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DATE: **February 10, 2023**
TO: **RASTF**
FROM: **IMM**
SUBJECT: **High level capacity market design proposal**

Key Elements of IMM Proposal for Capacity Market Design

1. Capacity offered is ICAP * Modified EAF (equivalent availability factor)
2. Capacity is paid only when available, by hour.
3. Capacity market clearing prices are determined per existing market clearing rules.
4. Must offer requirement in the capacity market for all capacity resources.
5. Must offer requirement for all cleared capacity resources equal to available ICAP in every hour in a combination of the energy, ancillary services and reserve markets.
6. Capacity resources must have firm fuel, including dual fuel or multiple pipelines and a firm commodity supply, or a defined number of days of onsite stored fuel. Intermittent, storage and demand side resources must have the equivalent obligation to be firm. All capacity resources must be tested weekly.

IMM Proposal

The IMM's proposal for the capacity market is a return to basics. The current capacity market design has deviated significantly from the purpose of the capacity market. The only purpose of the capacity market is to make the energy market work. That means two specific things. The capacity market needs to define the total MWh of energy that are needed to reliably serve load, calculated as the peak loads plus a reserve margin. This is the reliability analysis, which needs to be hourly and to incorporate generation and transmission availability and outages on a realistic basis (recognizing observed availability and correlations among outages). The capacity market needs to provide the missing money; the capacity market needs to allow all cleared capacity resources the opportunity to cover their net avoidable costs on an annual basis to ensure the economic sustainability of the reliable energy market. The capacity market design (RPM) introduced in 2007 was consistent with this approach.

Capacity does not provide reliability. A supply of energy greater than demand plus reserves provides reliability. Capacity is not more valuable on some days or in some hours than others. Energy is more valuable on some days and in some hours and that value equals the LMP in those hours resulting from the operation of the energy market and the ancillary services markets plus the price in the reserve markets. Using net avoidable cost as a metric, capacity is actually less valuable in high demand hours when energy prices are high. In high demand hours energy market net revenues are high and therefore net hourly avoidable costs are low or, more likely, negative. If energy market prices were high enough to cover the gross avoidable cost of capacity resources on an annual basis, and expected to remain high enough, the appropriate price of capacity would be zero. Although those conditions are unlikely to persist, that is the underlying concept of an all energy market.

The idea that capacity is always more valuable during one or five peak hours derives from the history of cost of service allocation issues in rate cases in the regulatory paradigm, and not from the operation of markets. In the cost of service world, the allocation of capacity costs in rate cases determined the rates paid by different customer classes and cost of service studies became exercises in how to allocate costs to the other customer classes. But the fact that the costs of a base load plant could be allocated to a single peak hour did not mean, to anyone, that the baseload unit was expected to operate only for that one hour. As has become clear during the discussions of ELCC calculations, the MW capacity value of a resource requires that the resource produce energy whenever it can, in the case of an intermittent resource, and whenever it is economic, in the case of a thermal resource. The obligation of a capacity resource, whether intermittent or thermal, is to be available whenever possible and to operate when called on. That is the essential link between the energy and capacity markets.

Capacity is a concept designed to make the energy market work. The concept of capacity is needed in the overall market design, given the requirement that the system must include a reserve margin and therefore that the energy market will almost always be long and therefore that revenues from the competitive energy market will not support a self sustaining overall market design. Capacity is not a thing. Capacity does not power light bulbs or refrigerators or air conditioners. The only real product provided in wholesale power markets is energy.

Issues with CP

The IMM's proposal for the capacity market recognizes that the Capacity Performance (CP) model was a failed experiment.

The fundamental mistake of the CP design was to attempt to recreate energy market incentives in the capacity market. The CP model was an explicit attempt to bring energy market shortage pricing into the capacity market design. The CP model was designed on the assumption that shortage prices in the energy market were not high enough and needed to be increased via the capacity market. The CP design focused on a small number of critical hours (performance assessment hours or PAH, translated into five minute intervals as PAI) and imposed large penalties on generators that failed to produce energy only during those hours. But the use of capacity market penalties rather than energy market incentives created risk. While there are differences of opinion about how to value the risk, this CP risk is not risk that is fundamental to the operation of a wholesale power market. This is risk created by the CP design in order, in concept, to provide an incentive to produce energy during high demand hours that is even higher than the energy market incentive, amplified by an operating reserve demand curves (ORDC). The potential risk created by CP is not limited to risk for individual generators, but extends to the viability of the market. If penalties create bankruptcies that threaten the viability of required energy output from the affected units, there is a risk to the market.

