Commissioner Primer

Wholesale Electric Capacity Markets

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Executive Summary

Capacity markets, a component of some of the existing organized wholesale electric markets, are an issue of significant debate within the larger discourse of the organizing and organization of wholesale electric markets. These markets place a tradable value on the availability of generation capacity. In theory, this commodity value removes some of the financial risk of building generation facilities in an open market where cost-recovery of the facility is not as secure as it might have been in a previous, integrated, single-provider market. Currently, PJM, ISO-NE and NYISO all have capacity auction markets. The earliest of these has been operating in some form since 1998.

This primer outlines the basics of capacity market operations and shows how the market makes available capacity a tradable value. The current markets are increasingly sophisticated. Market capacity quantities and values are not random or simply at the will of the auction participants. Coordinators establish tradable quantities considering peak-load forecasts, specific generator reliabilities and detailed outages/maintenance schedules. However, the variations in available capacity levels from region to region and state to state and the differing wholesale and retail market structures suggest that current Installed Capacity (ICAP) markets cannot be simply implemented in all regions in the hope of benefiting resource adequacy objectives. Additionally, given the market design of rewarding those with excess Unforced Capacity (UCAP) credits or penalizing those that fall short of requirements, there may be incentives to artificially manipulate the market to gain rewards or push penalties to competitors.

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INTRODUCTION

Generators in open wholesale markets have less certainty of recovering costs for facilities than integrated generators under traditional regulation.

Encouraging efficiency increases and price decreases are often stated among the policy goals of fostering open competitive utility markets. Whether or not the operation of the wholesale electricity generation market drives efficiencies and leads generators to move prices toward the marginal costs of production, one result of the open market is perhaps more certain. Generators that might have once had a certain level of expectation that the costs of building generation facilities could be recovered over time now have much less certainty of cost recovery.

Theoretically, as the number and/or competition level of wholesale electricity generators increase, the level of profit certainties for those generators continues to decrease. As this occurs, the fixed costs associated with new generation investment becomes more prohibitive. From the parlance of basic economics, in a perfectly competitive market, prices are driven to marginal costs and profits are driven to zero, making it impossible for a firm to recover its fixed costs. If this were to be the case, the result would be that new generation capacity would fail to grow in pace with the growth in demand for new capacity. The dilemma then is how to ensure sufficient capacity development within an open market.

Placing a commodity value on the availability of new capacity may be one way to entice investment.

Placing a commodity value on the availability of new capacity in addition to the value of the actual generation sold from a plant may be one way to entice new capacity investment. This is the theory behind the creation of "capacity markets." Capacity markets are a component of some of the existing organized wholesale electric markets under regional transmission operators (RTOs). The markets were developed to help ensure that the supply of electric generation grows in step with demand for electricity consumption.

Debate exists as to whether the current capacity markets do result in increased incentives to make new electric capacity available. There is also debate as to whether the capacity markets' current configuration encourages market power abuse and/or results in inappropriate price increases or profit shifting. In some areas of the country, where regional excess capacity levels appear relatively high, the very notion that there is a need to encourage additional generation capacity can fuel the debate on the desirability and feasibility of capacity markets. Conversely, where local capacity is in less abundant supply and transmission congestion is common, doing something to encourage capacity availability may seem essential.

Currently, capacity markets are most developed in the northeast United States. PJM, ISO-NE and NYISO all have established capacity markets. The earliest of these has been operating in some form since 1998. As capacity markets continue to evolve and/or expand, understanding the theoretical intent behind these markets and the basics of how these capacity markets operate is increasingly essential for all policymakers. It is very important to determine if the markets serve the intended and desired purpose or if they pose a threat of market abuse leading to increased prices and/or mere profit shifting.

Though the rules differ from market to market, many of the guiding principles are similar. This primer is intended to provide state public utility commissioners who have not yet become familiar with capacity markets with a basic understanding of the theories and operations of these markets. The goal of this primer is not to discuss pros and cons, but to introduce the reader to the key points of capacity markets. Capacity markets appear to be a growing trend and are being strongly promoted and just as strongly opposed within the organized markets.

