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Federal Energy Regulatory Commission
888 First St NE
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RE: Centralized Capacity Markets (Docket No. AD13-7-000)

September 10, 2013

Dear Commissioners,

Thank you for the opportunity to provide comments at the Capacity Market Conference scheduled for September 25, 2013. Enclosed is our submission for Docket No. AD13-7-000.

Sincerely,

Julien Dumoulin-Smith
Executive Director
US Electric Utilities & IPPs Group
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Enclosure: 'UBS Utilities: Assessing the Effectiveness of Capacity Markets'

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Electric Utilities

Sector Comment

Assessing the Effectiveness of US Capacity Markets

10 September 2013

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- **Highlighting successes and structural issues ahead of FERC conference**

We are responding to the questions posed by the FERC ahead of its technical conference on generic capacity market issues on September 25th. These markets largely continue to function effectively in maintaining adequate reliability across restructured capacity markets and have done so for roughly a decade. There are a multitude of consistent issues arising in all markets, including overall price volatility, regulated-deregulation market interactions (including buyer-side mitigation), and the need to increasingly bifurcate value on the true reliability profile of underlying assets through multiple-products. *We see an energy-only market structure as largely unsustainable*, given its extreme price volatility (inherently capped in all markets), higher cost of capital for investors, and lack of predictability in analyzing reliability outcomes for regulatory institutions.

- **Growing reliance on capacity markets, as energy prices continue to wane**

We believe capacity markets will continue to feature disproportionately in discussions around the effectiveness of restructured markets, both to the extent to which high-fixed cost structure assets such as nuclear and coal rely on such payments to survive a protracted downturn in gas-linked energy prices, and to increasingly provide supplemental compensation for 'backstopping capabilities.' With renewables increasingly penetrating the grid, the value proposition of energy payments will increasingly face pressure, aside for brief 'scarcity' events and other periods in which high-cost Demand Response 'sets' prices. As such, we anticipate generators will lean ever-more on fixed capacity-based compensation schemes, rather than for the energy sold into the market.

We respond below to prompts provided by the FERC as part of its ongoing review of US capacity markets.

Mechanics of current centralized capacity markets

1. How effective are the existing centralized capacity markets in assuring that resource adequacy needs are met at just and reasonable rates?

Overall, we believe existing centralized capacity markets have proven successful in procuring adequate capacity to achieve reliability needs. This is certainly true in contrast to restructured markets *without* any such compensation, such as ERCOT. Amidst all of the discussion around capacity constructs, there has *never* been a debate around whether it has procured adequate capacity, rather it is the *price and quality of the capacity procured that have been under consistent scrutiny*. With regards to whether the prices charged have been just and reasonable, it is nearly unequivocal that the cost has been exceptionally competitive relative to a traditionally integrated utility. Under such a construct, prices have largely resulted in effective returns on equity *below* those otherwise garnered in regulated markets. This is illustrated by prices clearing meaningfully below the cost of new entry (CONE) across many of the integrated markets. Why has this been? This is largely a consequence of generator bidding structures, which drive outcomes *closer* to 'going forward' cash costs (those costs incurred to *continue* to operate), rather than enabling an existing generator to bid in, and recover both the recovery *of* (i.e depreciation) and *on* (i.e. return on equity, recovery of interest) capital. Moreover, in an environment of flat or declining demand, as is currently projected for many markets, it is increasingly apparent that capacity constructs trend towards the going-forward cost of the *marginal* asset. This outcome can be meaningfully below CONE, with recovery on and of making up a meaningful portion of total revenue requirement relative to just an asset's 'going forward' cost; for example a revenue requirement in California for a new CCGT is upwards of $200/kW-yr under a new tolling arrangement, whereas ongoing fixed costs for the plant are closer to ~$20-30/kW-yr. In the absence of meaningful reform of demand curve constructs, the *ability* to bid in an adequate price to recover full recovery of costs is an alternative approach to capacity market design.