Winter storm Elliott provided the first real test of the CP design. Elliott showed that the CP design does not provide effective incentives. There was an extremely high forced outage level during Elliott despite the incentives and despite the fact that the effectively uncapped market seller offer cap (MSOC) was in place (Net CONE times B) for RPM auctions conducted for the 2022/2023 Delivery Year. In addition, it has been clear from prior, very brief and local PAI events that the process of defining excuses and retroactive replacement transactions is complex and very difficult to administer, and includes subjective elements. The energy market clearing, in contrast, is transparent and efficient and timely. While there are issues with the details of energy market pricing that must be addressed, including shortage pricing, the energy market does not include or create the significant and long lasting uncertainty created by the PAI rules as exhibited most dramatically by the results of Elliott. The PAI design creates an administrative process that adds unacceptable uncertainty to the process and that can never approach the effectiveness of the energy market in providing price signals and timely settlement.

There is no reason that in a rational market design two cold days would result in a crisis and a level of administrative complexity that threatens to undermine the incentives to invest in existing and new supply resources at a time when those resources are needed. The CP design undermines incentives rather than creating positive incentives to invest and perform.

The IMM supports FERC's elimination of the CP MSOC defined as Net CONE times B and the return to the MSOC defined by net avoidable costs (ACR), and recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. The use of Net CONE as the basis for the CP penalty rate is unsupported by economic logic. The use of Net CONE to establish penalties is a form of arbitrary administrative pricing that creates arbitrarily defined risk for generators, creates corresponding arbitrary complexity in the calculation of CPQR and ultimately raises the price of capacity.

The CP design was a radical change to the capacity market paradigm. The CP design is a failed experiment. The challenge is to create a straightforward capacity market design that meets the simple objectives of a capacity market and that does not become a vehicle for energy market incentives or rent seeking or attempts to limit the ways in which specific types of generation participate in PJM markets. Energy market incentives should remain in the energy market.

ELCC Issues

The IMM's proposal for the capacity market recognizes that the ELCC approach is not an appropriate way to define the MW capacity value for intermittent and storage resources, or for thermal resources, in a market.

ELCC was developed as, and remains, a utility planning tool rather than a market design tool. ELCC was attractive as a possible analytical basis for the derating of intermittent and storage resources to a MW level consistent with their actual availability and consistent with a perfect resource, or at least a thermal resource. The impetus made sense but the actual application of the ELCC planning tool cannot work in markets that include intermittent or thermal resources. The underlying logic makes sense. Neither intermittent nor thermal resources are the perfect resource. There are thermal resources, currently credited with full capacity value, that are much less available than some intermittent resources that are derated. The correct application of ELCC, from a mathematical and economic perspective, is to define ELCC as the marginal ELCC. It is clear that as the market share of intermittents grows, the marginal value of intermittents will decrease quickly. The result will be that a 100 MW solar resource will have a very small capacity value, e.g. 5 MW, but have a performance obligation, and associated penalty exposure, equal to its full CIRs of 100 MW.[1] The competitive offer of that capacity will be high because it is the full annual net avoidable cost divided by 5 MW and not by 100 MW. That tension between the derated MW that qualify as capacity and can be sold in the capacity market, and the obligation to perform, will make offering intermittent resources as capacity increasingly untenable. That tension does not reflect the economic or reliability value of the intermittent resources. This is not an argument for average ELCC, which is clearly wrong. It is an argument for abandoning ELCC as the definition of capacity for intermittents or for thermals and replacing ELCC with a metric that reflects the actual availability of all resource types. This will ensure comparable treatment within and across categories of capacity resources.

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[1] Although PJM has not yet modified the OATT to reflect that the obligation of derated resources is the full CIR value rather than the derated value, that is the clear implication of the ELCC/CIR discussions in the stakeholder process, the requirement that derated resources have CIRs equal to the highest energy output assumed in the ELCC calculation of the derated MW value, and the associated recognition that the ELCC value assumes the deliverability of energy at the full ICAP level.

6. Capacity resources must have firm fuel, including dual fuel or multiple pipelines and a firm commodity supply, or a defined number of days of onsite stored fuel. Intermittent, storage and demand side resources must have the equivalent obligation to be firm. All capacity resources must be tested weekly.

Availability

The metric for whether a capacity resource is meeting its obligation is its availability. The reasons for the lack of availability do not matter. It does not matter if the resource does not have fuel for any reason. It does not matter if the resource is on a six month planned outage. It does not matter if the resource is not repairable but is on a lengthy forced outage. It does not matter if the sun is not shining. It does not matter if the wind is not blowing. It does not matter if the temperature is high and the gas fired thermal resource cannot meet its full ICAP. In all those cases, the capacity is not available or is only partially available.

Currently defined performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

While the EAF is not the exact availability metric that should be used in the capacity market, the concept of availability is the right concept. The formal definition of availability needs to be expanded to include intermittent, storage and demand side resources.

Rather than penalizing capacity resources for nonperformance, capacity resources should be paid the daily price of capacity only to the extent that they are available to produce energy or provide reserves, as required by PJM on a daily/hourly basis, based on the full ICAP value of their cleared capacity. This is a positive performance incentive based on the market price of capacity rather than a penalty based on an arbitrary assumption. This would mean that capacity resources are paid to provide energy and reserves based on their full ICAP and are not paid a bonus for doing so. The reduced payments for capacity would directly reduce customers' bills for capacity. This would also end the need for complex CPQR calculations based on the penalty rate and assumptions about the number and timing of PAI.

