Supply Analysis Working Group

Presents Discussion

on ORDC Parameters

with ERCOT Staff Analysis

and Stakeholder Position Papers

January 5, 2016

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A Review of ORDC Options

January 4, 2016

ERCOT Supply Analysis Working Group

Brandon Whittle, Chair

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Introduction

The Supply Analysis Working Group (SAWG) was asked by the Wholesale Market Subcommittee (WMS) to review and consider whether there is a need for minor adjustments to ORDC per the 10-7-2015 memo[1] filed by Commissioner Anderson, hereinafter referred to as *the memo*. The SAWG should deliver a preliminary outline of work product to December WMS meeting with a final work product no later than January WMS meeting**.**

This paper's purpose is to be that work product and to inform discussion on the topic. Its contents are an aggregation of recommendations from ERCOT stakeholders and analysis by ERCOT Staff. This paper is not intended to address any threshold issues such as what an appropriate reserve margin is for the ERCOT region or how it should be attained.

The main body of the paper is the work of the SAWG which is intended to be agnostic of potential changes. Following this paper is an ERCOT Analysis of the options presented here, then position papers authored by ERCOT Stakeholders.

CURRENT STATUS – This status section to be deleted before 1/6 WMS.
1/4/16, organizational edits
12/16/15, organizational edits and edits during 12/16 SAWG.
12/8/15, updated to include additional scenarios requested by stakeholders
12/3/15, updated following 12/2 SAWG. This will be redrafted and graphics to be updated after ERCOT's analysis is available for inclusion before the 12/16 SAWG.
11/16/15, this is modified to reflect discussion at 11/13/15 SAWG meeting and amended to include specific possible adjustments.
11/12/15, this is purely a draft strawman outline.

List of Observations regarding ORDC performance

Stakeholders do not generally agree what, if anything, needs to be addressed with the ORDC mechanism. This is a list of various stakeholder observations and it does not imply stakeholder consensus.

A. ORDC is performing as intended and designed.
B. ORDC is not aligned with operations demonstrated by the 8/13/2015 event. The event is described both in ERCOT's presentation[2] to TAC and this comment from the memo, "I ask this question because at certain hours of certain days last summer the price adder resulting from the ORDC seemed to suggest LOLP of well under 1% even though ERCOT was considering making conservation appeals."
C. Hockey stick curve[3] makes optimization difficult and is driven by VOLL being identical to SWOC. Pricing outcomes during scarcity events are extremely volatile.

[1] http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/40000_667_868214.PDF
[2] "As we approach scarcity PRC will be around 2500 and ORDC will gradually approach PRC as prices increase causing QSGRs to come online, resources to put their duct firing online and SCED to move resources to the top making the remaining capacity within 20%HSL. However, since minimum RRS level is 2300MW there could be situations where PRC stays just above 2300MW for a long time and could drop below 2300 when we still have lot of quick starts physically offline but available to SCED. " http://www.ercot.com/content/wcm/key_documents_lists/77254/14._08132015_Analysis_of_PRC_Vs_ORDC_Corrected.pptx
[3] Hockey Stick refers to the price being equal to $9,000 at reserves less than or equal to 2,000 MW while sharply decreasing to roughly $4,500 with the addition of one MW of additional reserves.

D. The value of X being lower than RRS and URS can lead to reserves being converted to energy at prices less than 25% of SWOC.
E. Because X=2,000 is lower than Ancillary Service reserve requirements, when ORDC reserves fall below 2,000 MW it's too late to send signals to resources and consumers.
F. Current mechanism introduces the potential for lack of consistency and convergence in the Day Ahead Market outcomes compared to the Real-Time Market. Value differentiation of ancillary reserves is needed.

Stakeholder Proposals for Improvement

To address perceived shortcomings listed above, stakeholders suggested many different options listed below. This section serves as a summary for different options, none of which is a consensus view or an endorsement by any stakeholder group. Due to their similarity in structure, proposals 6 through 10 are repeated in table form.

1. There is no need to make any changes. Addresses item A from section II above.
2. Add ORDC to the DAM. The ORDC curve would be used as the demand curve for AS procurement and pricing instead of today's inelastic procurement. Could be applied to all other options (1, 3-8). Addresses F
3. Apply dynamic Reserve Discount Factor (RDF) from PRC calculation instead of the static RDF in the ORDC Real Time Online Capacity (RTOLCAP). Addresses B
4. Set Real Time Offline Capacity (RTOFFCAP) = 0 at PRC =2500 to increase adder amounts. Addresses B
5. Upon deployment of NSRS by the ERCOT operator, require that all Quick Start Resources providing NSRS during that time to come physically online[4]. Could be applied to all other options. Addresses B
6. Set minimum RRS procurement at 2,750; Set X each hour equal to the sum of RRS and URS procured; Set VOLL = $18,000; Retain "effective price cap" = SWOC ($9,000); Addresses B,C,D,E
7. Set minimum RRS procurement at 2,750; Set X each hour = sum of RRS and URS; Modify ORDC such that price adder plus system lambda is >= $4,500 when PRC is less than 2500MW and is at offer cap when PRC is less than 2300MW. Addresses B,C,D,E
8. Set X =2,300; Set VOLL = $12,000; Retain "effective price cap" = SWOC ($9,000); Addresses B,C,D,E
9. Set minimum RRS procurement at 2750; Set X =2,750; Set VOLL = $18,000; "effective price cap" = SWOC ($9,000); Addresses B,C,D,E
10. Set X=1708[5]; Set VOLL = $18,000; Retain "effective price cap" = SWOC ($9,000); Addresses C

[4] QMWG currently is discussing this concept and refinements to this proposal may be forthcoming through that effort.
[5] Reduction from current level of 2,000 to keep ORDC changes revenue neutral.

Table 1 Summary of proposals 6 though 10

#	Minimum RRS	Value of X (MCL)	VOLL	"Effective Price Cap"[6]	Other	Addresses
6	2,750 MW	Sum of RRS & URS[7]	$18,000	$9,000		B,C,D,E
7	2,750 MW	Sum of RRS & URS	$9,000	N/A	PRC Based Adder Floor[8]	B,C,D,E
8	2,300 MW[9]	2,300 MW	$12,000	$9,000		B,C,D,E
9	2,750 MW	2,750 MW	$18,000	$9,000		B,C,D,E
10	2,300 MW	1,708 MW	$18,000	$9,000		C

Stakeholders in SAWG did find consensus on two items which should not change:

1) Stakeholders do not recommend any more discretion in calling EEA than what is provided in NPRR708.
2) Stakeholders do not recommend increasing the "effective price cap" beyond the current $9,000 level.

ERCOT Analysis

ERCOT has provided back cast analysis based on the stakeholder proposals above in the following paper[10].

The Back Cast Tool

To aid in this analysis, ERCOT developed a tool[11] reminiscent the 2011-12 back casts for the original ORDC discussion. The tool is flexible enough to handle different combinations of these changes including behavioral changes.

Understanding where back casts excel and where they have difficulty is important, especially when considering policy changes.

Pros:

1) Relatively easy to produce.
2) Familiar to analysists and decision makers, used for previous ORDC analysis.
3) Better suited to gauge relative differences in options.

Cons:

1) Magnitude of impact due to a modeled change can be misleading.
2) Behavioral changes from resources are difficult to model, and when those changes lead to additional commitment the model will generally overestimate the effect of ORDC changes. ERCOT has supplied some ability

[6] "Effective Price Cap" is a suggestion to form the ORDC adder such that system lambda plus the adder does not exceed the system wide offer cap (SWOC). Today the "effective price cap" is equal to VOLL which happens to be the same as SWOC.
[7] X would change hourly and be equal to sum of RRS and URS procured for that hour.
[8] Floor RTORPA plus System Lambda at $4,500 when PRC is below 2,500 MW and at $9,000 when PRC is below 2,300 MW.
[9] RRS minimum of 2,300 is today's practice and this recommendation does not suggest a change.
[10] Available directly at http://www.ercot.com/content/wcm/key_documents_lists/80837/ERCOT_ORDC_Options_Analysis.pdf
[11] The latest versions of the tool can be found at the 12/2/15 SAWG meeting page. http://www.ercot.com/calendar/2015/12/2/80827-SAWG

to modify behavior in the tool but currently it can only anticipate changes interval by interval so temporal considerations are ignored.

Discussion of the Bullet Points from The Memo

In this sections, some rudimentary discussion and suggestions were captured surrounding each bullet point in the original memo.

Level of X

From the memo: “The level of X used in the ORDC formula, which is 2,000 MW of operating reserves, selected to represent a level below which ERCOT operators cease relying on the market and begin to take out-of-market actions”

Discussion: X is also called the Minimum Contingency Level (MCL), and it is the level of ORDC Online Reserves which will trigger a price at VOLL (currently $9,000). It is important to remember that the Online Reserves is typically more than the Physical Responsive Capability (PRC) reserves, (see Chapter VII).

Alternatives:

a) X=2000 (Current level). The rationale for retaining X=2000 is:
    a. There is not clarity in what needs to be fixed or what goal is to be achieved by adjustment
b) X=Regup + RRS. The rationale is:
    a. Would continuously keep ERCOT in compliance with NERC BAL-003-1
    b. From a practical standpoint would ensure ERCOT could recover frequency from a loss of 2,750 MW
c) X= Regup + RRS with RRS floor of 2750. The rationale is:
    a. Provides appropriate prices signals during scarcity triggered by EEA
    b. Makes ORDC consistent with Demand curves in Real-Time Co-Optimization
d) X= 2000 with a multiplier of RT Load/average Load. The rationale is:
    a. Ties the X value to the level of unloaded capacity in the Market
e) X= Reduced value when used in combination with other changes.

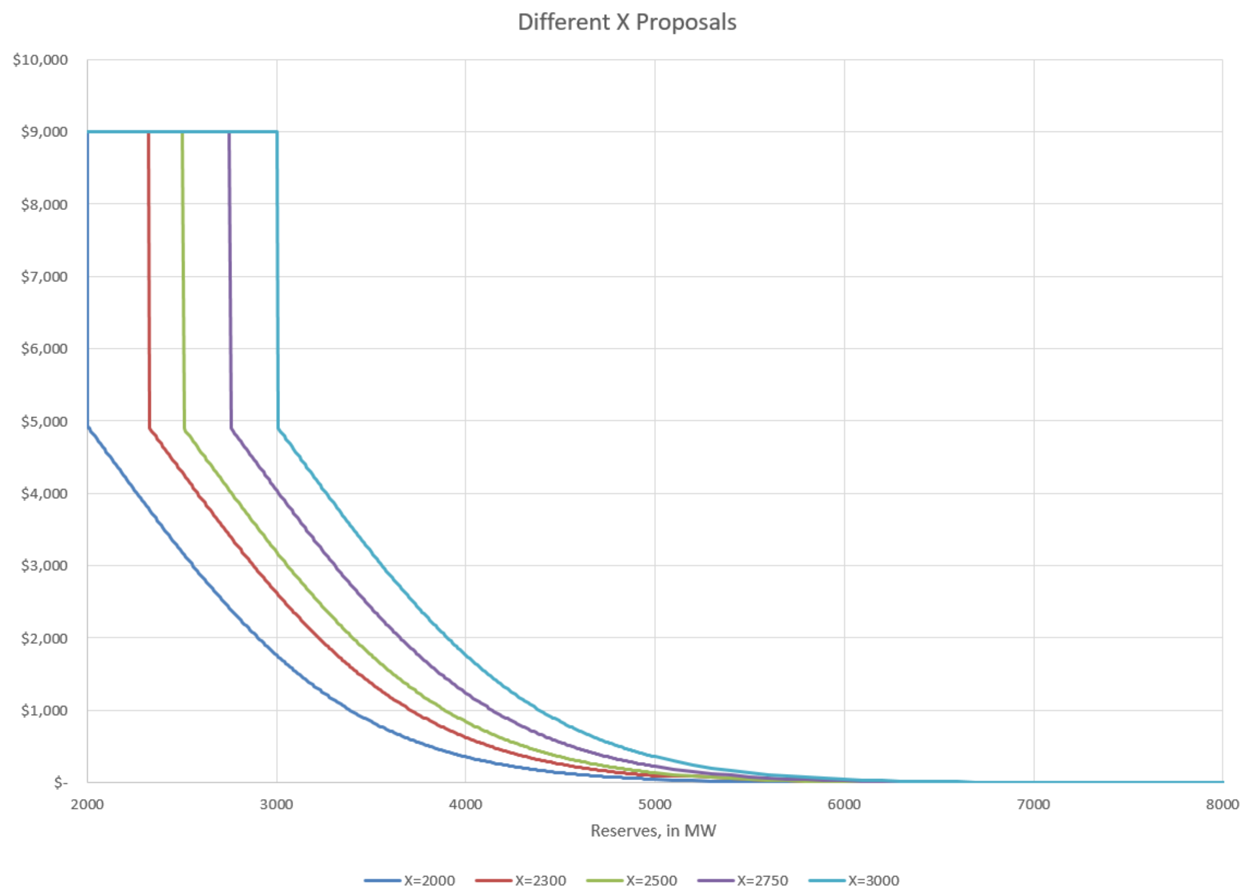

Figure 1, X Options

Conclusion: As you can see in the figure above, the higher X merely shifts the curve to the right.

Standard Deviation of the LOLP

From the memo: "The number of standard deviations used to formulate of the loss of load probability curve in the ORDC."

Discussion: The LOLP is determined by analyzing historic events defined as the difference between the hour-ahead forecasted reserves with the reserves that were available in Real-Time during the Operating Hour[12]. Currently we use one Standard Deviation when calculating the LOLP.

Alternatives:

a) Use One Standard Deviation (SD) (Current practice). The rationale for retaining the current value is:
   a. There is not clarity in what needs to be fixed or what goal is to be achieved by adjustment
b) Increase SD .The rationale is:
   a. Shifts the slope of the curve to make it more gradual of a change between reserve levels.
   b. A value higher than one SD may be appropriate to better capture the risk on some winter mornings where RUC has been necessary (Further analysis may be necessary).

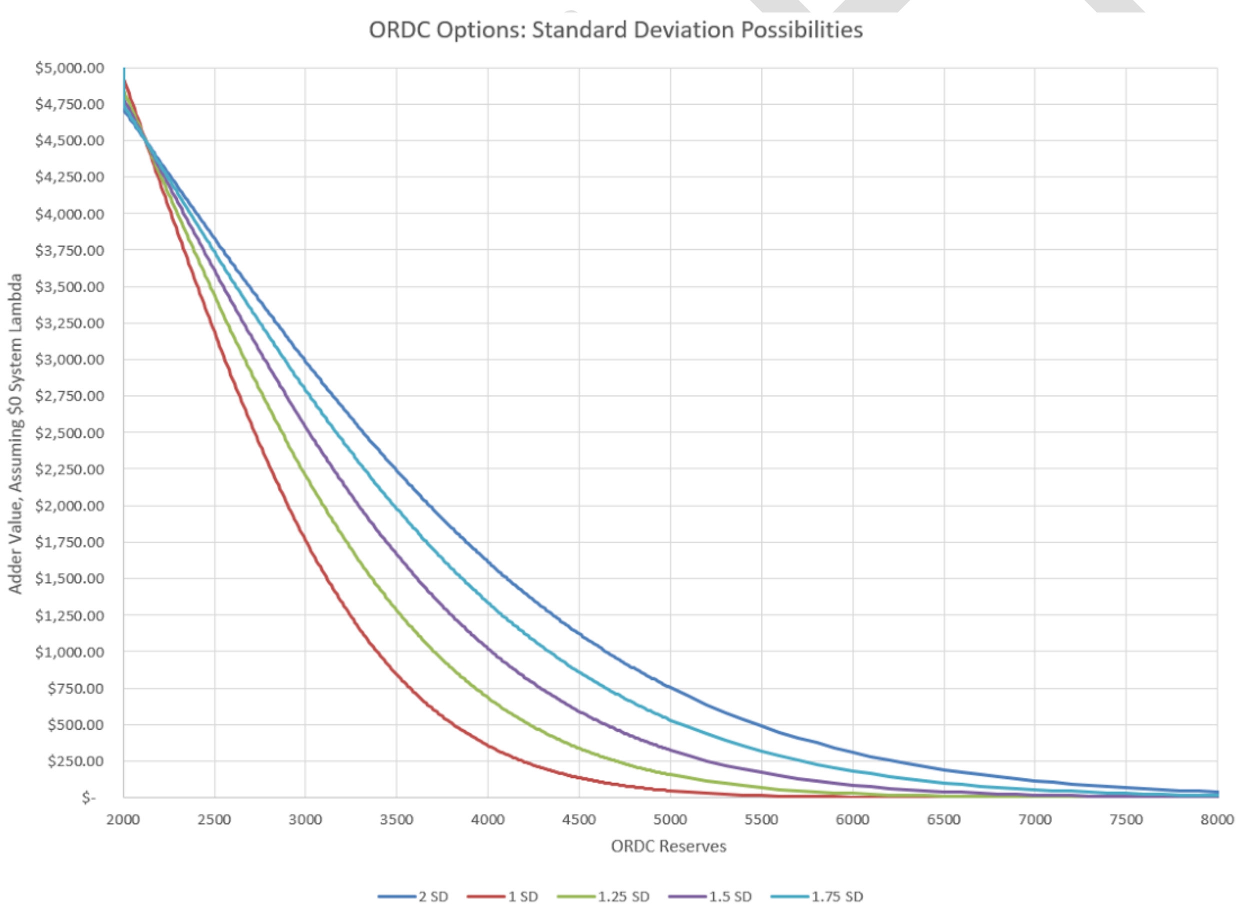

Figure 2, Effect of increasing the Standard Deviation used in LOLP

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12 Methodology for Implementing Operating Reserve Demand Curve

Conclusion: As you can see in the figure above, adding standard deviations "flattens" the curve and extends the duration of a meaningful adder.

VOLL

From the memo: "The value of lost load (VOLL) used in the ORDC, which currently is $9,000 MWh (and whether $9,000 MWh should remain as the effective price cap even if the VOLL is increased)"

Discussion: A significant issue is the consideration of the "effective price cap". Currently VOLL *is* the effective price cap, not the System Wide Offer Cap (SWOC), so if VOLL is greater than the SWOC the energy price could exceed SWOC even in intervals without congestion.

Alternatives:

a) VOLL = $9,000. Current value, as there is not clarity in what needs to be fixed or what goal is to be achieved by adjustment.

b) VOLL = $18,000, but the effective price cap remains at $9,000.
    a. Shifts the slope of the curve resulting in a more gradual change between reserve levels
    b. Places a higher value on real-time operating reserves during periods of increased system risk

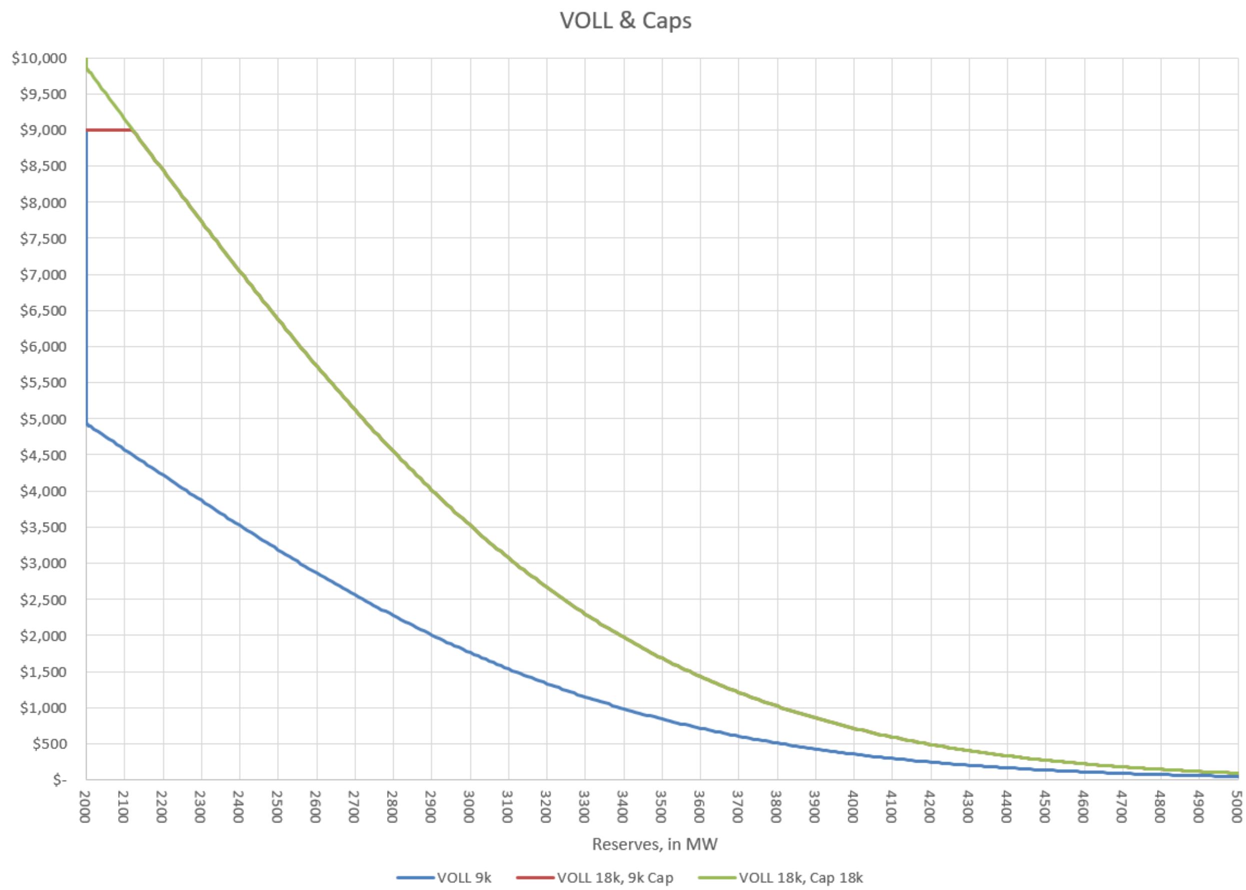

Figure 3, VOLL at 9 & 18k, with and without 9k cap. Note, the 18k capped curve does go to 18k but the chart is truncated at 10k for ease of viewing.

Conclusion: In the figure above we see that an increase in VOLL would be a straight forward increase to the ORDC adder (RTORPA) but the cap question is an important one. It's also important to note that the only time the "effective price cap" issue matters is when reserves are near the minimum contingency level.

PRC vs Online Operating Reserves

From the memo: "Should operating reserves counted in ORDC become more closely correlated to PRC, and if so, how?"

Discussion: The PRC, which ERCOT uses to determine if it's in an Energy Emergency Alert (EEA), is a more conservative value than the Operating Reserves calculation due to the requirement that PRC only count frequency responsive resource capacity. ERCOT presented an analysis at the 10-29-15 TAC[13]. ERCOT and stakeholders have identified a few options.