Among the greatest successes of structured capacity markets has been their unique ability to allow novel technologies to compete on a nearly fungible basis with conventional generation. This phenomenon has substantially muted capacity prices during its nascent years, and should have a comparable mitigating effect on markets contemplating more formalized capacity markets (CAISO, ERCOT). While the CONE has been appropriately tagged to a conventional gas peaking plant, the effective source of incremental new capacity in recent years for PJM has been Demand Response (DR). DR has provided this incremental capacity at a fraction of the cost and efforts should be taken to continue to encourage such innovative solutions, including the continued development of mechanisms to allow energy efficiency and storage products to bid into auctions. These products have tangibly delivered great value to consumers.

One of the largest complexities in the design of capacity markets relates to concerns over buyer-side market power. Broadly, we see the latest efforts taken by the commission to implement Minimum Offer Prices Rules (MOPR) into auction bidding as largely effective. However, we see a need for the consistent application of such rules across all markets nominally committed to such constructs, including NYISO. *We see so no reason to discriminate between localized regions of a state and the balance of the market* (Rest of State). Moreover, without an effective MOPR policy in adjacent markets, it is challenging to pursue transactions across Regional Transmission Organization (RTO) seams (MISO-PJM), given the carryover effects of regional price suppression. Meanwhile, there is a need to assess the broader ability for regulated utilities and utility procurement to exist side-by-side with capacity markets in order to maintain just and reasonable rates for incumbent capacity. Without a conceivable need to procure new capacity, the use of regular utility-driven procurements effectively side-steps the need for a capacity market, limiting any opportunity for the auction mechanism to provide any new-investment price signals, driving market prices back down to largely breakeven compensation for the balance of the (uncontracted) existing portfolio, as is effectively the case under California's existing two-tier market (Long Term Procurement Planning and Resource Adequacy Markets). Rather, we advocate creating clearer price distinctions within RTOs, allowing regions that desire to leverage capacity markets to meet resource adequacy needs to allow prices to appropriately fluctuate. Ideally, by providing clear 'black-and-white' lines, this would allow for accurate price signals areas committed to restructured markets (i.e. Illinois in MISO), in addition to allowing (or even encouraging) integrated utilities to self-supply capacity (i.e. the balance of the MISO market). For those markets explicitly pursuing a PPA approach to new development as a matter of policy (i.e. California), any forward capacity market contemplated would inevitably reflect the relative procurement decisions of the state; Inevitably, once states and RTOs have made clear decisions as to where and how generators can recoup investment costs, developers will adjust their return and price expectations accordingly, reflecting an adequate return on investment amortized through either the contracted life (as is the case under California's current market design, leaving little in terminal value) or through the asset's entire life in the context of a truly merchant market.

As for the ability of competitive markets to attract new investment, we have been consistently surprised by the relative abundance of developers actively pursuing new sites in credible markets such as PJM. Ongoing power project development efforts in PJM are reaching levels not seen since the last build cycle in the early part of the last decade. *We caution that without real reform to limit the impact of state-led procurement activities, credibility of investment prospects can be quickly eroded, as generators wait for the next contract award cycle.*

2. What modifications, if any, would you recommend be made to capacity markets in general or to specific capacity market design elements?

The greatest issue we perceive in capacity market design relates to price volatility, leading to irreversible decisions on future capacity. While Demand Response aggregators can be nimble in their participation in these auctions, most conventional generation is effectively a price taker. Notably, recent price volatility has resulted in substantial baseload capacity retirement. Among the most damaging issues relating to capacity is the relative value ascribed by the market to capacity payments, relative to energy market revenues. Indicative of the recent volatility, investors continue to see greater comfort in energy revenues than capacity, despite its typical linkage with natural gas, a particularly volatile commodity itself.

An initial solution to dampen volatility could be to further flatten demand curves, in order to mitigate volatility from shifts in supply, as well as encourage implementation of sloped demand curves in markets currently without such constructs (ISO-NE). While returns on equity of merchant generators have generally been underwhelming relative to those of regulated investments, it is important to realize the *actual* cost of capital is *higher* for the IPP business model than for regulated utilities given this volatility. For example, the typical return on equity thresholds is in the low-to-mid teens at a minimum for IPPs. While capacity markets were initially designed in part to reduce energy market volatility, and have successfully done so, there is still an opportunity to improve the predictability and credibility of this revenue stream to generators.

