Structuring RPSs to Recognize the Value of Renewable Reserve Margin Contribution

Prepared for: State-Federal RPS Collaborative Webinar

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Webinar Outline

- Executive Summary
- Resource Adequacy and Capacity Prices
- Renewable Portfolio Standards
- An Alternative RPS Design
- Concluding Remarks

Executive Summary

- In deregulated wholesale power markets number of different products are traded routinely. These products are energy, capacity, ancillary services (e.g. spinning reserves, non-spinning reserves, regulation up/down).
- Each of these products are needed for reliability and network stability.
- Majority of Renewable Portfolio Standards today focus on single product, energy (MWh). Put another way renewable energy sources earn premiums only for the energy services.
- Pricing of renewable capacity (reserve margin contribution), in addition to the renewable energy, can serve as an alternative incentive structure to encourage renewable resource diversity and reward the reliability contribution from renewables.
- The webinar does not opine on whether renewable energy incentives are effective and useful mechanisms for public benefit purposes but focuses on potential improvements to the existing implementations of renewable portfolio standards.

Resource Adequacy and Capacity Pricing in Deregulated Wholesale Markets

Resource Adequacy

- Resource Adequacy is defined as capability of meeting demand for electric power in a defined planning area during peak hours.
- One of the most commonly used resource adequacy metrics is defined as Loss of Load Expectation (LOLE) which is defined as probability of failure in meeting electric power demand in certain time frame.
- 1-day in 10-year or 2.4-hours per year is the minimum level of reliability level used by many planning entities.
- Planners determine the adequate level of planning reserve margin based on 1-day in 10-year or 1-in-10 LOLE.
- Standard resource adequacy studies indicate 1-in-10 LOLE can be achieved by maintaining reserve margins around 15%.

Economics of Resource Adequacy

- In a deregulated market where bids are constrained to short- run variable costs, the last unit called does not cover its fixed costs (e.g., property taxes, annual labor, OEM upgrade fees, etc.)
- In U.S. two market designs have emerged to enable generators to recover their fixed costs and maintain adequate level of reserves;
  - Capacity Markets (PJM, ISONE, NYISO)
  - Scarcity Pricing via Energy Only Markets (ERCOT)
- In regions where capacity markets exist energy prices are capped at $1,000/MWh and generators are required to bid their short-run variable costs. In this design generators are paid additional revenues in $/kW-yr.
- In ERCOT's energy only market design energy prices are capped at $4,500/MWh and generators are able to bid more than their variable costs as long as they don't have the market power. Generators recover their fixed costs during price spikes, i.e., scarcity pricing hours.

Capacity Markets

- Capacity markets provide a means of assuring resource adequacy (i.e. meeting reserve margins) in deregulated electricity markets.
  - Capacity markets are necessary in markets where there are administrative short run variable cost-based caps on generators' dispatch bids and electrical energy price caps.
  - With electrical energy price caps, the last unit dispatched may not earn enough to recover capital and fixed operating cost. This is known as the *Missing Money Problem*[1].
  - Additional payments are thus required in the form of capacity prices to maintain marginal existing capacity needed for reliability (i.e. avoid over-retirements) by covering fixed going forward costs and any capital investments for required retrofits.
  - Additional payments are also required in the form of capacity prices to incentivize new builds and to provide sufficient recovery of the associated capital investment.
- Theoretically, capacity markets are not required in competitive markets where there are no price caps and electricity prices are allowed to spike (i.e. scarcity premiums can be realized) in period of shortages, i.e. in competitive energy-only markets.
  - However, energy only markets need to address price volatility and the significant lead times required for new generation to come online.
  - They also need to address supply side market power concerns. Market power rises during scarcity periods.

[1]: Peter Cramton and Steve Stoft (2006), The Convergence of Market Designs for Adequate Generating Capacity, manuscript, April,25,2006.