The operation of capacity markets is not a simple matter and even a basic explanation must include a fair amount of complexity. Even if the reader does not wish to pore over the most technical sections, this primer should enable him or her to understand:

- That capacity markets are components or subfeatures of some of the organized regional wholesale energy markets
- That capacity auctions do not trade electricity, but the availability of electricity
- The difference between Installed Capacity (ICAP) and Unforced Capacity (UCAP)
- The calculation methods for ICAP and UCAP levels
- Pricing of UCAP in coordinator-run auctions

DEFINING CAPACITY

Capacity, generally speaking, refers to an amount of electricity generation and is commonly measured in megawatts (MW). For example, a generator selling 500MW of electricity generation is said to be offering 500MW of capacity. A generation unit typically has a technical capacity rating sometimes referred to as the "nameplate" or "boilerplate" rating. Within the capacity markets, the commodities traded are ICAP and UCAP. A third type, Locational Installed Capacity (LICAP), is used in some markets and is briefly discussed below.

ICAP

Within the capacity markets, ICAP should not be confused with the physically installed capacity or nameplate rating of a generation unit. The required market ICAP level is the sum of a peak load forecast and required reserve margin. The owner of the generator owns the ICAP associated with that generator. At the inception of the capacity markets, it was "ICAP credits" that were bought and sold.

ICAP = Peakload forecast + Required reserve margin.

UCAP

As the markets matured, market coordinators realized a need to encourage generator reliability and remove a potential source of market power. Consequently, UCAP was developed. Intended to improve reliability and eliminate a potential for strategic forced outages, UCAP value is calculated by taking the ICAP and adjusting it based on the reliability of the generator. This conversion, which is discussed in more detail below, gives generators "UCAP credits."

UCAP = ICAP - Reliability factor

Upon introducing UCAP, the common reference to the markets as ICAP markets was not changed. Therefore, though it may be confusing, today UCAP credits are traded in ICAP markets.

LICAP

Some capacity market operators have either implemented or are pursuing a form of ICAP that includes specific locational considerations. In the ISO-NE markets, this form of ICAP was LICAP. For simplicity, this primer uses the term LICAP as a broader reference to capacity market mechanisms in any of the organized markets that include location specific parameters. The idea behind LICAP is that there are pockets within a market where transmission congestion is enough of a regular concern that it is factored into the determination of how UCAP obligations are filled. The development of LICAP in some of the organized markets has encountered significant opposition and

LICAP = Locational specific ICAP

has heightened the overall debate about capacity markets. The concern being that LICAP markets by their nature (as opposed to simple head-to-head competition) may result in some market participants being the beneficiaries of significant price/profit increases at the cost of other participants.

MARKET PARTICIPANTS

Sellers

ICAP and the derived UCAP credits belong, in the first instance, to the entity that owns/controls the specific generation units associated with the ICAP. Consequently, any entity with control rights for wholesale electric generation (whether through direct ownership or an operating agreement) within a designated capacity market can be a seller of capacity in that market.

The development of LICAP in some organized markets has met with significant debate.

Sources outside the defined market may also be eligible to offer UCAP for sale, provided the outside seller meets the same market requirements as those sellers within the market and can guarantee that the unit(s) will not be recalled by its native market.

Buyers

In an ICAP market, UCAP buyers are typically retail electric load serving entities (LSEs) buying credits to fulfill their UCAP obligations. However, the reselling of UCAP credits is also permitted. Thus, any time prior to the final auction in a given market, in addition to LSEs, non-LSEs such as brokerage houses, marketers, or other interested parties may also purchase UCAP credits. For example, a wholesale provider might buy UCAP credits at auction as part of a business strategy to control more UCAP credits for sale at auction or through bilateral contracts. Thus, a buyer in one transaction may become a seller in the next. Non-LSEs that wish to purchase UCAP can do so prior to the final auction, but generally must offer all UCAP that they still possess into the final auction or lose any profits that can be made from its sale. The final auction is the last opportunity for an LSE to obtain UCAP, therefore, the final auction is reserved for LSEs only.