The obligations of committed capacity resources include the requirement to offer their full available ICAP in the day-ahead energy market every hour of every day. The need for the energy from capacity is not limited to one peak hour or five peak hours. Customers require energy from capacity resources all 8,760 hours per year.

Payment

Capacity resources are paid the hourly price of capacity only when available to provide energy equal to the ICAP of the resource.

Capacity Market Clearing

The capacity market clearing process would remain unchanged. UCAP (equal to modified EAF * ICAP) would be offered and the must offer obligation in the energy market, ancillary services and reserve markets would remain at available ICAP. The MSOC would remain at net ACR, using forward energy and ancillary services net revenues.

Capacity Market Must Offer Requirement

All capacity resources have a must offer requirement in the capacity market, including thermal, intermittent, storage and demand resources.

Prior to the implementation of the capacity performance design, all capacity resources, except DR, were subject to the must offer requirement. There is no reason to exempt intermittent and capacity storage resources, including hydro, and demand resources from the must offer requirement. The same rules should apply to all capacity resources. The purpose of the must offer rule, which has been in place since the beginning of the capacity market in 1999, is to ensure that the capacity market works based on the inclusion of all demand and all supply, and to prevent the exercise of market power via withholding of supply. The purpose of the must offer requirement is also to ensure equal access to the transmission system through CIRs (capacity interconnection rights). If a resource has CIRs but fails to use them by not offering in the capacity market, the resource is withholding and denying the opportunity to offer to other resources that would use the CIRs. For these reasons, existing resources are currently required to return CIRs to the market within one year after retirement. The same logic should be applied to intermittent and storage resources. The failure to apply the must offer requirement will create increasingly significant market design issues and market power issues in the capacity market as the level of capacity from intermittent and storage resources increases and the level of demand side resources remains high. The failure to apply the must offer requirement consistently could also result in significant shifts in supply from year to year and therefore create price volatility and uncertainty in the capacity market and put PJM's reliability margin at risk. The capacity market was designed on the basis of a must buy requirement for load and a corresponding must offer requirement for capacity resources. The capacity market can work only if both are enforced.

Total reserves on June 1, 2023, will be 25,409.8 MW, of which 8,452.8 MW are in excess of the required level of reserves, which is 16,957.0 MW. In the 2023/2024 BRA, 17,037.1 MW were considered categorically exempt from the must offer requirement based on intermittent and capacity storage classification. Some of these resources were offered as capacity in the BRA and as part of FRR plans. The result was that 5,308.3 MW of intermittent and storage resources (3.7 percent of total cleared MW) were not offered in the 2023/2024 BRA. After accounting for FRR status and exports, 41.3 percent of intermittent and storage capacity resources were not offered in the 2023/2024 BRA.

In the 2023/2024 BRA, the sum of cleared MW that were considered categorically exempt from the must offer requirement is 7,534.3 MW, or 44.4 percent of the required reserves and 30.4 percent of total reserves. The cleared MW of DR is 8,203.3 MW, or 48.4 percent of required reserves and 33.1 percent of total reserves. The sum of cleared MW that were categorically exempt from the must offer requirement and the cleared MW of DR is 15,737.7 MW, or 92.8 percent of required reserves and 63.5 percent of total reserves.

Must Offer Requirement in Energy, Ancillary Services and Reserve Markets

All cleared capacity resources have a must offer requirement in the energy, ancillary services and reserve markets equal to available committed ICAP. This is the essential link between the energy market and the capacity market. There is no reason to have a capacity market without this requirement.

Firm Fuel/Testing

All capacity resources must have firm fuel in the form of dual fuel or multiple pipelines and a firm commodity supply, or a defined number of days of onsite stored fuel. The number of required days of onsite fuel should be based on a PJM reliability analysis including data on the duration of extreme weather. Intermittent, storage and demand side resources must have the equivalent obligation to be firm.

All capacity resources must be tested weekly.

The experience of Elliott shows that even extreme penalties do not ensure that supply resources will obtain firm fuel or do adequate testing. While there is a lot of work to be done in addressing coordination between the power market and the gas market, specific requirements for firm fuel are an effective and efficient part of addressing the issue.

None of these requirements are a panacea. For example, multiple gas pipelines can have simultaneous delivery issues, regardless of the firmness of the tariff service, commodity gas may be unavailable regardless of the contract, and onsite fuel can freeze. Solar and wind resources do not have a firm fuel requirement.

None of the market design changes proposed by any participant in the RASTF discussions directly address the current dysfunction in the gas/electric interface which creates a significant barrier to the functioning of power markets on cold weather, high demand days. Those issues can only be addressed by FERC, in consultation with all gas and electric market stakeholders. The goal should be to make the gas/electric interface work more efficiently and to reduce the risk created by the current structure rather than simply shifting risk to customers.