U.S. Capacity Market Structures are Predicated on Reserve Margin Requirements

- Most deregulated electricity markets in the U.S. include a form of capacity market. While there is a significant differentiation in the design of the capacity market, all existing capacity markets are based on reserve margins as the basis for determining resource adequacy and reliability.

- Load Serving Entities (LSEs) are required to procure capacity up to a specified or target reserve margin, i.e. expected peak demand plus reserves.

- Reserve margins are established by the regulatory bodies (generally the ISO) with Loss of Load Probability (LOLP) studies that typically target LOLE less than 1 day every 10 years.

Current U.S. ISO and RTO Capacity Market Structure

	Capacity Market	Procurement	Auction Format	Time Scope	Locational Markets
ISO-NE	Yes	Centralized Auction	Descending Clock	3-yr forward with incremental reconfiguration auctions	Limited; plans for full configuration
NY-ISO	Yes	Centralized Auction	Demand Curve	Mostly spot; up to six month forward	Yes
PJM-ISO	Yes	Centralized Auction	Demand Curve	3-yr forward with incremental reconfiguration auctions	Yes
MISO	Yes	Auction	Simple auction	Upcoming year	Yes; filing approved
CAISO	Yes	Bilateral Contracts	NA	Upcoming year	Yes
SPP ISO	No	NA	NA	NA	NA
ERCOT ISO	No	NA	NA	NA	NA

Source: 2010 ISO/RTO Metrics Report; ISOs/RTOs Council

PJM Forward Capacity Auction Results are Illustrative of the Range of Potential Capacity Prices

- Both renewable and fossil-fuel fired generation receive capacity payments based on their contribution to the installed capacity.

PJM Capacity Prices ($/kW-yr)

LDAs	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015	2015/2016
RTO	14.9	40.9	37.2	63.6	40.2	6.1	10.1	46.0	49.6
MAAC	14.9	40.9	69.8	63.6	40.2	48.9	82.5	49.8	61.1
EMAAC	72.1	54.3	69.8	63.6	40.2	53.6	89.4	49.8	61.1
SWMAAC	68.8	76.7	86.6	63.6	40.2	48.9	82.5	49.8	61.1
PSEG	-	-	-	-	-	53.6	89.4	49.8	61.1
PS-NORTH	-	-	-	-	-	89.5	89.4	82.1	61.1
DPL-SOUTH	-	-	-	-	-	81.1	89.4	49.8	61.1
PEPCO	-	-	-	-	-	-	90.2	49.8	61.1
ATSI	-	-	-	-	-	-	-	-	130.3

Source: PJM

Capacity Payments are Based on Reserve Margin Contributions (a.k.a. Capacity Value)

- Reserve margin contribution can be defined as plant's contribution to the installed capacity requirement during peak periods.
- For fossil fuel fired generation, geothermal, biomass and landfill resources reserve margin contribution and operating capacity are usually the same or close.
- Reserve margin contributions of variable energy resources are calculated based on various approaches e.g. performance measurements, loss of load modeling.

Determining the Reserve Margin Contribution of the Wind

PJM	NYISO	ISO-NE	Midwest ISO
3-year rolling average of capacity factor of wind plant between 2 pm and 6 pm (local time), 6/1 through 8/31. Default value: class average of 13% of nameplate capacity until operating data becomes available. Wind capacity resources must bid into day-ahead energy market to participate in the RPM.	Capacity factor of wind plant between 2 pm and 6 pm from June through August and 4 pm through 8 pm from December through February. Default summer capacity value: 10% of nameplate capacity until operating data becomes available for onshore wind; 38% for offshore wind. Default winter capacity value: 30% of nameplate capacity until operating data becomes available for onshore wind; 38% for offshore wind. Intermittent resources not required to participate in day-ahead market to receive capacity revenues.	Summer capacity credit is the 5 year rolling average from 1pm – 6pm from June to September. Winter capacity credit is the 5 year rolling average from 5 pm – 7 pm from October to May. New facilities determine capacity credit based on 1 year of on-site data.	Uses the ELCC method of calculation. Capacity credit currently 12.9% of rated capacity in 2011 and 14.9% in 2012.