Market Coordinators

The capacity market coordinator acts as a neutral market operator. The coordinator has no financial interest in the market and receives no benefits from the outcome of any capacity market transaction. The coordinator acts as the market auctioneer. The auctions are held periodically in each market. Not all coordinators hold the same number of auctions or follow the same schedule. For example, NYISO offers three auctions (period-long, monthly, and deficiency), while PJM offers four (period-long, multi-monthly, monthly, and daily). A coordinator may host additional auction(s) to allow LSEs more opportunities to fulfill UCAP obligations as the deadlines approach.

The coordinator is responsible for maintaining a properly functioning market. The coordinator establishes, enforces and referees market rules and standards. Penalties may be imposed by the coordinator if a market participant fails to meet the requirements or comply with rules set forth such as audits or data submission. The required level of ICAP in the specific market area, UCAP obligations, the reserve margins, and the manner in which generator reliability is measured are all set and assigned by the coordinator. The coordinator also determines if a UCAP provider located outside the market area can qualify to sell UCAP into the market.

THE BASICS OF CAPACITY MARKET OPERATIONS

Market Periods

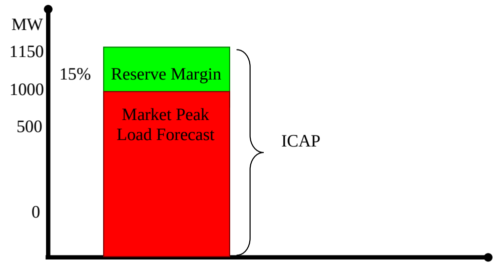
ICAP and UCAP requirements are generally set in two or three seasonal periods. The UCAP requirements are set for the entire operating area, and then divided among LSEs, based on each LSE's serviced load to determine the LSE's obligation. As briefly discussed above, some markets have established LICAP obligations in addition to the market-wide requirements. Though requirements are set by season, the LSE has until the close of the final auction in a given market to fulfill its capacity obligations. An LSE may have to fulfill its obligation daily, monthly, or for an entire period, depending on the market rules established by the coordinator. For example, PJM clears daily, while NYISO clears monthly.

Determining the level of ICAP

ICAP requirements are established by regional coordinators (such as the Northeast Power Coordinating Council or the Mid Atlantic Area Council), state reliability councils, and/or the North American Electric Reliability Council (NERC). The level of ICAP required in a market is based on the peak load forecasts for that market. The coordinator determines the minimum ICAP requirement for the market using a weather-adjusted load level history, a forecast of load growth, and the required reserve margin. The reserve margin is generally the amount of capacity above the peak load forecast that is required to ensure adequate resources. For a given capacity period as defined above, the minimum ICAP requirement for the market is found as follows:

$$ICAP = \text{Peak Load Forecast} \times (1 + \text{Reserve Margin})$$

For example, if the coordinator forecasts the peak load to be 1,000 MW and needs a reserve margin of 15 percent, then the minimum acceptable ICAP is 1,150 MW. See Figure 1.



Source: Author's construct.

Fig. 1: Determining level of ICAP.

A "pool" UCAP obligation is set for the entire market then divided among the LSEs as individual UCAP obligations based on each LSE's percentage of market load served.