Possible solutions:

a) When Non-Spin Reserve Service (NSRS) is deployed, require all NSRS to be physically online which increases PRC so less likely EEA events, but also could decrease system lambda and the ORDC adder. Quick Start Generators (QSGRs) providing NSRS should also be required to be physically online at a particular PRC level which may be in economic order (after offline NSRS is deployed at 2500 MW)

[13] http://www.ercot.com/content/wcm/key_documents_lists/77254/14._08132015_Analysis_of_PRC_Vs_ORDC.pptx

- Manual deployment is out of market action
- Is deploying a reliability product procured to provide more capacity online when PRC drops below 2500?
- Bringing on capacity could depress prices which could be partially mitigated using the Reliability Deployment Price Adder.

b) Increase Responsive Reserve Service (RRS) Procurement by putting a min RRS level above 2300 MW with a buffer
   - Market based solution
   - Would be procuring RRS more than what is needed per ERCOT's reliability analysis for Frequency Response Obligation

c) Require all NSRS to be offline and to be brought online upon ERCOT deployment
   - Removes the ability for small fleet to provide NSRS
   - Reduces competition in NSRS market by reducing the supply stack
   - Will help converge ORDC to PRC if offline NSRS is required to be physically online when PRC=2300 MW
   - Aggravates price reversal issues
   - No additional service is provided if the behavior is otherwise the same

d) Allow operator to use more discretion in calling EEA[14] – Modification to NPRR708

e) Increase ORDC parameters to create economic incentive for resources to be online.

[14] 11/13/15 SAWG consensus is to not recommend any more discretion in calling EEA than what is stated in NPRR708

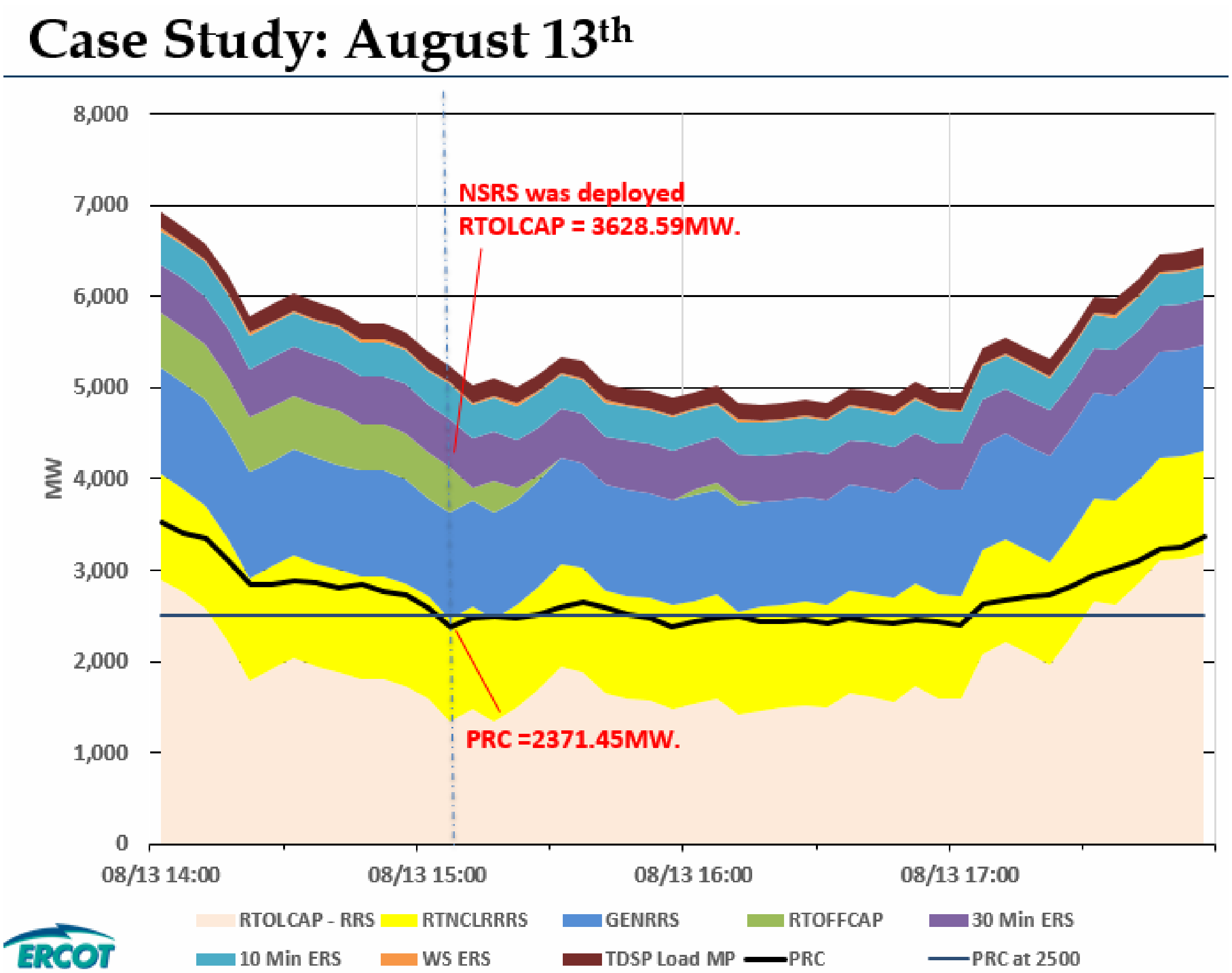

Figure 4, Low PRC from ERCOT analysis presented to 10-29-15 TAC.

Other inputs to LOLP

From the memo: "Are the current inputs used to calculate the loss of load probability (LOLP) for any given period a sufficiently reasonable approximation or should the method and inputs be reevaluated? I ask this question because at certain hours of certain days last summer the price adder resulting from the ORDC seemed to suggest LOLP of well under 1% even though ERCOT was considering making conservation appeals."

Discussion: Alternatives to LOLP cannot be considered in a vacuum. Alternatives would necessitate a review of recommendations/options to the above and below questions.

a. Does the error distribution used for the LOLP calculation need to be re-examined?
b. Is the error distribution capturing risk appropriately?
c. Should the timing of conservation appeals be re-evaluated?

Recommendations: None.

Other Suggestions

Stakeholders have suggested these other considerations which have not been evaluated in this effort.

1) Has the Non-Spin floor created a de-facto cap on energy prices? Should Non-Spin offer floors be increased?

2) LCAP/HCAP - Drop the HCAP as a pressure release (Should the pressure release valve remain or be applied to another value such as VOLL)?

Record of Stakeholder Meetings

10-29-15 Technical Advisory Committee (TAC)

11-4-15 Wholesale Market Subcommittee (WMS)

11-11-15 Supply Analysis Working Group (SAWG)

11-13-15 Supply Analysis Working Group (SAWG)

11-19-15 Technical Advisory Committee (TAC)

12-2-15 Wholesale Market Subcommittee (WMS)

12-2-15 Supply Analysis Working Group (SAWG)

12-16-15 Supply Analysis Working Group (SAWG)

12-17-15 Technical Advisory Committee (TAC)

1-5-16 Supply Analysis Working Group (SAWG)

1-6-16 Wholesale Market Subcommittee (WMS)

1-28-16 Technical Advisory Committee (TAC)

ERCOT ORDC Options Analysis

January 5, 2015

SAWG

Market Analysis, ERCOT

Version 1.0

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Introduction

Options for changing the Operation Reserve Demand Curve (ORDC) parameters were proposed at the November 13, 2015[1] and December 2, 2015[2] Supply Analysis Working Group (SAWG). ERCOT was asked to analyze the options and present the following results:

1. Additional Peaker Net Margin (PNM) contributed by ORDC
2. Real-time On-line Price Adder (RTORPA)
3. Number of hours histogram where RTORPA was greater than \$100/MWh, \$500/MWh, and \$1,000/MWh

Following the December 16, 2015 SAWG meeting, clarification was needed on the weighting method used for calculating RTORPA. As a result, two weighting methods will be presented:

1. Energy and Time-weighted RTORPA (originally presented on December 16, 2015)
2. Time-weighted RTORPA

Energy is weighted by generation to be dispatched (GTBD) and time is weighted by each SCED interval length. Calculations using on-peak hours include hour ending 0700-2200 CPT weekdays and exclude NERC defined holidays. Off-peak hours include all other hours.

ERCOT was asked to analyze the following dates with actual FIPs:

1. June 1, 2014 – October 31, 2015
2. January 1, 2011 – December 31, 2011

Market behavior changes after ORDC implementation, changes in the System-Wide Offer Cap (SWOC), and changes in price floors will significantly affect the validity of 2011 backcast results. Additionally, it is recommended to use the backcast only to compare options since changes in market behavior can affect both periods

How does the market behavior price response mechanism work? Using the proposed options, the new RTORPA is calculated for each option. If System Lambda plus the new RTORPA is greater than the price response value (i.e. \$75), then offline and available capacity with cold start time greater than 30 minutes is added to the Real-Time On-Line Capacity (RTOLCAP) until either offline and available capacity is exhausted or System Lambda + RTORPA reaches the price response value.

[1] http://www.ercot.com/calendar/2015/11/13/78245-SAWG
[2] http://www.ercot.com/calendar/2015/12/2/80827-SAWG

Options

Current ORDC implementation values are in red.

See ORDC Options Whitepaper from 12-16-15 for more details[3].

Option	Minimum RRS	Value of X (MCL)	VOLL	Effective Price Cap	Price Response	Other
0	2,300 MW	2,000 MW	$9,000	$9,000	None	
1	2,300 MW	2,000 MW	$9,000	$9,000	$75	
2	See Section 4					
3	2,300 MW	2,000 MW	$9,000	$9,000	$75	Discount Factor = 0.98 (0.99)
4	2,300 MW	2,000 MW	$9,000	$9,000	$75	RTOFFCAP = 0 when PRC < 2500 (2300)
5	Same results as base case					
6	2,750 MW	Sum of RRS & URS	$18,000	$9,000	$75	
7	2,750 MW	Sum of RRS & URS	$9,000	$9,000	$75	RTORPA+System Lambda = $4,500 when PRC < 2,500 MW (None) RTORPA+System Lambda = $9,000 when PRC < 2,300 MW (None)
8	2,300 MW	2,300 MW	$12,000	$9,000	$75	
9	2,750 MW	2,750 MW	$18,000	$9,000	$75	
10	2,300 MW	1,708 MW	$18,000	$9,000	$75	

Table 1. Proposed options

Option 0 – Base Case No Response

- X = 2000
- VOLL = $9,000
- SWOC = $9,000
- RDF = 0.99
- PRC Threshold to set RTOFFCAP to 0 = 2300

Option 1 – Base Case

- Option 0 with price response at $75/MWh

Option 2

- Convert ORDC into Ancillary Services Demand Curves in the DAM

[3] http://www.ercot.com/calendar/2015/12/2/80827-SAWG

Option 3 – RDF=0.98

- Price response at $75/MWh
- RDF = 0.98

Option 4 – RTOFFCAP=0 PRC<2500

- Price response at $75/MWh
- PRC Threshold to set RTOFFCAP to 0 = 2500

Option 5

Upon deployment of NSRS by the ERCOT operator, require all Quick Start Resources providing NSRS to come physically online. **Note:** *This would not change RTOLCAP if implemented but would increase PRC.*

Option 6 – X=RRS+URS VOLL=18000

- Price response at $75/MWh
- X = RRS + URS
- Min. RRS = 2750
- VOLL = $18,000

Option 7 – X=RRS+URS Price Floor

- Price response at $75/MWh
- X = RRS + URS
- Min. RRS = 2750
- Floor Price to $4,500 when PRC<2500 and Price to $9,000 when PRC<2300

Option 8 – X=2300 VOLL=12000

- Price response at $75/MWh
- X = 2300
- VOLL = $12,000

Option 9 – X=2750 VOLL=18000

- Price response at $75/MWh
- X = 2750
- VOLL = $18,000

Option 10 – X=1708 VOLL=18000

- Price response at $75/MWh
- X = 1708
- VOLL = $18,000

Section 1: June 1, 2014 – October 31, 2015 Backcast

Real-Time On-Line Price Adder

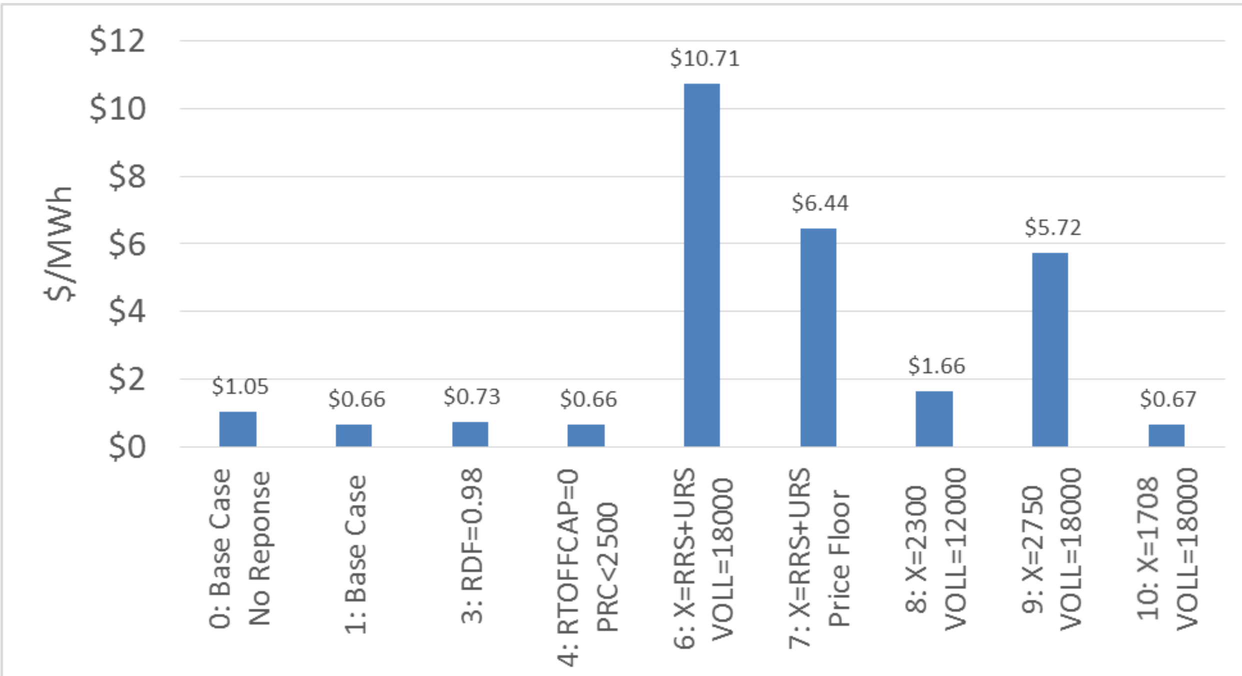


Figure 1. Energy and Time Weighted Average RTORPA of All Hours (6/1/2014 – 10/31/2015)

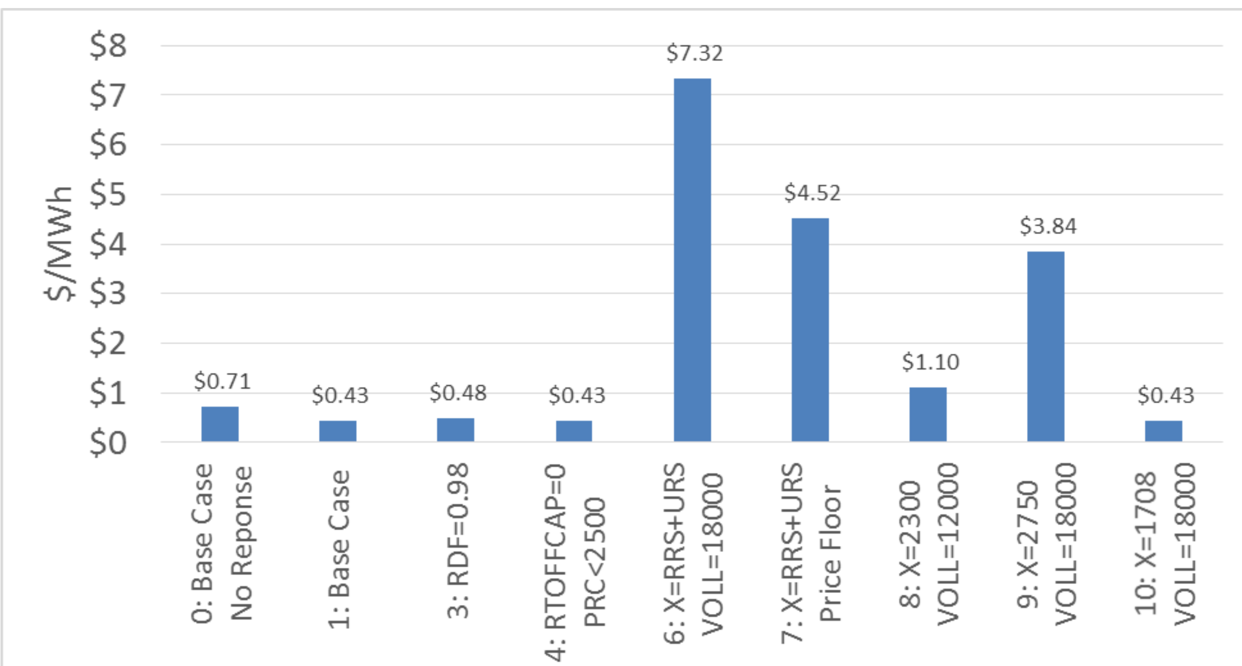


Figure 2. Time Weighted Average RTORPA of All Hours (6/1/2014 – 10/31/2015)

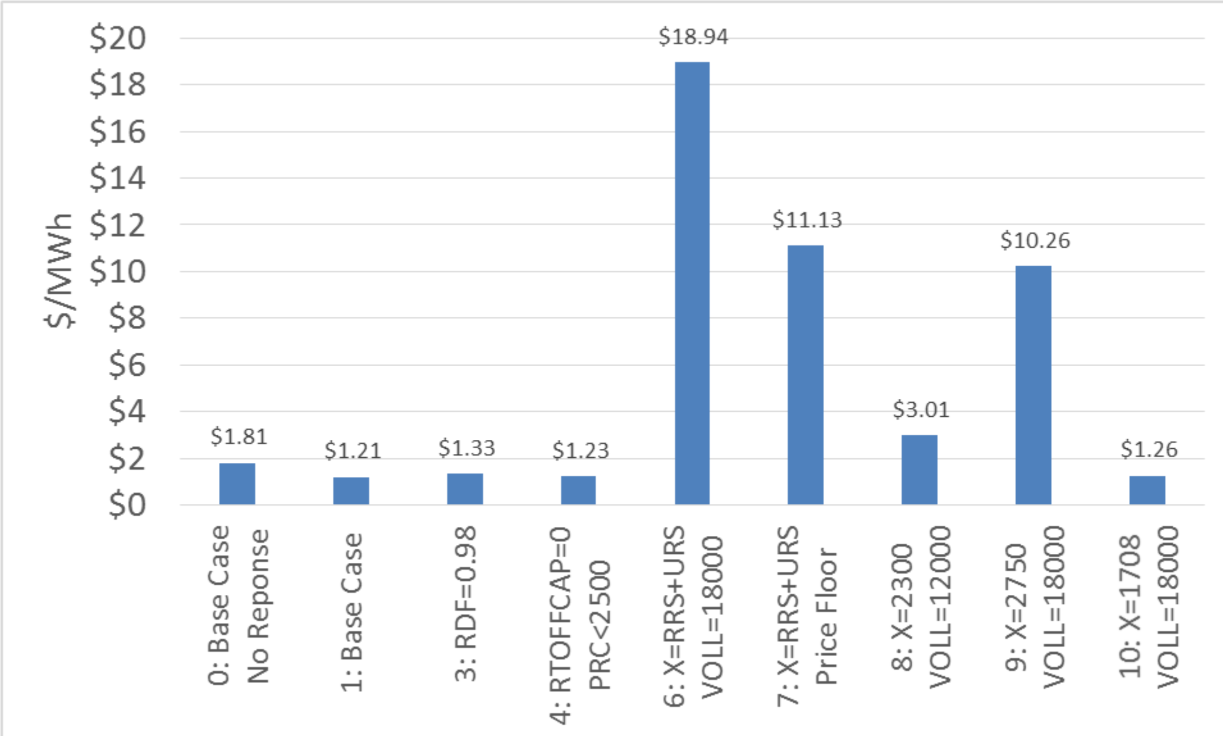


Figure 3. ONPEAK Energy and Time Weighted Average RTORPA (6/1/2014 – 10/31/2015)

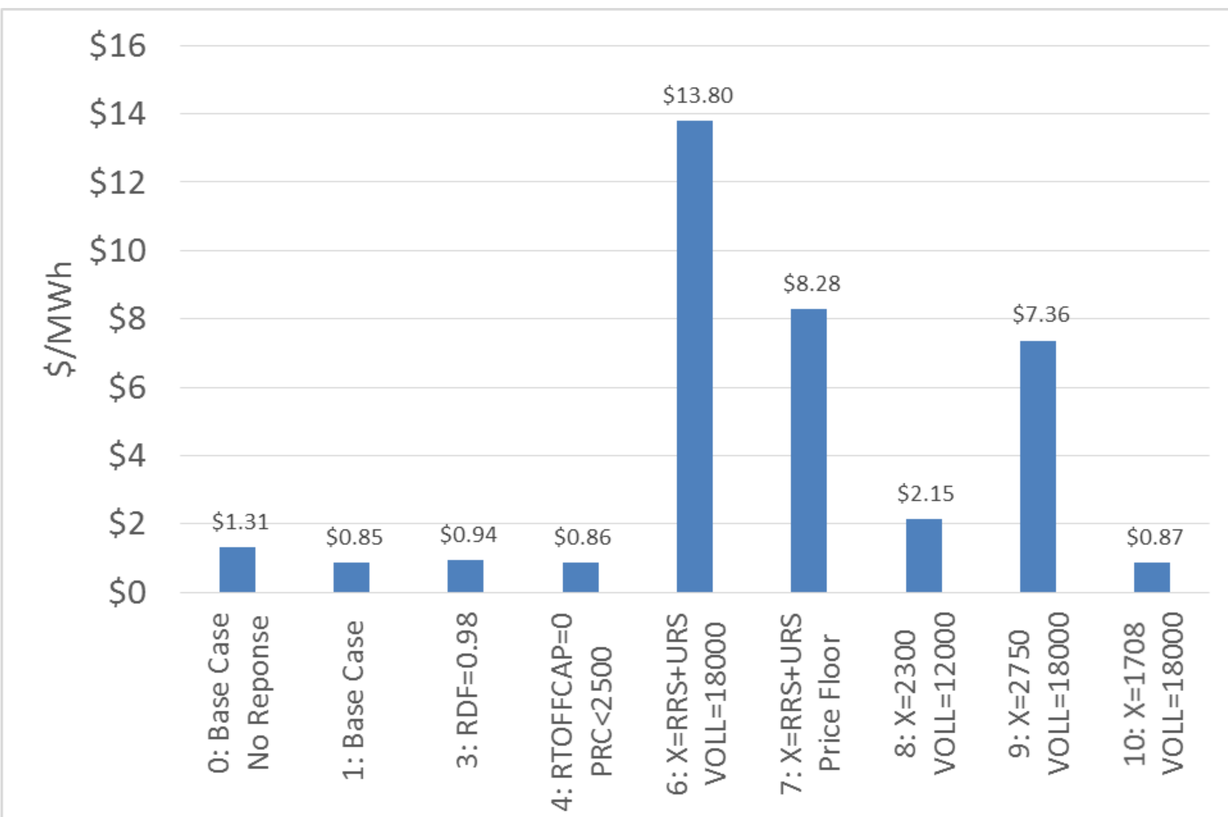


Figure 4. ONPEAK Time Weighted Average RTORPA (6/1/2014 – 10/31/2015)