Source: Utility Wind Integration Group, http://www.uwig.org/windinmarketstableOct2011.pdf

Compensation of Variable Energy Resources in Capacity Markets

- Variable energy resources are eligible to receive capacity payments for reserve margin contributions. Depending on the type of the resource and the market, the reserve margin contribution usually range anywhere between 0 percent and 50 percent.

Resource	Approximate Reserve Margin Contribution
Geothermal	90% - 100%
Biomass	90% - 100%
Solar	20% - 50%
Wind	0% - 40%

Note: Table provides a representative range. Resource specific values may differ.

Renewable Portfolio Standards and Other Incentives

Renewable Incentives

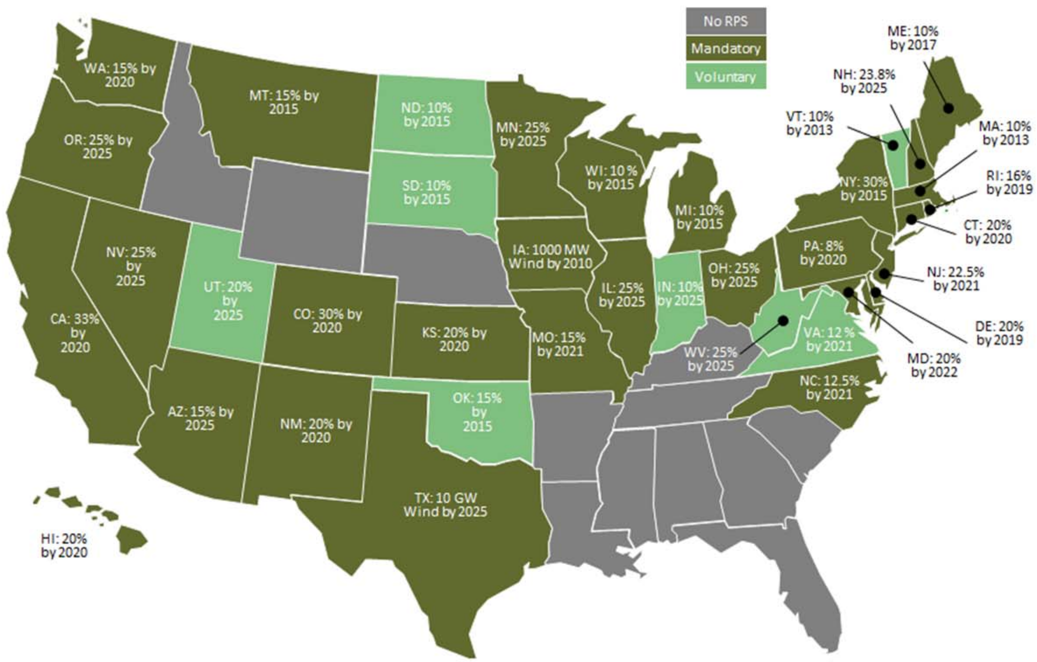
- The primary goal of renewable incentive mechanisms to facilitate market penetration of clean (zero/low emission) generation resources.

- Renewable incentives aim bridging the economic gap between economic new entry and renewable alternatives.

- In the U.S. the most popular market based incentives Production Tax Credit (PTC) and RPS compensations are both based on produced megawatt-hours without any regard to generation profiles (e.g. peak vs. off-peak, summer vs. shoulder) .

Renewable Portfolio Standards

- Renewable portfolio standards create a premium for the energy produced from renewable energy resources by establishing targets for market penetration of renewable energy.
- RPS targets are usually defined as a percentage of retail electricity load.
- RPS rules create a new energy product called the renewable energy credit (REC). For every MWh generated from eligible renewable sources, a certain amount of RECs are created based on a pre-determined ratio.
- In an ideal RPS design, the price of the REC is set at the marginal cost of renewable generation over and above the revenue earned by the renewable generator in energy markets.