Determining the Level of UCAP

The coordinator, after calculating the ICAP, will calculate the total or "pool" UCAP obligation for the market by examining the reliability factor called the Equivalent Demand Forced Outage Rate ($EFOR_d$). $EFOR_d$ is a measurement of the reliability of generators in the market system. It considers how often a generator(s) was called to supply electricity, how often the generator was able to actually supply the called for generation, how many hours the generator operated, and, if the generator was down, how much generation capacity was out of the market and for how long. The coordinator calculates two types of $EFOR_d$: one for the pool and another for individual generators. The pool UCAP obligation is determined using the pool $EFOR_d$, which considers the reliability of all generators in the market. The pool $EFOR_d$ uses an aggregated weighted measurement that combines all generators. $EFOR_d$ is calculated using the following formula:

$EFOR_d$ = Equivalent demand forced outage rate is a rating of reliability used to adjust the UCAP obligations.

$$EFOR_d = \frac{(FULL \times FOH) + (PARTIAL \times EFPOH)}{SH + (FULL \times FOH)}$$

In the $EFOR_d$ formula, FULL and PARTIAL reflect the probabilities that a plant is fully or partially unable to produce when called. FOH and EFPOH refer to the number of hours with forced outage that a generator is completely shut down and the number of equivalent full hours of a partial forced outage, respectively. EFPOH does not include outages that fall under FOH.

$EFOR_d$ is calculated for the pool and for each generator.

$$EFPOH = \text{Number of equivalent hours forced out} - FOH$$
$$= \left(\frac{\text{\# of hours partially out x MWs Out}}{\text{Capacity of Generator}}\right) - FOH$$

In the event of a partial forced outage an EFPOH is found by the number of MWs out times the number of hours out. This number is then divided by the generator's capacity. For example, if a 100MW plant is running at 75 percent capacity for four hours, then EFPOH is one equivalent hour. SH is the total number of hours of actual generation provided. For example, using hypothetical numbers to show the calculations, if FULL is 95 percent, FOH is 250 hours, PARTIAL is 80 percent, EFPOH is 100, and SH is 5000 hours, then

$$EFOR_d = \frac{(.95 \text{ x } 250) + (.80 \text{ x } 100)}{5000 + (.95 \text{ x } 250)} = .06$$

Using the $EFOR_d$, the coordinator is able to adjust for forced outages to maintain reliability. Once the $EFOR_d$ is determined, UCAP is calculated as follows:

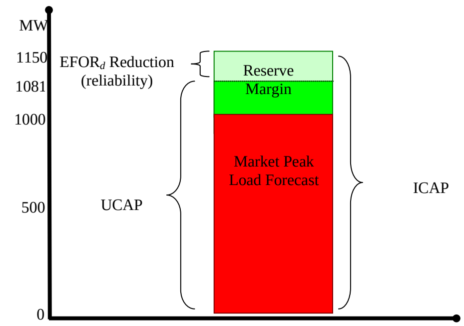
Higher reliability = lower $EFOR_d$ = more UCAP credits to sell = more revenue/profits.

$$UCAP = ICAP(1\text{-}EFOR_d)$$

Using the values from the calculations above, where the ICAP requirement was 1,150 MW and $EFOR_d$ was .06, the UCAP requirement calculation for the market would look like this:

$$UCAP = 1{,}150*(1\text{-}.06) = 1081 \text{ MW}$$

Figure 2 illustrates the relationship between ICAP, UCAP and $EFOR_d$ graphically.



Source: Author's construct.

Fig. 2: The relationship between ICAP, UCAP and $EFOR_d$ graphically.

The pool UCAP requirement is found using a system-wide $EFOR_d$. The generator's allotted UCAP credits are determined using the generator's specific $EFOR_d$. For example, if a generator sold UCAP using the market $EFOR_d$ of .06 from above, a 200MW unit would be able to offer 188MW of UCAP to a seller. However, the generator can sell as much UCAP as it is reliably able to produce. More reliable generators can sell more UCAP than less reliable generators. If a 200MW generator's $EFOR_d$ is .03, then it could sell 194 MW of UCAP, while a 200 MW generator with an $EFOR_d$ of .1 could only sell 180 MW of UCAP. Ideally, this would create greater incentives to improve reliability.