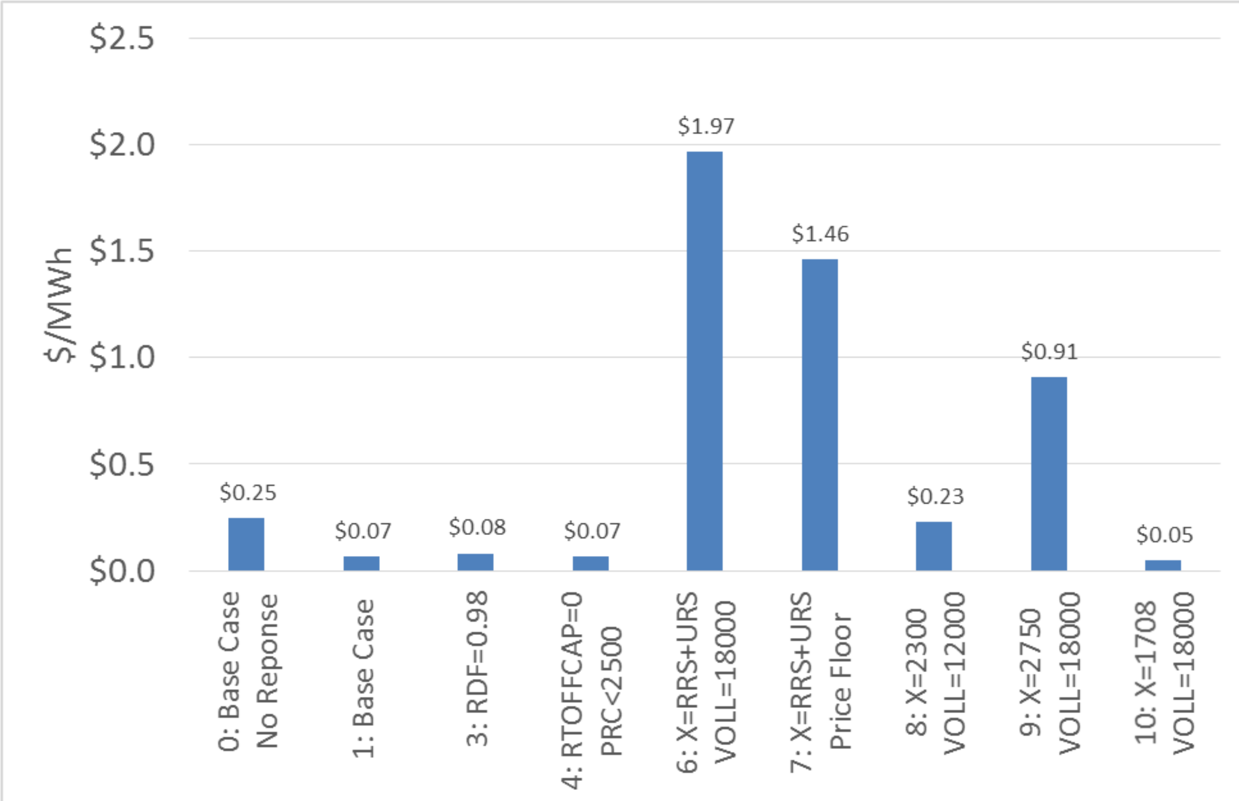


Figure 5. OFFPEAK Energy and Time Weighted Average RTORPA (6/1/2014 – 10/31/2015)

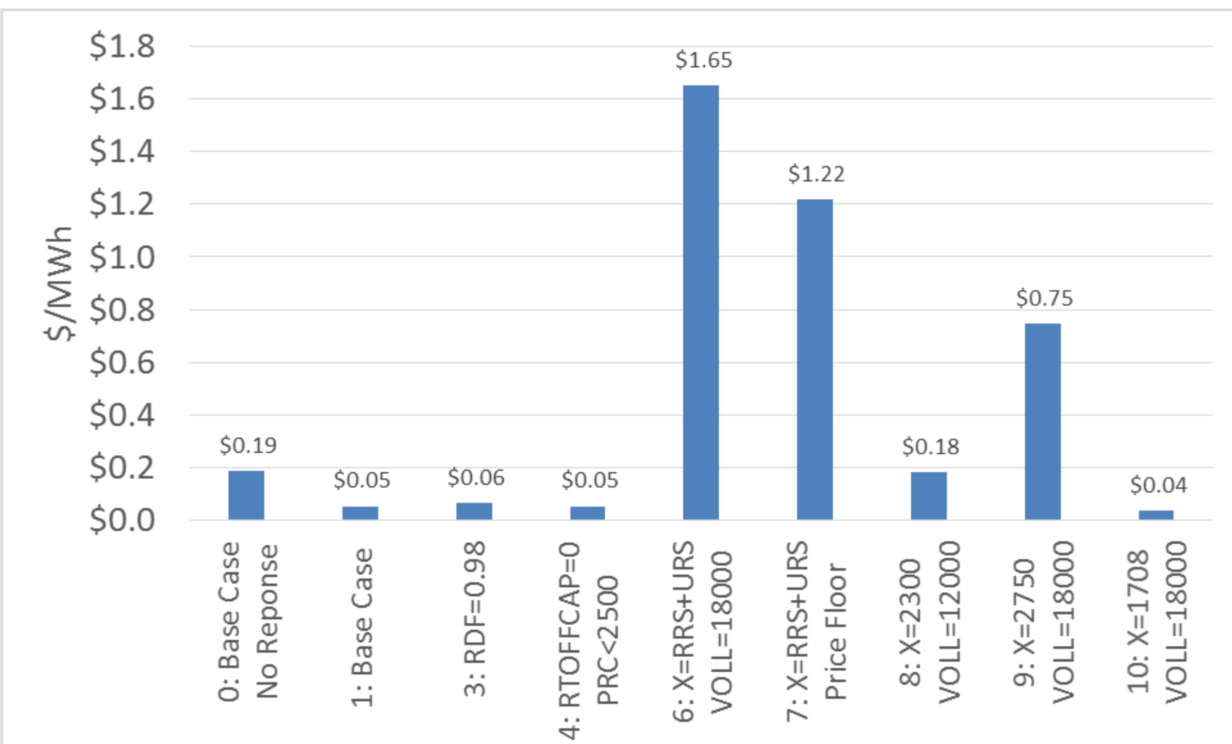


Figure 6. OFFPEAK Time Weighted Average RTORPA (6/1/2014 – 10/31/2015)

Option	Energy and Time Weighted Average RTORPA($/MWh)	Time Weighted Average RTORPA($/MWh)	ONPEAK Energy and Time Weighted Average RTORPA($/MWh)	ONPEAK Time Weighted Average RTORPA($/MWh)	OFFPEAK Energy and Time Weighted Average RTORPA($/MWh)	OFFPEAK Time Weighted Average RTORPA($/MWh)
0: Base Case No Reponse	$ 1.05	$ 0.71	$ 1.81	$ 1.31	$ 0.25	$ 0.19
1: Base Case	$ 0.66	$ 0.43	$ 1.21	$ 0.85	$ 0.07	$ 0.05
3: RDF=0.98	$ 0.73	$ 0.48	$ 1.33	$ 0.94	$ 0.08	$ 0.06
4: RTOFFCAP=0 PRC<2500	$ 0.66	$ 0.43	$ 1.23	$ 0.86	$ 0.07	$ 0.05
6: X=RRS+URS VOLL=18000	$ 10.71	$ 7.32	$ 18.94	$ 13.80	$ 1.97	$ 1.65
7: X=RRS+URS Price Floor	$ 6.44	$ 4.52	$ 11.13	$ 8.28	$ 1.46	$ 1.22
8: X=2300 VOLL=12000	$ 1.66	$ 1.10	$ 3.01	$ 2.15	$ 0.23	$ 0.18
9: X=2750 VOLL=18000	$ 5.72	$ 3.84	$ 10.26	$ 7.36	$ 0.91	$ 0.75
10: X=1708 VOLL=18000	$ 0.67	$ 0.43	$ 1.26	$ 0.87	$ 0.05	$ 0.04

Table 2. Averages of RTORPA (6/1/2014 – 10/31/2015)

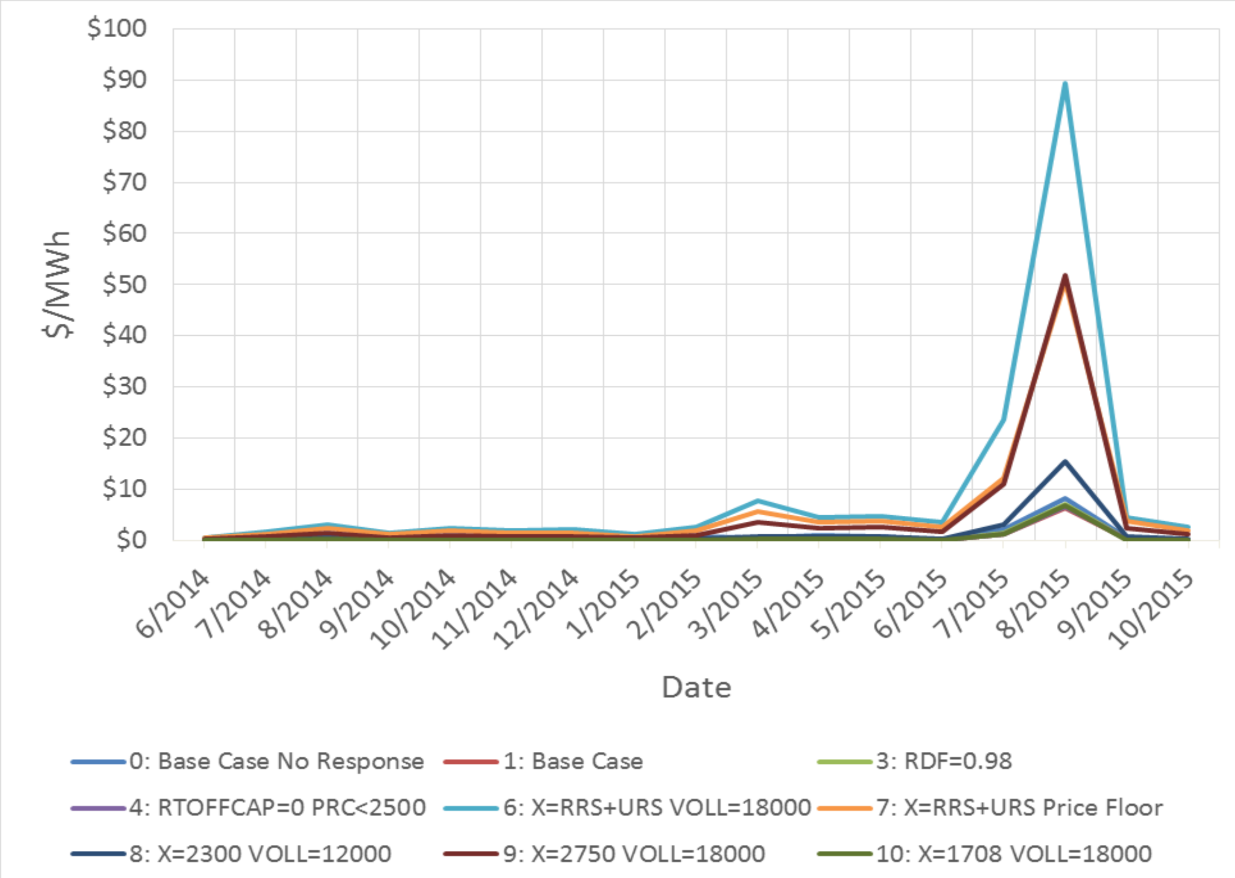


Figure 7. Energy and Time Weighted Average RTORPA of All Hours by Month (6/1/2014 – 10/31/2015)

Month	0: Base Case No Response	1: Base Case	3: RDF=0.98	4: RTOFFCAP=0 PRC<2500	6: X=RRS+URS VOLL=18000	7: X=RRS+URS Price Floor	8: X=2300 VOLL=12000	9: X=2750 VOLL=18000	10: X=1708 VOLL=18000
6/2014	$ 0.03	$0.01	$ 0.02	$ 0.01	$ 0.56	$ 0.40	$ 0.05	$ 0.24	$ 0.01
7/2014	$ 0.13	$0.05	$ 0.06	$ 0.05	$ 1.77	$ 1.26	$ 0.19	$ 0.73	$ 0.03
8/2014	$ 0.80	$0.27	$ 0.29	$ 0.27	$ 3.11	$ 2.34	$ 0.55	$ 1.50	$ 0.23
9/2014	$ 0.13	$0.04	$ 0.04	$ 0.04	$ 1.56	$ 1.12	$ 0.13	$ 0.58	$ 0.02
10/2014	$ 0.35	$0.06	$ 0.07	$ 0.06	$ 2.43	$ 1.84	$ 0.22	$ 0.96	$ 0.03
11/2014	$ 0.15	$0.03	$ 0.04	$ 0.03	$ 1.97	$ 1.44	$ 0.13	$ 0.73	$ 0.02
12/2014	$ 0.11	$0.09	$ 0.10	$ 0.09	$ 2.20	$ 1.51	$ 0.23	$ 0.82	$ 0.07
1/2015	$ 0.10	$0.05	$ 0.06	$ 0.05	$ 1.10	$ 0.77	$ 0.13	$ 0.42	$ 0.04
2/2015	$ 0.66	$0.08	$ 0.09	$ 0.08	$ 2.62	$ 1.89	$ 0.24	$ 1.08	$ 0.06
3/2015	$ 0.49	$0.24	$ 0.29	$ 0.24	$ 7.68	$ 5.75	$ 0.82	$ 3.48	$ 0.17
4/2015	$ 0.96	$0.32	$ 0.37	$ 0.32	$ 4.51	$ 3.47	$ 0.86	$ 2.41	$ 0.25
5/2015	$ 0.79	$0.24	$ 0.28	$ 0.24	$ 4.83	$ 3.78	$ 0.77	$ 2.60	$ 0.18
6/2015	$ 0.14	$0.10	$ 0.12	$ 0.10	$ 3.56	$ 2.54	$ 0.34	$ 1.62	$ 0.06
7/2015	$ 2.12	$1.23	$ 1.36	$ 1.23	$ 23.65	$ 12.08	$ 3.04	$ 11.12	$ 1.27
8/2015	$ 8.32	$6.39	$ 6.97	$ 6.50	$ 89.28	$ 50.70	$ 15.54	$ 51.73	$ 6.89
9/2015	$ 0.43	$0.23	$ 0.27	$ 0.23	$ 4.49	$ 3.68	$ 0.75	$ 2.48	$ 0.15
10/2015	$ 0.05	$0.04	$ 0.05	$ 0.04	$ 2.61	$ 1.96	$ 0.18	$ 1.12	$ 0.02

Table 3. Energy and Time Weighted Average RTORPA of All Hours by Month (6/1/2014 – 10/31/2015)

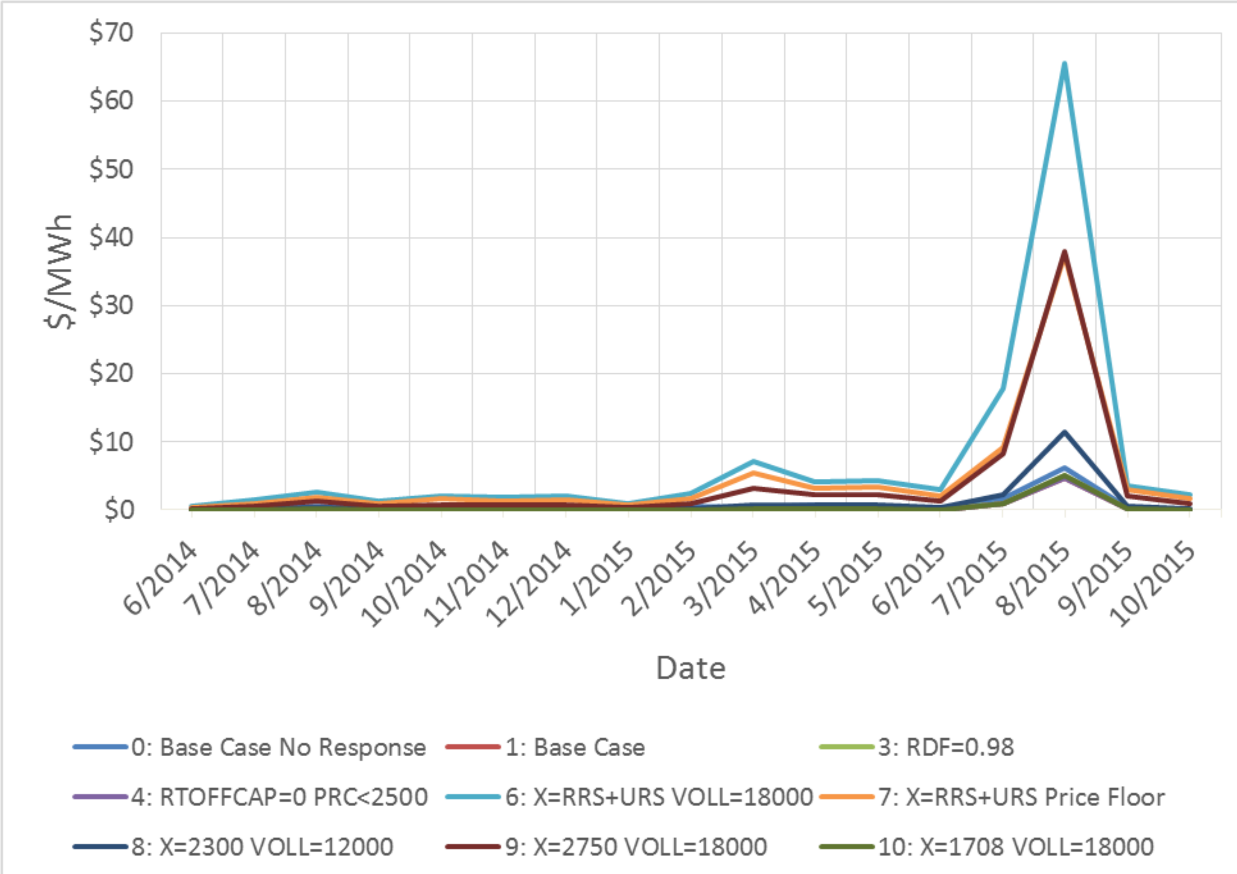


Figure 8. Time Weighted Average RTORPA of All Hours by Month (6/1/2014 – 10/31/2015)

Month	0: Base Case No Response	1: Base Case	3: RDF=0.98	4: RTOFFCAP=0 PRC<2500	6: X=RRS+URS VOLL=18000	7: X=RRS+URS Price Floor	8: X=2300 VOLL=12000	9: X=2750 VOLL=18000	10: X=1708 VOLL=18000
6/2014	$ 0.02	$0.01	$ 0.01	$ 0.01	$ 0.46	$ 0.33	$ 0.04	$ 0.19	$ 0.01
7/2014	$ 0.10	$0.04	$ 0.05	$ 0.04	$ 1.46	$ 1.02	$ 0.15	$ 0.59	$ 0.03
8/2014	$ 0.64	$0.21	$ 0.24	$ 0.21	$ 2.58	$ 1.93	$ 0.45	$ 1.22	$ 0.18
9/2014	$ 0.11	$0.03	$ 0.04	$ 0.03	$ 1.27	$ 0.91	$ 0.10	$ 0.48	$ 0.02
10/2014	$ 0.29	$0.05	$ 0.06	$ 0.05	$ 2.15	$ 1.62	$ 0.19	$ 0.84	$ 0.03
11/2014	$ 0.13	$0.03	$ 0.03	$ 0.03	$ 1.86	$ 1.36	$ 0.12	$ 0.69	$ 0.02
12/2014	$ 0.11	$0.08	$ 0.09	$ 0.08	$ 2.08	$ 1.42	$ 0.22	$ 0.77	$ 0.06
1/2015	$ 0.08	$0.04	$ 0.05	$ 0.04	$ 0.95	$ 0.66	$ 0.10	$ 0.35	$ 0.03
2/2015	$ 0.52	$0.07	$ 0.08	$ 0.07	$ 2.38	$ 1.71	$ 0.22	$ 0.98	$ 0.05
3/2015	$ 0.43	$0.22	$ 0.26	$ 0.22	$ 7.18	$ 5.35	$ 0.74	$ 3.22	$ 0.15
4/2015	$ 0.81	$0.28	$ 0.33	$ 0.28	$ 4.19	$ 3.21	$ 0.77	$ 2.20	$ 0.22
5/2015	$ 0.62	$0.21	$ 0.24	$ 0.21	$ 4.28	$ 3.34	$ 0.67	$ 2.27	$ 0.15
6/2015	$ 0.11	$0.08	$ 0.09	$ 0.08	$ 2.91	$ 2.07	$ 0.27	$ 1.31	$ 0.05
7/2015	$ 1.59	$0.92	$ 1.01	$ 0.92	$ 17.81	$ 9.11	$ 2.28	$ 8.35	$ 0.95
8/2015	$ 6.11	$4.69	$ 5.12	$ 4.77	$ 65.65	$ 37.34	$ 11.42	$ 38.03	$ 5.06
9/2015	$ 0.34	$0.19	$ 0.22	$ 0.19	$ 3.61	$ 2.95	$ 0.60	$ 1.98	$ 0.12
10/2015	$ 0.04	$0.03	$ 0.04	$ 0.03	$ 2.26	$ 1.70	$ 0.16	$ 0.96	$ 0.02

Table 4. Time Weighted Average RTORPA of All Hours by Month (6/1/2014 – 10/31/2015)