Focusing on energy market volatility, we believe the ongoing replacement of large-fixed cost structure plants, with lower capital cost, but higher dispatch cost units, will increasingly drive greater energy market volatility as well. This is a phenomenon increasingly worth noting given the initial goal of capacity markets to encourage innovative solutions to achieving resource adequacy outcomes, particularly with DR resources now able to *set* these prices. Moreover, since DR commitments themselves are a single-year investment relative to large-fixed capital investments stretching for much longer periods, *we think it appropriate for the commission to contemplate procuring beyond a three-year forward basis.* While nominally achieving the goals of procuring sufficient resources to meet reserve margin thresholds, capacity markets of less than three-years cannot meaningfully provide a venue for *new* resources to successfully compete to provide supply; this construct will inevitably lead to state resource planning to construct new assets. Even at three-years, there is little credibility to pursuing long-lead time fixed capital investments, such as new nuclear. The capacity construct, as designed, effectively favors low-capital cost, quick installation solutions. A structure well worth evaluating is one that allows for both greater visibility beyond three-years through a partial or tiered procurement, and enabling (all) assets to 'lock-in' initial prices received for a prolonged period, akin to ISO-NE's five-year new entrant compensation scheme.

As for further policy considerations, we flag the extent to which capacity markets have proven a complementary source of revenues to energy, and counter-cyclical to the natural gas price (the marginal fuel in many power markets). Capacity markets have proven pivotal in preserving underlying fuel diversity of the grid, specifically coal and nuclear units; a growing policy question remains whether it is appropriate to explicitly design these markets to *maintain* the grid's underlying diversity. While retiring coal plants may have aligned well with administration goals of reducing criteria and hazardous pollutants domestically in recent years, we expect a more robust discussion in coming years around fuel diversity as nuclear plants continue to announce pre-license expiration retirements. Both the latest Vermont Yankee and Kewaunee nuclear plant retirements cannot be seen in isolation, but as part of a *growing* trend in the industry. Rather, with growing renewable penetration across markets to comply with state-level Renewable Portfolio Standards (RPS) exacerbating any potential recovery in energy prices given their subsidized development without regard to underlying economics of need for new supply, we anticipate the gradual pressure on energy to result in a growing reliance on capacity payments to provide the bulk of the compensation for many generators. We see this as an appropriate transition. Rather, given the intermittency issues associated with renewables, *we see it as appropriate for the Commission to continue to explore explicit flexibility procurements within the context of existing capacity market frameworks*. Rather than waiting for revenue pressure to arise on existing flexible assets, we see the pre-emptive approach taken in California to retain such assets as worth mirroring in other markets as renewable penetration grows.

The Commission should note the growing financial fragility of the underlying conventional resource portfolio as it contemplates any further market reforms. With the growing exhaustion of generator liquidity given the protracted downturn in both demand and gas prices, we see retirement decisions over short term fluctuations in capacity prices as becoming more worrisome, with little ability for generators to weather transient price signals.

3. Centralized capacity market design elements necessarily interact with each other and with the energy and ancillary services markets. Are there problems created by this interaction that should be addressed to improve the functioning of centralized capacity markets or energy markets?

The most immediate example of capacity and energy market interaction relates to the derivation of Net CONE, which is the cost of new entry (CONE) net of calculated energy revenues. While exceptionally controversial, we believe it is necessary to embed a *forward*-looking view of project energy revenues in this calculation rather than embedding historically realized revenues. Given the volatility of energy and gas prices, this can result in a mismatch within the cycle, inaccurately representing Net CONE in the capacity market's demand curve parameters. Moreover, the inability to reflect a current view of energy market revenues reduces the capacity construct's effectiveness in providing a complementary stream of revenues. While the Commission has consistently been tempted to implement complicated energy revenue schemes, a simple forward view of energy revenues using a widely quoted projected power and gas curves as of a given date remains the most appealing design in our view. That said, *we believe the Commission should prove diligent in monitoring the use of 'out-of-market' forward commodity assumptions embedded in unit specific exemptions of Minimum Offer Price Rules.*

4. Regional capacity markets also interact with each other. What are the implications of regional differences in capacity market designs?