All LSEs in the market are informed of the calculated pool UCAP obligation. Once this is determined, the coordinator determines each LSE's individual UCAP obligation – the portion of the pool UCAP for which the LSE is responsible. In the example market above, if an LSE is responsible for serving 40 percent of the load, then it must obtain 432.4 MW of UCAP credits (40 percent of the total 1081MW). The capacity obligation is set for the entire obligation period, which is described below. However, it can be amended for load-shift from one LSE to another, loss of load, or demand-side responses.

MARKET CONTROLS

The market coordinators have established monitoring and enforcement procedures, as well as specific market participant rules and guidelines. These market controls are basically similar across the various capacity markets, though each market will have specific rules and differences in the details.

Monitoring Supply

Generators must provide data periodically detailing the operations of the generating unit. Additionally, generators must submit to periodic audits by the coordinator to determine if the claimed amount of capacity matches the actual amount of capacity. Generators can be penalized for failure to timely comply with coordinator data and audits requests.

The coordinator tracks and reviews generators' maintenance schedules. The schedules are used by the coordinator to evaluate the supply and reliability impacts of planned maintenance on the electricity grid, including when units are being taken down for repairs. If the coordinator believes that a generator's maintenance needs to be rescheduled to best accommodate the forecasted load, it will attempt to coordinate such rescheduling with the generator.

If a generator does not comply with audits, data requests, or requests to reschedule planned outages, the coordinator may increase the generator's $EFOR_d$, thus lower generator's reliability rating and the amount of UCAP credits available for the generator to sell.

Eligibility to Buy and Sell

Eligibility rules for the use of UCAP requires that UCAP be committed to a market for an entire obligation period and prohibits UCAP bought in one market from being sold out of the committed market and into another market.

An LSE must meet its UCAP requirement by showing that it has obtained sufficient UCAP credits. These credits can be unit-specific, but need not be. This requirement differs by market. By definition, UCAP is tied to a generator. However, due to the fact the sellers of UCAP may have extensive asset portfolios and that capacity may be sold multiple times, and premiums and discounts are offered based on which party assumes the risk of a forced outage after the transaction, UCAP *credits* might not be tied to a specific unit.

UCAP calculation rewards more reliable generators.

Outside resources are limited by region based on capacity constraints and reliability concerns. Outside provisions are sold on a first-come-first-serve basis. So, if the limit for outside provision is 500MW of UCAP, then the first 500MW to come forward that meet the coordinator's requirements will be permitted to sell, while the next outside MW offered will not be allowed.

Auction Rules

In capacity market auctions, buyers and sellers submit price and quantity bids for the UCAP which they are willing to buy or offering to sell. Market participants may submit multiple bids with different prices and/or quantities. Only LSEs may submit bids to buy UCAP in final auctions. The basic auction operations are largely similar between the organized capacity market auctions, but there are some notable differences in auction rules, procedures and structures. Below is a short list of some of the more noticeable market auction rule differences between markets:

- Some markets stack all LSE bids to make one singular demand curve, and

Market coordinators monitor and enforce rules and guidelines. Non-compliance can result in penalties.

price is set where this demand curve intersects the supply curve, while others use individual LSE demand curves by matching the highest price buyer with the lowest price seller.

- In some markets any supplier with unsold capacity and any LSE with capacity greater than its minimum requirement may offer that capacity into that final spot auction, but is not required to, while other markets make the submission of excess UCAP into the final auction a requirement.

- In some markets if the owner of excess UCAP does not submit all of its excess UCAP at a price it selects, then the coordinator automatically submits this UCAP into the auction with a price of zero, while in others the owner of the UCAP will simply not get credit for owning it if they don't offer it for sale.