Additional Peaker Net Margin

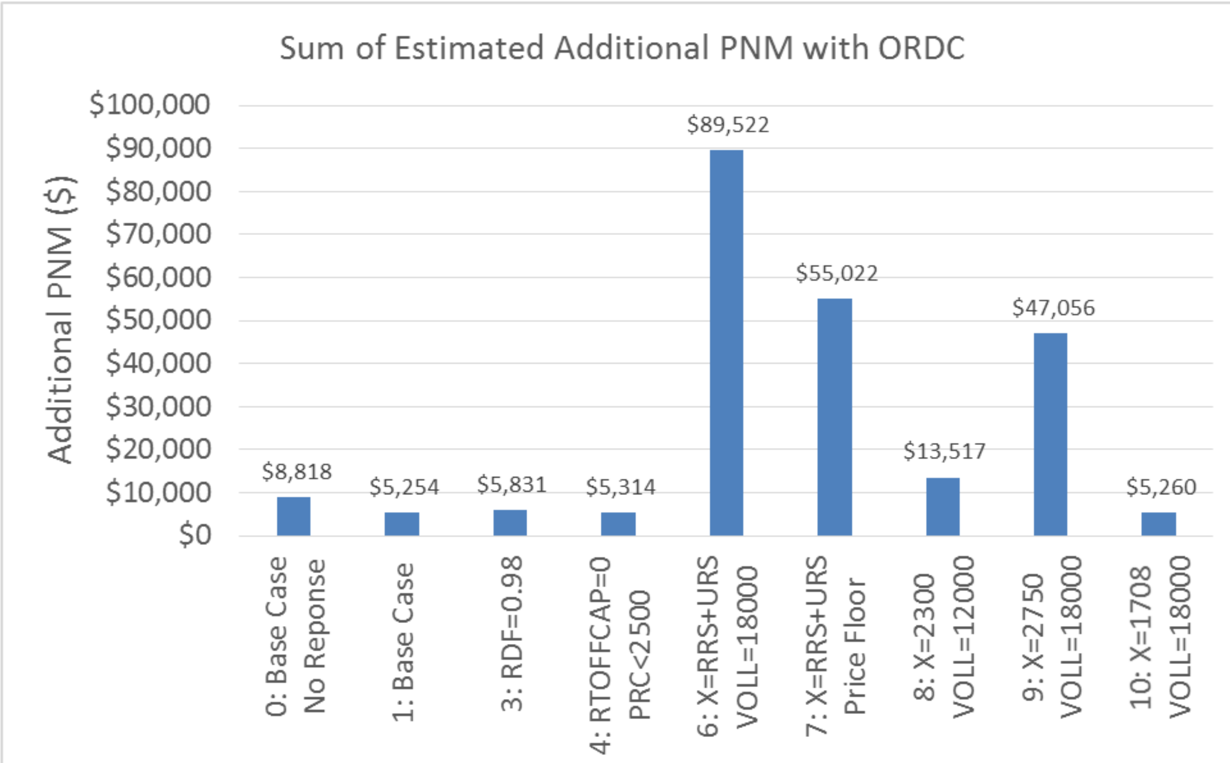


Figure 9. Sum of Estimated Additional PNM with ORDC (6/1/2014 – 10/31/2015)

Option	Sum of Estimated PNM without ORDC	Sum of Estimated Additional PNM with ORDC
0: Base Case No Reponse	$ 42,731	$ 8,818
1: Base Case		$ 5,254
3: RDF=0.98		$ 5,831
4: RTOFFCAP=0 PRC<2500		$ 5,314
6: X=RRS+URS VOLL=18000		$ 89,522
7: X=RRS+URS Price Floor		$ 55,022
8: X=2300 VOLL=12000		$ 13,517
9: X=2750 VOLL=18000		$ 47,056
10: X=1708 VOLL=18000		$ 5,260

Table 5. Sum of Estimated Additional PNM with ORDC (6/1/2014 – 10/31/2015)

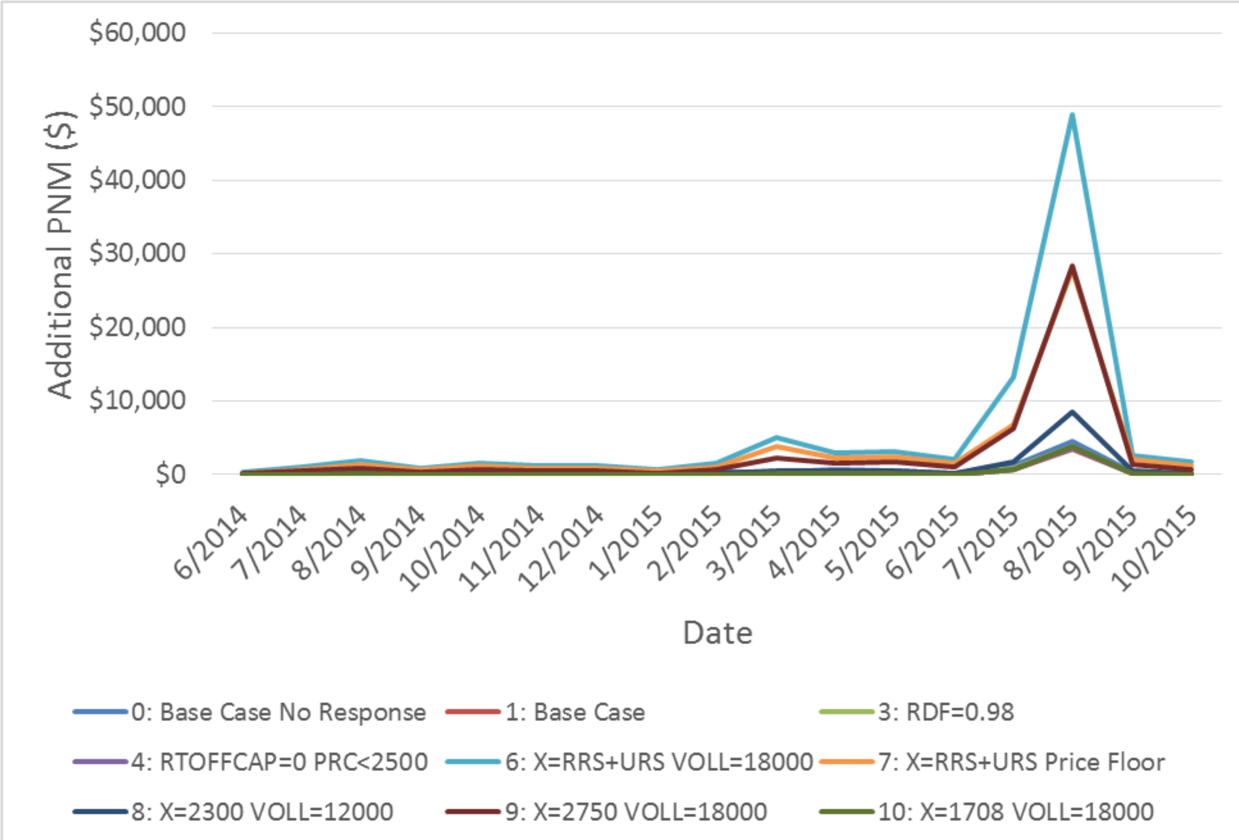


Figure 10. Sum of Estimated Additional PNM with ORDC by Month (6/1/2014 – 10/31/2015)

Month	0: Base Case No Response	1: Base Case	3: RDF=0.98	4: RTOFFCAP=0 PRC<2500	6: X=RRS+URS VOLL=18000	7: X=RRS+URS Price Floor	8: X=2300 VOLL=12000	9: X=2750 VOLL=18000	10: X=1708 VOLL=18000
6/2014	$ 14.86	$ 7.36	$ 8.87	$ 7.36	$ 305.97	$ 217.27	$ 28.17	$ 128.83	$ 4.92
7/2014	$ 69.75	$ 29.28	$ 35.52	$ 29.28	$ 998.82	$ 699.81	$ 104.33	$ 413.44	$ 19.27
8/2014	$ 473.71	$ 157.52	$ 173.72	$ 157.52	$ 1,846.57	$ 1,389.05	$ 326.54	$ 888.93	$ 134.37
9/2014	$ 76.13	$ 21.34	$ 25.48	$ 21.34	$ 900.39	$ 644.86	$ 73.87	$ 340.78	$ 14.10
10/2014	$ 214.86	$ 35.78	$ 43.58	$ 35.78	$ 1,521.75	$ 1,153.09	$ 135.47	$ 596.89	$ 21.31
11/2014	$ 86.20	$ 16.54	$ 20.20	$ 16.54	$ 1,164.19	$ 851.87	$ 70.18	$ 431.18	$ 9.99
12/2014	$ 62.67	$ 44.84	$ 51.88	$ 44.84	$ 1,201.24	$ 798.00	$ 118.62	$ 419.45	$ 35.59
1/2015	$ 54.00	$ 26.86	$ 30.57	$ 26.86	$ 628.04	$ 430.34	$ 66.16	$ 226.74	$ 22.28
2/2015	$ 343.78	$ 39.23	$ 46.26	$ 39.23	$ 1,520.89	$ 1,081.91	$ 132.59	$ 617.93	$ 28.84
3/2015	$ 300.44	$ 143.71	$ 172.28	$ 143.71	$ 5,084.24	$ 3,767.30	$ 505.38	$ 2,259.15	$ 99.12
4/2015	$ 583.11	$ 202.09	$ 231.79	$ 202.09	$ 2,909.51	$ 2,232.03	$ 547.75	$ 1,545.47	$ 156.83
5/2015	$ 454.13	$ 145.29	$ 171.83	$ 145.29	$ 3,060.30	$ 2,382.47	$ 477.50	$ 1,630.15	$ 107.49
6/2015	$ 77.00	$ 54.52	$ 65.97	$ 54.52	$ 2,055.34	$ 1,462.64	$ 193.75	$ 930.77	$ 33.67
7/2015	$ 1,186.30	$ 682.24	$ 754.96	$ 682.24	$ 13,244.37	$ 6,772.57	$ 1,693.03	$ 6,209.98	$ 708.81
8/2015	$ 4,543.84	$ 3,489.59	$ 3,809.42	$ 3,549.14	$ 48,845.74	$ 27,783.47	$ 8,498.72	$ 28,290.83	$ 3,761.93
9/2015	$ 245.87	$ 134.43	$ 158.34	$ 134.43	$ 2,578.62	$ 2,111.61	$ 431.38	$ 1,417.91	$ 88.85
10/2015	$ 31.73	$ 23.84	$ 30.00	$ 23.84	$ 1,656.42	$ 1,243.23	$ 113.70	$ 707.79	$ 12.55

Table 6. Sum of Estimated Additional PNM with ORDC by Month (6/1/2014 – 10/31/2015)

Real-Time On-Line Price Adder Histogram

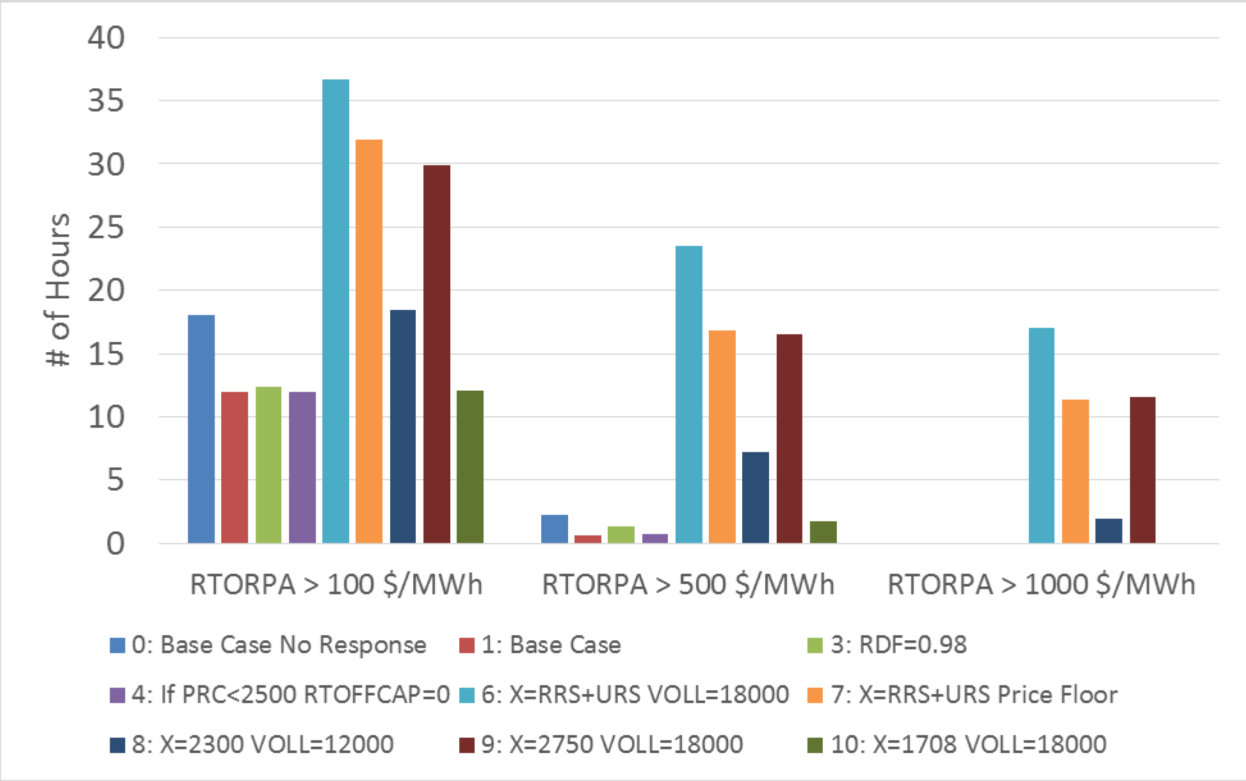


Figure 11. Number of Hours where RTORPA > Threshold (6/1/2014 – 10/31/2015)

Option	# of Hours RTORPA > 100 $/MWh	# of Hours RTORPA > 500 $/MWh	# of Hours RTORPA > 1000 $/MWh
0: Base Case No Reponse	18.05	2.25	0.00
1: Base Case	12.00	0.58	0.00
3: RDF=0.98	12.34	1.33	0.00
4: RTOFFCAP=0 PRC<2500	12.00	0.75	0.00
6: X=RRS+URS VOLL=18000	36.67	23.54	17.00
7: X=RRS+URS Price Floor	31.96	16.84	11.33
8: X=2300 VOLL=12000	18.42	7.17	2.00
9: X=2750 VOLL=18000	29.88	16.51	11.58
10: X=1708 VOLL=18000	12.09	1.75	0.00

Table 7. Number of Hours where RTORPA > Threshold (6/1/2014 – 10/31/2015)

Month	0: Base Case No Response	1: Base Case	3: RDF=0.98	4: RTOFFCAP=0 PRC<2500	6: X=RRS+URS VOLL=18000	7: X=RRS+URS Price Floor	8: X=2300 VOLL=12000	9: X=2750 VOLL=18000	10: X=1708 VOLL=18000
6/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8/2014	0.42	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.00
9/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10/2014	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2/2015	1.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4/2015	1.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5/2015	1.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7/2015	3.04	2.17	2.25	2.17	12.75	10.29	3.75	9.12	2.25
8/2015	10.84	9.84	10.09	9.84	23.84	21.68	14.67	20.76	9.84
9/2015	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 8. Number of Hours where RTORPA > $100/MWh by Month (6/1/2014 – 10/31/2015)

Month	0: Base Case No Response	1: Base Case	3: RDF=0.98	4: RTOFFCAP=0 PRC<2500	6: X=RRS+URS VOLL=18000	7: X=RRS+URS Price Floor	8: X=2300 VOLL=12000	9: X=2750 VOLL=18000	10: X=1708 VOLL=18000
6/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7/2015	0.00	0.00	0.00	0.00	6.29	3.75	0.83	3.34	0.00
8/2015	2.25	0.58	1.33	0.75	17.25	13.09	6.33	13.17	1.75
9/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 9. Number of Hours where RTORPA > $500/MWh by Month (6/1/2014 – 10/31/2015)

Month	0: Base Case No Response	1: Base Case	3: RDF=0.98	4: RTOFFCAP=0 PRC<2500	6: X=RRS+URS VOLL=18000	7: X=RRS+URS Price Floor	8: X=2300 VOLL=12000	9: X=2750 VOLL=18000	10: X=1708 VOLL=18000
6/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7/2015	0.00	0.00	0.00	0.00	3.83	2.00	0.00	2.08	0.00
8/2015	0.00	0.00	0.00	0.00	13.17	9.33	2.00	9.50	0.00
9/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 10. Number of Hours where RTORPA > $1,000/MWh by Month (6/1/2014 – 10/31/2015)

Month	0: Base Case No Response	1: Base Case	3: RDF=0.98	4: RTOFFCAP=0 PRC<2500	6: X=RRS+URS VOLL=18000	7: X=RRS+URS Price Floor	8: X=2300 VOLL=12000	9: X=2750 VOLL=18000	10: X=1708 VOLL=18000
6/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7/2015	0.00	0.00	0.00	0.00	0.92	0.00	0.00	0.00	0.00
8/2015	0.00	0.00	0.00	0.00	6.50	1.75	0.00	2.25	0.00
9/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 11. Number of Hours where RTORPA > $3,000/MWh by Month (6/1/2014 – 10/31/2015)

Month	0: Base Case No Response	1: Base Case	3: RDF=0.98	4: RTOFFCAP=0 PRC<2500	6: X=RRS+URS VOLL=18000	7: X=RRS+URS Price Floor	8: X=2300 VOLL=12000	9: X=2750 VOLL=18000	10: X=1708 VOLL=18000
6/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8/2015	0.00	0.00	0.00	0.00	1.42	0.00	0.00	0.00	0.00
9/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 12. Number of Hours where RTORPA > $5,000/MWh by Month (6/1/2014 – 10/31/2015)

Month	0: Base Case No Response	1: Base Case	3: RDF=0.98	4: RTOFFCAP=0 PRC<2500	6: X=RRS+URS VOLL=18000	7: X=RRS+URS Price Floor	8: X=2300 VOLL=12000	9: X=2750 VOLL=18000	10: X=1708 VOLL=18000
6/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12/2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8/2015	0.00	0.00	0.00	0.00	0.17	0.00	0.00	0.00	0.00
9/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10/2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 13. Number of Hours where RTORPA > $7,000/MWh by Month (6/1/2014 – 10/31/2015)

Probability of Falling Below Minimum Contingency Level on August 13, 2015

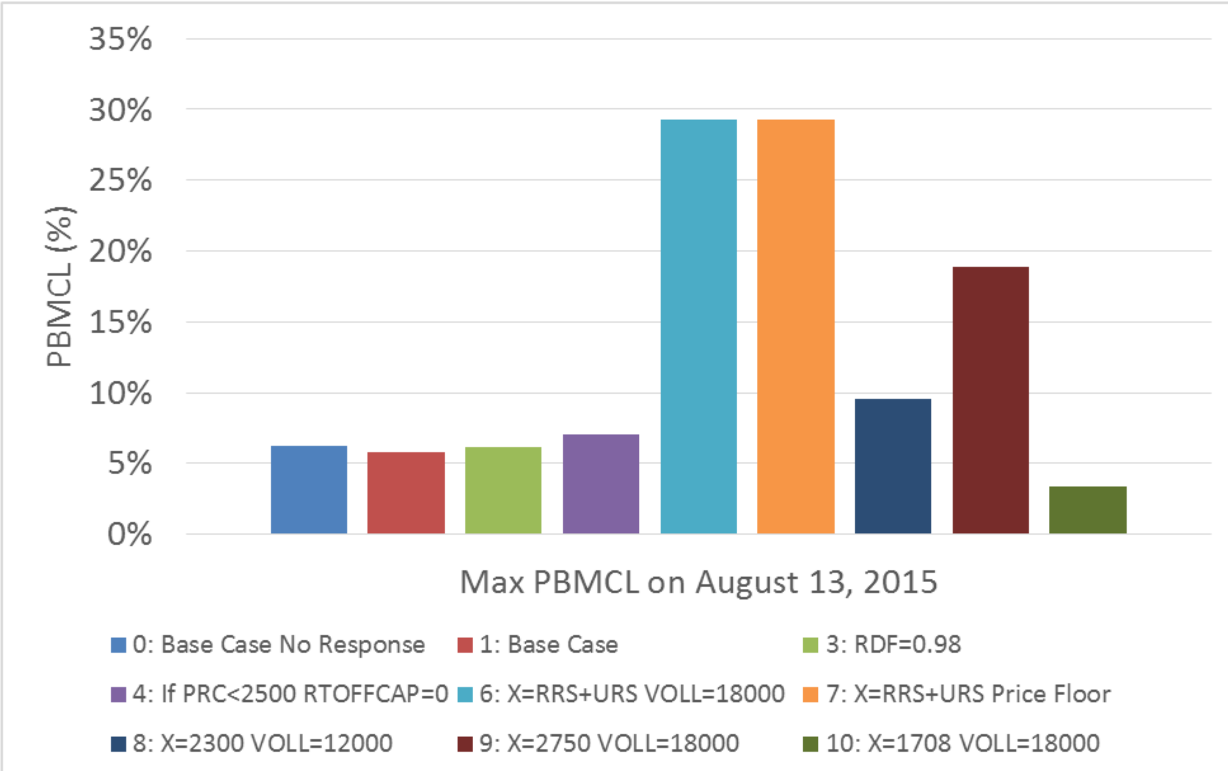


Figure 12. Max PBMCL on August 13, 2015

Option	Max PBMCL on August 13, 2015 by SCED Interval
0: Base Case	6.2%
1: Base Case Price Response	5.8%
3: RDF=0.98	6.2%
4: RTOFFCAP=0 PRC<2500	7.0%
6: X=RRS+URS VOLL=18000	29.3%
7: X=RRS+URS Price Floor	29.3%
8: X=2300 VOLL=12000	9.6%
9: X=2750 VOLL=18000	18.8%
10: X=1708 VOLL=18000	3.4%

Table 14. Max PBMCL on August 13, 2015

Section 2: January 1, 2011 – December 31, 2011 Backcast

Real-Time On-Line Price Adder

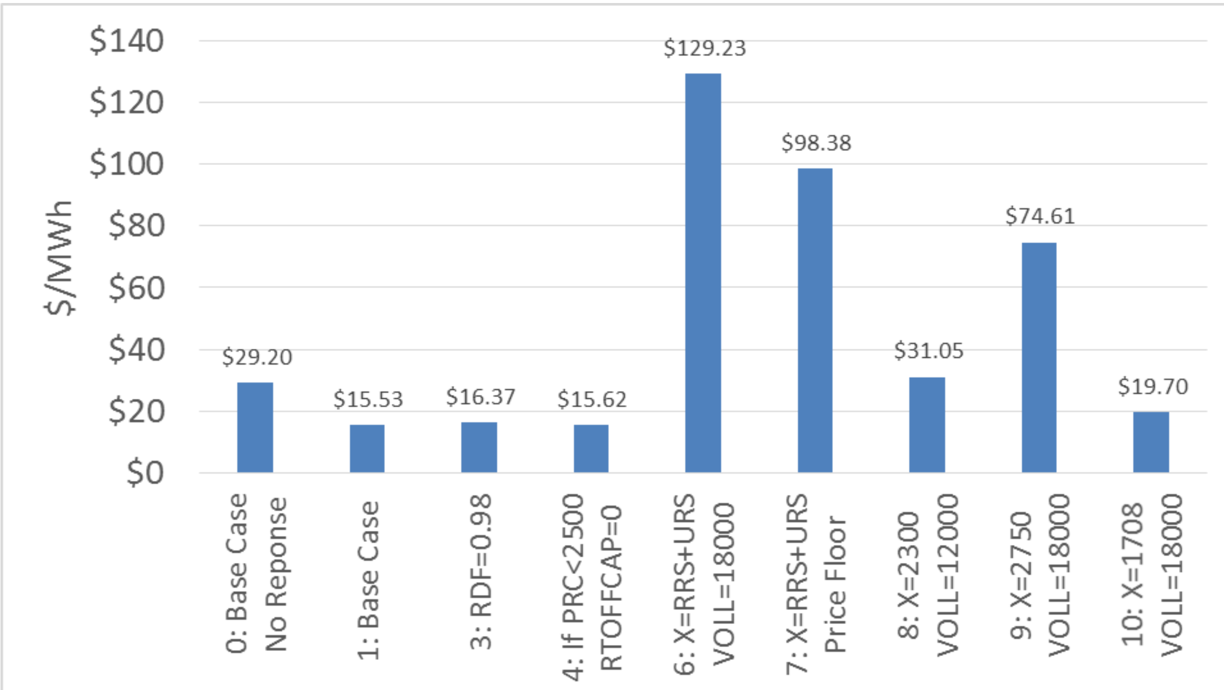


Figure 13. Energy and Time Weighted Average RTORPA of All Hours (2011)