Alternative Designs

Capacity (Reserve Margin) Premium for Renewables

- In this design, RPS targets are set as both percentage of retail load, and as percentage of the control area installed capacity (ICAP) requirement. E.g. 5-percent of the peak demand will be met by renewable capacity.
- This design creates a new product called the renewable capacity credit (RCC). Renewable energy sources receive additional credits for each kW they contribute to the reserve margin (installed capacity) requirement.
- RCC payments do not replace REC payments but provide additional revenue for the reserve margin contribution. For example, if a geothermal power plant has 60 MW net installed summer capacity, it will be entitled to have 60 RCCs. RCC prices can be set annually or monthly in $/kW-yr or $/kW-mo.
- By establishing a market that values the installed renewable capacity, part of the focus of renewable developers will be channeled towards contributing reserve margin requirements, which may lead to deployment of storage systems and other types of designs that target both generation and reserve reliability.

Example

- Load Serving Entity with 100-MW peak and 490,560-MWh energy demand.
- The region has two renewable sources with following characteristics:

Resource	Levelized Cost ($/MWh)	Capacity Factor (%)	Reserve Margin Contribution (%)
A	90	90	90
B	80	40	10

- Average energy price is $60/MWh.
- Two RPS design options:
  - Classic RPS: 20% of the energy demand
  - Alternative RPS: 20% of the energy demand and 5% of the peak demand (based on reserve margin contribution not nameplate capacity).

Comparing Two RPS Designs

- Case 1 – Classic RPS
  - RPS requirement = 20% of Energy Demand
  - Build 28-MW (Nameplate) of Resource B
  - 2.8-MW reserve margin contribution from renewables
  - REC: $20/MWh
  - Total Cost of RPS: $1.96MM

- Case 2 - Alternative RPS
  - RPS requirement = 20% of Energy Demand and 5% Reserve Margin Contribution
  - Build 3.1-MW of Resource A and 21.6-MW of Resource B
  - 5-MW reserve margin contribution from renewables
  - REC: 20-MWh
  - RCC: $80/kW-yr (Both Resource A and B receives RCC derated by their RM contributions)
  - Total Cost of RPS: $2.34MM

In Case 2, Load Serving Entity does not need to procure 2.2 MW peaking capacity.

Caveat

- RPS design awarding renewable capacity (reserve margin contribution) is not based on the principle on which standard capacity markets are established.
- As mentioned in the resource adequacy discussion, capacity markets are designed to help generators recover their fixed costs that cannot be recovered energy markets where the prices are capped by short-run variable costs.
- The recommended concept of pricing renewable capacity at premium is not based on the *missing money problem*. Instead, pricing of renewable capacity is recommended as an alternative incentive structure to encourage renewable resource diversity and reward the reliability contribution from renewables.

Concluding Remarks

Final Remarks

- The continuously evolving nature of energy markets requires the renewable industries to stay on top of energy market rules, regulations, and developments at all times.
- RPSs have been effective in increasing market penetration of renewables. Customized RPS designs can provide further benefits in maintaining the momentum of renewable market penetration and reliability.
- An ideal RPS design should hit the right balance between generated energy and reserve margin contribution. Awarding renewable reserve margin contribution would benefit baseload renewables, incentivize new technologies such as energy storage and provide incentives for variable energy resources to increase their contributions to reserves.

Recommended Reading

- Sener, A.C., 2011, Redefining Renewable Portfolio Standards: The Value of Installed Renewable Capacity, Electricity Journal, Volume 24, Issue 1, January, February 2011.
- Joskow, P.L., 2010, Comparing the Costs of Intermittent and Dispatchable Electricity Generating Technologies, http://economics.mit.edu/files/6317

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