Generators must:
- *Report operations details*
- *Submit maintenance and planned outages schedules.*
- *Undergo periodic audits*
- *Respond to coordinator data requests*

Dealing with Deficiencies

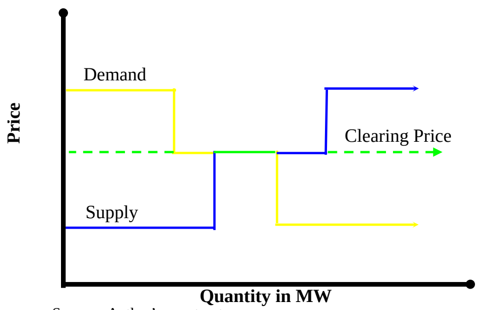
Market participants do not always fulfill their UCAP obligation by the end of the final coordinator-run auctions. If a LSE does not fulfill its UCAP obligation by the close of the final auction, then it may be subject to certain charges and possibly other sanctions from the coordinator. Some markets charge LSEs a "deficiency charge," which is an established fee times the number of MW of UCAP the LSE is short. The deficiency payments collected by the coordinator are reallocated to LSEs that met or exceeded their UCAP requirements for the period in question as well as to owners of unsold UCAP. Some markets do not use "deficiency charges," but rather charge the LSE the established final auction clearing price for the number of MW of UCAP that the LSE is short.

AUCTION PRICES

In an auction, one might imagine bids to sell and bids to buy along two curves. Where those curves intersect is where supply meets demand and a price would be set. When bids are placed for single units, this is generally how prices are determined. However, rather than smooth curves, bids for UCAP might be placed in blocks where a given range of capacity is offered or sought at a specific price. When the supply or demand bids are stacked the resulting curves look more like stairsteps. Still, the term "curve" is used for simplicity. The market clears when the supply (or seller) curve intersects the demand (or buyer) curve. Bids to buy or sell may be partially filled as the coordinator optimally matches supply and demand to achieve least-cost clearing prices.

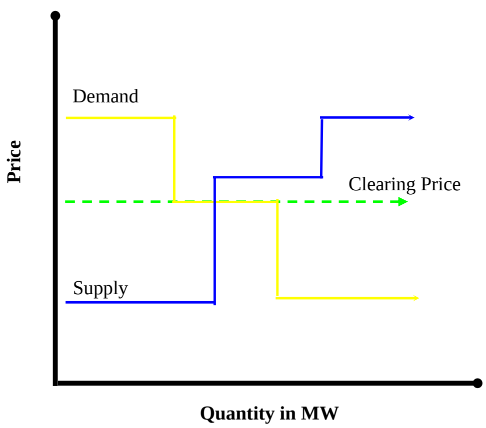
Commonly, the price in the auction is set at the intersected step whether it is the buyer's or the seller's price bid, as seen in Figures 3 and 4. If the intersection of the two curves occurs only between the steps of both the buyer and the seller, then the clearing price is set at the price to buy one MW of UCAP back (i.e. demand price) or the price to purchase one more MW of UCAP (i.e. supply price), whichever is lower.

In LICAP markets deliverability is a consideration from sources within the market, just as the ICAP market already considers deliverability from sources outside the market. There have been two general methods proposed to account for locational concerns. The first is a zonal approach. In this approach a certain percentage of UCAP has to be purchased from within a defined location. The other approach is to use a pricing scheme that resembles that of Locational Marginal Pricing (LMP) of wholesale electricity.



Source: Author's construct.

Fig. 3: Intersection of buyer's and seller's price.



Source: Author's construct.

Fig. 4: Clearing price set on buyer's price.

Each of these approaches essentially creates new markets with higher prices for areas in which deliverability is a concern.

Pricing in final auctions can operate differently than the non-final auctions discussed above. In some markets, coordinators offer LSEs one "final," or "deficiency" auction to fulfill the UCAP requirement. In the final auctions where the pricing mechanism differs, the coordinator may act as the sole buyer. Any LSE that has not met its minimum UCAP obligation must submit its statement of shortage to the coordinator. The coordinator sums all the shortages and enters the final auction as a single buyer with one UCAP quantity demanded. The coordinator does not include a price for its UCAP demand. Sellers operate as they would in the previous auction. Depending on the rules of the market the auction price can clear when the UCAP supply equals the demand from the coordinator or the UCAP supply bid price equals the deficiency rate. If the final auction market clears below the deficiency rate, then all LSEs that were short prior to the auction must buy the necessary UCAP from the coordinator at the final auction market clearing price. If the auction clears at the deficiency rate, then the coordinator will purchase all the UCAP it can below the deficiency rate, sell it to LSEs, and charge each LSE the deficiency rate for every MW of UCAP it is short.