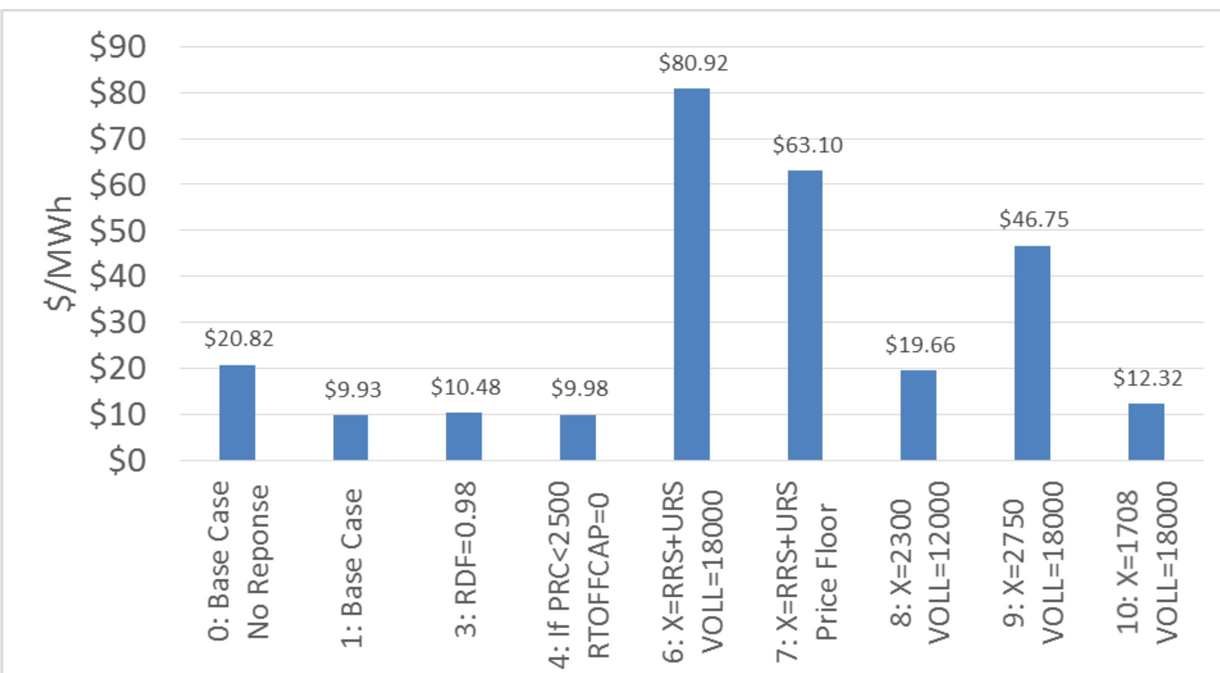


Figure 14. Time Weighted Average RTORPA of All Hours (2011)

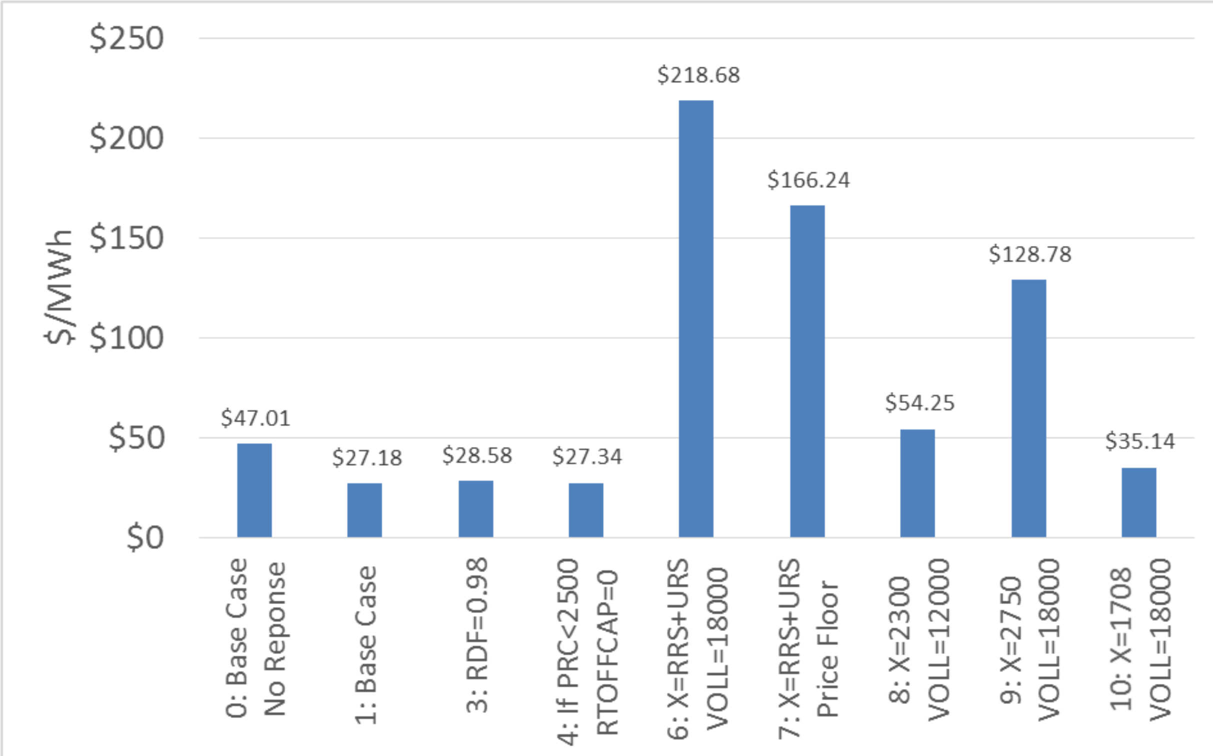


Figure 15. ONPEAK Energy and Time Weighted Average RTORPA (2011)

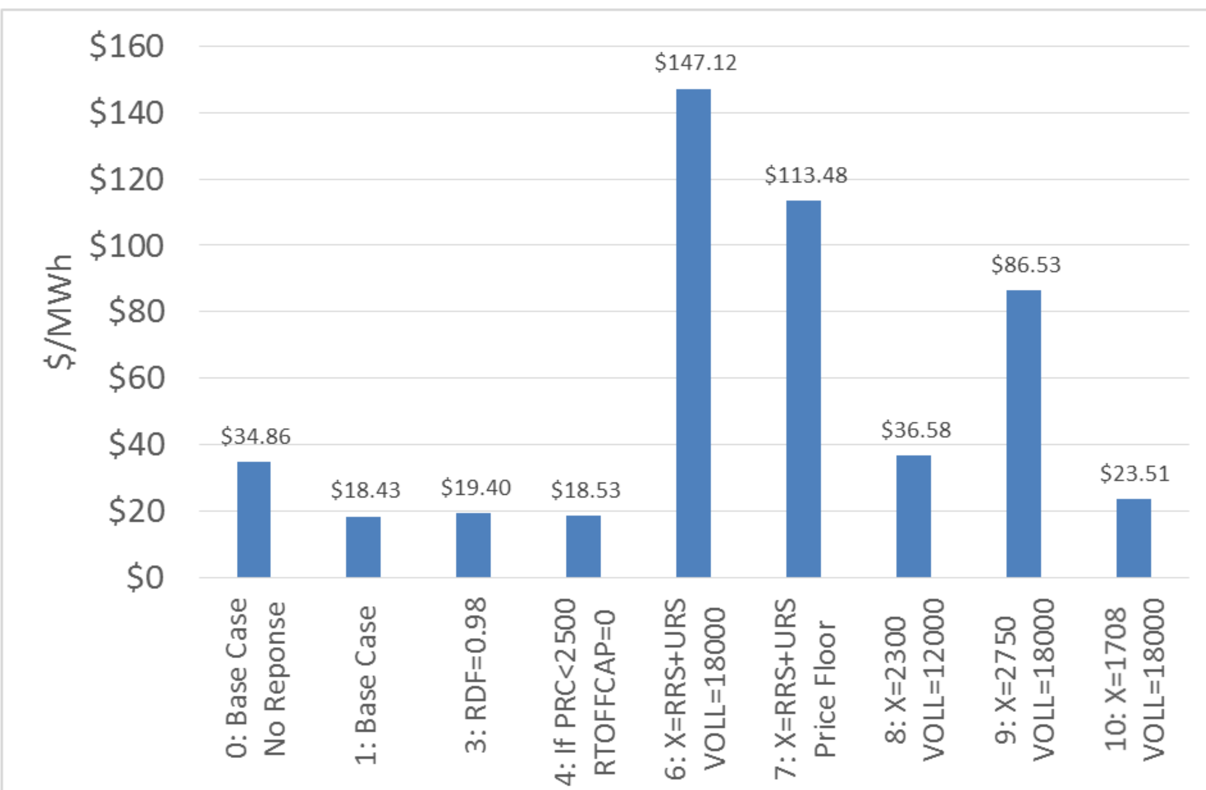


Figure 16. ONPEAK Time Weighted Average RTORPA (2011)

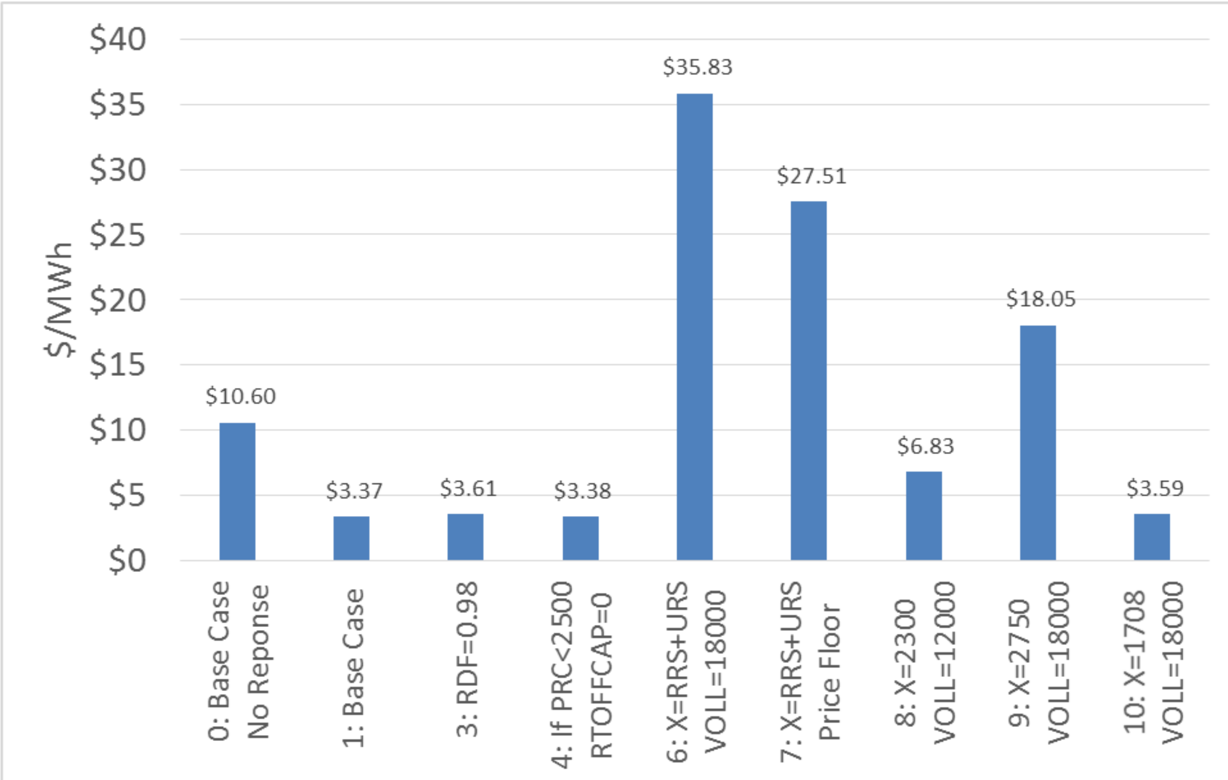


Figure 17. OFFPEAK Energy and Time Weighted Average RTORPA (2011)

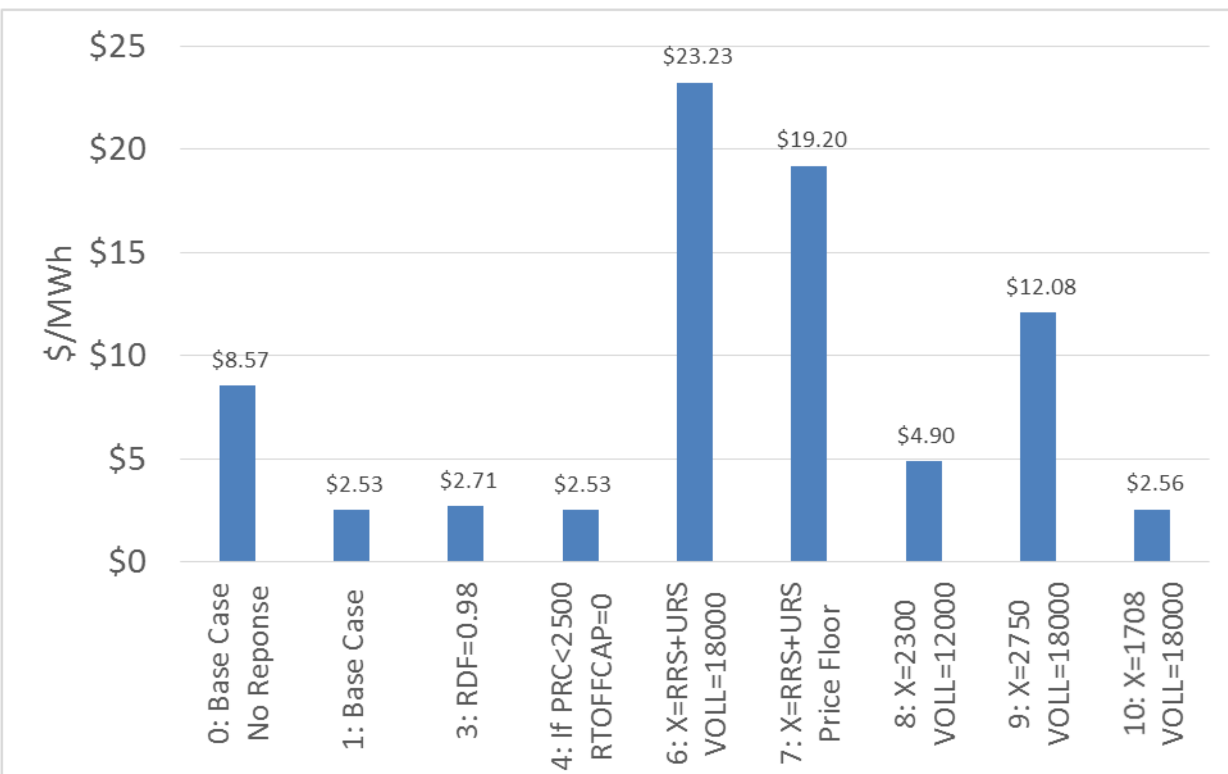


Figure 18. OFFPEAK Time Weighted Average RTORPA (2011)

Option	Energy and Time Weighted Average RTORPA($/MWh)	Time Weighted Average RTORPA($/MWh)	ONPEAK Energy and Time Weighted Average RTORPA($/MWh)	ONPEAK Time Weighted Average RTORPA($/MWh)	OFFPEAK Energy and Time Weighted Average RTORPA($/MWh)	OFFPEAK Time Weighted Average RTORPA($/MWh)
0: Base Case No Reponse	$ 29.20	$ 20.82	$ 47.01	$ 34.86	$ 10.60	$ 8.57
1: Base Case	$ 15.53	$ 9.93	$ 27.18	$ 18.43	$ 3.37	$ 2.53
3: RDF=0.98	$ 16.37	$ 10.48	$ 28.58	$ 19.40	$ 3.61	$ 2.71
4: If PRC<2500 RTOFFCAP=0	$ 15.62	$ 9.98	$ 27.34	$ 18.53	$ 3.38	$ 2.53
6: X=RRS+URS VOLL=18000	$ 129.23	$ 80.92	$ 218.68	$ 147.12	$ 35.83	$ 23.23
7: X=RRS+URS Price Floor	$ 98.38	$ 63.10	$ 166.24	$ 113.48	$ 27.51	$ 19.20
8: X=2300 VOLL=12000	$ 31.05	$ 19.66	$ 54.25	$ 36.58	$ 6.83	$ 4.90
9: X=2750 VOLL=18000	$ 74.61	$ 46.75	$ 128.78	$ 86.53	$ 18.05	$ 12.08
10: X=1708 VOLL=18000	$ 19.70	$ 12.32	$ 35.14	$ 23.51	$ 3.59	$ 2.56

Table 15. Averages of RTORPA (2011)

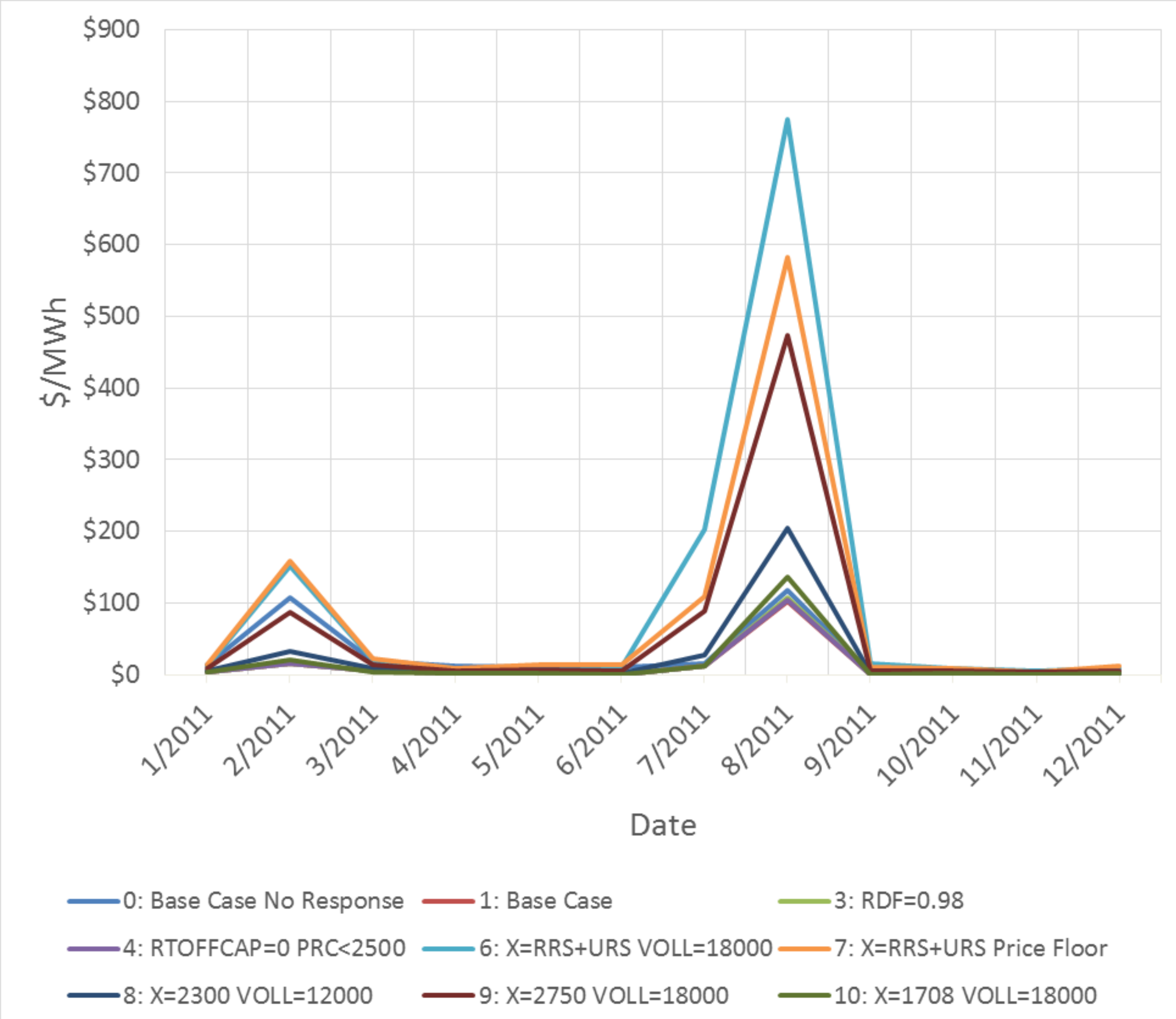


Figure 19. Energy and Time Weighted Average RTORPA of All Hours by Month (2011)

Month	0: Base Case No Response	1: Base Case	3: RDF=0.98	4: RTOFFCAP=0 PRC<2500	6: X=RRS+URS VOLL=18000	7: X=RRS+URS Price Floor	8: X=2300 VOLL=12000	9: X=2750 VOLL=18000	10: X=1708 VOLL=18000
1/2011	$ 14.73	$ 3.80	$ 4.02	$ 3.80	$ 12.92	$ 13.81	$ 5.81	$ 9.29	$ 3.42
2/2011	$ 106.89	$ 15.44	$ 16.36	$ 15.47	$ 151.26	$ 159.34	$ 32.30	$ 87.95	$ 21.04
3/2011	$ 18.41	$ 5.03	$ 5.38	$ 5.03	$ 20.47	$ 23.07	$ 8.40	$ 14.25	$ 4.43
4/2011	$ 11.58	$ 1.52	$ 1.62	$ 1.52	$ 9.15	$ 8.92	$ 2.58	$ 5.13	$ 1.34
5/2011	$ 10.69	$ 2.45	$ 2.60	$ 2.45	$ 10.61	$ 14.16	$ 3.80	$ 6.67	$ 2.19
6/2011	$ 10.36	$ 0.86	$ 0.93	$ 0.86	$ 11.27	$ 14.64	$ 1.68	$ 4.82	$ 0.76
7/2011	$ 15.00	$ 11.62	$ 12.54	$ 11.63	$ 202.80	$ 109.32	$ 27.59	$ 89.50	$ 12.74
8/2011	$ 118.42	$ 103.01	$ 107.98	$ 103.71	$ 773.97	$ 582.84	$ 204.89	$ 473.62	$ 136.40
9/2011	$ 2.81	$ 0.74	$ 0.82	$ 0.74	$ 15.04	$ 10.05	$ 1.67	$ 5.23	$ 0.63
10/2011	$ 5.54	$ 1.75	$ 1.87	$ 1.75	$ 9.48	$ 8.96	$ 2.87	$ 5.53	$ 1.52
11/2011	$ 5.13	$ 1.12	$ 1.19	$ 1.12	$ 5.62	$ 4.54	$ 1.76	$ 3.27	$ 0.98
12/2011	$ 4.27	$ 1.58	$ 1.72	$ 1.60	$ 9.08	$ 12.16	$ 2.88	$ 5.63	$ 1.44