As part of its market design re-evaluation, it should be the commission's broader ambition to create markets that are consistent in design and goal. Given the exceptional complexity of power markets, it is worth striving to create a more uniform set of rules across the various RTOs in order to reduce the repetitive litigious processes seen across a range of markets. Additionally, a more consistent set of rules should limit potential price discrepancies arising from 'regulatory arbitrage' of different market designs (PJM-MISO). In order to improve integration, *we would recommend all markets implement a consistent procurement schedule*, allowing generators the greatest ability to contrast market opportunities, and allowing for the most consistent set of corresponding market rules. A shift towards a uniform three-year forward procurement across all markets would also reduce the cost of capital for generators given the added visibility.

5. What is the impact on centralized capacity markets of transmission system upgrades and expansions? Can transmission planning be more effectively integrated with or accounted for in the design elements of centralized capacity markets?

We continue to see the nexus of generation and transmission policy as rife for further reform. It remains clear that there is indeed an ultimate fungibility in the development of transmission and generation solutions in addressing a regional reliability issue. As designed today, the *current framework would appear to be biased towards transmission solutions* given the ability to both identify and meet needs through coordinated planning processes. A clear focus on improving the quality of existing capacity auctions is modelling only those transmission projects credibly expected in-service in a given delivery period in order to reduce swings in capacity procurement for specific sub-regions. The inability to deliver on transmission development plans has been one of several factors contributing to capacity price volatility, particularly within smaller delivery areas.

As for the commitment of transmission resources into capacity markets, in order to reduce the effective arbitrage of committed capacity prices between base and incremental auctions, we *believe nascent efforts in PJM to ensure projects are 'firm' or sufficiently credible are well warranted.*

■ Statement of Risk

Risks for Utilities and Independent Power Producers (IPPs) primarily relate to volatile commodity prices for power, natural gas, and coal. Risks to IPPs also stem from load variability, and operational risk in running these facilities. Rising coal and, to a certain extent, uranium prices could pressure margins as the fuel hedges roll off Competitive Integrateds. Further, IPPs face declining revenues as in the money power and gas hedges roll off. Other non-regulated risks include weather and for some, foreign currency risk, which again must be diligently accounted in the company's risk management operations. Major external factors, which affect our valuation, are environmental risks. Environmental capex could escalate if stricter emission standards are implemented. We believe a nuclear accident or a change in the Nuclear Regulatory Commission/Environment Protection Agency regulations could have a negative impact on our estimates.

Risks for regulated utilities include the uncertainty around the composition of state regulatory Commissions, adverse regulatory changes, unfavorable weather conditions, variance from normal population growth, and changes in customer mix. Changes in macroeconomic factors will affect customer additions/subtractions and usage patterns

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UBS Investment Research: Global Equity Rating Allocations

UBS 12-Month Rating	Rating Category	Coverage[1]	IB Services[2]
Buy	**Buy**	45%	35%
Neutral	**Hold/Neutral**	44%	37%
Sell	**Sell**	10%	22%
UBS Short-Term Rating	**Rating Category**	**Coverage[3]**	**IB Services[4]**
Buy	**Buy**	less than 1%	33%
Sell	**Sell**	less than 1%	20%

1:Percentage of companies under coverage globally within the 12-month rating category.
2:Percentage of companies within the 12-month rating category for which investment banking (IB) services were provided within the past 12 months.
3:Percentage of companies under coverage globally within the Short-Term rating category.
4:Percentage of companies within the Short-Term rating category for which investment banking (IB) services were provided within the past 12 months.

Source: UBS. Rating allocations are as of 30 June 2013.

UBS Investment Research: Global Equity Rating Definitions

UBS 12-Month Rating	Definition
Buy	FSR is > 6% above the MRA.
Neutral	FSR is between -6% and 6% of the MRA.
Sell	FSR is > 6% below the MRA.
UBS Short-Term Rating	**Definition**
Buy	Buy: Stock price expected to rise within three months from the time the rating was assigned because of a specific catalyst or event.
Sell	Sell: Stock price expected to fall within three months from the time the rating was assigned because of a specific catalyst or event.

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