Final Auctions: Last chance for LSEs to meet UCAP obligations. Non-LSEs may not buy in a final auction.

MARKET ILLUSTRATIONS

To help illustrate the operation of an ICAP auction, a series of examples follows. The simple examples will be built from the same hypothetical organized market with a coordinator-run capacity auction.

Assumptions for Examples

- Peak Load = 2000 MW
- Reserve Margin = 15%
- ICAP Requirement = 2300 MW
- Pool EFOR$_d$ = 0.1
- UCAP allocation = 2070 MW
- Penalties for failing to meet UCAP obligations

Example 1 – Base Model

In the first example, set up in Figure 5, Seller A is a vertically integrated supplier which has affiliated wholesale generation and retail electric service operations. Buyer X, an LSE, could self-supply UCAP from its affiliated firm, Seller A, by having A allocate all 828MW of UCAP credits needed to meet X's UCAP obligation. Seller A would have a remaining 522MW of UCAP to sell in the market. This is only one possibility for Buyer X and Seller A. In this example, all the buyers and sellers could have several options. A broker like Buyer Z might typically have a contract with one of the sellers for

Clearing price is, commonly, set at the intersected step, whether it is the buyer's or the seller's price.

The Sellers

Type	Capacity	$EFOR_d$	UCAP Credits
Seller A Integrated w/Buyer X	1500MW	0.1	1350MW
Seller B Independent Supplier	1000MW	0.2	800MW

The Buyers

Type	Percent of Market Load	UCAP Obligation
Buyer X – LSE	40	828MW
Buyer Y – LSE	60	1242MW
Buyer Z - Broker	N/A	N/A

Fig. 5: Example 1 - base model hypothetical ICAP auction setup.

a specific UCAP amount. Assume that X self-supplies and Buyer Z is contracted with Seller B for 500MW. Buyer Y still has multiple options to fulfill its UCAP obligation. Buyer Y could:

- Negotiate contracts with Seller A, and/or Seller B, and/or Buyer Z for some or/all of its 1242MW obligation
- Bid into the capacity market auction(s) for some or/all of its obligation
- Engage in a combination of these contracts and auction purchases

Any of these options is acceptable to the coordinator, as long as the total amount purchased by Buyer Y is greater than or equal to 1242MW and this amount is acquired by the close of the final auction.

Example 2 – The Auction: Simple Clearing Price

The second example, as seen in Figure 6, includes pricing. Assume that all buyers and sellers are independent, that all UCAP trading will occur at the auction, that sellers will bid to sell all eligible UCAP in a single bid and buyers will bid to buy their entire UCAP obligation in one bid. The capacity market clearing price is $20 and all UCAP obligations are fulfilled. Seller A makes $27,000 in the auction from selling all of its capacity, while B makes $14,400 from selling 720MW of its 800MW of UCAP.

Example 3 – The Auction: Deficiency and “Buy Back” Clearing Price

Example 3, set up in Figure 7, demonstrates how significantly the market results can be changed from even a minor change in pricing by one participant. Using Example 2, assume the only change is that Seller B raises its price one dollar per MW of UCAP. Therefore, Seller A is bidding $15 and B is bidding $21 for the respective supplies. In this case, Buyer Y would fulfill its obligation, while Buyer X would buy 108MW of UCAP, but would still fall 720MW short of its UCAP obligation, as seen in Figure 7. Buyer X could then be subject to a penalty if it does not make up its UCAP shortage by the close of a final auction. In this case, to buy back 1MW of UCAP would cost $20. To buy an additional MW would cost $21. Therefore, the market clearing price is at the intersected step, the buyer’s step in this case, at $20.