Table 16. Energy and Time Weighted Average RTORPA of All Hours by Month (2011)

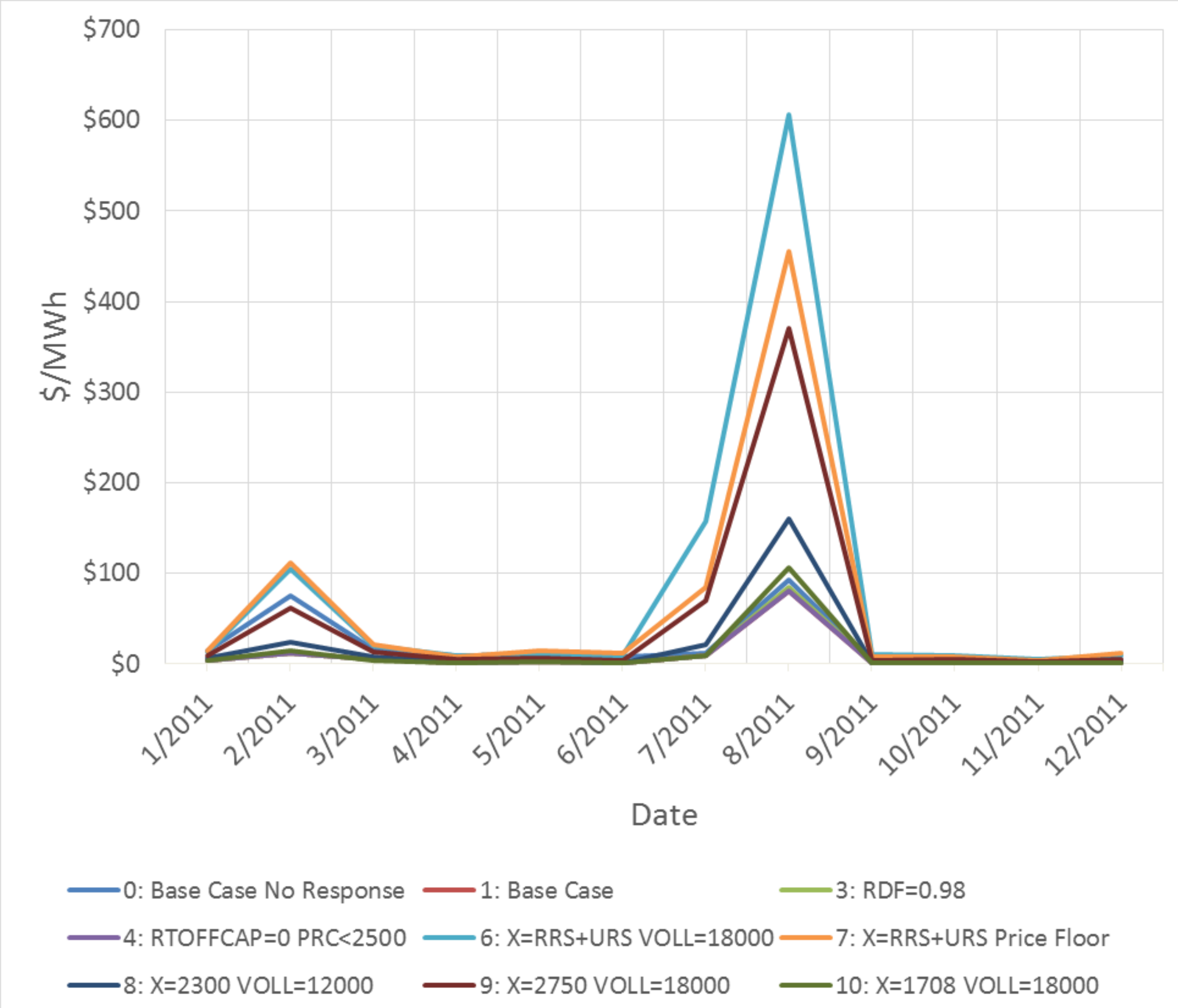


Figure 20. Time Weighted Average RTORPA of All Hours by Month (2011)

Month	0: Base Case No Response	1: Base Case	3: RDF=0.98	4: RTOFFCAP=0 PRC<2500	6: X=RRS+URS VOLL=18000	7: X=RRS+URS Price Floor	8: X=2300 VOLL=12000	9: X=2750 VOLL=18000	10: X=1708 VOLL=18000
1/2011	$ 15.07	$ 3.90	$ 4.12	$ 3.90	$ 13.08	$ 14.46	$ 5.94	$ 9.45	$ 3.50
2/2011	$ 74.94	$ 11.45	$ 12.14	$ 11.47	$ 104.95	$ 111.32	$ 23.41	$ 61.90	$ 15.13
3/2011	$ 16.20	$ 4.74	$ 5.08	$ 4.74	$ 20.01	$ 21.60	$ 8.03	$ 13.85	$ 4.16
4/2011	$ 9.40	$ 1.35	$ 1.44	$ 1.35	$ 8.78	$ 8.36	$ 2.36	$ 4.86	$ 1.18
5/2011	$ 10.11	$ 2.27	$ 2.41	$ 2.27	$ 10.58	$ 14.97	$ 3.58	$ 6.50	$ 2.01
6/2011	$ 8.11	$ 0.77	$ 0.84	$ 0.77	$ 9.56	$ 11.89	$ 1.50	$ 4.15	$ 0.68
7/2011	$ 11.62	$ 8.98	$ 9.69	$ 8.98	$ 157.34	$ 84.91	$ 21.34	$ 69.25	$ 9.83
8/2011	$ 92.35	$ 80.19	$ 84.07	$ 80.74	$ 606.41	$ 455.65	$ 159.69	$ 369.78	$ 106.11
9/2011	$ 2.02	$ 0.55	$ 0.61	$ 0.55	$ 10.90	$ 7.69	$ 1.25	$ 3.88	$ 0.47
10/2011	$ 4.55	$ 1.47	$ 1.58	$ 1.47	$ 8.64	$ 8.18	$ 2.49	$ 4.96	$ 1.27
11/2011	$ 4.58	$ 0.99	$ 1.06	$ 0.99	$ 5.18	$ 4.18	$ 1.58	$ 3.00	$ 0.88
12/2011	$ 4.17	$ 1.52	$ 1.65	$ 1.53	$ 8.66	$ 11.58	$ 2.74	$ 5.37	$ 1.38

Table 17. Time Weighted Average RTORPA of All Hours by Month (2011)

Additional Peaker Net Margin

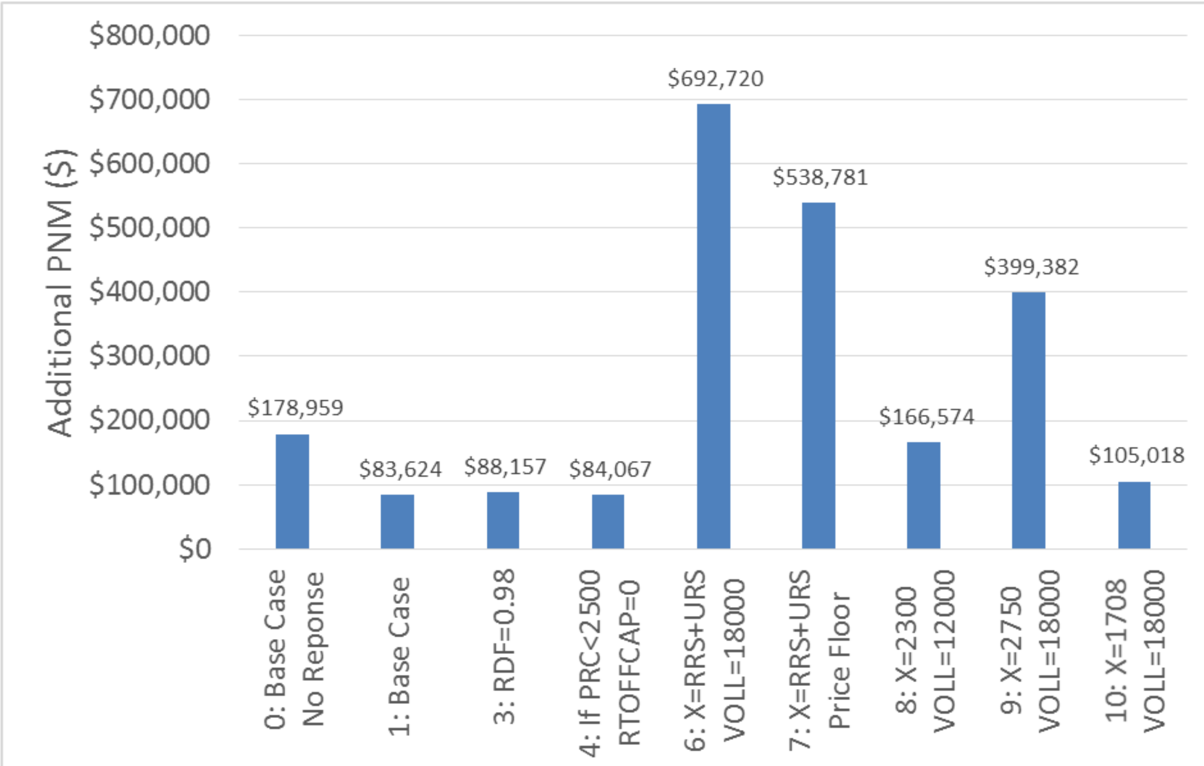


Figure 21. Sum of Estimated Additional PNM with ORDC (2011)

Option	Sum of Estimated PNM without ORDC	Sum of Estimated Additional PNM with ORDC
0: Base Case No Reponse	$ 130,794	$ 178,959
1: Base Case		$ 83,624
3: RDF=0.98		$ 88,157
4: If PRC<2500 RTOFFCAP=0		$ 84,067
6: X=RRS+URS VOLL=18000		$ 692,720
7: X=RRS+URS Price Floor		$ 538,781
8: X=2300 VOLL=12000		$ 166,574
9: X=2750 VOLL=18000		$ 399,382
10: X=1708 VOLL=18000		$ 105,018

Table 18. Sum of Estimated Additional PNM with ORDC (2011)

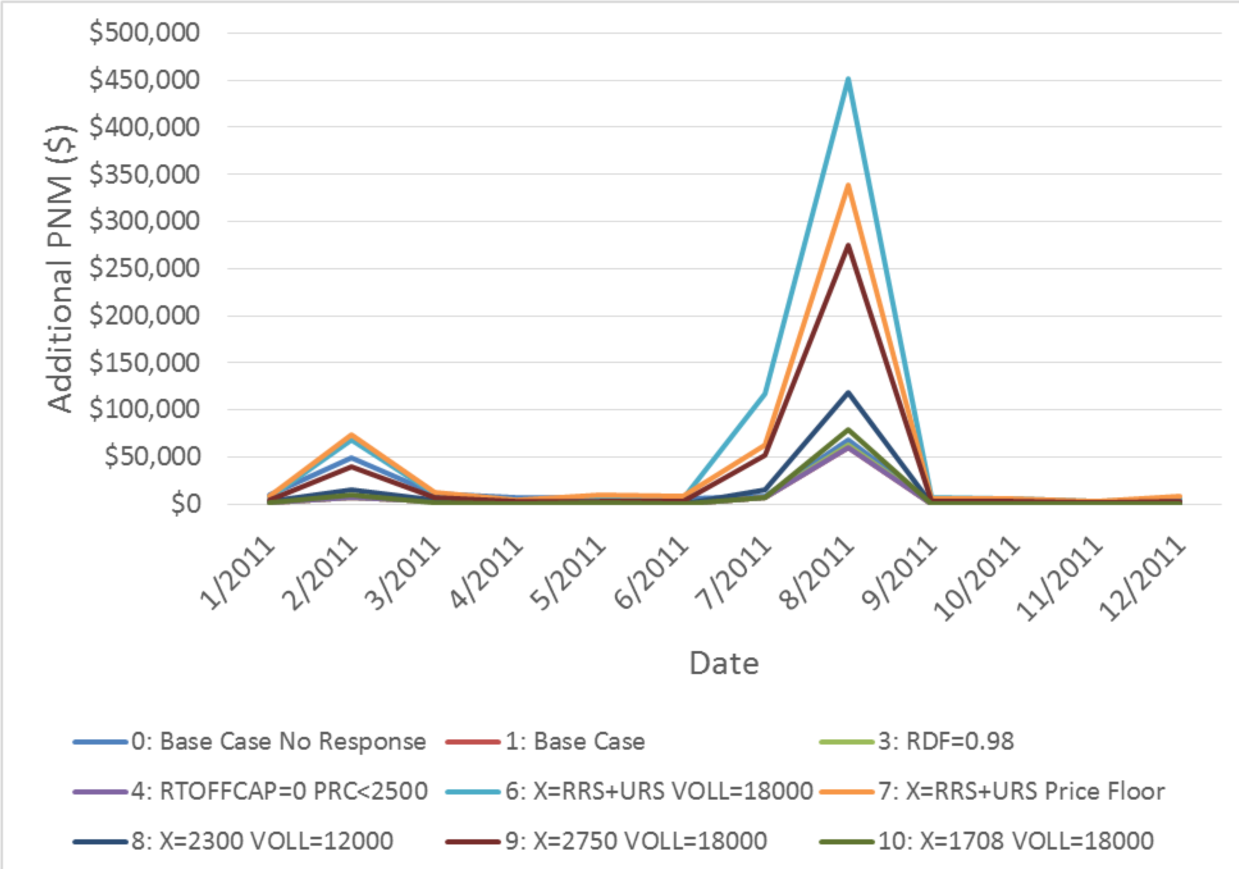


Figure 22. Sum of Estimated Additional PNM with ORDC by Month (2011)

Month	0: Base Case No Response	1: Base Case	3: RDF=0.98	4: RTOFFCAP=0 PRC<2500	6: X=RRS+URS VOLL=18000	7: X=RRS+URS Price Floor	8: X=2300 VOLL=12000	9: X=2750 VOLL=18000	10: X=1708 VOLL=18000
1/2011	$ 10,334.23	$ 2,018.66	$ 2,132.70	$ 2,018.66	$ 6,823.95	$ 8,201.16	$ 3,110.08	$ 4,984.70	$ 1,830.92
2/2011	$ 49,866.65	$ 7,203.44	$ 7,636.47	$ 7,218.87	$ 68,705.12	$ 73,194.77	$ 14,978.57	$ 40,319.24	$ 9,736.46
3/2011	$ 10,994.73	$ 2,471.20	$ 2,643.77	$ 2,471.20	$ 10,778.66	$ 12,369.94	$ 4,250.63	$ 7,390.88	$ 2,202.16
4/2011	$ 6,570.79	$ 770.88	$ 820.20	$ 770.88	$ 4,579.64	$ 4,579.08	$ 1,292.48	$ 2,600.00	$ 692.53
5/2011	$ 7,224.06	$ 1,388.16	$ 1,463.92	$ 1,388.16	$ 5,923.15	$ 9,437.61	$ 2,105.57	$ 3,703.47	$ 1,255.33
6/2011	$ 5,726.66	$ 441.76	$ 483.95	$ 444.43	$ 6,060.62	$ 7,881.91	$ 882.65	$ 2,571.50	$ 393.93
7/2011	$ 8,620.56	$ 6,654.00	$ 7,181.38	$ 6,656.98	$ 116,650.84	$ 62,867.71	$ 15,820.41	$ 51,369.10	$ 7,289.52
8/2011	$ 68,702.32	$ 59,659.33	$ 62,546.14	$ 60,067.85	$ 451,069.39	$ 338,934.95	$ 118,802.12	$ 275,088.91	$ 78,944.56
9/2011	$ 1,445.17	$ 391.63	$ 434.07	$ 391.90	$ 7,660.98	$ 5,391.39	$ 882.19	$ 2,733.68	$ 334.21
10/2011	$ 3,311.26	$ 1,017.66	$ 1,085.72	$ 1,019.47	$ 5,642.16	$ 5,424.93	$ 1,679.68	$ 3,276.30	$ 887.02
11/2011	$ 3,254.25	$ 673.95	$ 713.15	$ 673.95	$ 3,204.54	$ 2,587.50	$ 1,041.62	$ 1,898.72	$ 601.41
12/2011	$ 2,908.63	$ 933.25	$ 1,015.63	$ 944.30	$ 5,620.91	$ 7,909.86	$ 1,727.83	$ 3,445.61	$ 850.16

Table 19. Sum of Estimated Additional PNM with ORDC by Month (6/1/2014 – 10/31/2015)

Real-Time On-Line Price Adder Histogram

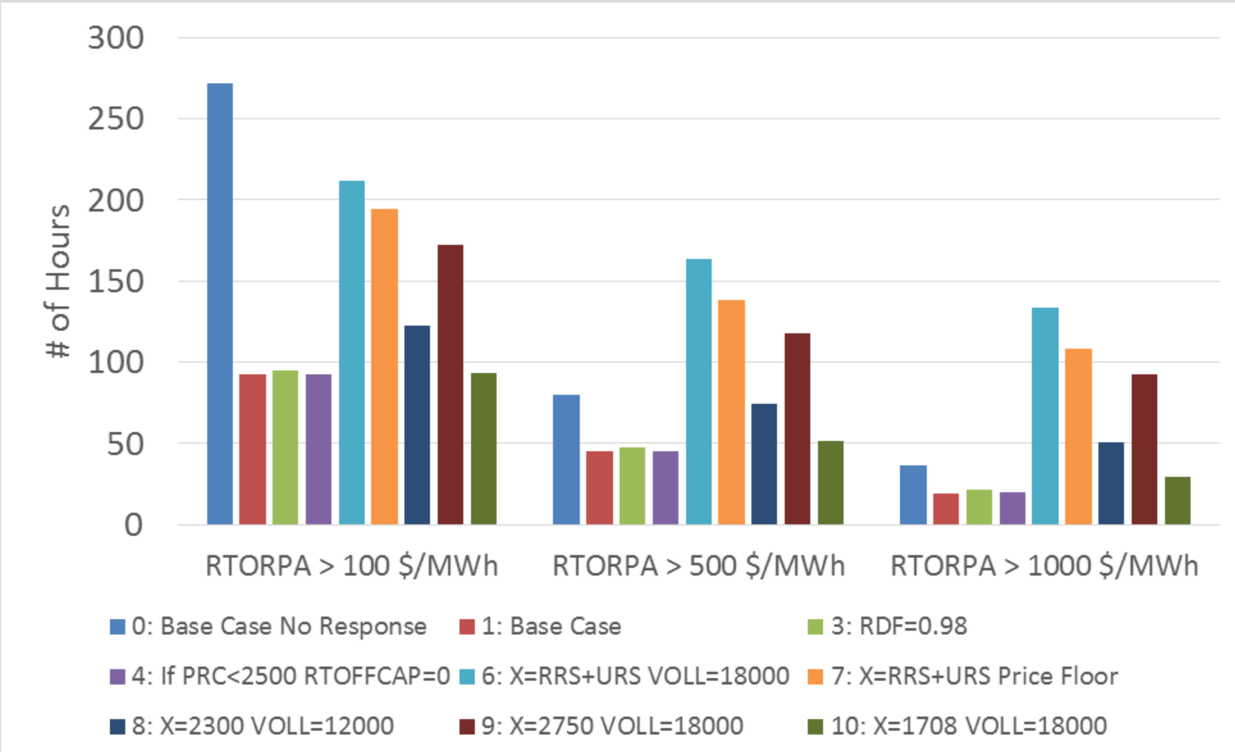


Figure 23. Number of Hours where RTORPA > Threshold (2011)

Option	# of Hours RTORPA > 100 $/MWh	# of Hours RTORPA > 500 $/MWh	# of Hours RTORPA > 1000 $/MWh
0: Base Case No Reponse	271.66	79.72	36.67
1: Base Case	92.73	45.19	19.61
3: RDF=0.98	95.31	47.30	21.36
4: If PRC<2500 RTOFFCAP=0	92.90	45.53	20.27
6: X=RRS+URS VOLL=18000	211.58	163.52	133.28
7: X=RRS+URS Price Floor	194.65	138.21	108.57
8: X=2300 VOLL=12000	122.74	74.17	50.53
9: X=2750 VOLL=18000	172.46	117.57	92.37
10: X=1708 VOLL=18000	93.35	51.41	29.52

Table 20. Number of Hours where RTORPA > Threshold (2011)

Month	0: Base Case No Response	1: Base Case	3: RDF=0.98	4: RTOFFCAP=0 PRC<2500	6: X=RRS+URS VOLL=18000	7: X=RRS+URS Price Floor	8: X=2300 VOLL=12000	9: X=2750 VOLL=18000	10: X=1708 VOLL=18000
1/2011	31.47	0.00	0.00	0.00	0.00	0.50	0.00	0.00	0.00
2/2011	32.66	10.72	11.13	10.80	24.17	22.34	15.85	21.23	11.44
3/2011	28.90	0.00	0.00	0.00	0.00	0.44	0.00	0.00	0.00
4/2011	13.60	0.00	0.00	0.00	0.00	0.23	0.00	0.00	0.00
5/2011	19.49	0.00	0.00	0.00	0.00	1.01	0.00	0.00	0.00
6/2011	9.41	0.00	0.00	0.00	6.55	6.03	0.00	4.25	0.00
7/2011	21.84	15.67	16.17	15.67	53.02	46.28	24.16	40.48	15.25
8/2011	80.68	66.34	68.01	66.43	122.60	113.58	81.66	104.01	66.66
9/2011	3.83	0.00	0.00	0.00	5.25	3.41	1.08	2.50	0.00
10/2011	11.27	0.00	0.00	0.00	0.00	0.17	0.00	0.00	0.00
11/2011	11.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12/2011	6.66	0.00	0.00	0.00	0.00	0.67	0.00	0.00	0.00

Table 21. Number of Hours where RTORPA > $100/MWh by Month (2011)

