORONTO
LONDON

MADRID
ROME
SYDNEY

THE Brattle GROUP