The Sellers

Type	Capacity	$EFOR_d$	UCAP Credits	Sell Bids
Seller A Independent Supplier	1500MW	0.1	1350MW	$15/MW
Seller B Independent Supplier	100MW	0.2	800MW	$20/MW

The Buyers

Type	Percent of Market Load	UCAP Obligation	Buy Bids
Buyer X – LSE	40	828MW	$20/MW
Buyer Y – LSE	60	1242MW	$25/MW

Fig. 6: Example 2 - hypothetical ICAP auction setup with pricing.

The Sellers

Type	Capacity	$EFOR_d$	UCAP Credits	Sell Bids
Seller A Independent Supplier	1500MW	0.1	1350MW	$15/MW
Seller B Independent Supplier	100MW	0.2	800MW	$21/MW

The Buyers

Type	Percent of Market Load	UCAP Obligation	Buy Bids
Buyer X – LSE	40	828MW	$20/MW
Buyer Y – LSE	60	1242MW	$25/MW

Fig. 7: Example 3 - hypothetical ICAP auction setup with pricing and a deficiency.

Market results can significantly change with even minor price changes by one participant.

CONCLUSION

The capacity market has been promoted as a mechanism to create market value in the availability of generation in addition to the market value of the actually generated electricity. An often touted goal of capacity markets is to create incentives that would encourage supply to grow with demand, and provide for adequate resource reserves. Though some of the markets have been in operation for several years now, strong evidence that these markets have directly resulted in a marked improvement in resource adequacy or the significant construction of new capacity is not readily apparent.

Additionally, given the market design of rewarding those with excess UCAP credits or penalizing those that fall short of requirements it seems that there may be incentives to artificially manipulate the market to gain rewards or push penalties to competitors. In the 2004 "State of the Market Report," PJM expressed concerns of potential market power issues due to high levels of market concentration.

The debate about the value and effect of these markets notwithstanding, capacity markets do provide LSEs with an open-market mechanism – the auction – to meet the capacity obligations they might not have been able to fulfill through other means. Additionally, the markets provide a venue for holders of excess capacity to trade it in an open market.

The variations in available capacity levels from region to region and state to state and the differing wholesale and retail market structures would tend to suggest that the capacity markets now operating in the eastern organized markets may not be easily transplanted to other areas. This primer outlines the basics of capacity market operations, but that is only the foundation for considering the appropriateness of introducing or continuing a capacity market in a given region. The primer shows that a capacity market can easily add value to available capacity. Adding value to one side of the equation usually means adding cost to the other side, as demonstrated by the examples above.

This primer is only the technical explanation that underlies consideration of the appropriateness of introducing or continuing capacity markets in a given region.

If the added value (such as increased reliability and more certain resource adequacy) outweighs the added costs (such as LSE deficiency penalties and higher wholesale prices as a result of capacity market profit strategies and multiple resales of UCAP credits) then an ICAP market may be an appropriate addition to the wholesale trading of electricity. If, on the other hand, the capacity market serves only to shift costs and profits without a net system-wide benefit it would seem to serve no public-interest purpose.

Capacity markets are promoted as a mechanism to offset the risk of building generation in an open market and thereby encourage sufficient capacity investments, but maligned as a mechanism that rewards nonproduction, shifts profits and/or increases wholesale costs. Do the existing configurations of these markets encourage desired new capacity or undesired market power abuse? Does a tradable value of available capacity equate to new costs elsewhere in the wholesale to retail market cycle? In regions with sufficient or high available excess capacity, should there be a concern with the implementation of a capacity market in that region or with in-region generators participating in existing out-of-region capacity markets?

As capacity markets continue to evolve and and/or expand, understanding the theoretical intent and the basics of how the markets operate is increasingly essential for all policymakers.

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