Month	0: Base Case No Response	1: Base Case	3: RDF=0.98	4: RTOFFCAP=0 PRC<2500	6: X=RRS+URS VOLL=18000	7: X=RRS+URS Price Floor	8: X=2300 VOLL=12000	9: X=2750 VOLL=18000	10: X=1708 VOLL=18000
1/2011	3.18	0.00	0.00	0.00	0.00	0.50	0.00	0.00	0.00
2/2011	11.07	4.79	4.91	4.79	19.42	16.65	7.97	14.84	6.09
3/2011	4.64	0.00	0.00	0.00	0.00	0.44	0.00	0.00	0.00
4/2011	4.17	0.00	0.00	0.00	0.00	0.23	0.00	0.00	0.00
5/2011	2.29	0.00	0.00	0.00	0.00	1.01	0.00	0.00	0.00
6/2011	4.02	0.00	0.00	0.00	2.49	1.47	0.00	0.00	0.00
7/2011	4.75	3.25	4.33	3.25	37.97	27.18	11.09	23.08	4.92
8/2011	43.90	37.15	38.07	37.49	100.98	87.50	55.12	78.82	40.40
9/2011	0.08	0.00	0.00	0.00	2.66	2.41	0.00	0.83	0.00
10/2011	0.08	0.00	0.00	0.00	0.00	0.17	0.00	0.00	0.00
11/2011	0.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12/2011	1.00	0.00	0.00	0.00	0.00	0.67	0.00	0.00	0.00

Table 22. Number of Hours where RTORPA > $500/MWh by Month (2011)

Month	0: Base Case No Response	1: Base Case	3: RDF=0.98	4: RTOFFCAP=0 PRC<2500	6: X=RRS+URS VOLL=18000	7: X=RRS+URS Price Floor	8: X=2300 VOLL=12000	9: X=2750 VOLL=18000	10: X=1708 VOLL=18000
1/2011	0.08	0.00	0.00	0.00	0.00	0.50	0.00	0.00	0.00
2/2011	8.61	0.90	1.40	0.90	16.27	12.74	5.22	10.45	3.36
3/2011	0.50	0.00	0.00	0.00	0.00	0.44	0.00	0.00	0.00
4/2011	1.36	0.00	0.00	0.00	0.00	0.23	0.00	0.00	0.00
5/2011	0.48	0.00	0.00	0.00	0.00	1.01	0.00	0.00	0.00
6/2011	1.48	0.00	0.00	0.00	0.00	1.47	0.00	0.00	0.00
7/2011	0.00	0.00	0.00	0.00	27.26	18.08	5.25	15.50	0.33
8/2011	23.90	18.70	19.95	19.37	87.50	72.35	40.06	66.34	25.82
9/2011	0.00	0.00	0.00	0.00	2.25	0.91	0.00	0.08	0.00
10/2011	0.00	0.00	0.00	0.00	0.00	0.17	0.00	0.00	0.00
11/2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12/2011	0.25	0.00	0.00	0.00	0.00	0.67	0.00	0.00	0.00

Table 23. Number of Hours where RTORPA > $1,000/MWh by Month (2011)

Month	0: Base Case No Response	1: Base Case	3: RDF=0.98	4: RTOFFCAP=0 PRC<2500	6: X=RRS+URS VOLL=18000	7: X=RRS+URS Price Floor	8: X=2300 VOLL=12000	9: X=2750 VOLL=18000	10: X=1708 VOLL=18000
1/2011	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00	0.00
2/2011	6.50	0.00	0.00	0.00	8.87	8.78	0.00	4.93	0.00
3/2011	0.00	0.00	0.00	0.00	0.00	0.36	0.00	0.00	0.00
4/2011	0.00	0.00	0.00	0.00	0.00	0.17	0.00	0.00	0.00
5/2011	0.08	0.00	0.00	0.00	0.00	0.84	0.00	0.00	0.00
6/2011	0.00	0.00	0.00	0.00	0.00	0.75	0.00	0.00	0.00
7/2011	0.00	0.00	0.00	0.00	13.42	4.83	0.00	5.50	0.00
8/2011	2.00	2.00	2.17	2.00	62.18	42.40	8.15	40.31	6.18
9/2011	0.00	0.00	0.00	0.00	0.08	0.17	0.00	0.00	0.00
10/2011	0.00	0.00	0.00	0.00	0.00	0.17	0.00	0.00	0.00
11/2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12/2011	0.00	0.00	0.00	0.00	0.00	0.67	0.00	0.00	0.00

Table 24. Number of Hours where RTORPA > $3,000/MWh by Month (2011)

Month	0: Base Case No Response	1: Base Case	3: RDF=0.98	4: RTOFFCAP=0 PRC<2500	6: X=RRS+URS VOLL=18000	7: X=RRS+URS Price Floor	8: X=2300 VOLL=12000	9: X=2750 VOLL=18000	10: X=1708 VOLL=18000
1/2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2/2011	5.40	0.00	0.00	0.00	5.56	8.05	0.00	1.17	0.00
3/2011	0.00	0.00	0.00	0.00	0.00	0.25	0.00	0.00	0.00
4/2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5/2011	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.00
6/2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7/2011	0.00	0.00	0.00	0.00	7.75	1.83	0.00	0.08	0.00
8/2011	2.00	2.00	2.17	2.00	46.41	32.99	4.50	22.98	1.34
9/2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10/2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11/2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12/2011	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.00

Table 25. Number of Hours where RTORPA > $5,000/MWh by Month (2011)

Month	0: Base Case No Response	1: Base Case	3: RDF=0.98	4: RTOFFCAP=0 PRC<2500	6: X=RRS+URS VOLL=18000	7: X=RRS+URS Price Floor	8: X=2300 VOLL=12000	9: X=2750 VOLL=18000	10: X=1708 VOLL=18000
1/2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2/2011	0.29	0.00	0.00	0.00	0.58	2.56	0.00	0.00	0.00
3/2011	0.00	0.00	0.00	0.00	0.00	0.25	0.00	0.00	0.00
4/2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5/2011	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.00
6/2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7/2011	0.00	0.00	0.00	0.00	3.74	0.41	0.00	0.00	0.00
8/2011	0.00	0.00	0.00	0.00	19.37	11.95	0.08	2.17	0.00
9/2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10/2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11/2011	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12/2011	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.00

Table 26. Number of Hours where RTORPA > $7,000/MWh by Month (2011)

Probability of Falling Below Minimum Contingency Level on August 3, 2011

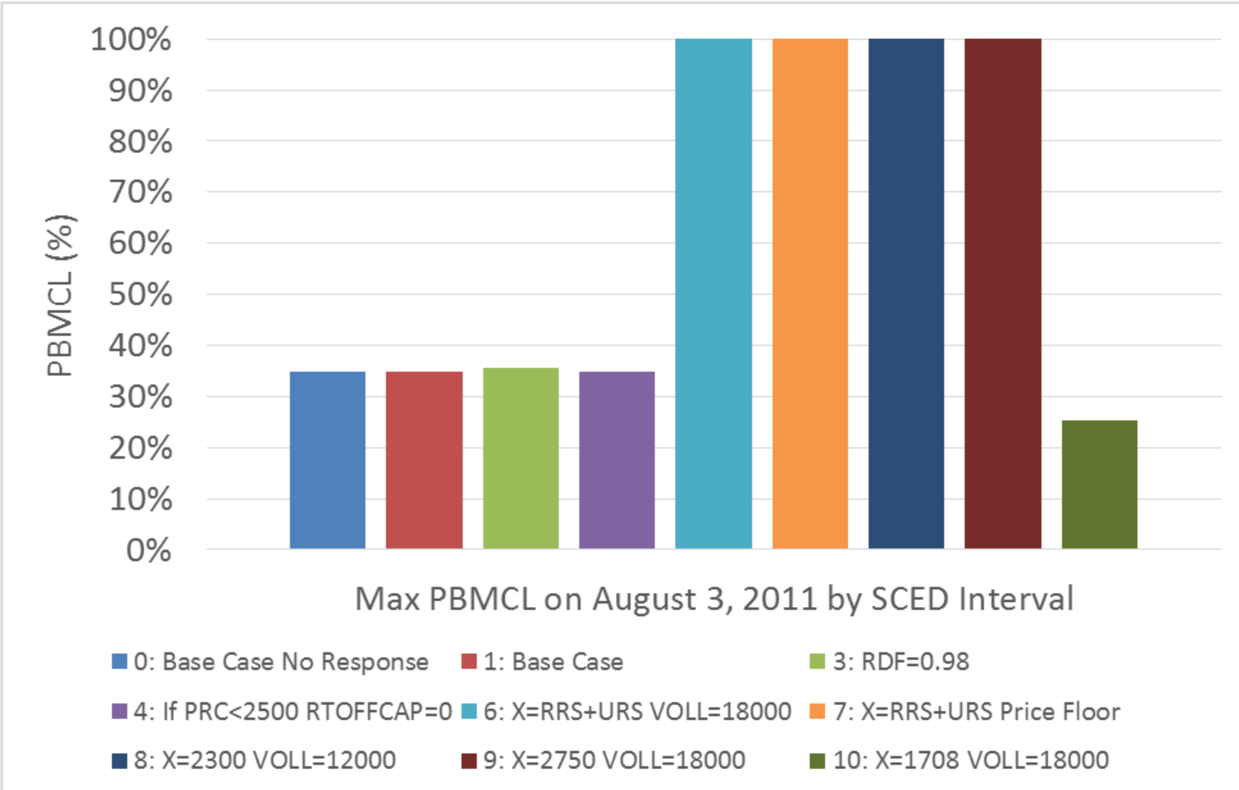


Figure 24. Max PBMCL on August 3, 2011

Option	Max PBMCL on August 3, 2011 by SCED Interval
0: Base Case No Reponse	34.8%
1: Base Case	34.8%
3: RDF=0.98	35.6%
4: If PRC<2500 RTOFFCAP=0	34.8%
6: X=RRS+URS VOLL=18000	100.0%
7: X=RRS+URS Price Floor	100.0%
8: X=2300 VOLL=12000	100.0%
9: X=2750 VOLL=18000	100.0%
10: X=1708 VOLL=18000	25.4%

Table 27. Max PBMCL on August 3, 2011

Section 3: Sensitivity Analysis

Offline and available resources had varying levels of startup time and startup cost. Assuming that all those resources will be online any time prices were greater than a particular level might lead to over commitment.

Hence, a sensitivity analysis was done to show a range of outcomes:

1. Price response any time prices were greater than $75/MWh
2. Price response when prices go above $75/MWh for 2 hours
3. Price response any time prices were greater than $250/MWh
4. Price response when prices go above $250/MWh for 2 hours
5. No price response

Two hours were estimated based on average start times, start costs, and time needed to recover average start costs.

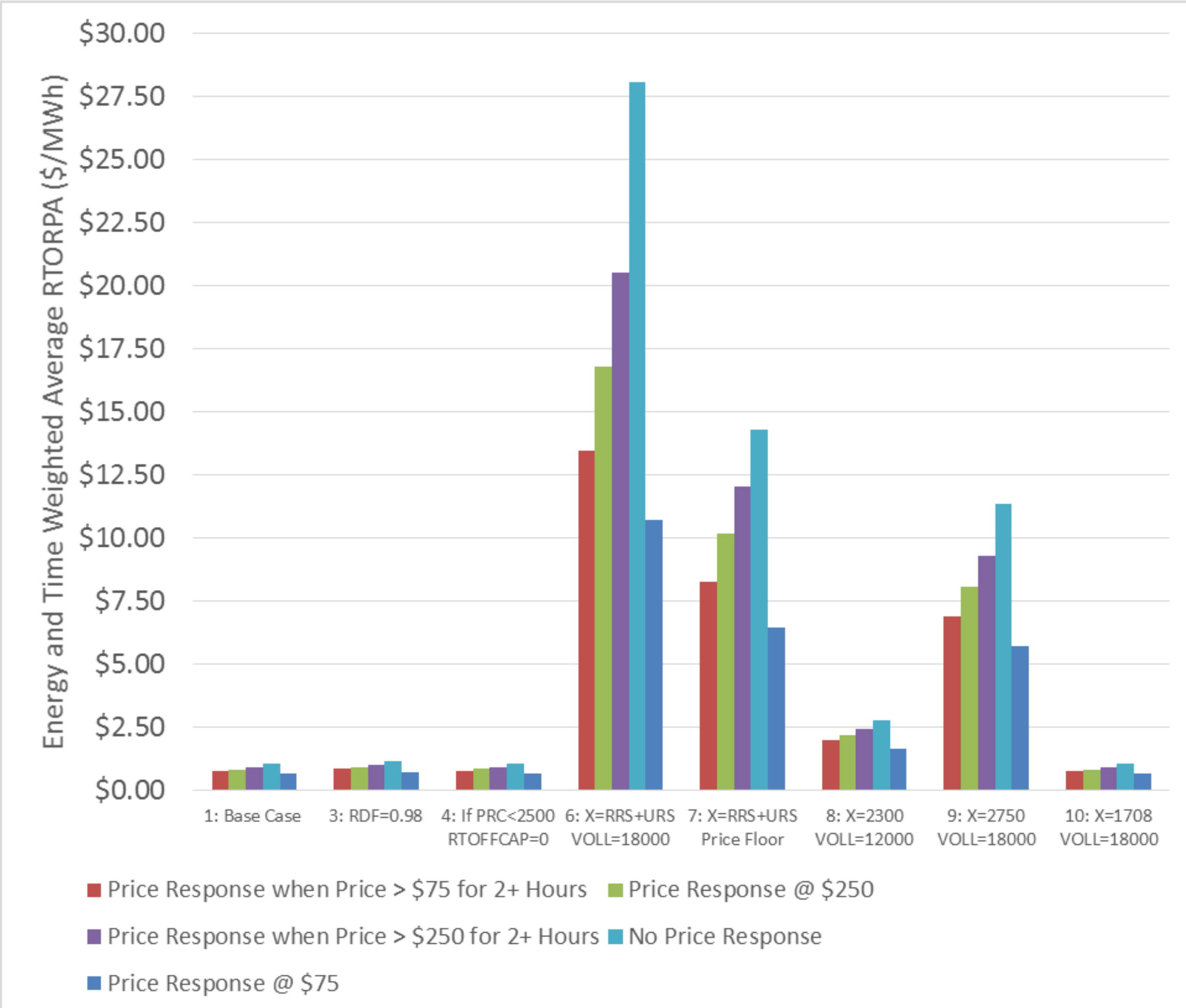


Figure 25. Energy and Time Weighted RTORPA Sensitivity to Market Behavior (6/1/2014 – 10/31/2015)

Option	Price Response @ $75	Price Response when Price > $75 for 2+ Hours	Price Response @ $250	Price Response when Price > $250 for 2+ Hours	No Price Response
1: Base Case	$0.66	$0.78	$0.85	$0.94	$1.05
3: RDF=0.98	$0.73	$0.86	$0.94	$1.04	$1.17
4: If PRC<2500 RTOFFCAP=0	$0.66	$0.79	$0.86	$0.95	$1.06
6: X=RRS+URS VOLL=18000	$10.71	$13.47	$16.81	$20.50	$28.08
7: X=RRS+URS Price Floor	$6.44	$8.26	$10.20	$12.07	$14.33
8: X=2300 VOLL=12000	$1.66	$2.02	$2.22	$2.43	$2.81
9: X=2750 VOLL=18000	$5.72	$6.90	$8.08	$9.29	$11.37
10: X=1708 VOLL=18000	$0.67	$0.77	$0.84	$0.93	$1.07

Table 28. Energy and Time Weighted RTORPA Sensitivity to Market Behavior (6/1/2014 – 10/31/2015)

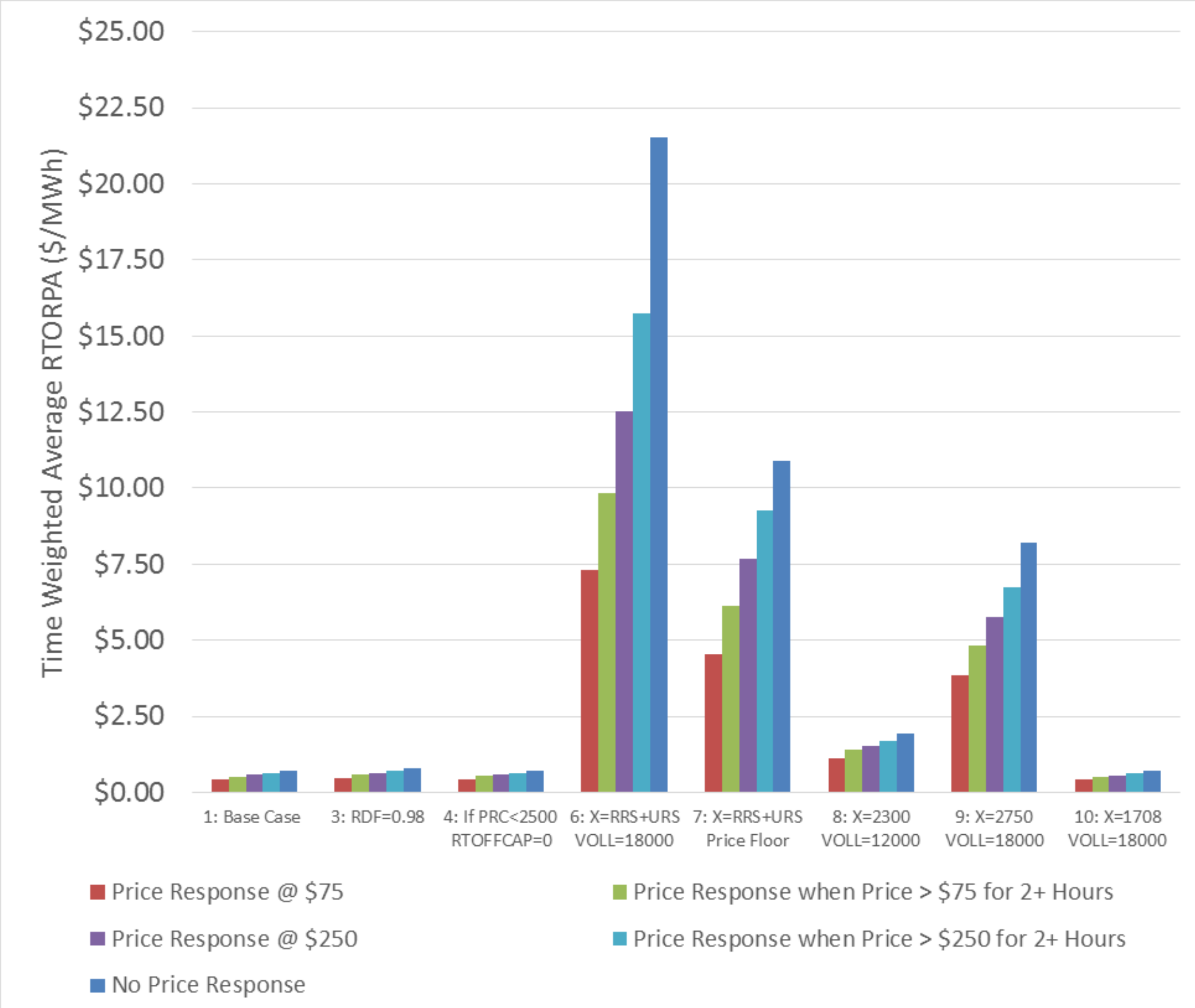


Figure 26. Time Weighted RTORPA Sensitivity to Market Behavior (6/1/2014 – 10/31/2015)

Option	Price Response @ $75	Price Response when Price > $75 for 2+ Hours	Price Response @ $250	Price Response when Price > $250 for 2+ Hours	No Price Response
1: Base Case	$0.43	$0.52	$0.58	$0.64	$0.71
3: RDF=0.98	$0.48	$0.58	$0.64	$0.71	$0.80
4: If PRC<2500 RTOFFCAP=0	$0.43	$0.53	$0.58	$0.64	$0.72
6: X=RRS+URS VOLL=18000	$7.32	$9.82	$12.52	$15.76	$21.51
7: X=RRS+URS Price Floor	$4.52	$6.12	$7.69	$9.27	$10.91
8: X=2300 VOLL=12000	$1.10	$1.39	$1.54	$1.70	$1.95
9: X=2750 VOLL=18000	$3.84	$4.83	$5.77	$6.73	$8.20
10: X=1708 VOLL=18000	$0.43	$0.51	$0.55	$0.62	$0.71

Table 29. Time Weighted RTORPA Sensitivity to Market Behavior (6/1/2014 – 10/31/2015)

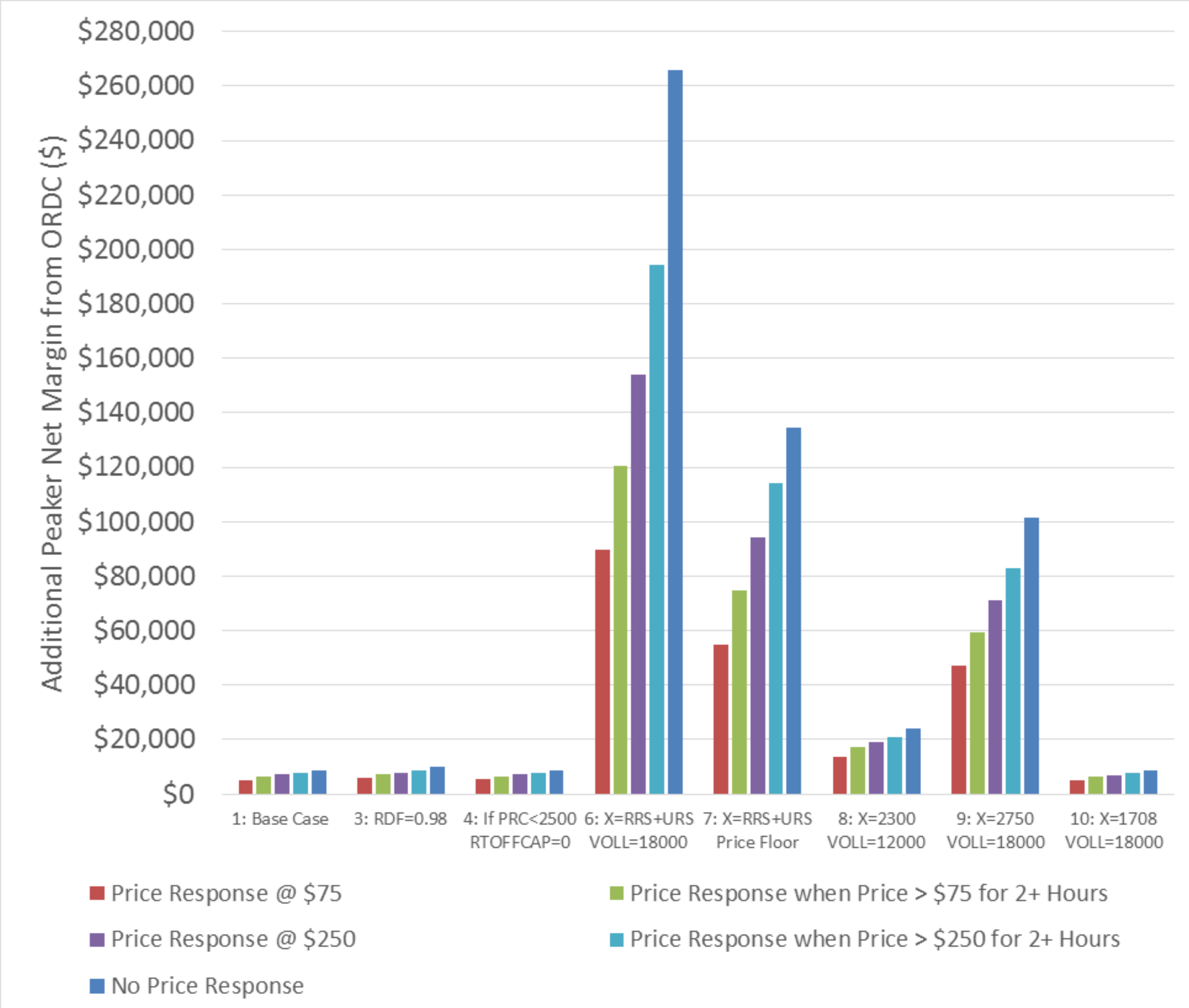


Figure 27. Additional Peaker Net Margin from ORDC Sensitivity to Market Behavior (6/1/2014 – 10/31/2015)

Option	Price Response @ $75	Price Response when Price > $75 for 2+ Hours	Price Response @ $250	Price Response when Price > $250 for 2+ Hours	No Price Response
1: Base Case	$5,254.46	$6,457.22	$7,089.44	$7,881.62	$8,818.39
3: RDF=0.98	$5,830.66	$7,088.94	$7,902.24	$8,786.55	$9,810.15
4: If PRC<2500 RTOFFCAP=0	$5,314.01	$6,516.77	$7,148.99	$7,941.17	$8,880.98
6: X=RRS+URS VOLL=18000	$89,522.41	$120,568.95	$154,169.90	$194,370.91	$265,834.38
7: X=RRS+URS Price Floor	$55,021.54	$74,886.36	$94,421.96	$114,050.91	$134,481.47
8: X=2300 VOLL=12000	$13,517.15	$17,054.73	$18,960.95	$20,997.12	$24,072.53
9: X=2750 VOLL=18000	$47,056.24	$59,453.59	$71,126.50	$83,079.55	$101,310.73
10: X=1708 VOLL=18000	$5,259.91	$6,243.16	$6,828.77	$7,666.11	$8,752.54

Table 30. Additional Peaker Net Margin from ORDC Sensitivity to Market Behavior (6/1/2014 – 10/31/2015)

Figure 28. Energy and Time Weighted RTORPA Sensitivity to Market Behavior (2011)

Option	Price Response @ $75	Price Response when Price > $75 for 2+ Hours	Price Response @ $250	Price Response when Price > $250 for 2+ Hours	No Price Response
1: Base Case	$15.53	$17.06	$18.74	$20.44	$29.20
3: RDF=0.98	$16.37	$18.03	$19.82	$21.63	$30.73
4: If PRC<2500 RTOFFCAP=0	$15.62	$17.26	$18.83	$20.67	$29.50
6: X=RRS+URS VOLL=18000	$129.23	$140.24	$152.56	$171.55	$318.40
7: X=RRS+URS Price Floor	$98.38	$105.00	$116.63	$128.59	$196.23
8: X=2300 VOLL=12000	$31.05	$34.13	$37.34	$41.89	$57.84
9: X=2750 VOLL=18000	$74.61	$80.34	$87.97	$99.23	$154.39
10: X=1708 VOLL=18000	$19.70	$21.60	$22.73	$24.78	$34.86

Table 31. Energy and Time Weighted RTORPA Sensitivity to Market Behavior (2011)

Figure 29. Time Weighted RTORPA Sensitivity to Market Behavior (2011)

Option	Price Response @ $75	Price Response when Price > $75 for 2+ Hours	Price Response @ $250	Price Response when Price > $250 for 2+ Hours	No Price Response
1: Base Case	$9.93	$11.50	$12.91	$14.55	$20.82
3: RDF=0.98	$10.48	$12.19	$13.70	$15.47	$21.98
4: If PRC<2500 RTOFFCAP=0	$9.98	$11.69	$12.96	$14.75	$21.09
6: X=RRS+URS VOLL=18000	$80.92	$92.20	$103.98	$123.48	$256.98
7: X=RRS+URS Price Floor	$63.10	$69.89	$81.08	$93.46	$151.79
8: X=2300 VOLL=12000	$19.66	$22.90	$25.68	$30.24	$42.13
9: X=2750 VOLL=18000	$46.75	$52.75	$59.89	$71.55	$118.12
10: X=1708 VOLL=18000	$12.32	$14.27	$15.12	$17.12	$24.30

Table 32. Time Weighted RTORPA Sensitivity to Market Behavior (2011)

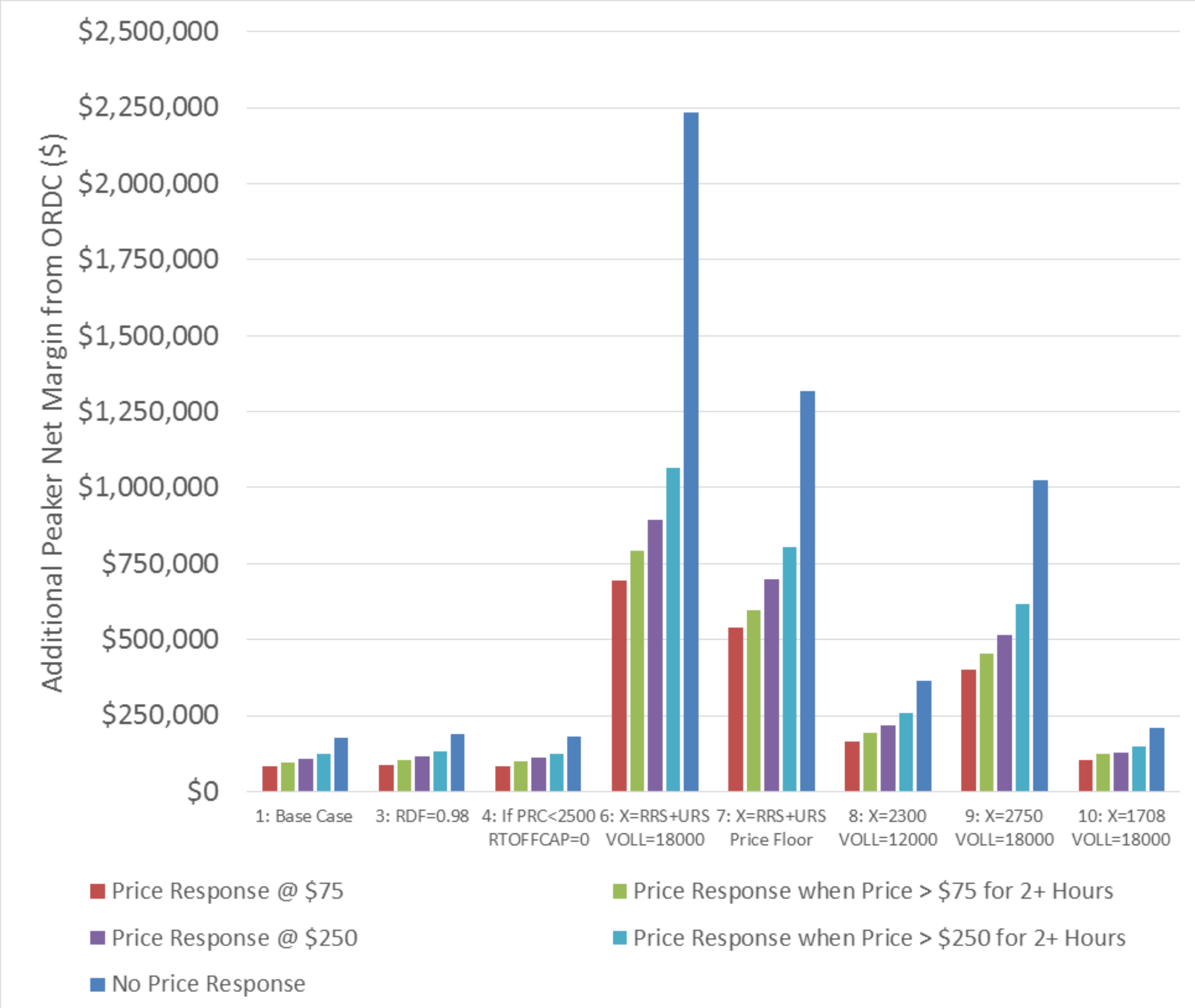
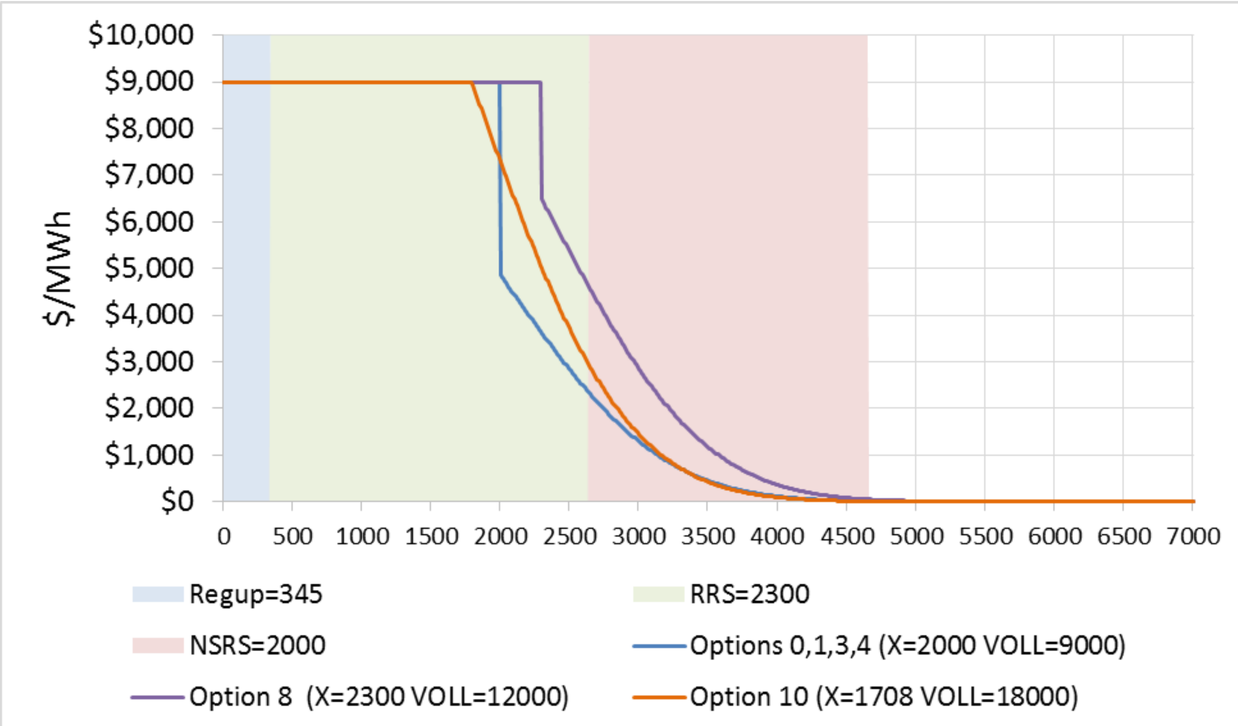


Figure 30. Additional Peaker Net Margin from ORDC Sensitivity to Market Behavior (2011)

Option	Price Response @ $75	Price Response when Price > $75 for 2+ Hours	Price Response @ $250	Price Response when Price > $250 for 2+ Hours	No Price Response
1: Base Case	$83,623.92	$97,350.80	$109,674.28	$124,043.89	$178,959.31
3: RDF=0.98	$88,157.10	$103,104.27	$116,363.82	$131,866.99	$188,855.42
4: If PRC<2500 RTOFFCAP=0	$84,066.63	$99,010.41	$110,134.02	$125,865.82	$181,385.05
6: X=RRS+URS VOLL=18000	$692,719.97	$791,496.48	$894,689.13	$1,065,525.65	$2,234,961.82
7: X=RRS+URS Price Floor	$538,780.82	$598,214.40	$696,304.42	$804,706.81	$1,315,720.45
8: X=2300 VOLL=12000	$166,573.81	$195,036.08	$219,345.77	$259,280.09	$363,466.42
9: X=2750 VOLL=18000	$399,382.10	$451,969.63	$514,522.44	$616,612.57	$1,024,588.17
10: X=1708 VOLL=18000	$105,018.20	$122,115.42	$129,587.81	$147,093.73	$209,985.04

Table 33. Additional Peaker Net Margin from ORDC Sensitivity to Market Behavior (2011)

Section 4: Add Demand Curves to DAM – Snapshot from August 13, 2015 Online ORDC Curve as an Example (Option 2)



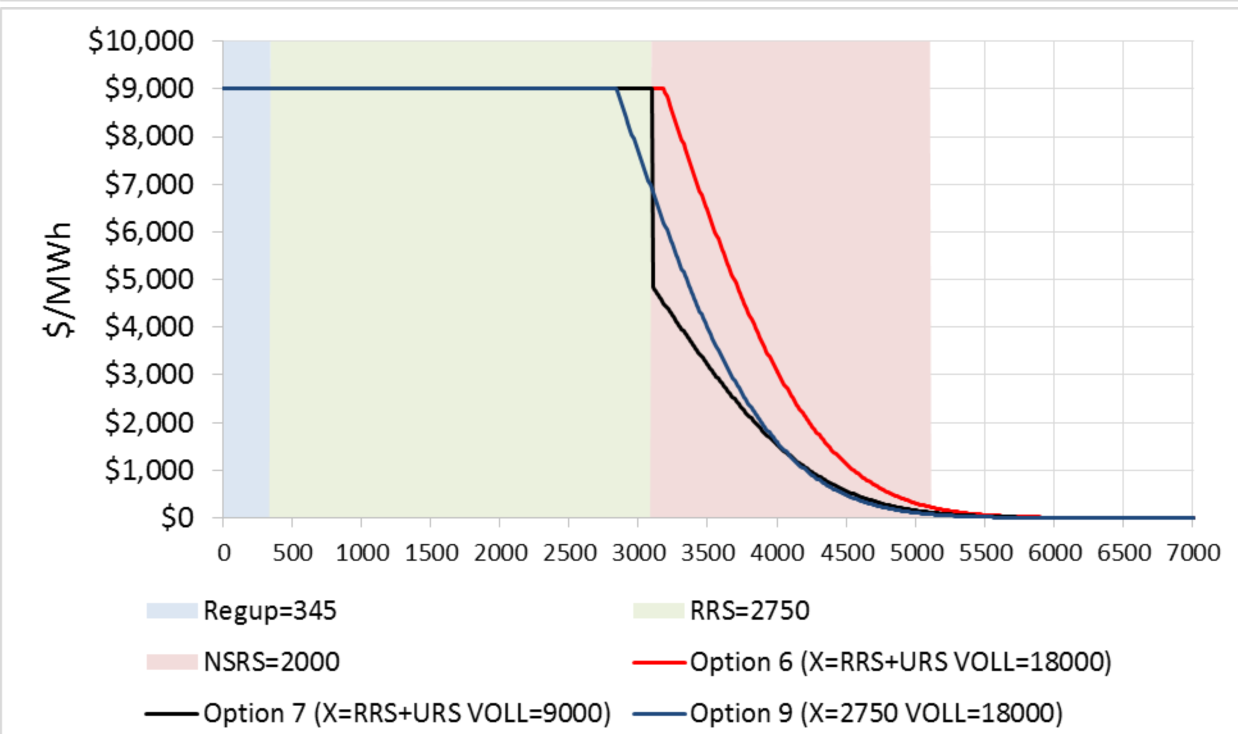


Figure 31. August 13, 2015 HE17 Online ORDC Curve (VOLL * LOLPs) Overlaid with AS Requirements

Penalty Price of AS Demand Curve for last MW of AS requirement in DAM using August 13, 2015 HE17 Online ORDC Curve as an example								
Ancillary Service Type		Total AS (Last MW)	Options 0,1,3,4 X=2000 VOLL=9000	Option 6 X=RRS+URS VOLL=18000	Option 7 X=RRS+URS VOLL=9000	Option 8 X=2300 VOLL=12000	Option 9 X=2750 VOLL=18000	Option 10 X=1708 VOLL=18000
URS		345	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000
RRS=2300	RRS	2645	$2,318	N/A	N/A	$4,577	N/A	$2,898
	NSRS	4645	$13	N/A	N/A	$51	N/A	$8
RRS=2750	RRS	3095	N/A	$9,000	$4,857	N/A	$6,866	N/A
	NSRS	5095	N/A	$234	$117	N/A	$77	N/A

Table 34. Penalty Price of AS Demand Curve for last MW of AS Requirement in DAM using August 13, 2015 HE17 Online ORDC Curve as an Example

Example for options 0,1,3,4

Last MW of URS = 345 MW where price would be $9,000/MWh on the curve

Last MW of RRS = 345 + 2300 = 2645 MW where price would be $2,319/MWh on the curve

Last MW of NSRS = 345 + 2300 + 2000 = 4645 MW where price would be $13/MWh on the curve

Section 5: X = URS + RRS – A look at the 2016 AS Methodology Values (Options 6 & 7)

Without RRS Floor

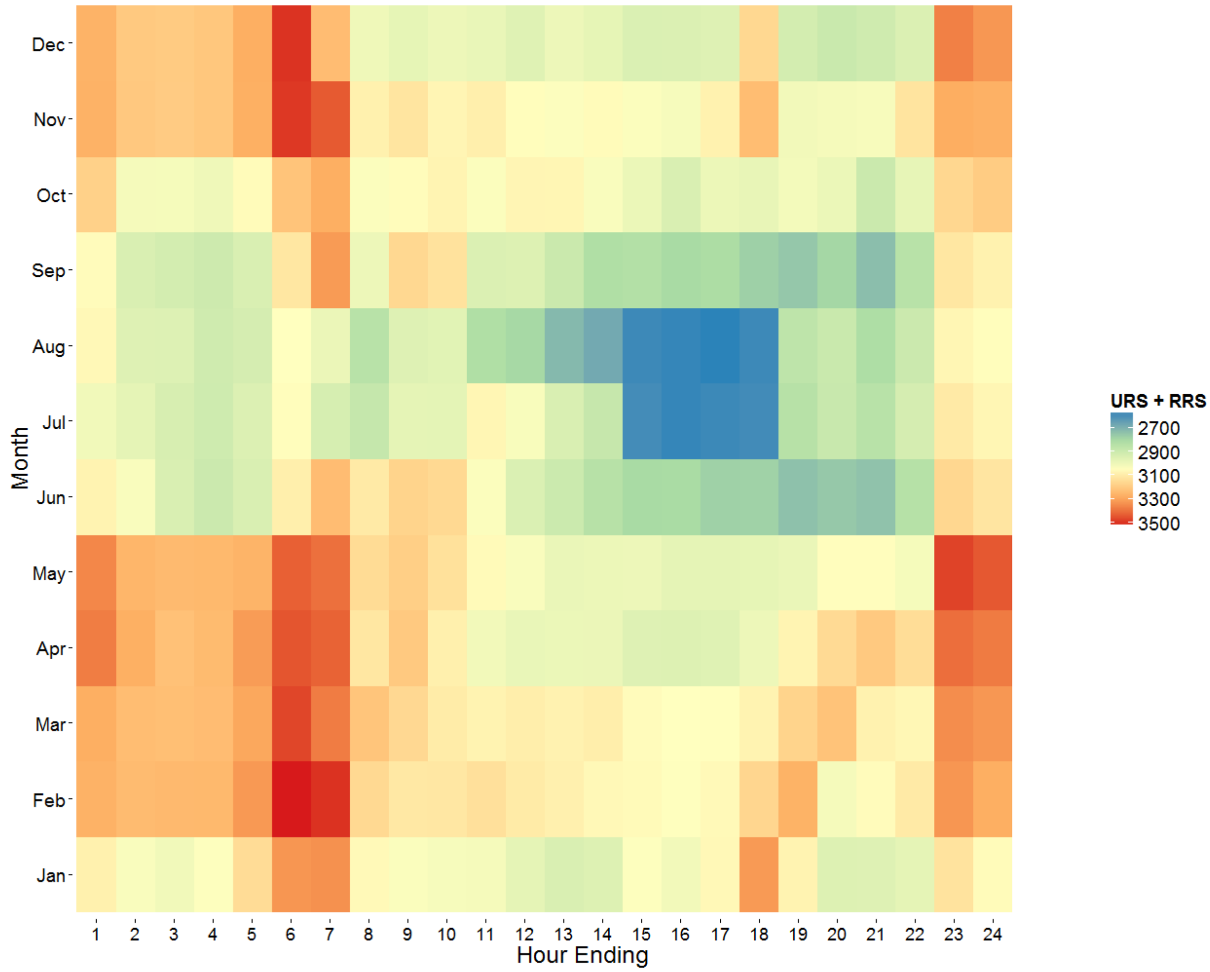


Figure 32. Heat map of URS + RRS without RRS floor from 2016 AS Methodology

URS+RRS without 2750 MW RRS Floor												2016
HE	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	3088	3273	3282	3380	3361	3079	3008	3067	3056	3183	3272	3268
2	3030	3245	3239	3277	3261	3031	2972	2954	2940	3018	3208	3204
3	3008	3252	3234	3228	3250	2941	2932	2952	2921	3020	3198	3199
4	3042	3253	3241	3247	3253	2898	2907	2909	2903	3004	3211	3211
5	3149	3326	3297	3319	3267	2939	2947	2927	2938	3059	3277	3281
6	3332	3524	3474	3452	3433	3092	3053	3047	3118	3221	3494	3500
7	3343	3501	3382	3429	3404	3242	2931	2990	3322	3282	3443	3242
8	3062	3157	3216	3117	3150	3108	2882	2846	2997	3038	3088	3002
9	3034	3111	3159	3203	3188	3173	2974	2954	3162	3054	3124	2977
10	3022	3115	3102	3091	3135	3158	2970	2964	3131	3078	3073	2998
11	3018	3137	3079	3010	3061	3038	3072	2823	2945	3036	3093	2986
12	2974	3104	3096	2986	3032	2942	3027	2799	2950	3074	3053	2955
13	2941	3089	3083	2992	2988	2901	2940	2717	2896	3071	3039	2996
14	2949	3066	3095	2990	2994	2843	2884	2676	2823	3029	3058	2977
15	3043	3061	3056	2954	2997	2804	2596	2589	2833	2991	3036	2943
16	3011	3046	3047	2950	2974	2807	2580	2580	2805	2938	3022	2944
17	3066	3062	3049	2955	2975	2780	2587	2570	2815	2994	3086	2953
18	3323	3168	3079	2997	2977	2781	2594	2590	2776	2983	3240	3162
19	3080	3271	3172	3077	2987	2738	2843	2864	2754	3012	3010	2922
20	2949	3018	3223	3153	3051	2757	2890	2894	2795	2991	3019	2892
21	2953	3057	3086	3203	3051	2742	2846	2818	2730	2896	3025	2910
22	2972	3108	3070	3147	3021	2840	2926	2898	2847	2979	3125	2946
23	3128	3334	3351	3407	3479	3163	3108	3072	3118	3163	3284	3376
24	3058	3282	3329	3384	3446	3121	3072	3053	3086	3195	3274	3330

Table 35. URS + RRS without RRS floor from 2016 AS Methodology

With RRS Floor of 2,750 MW

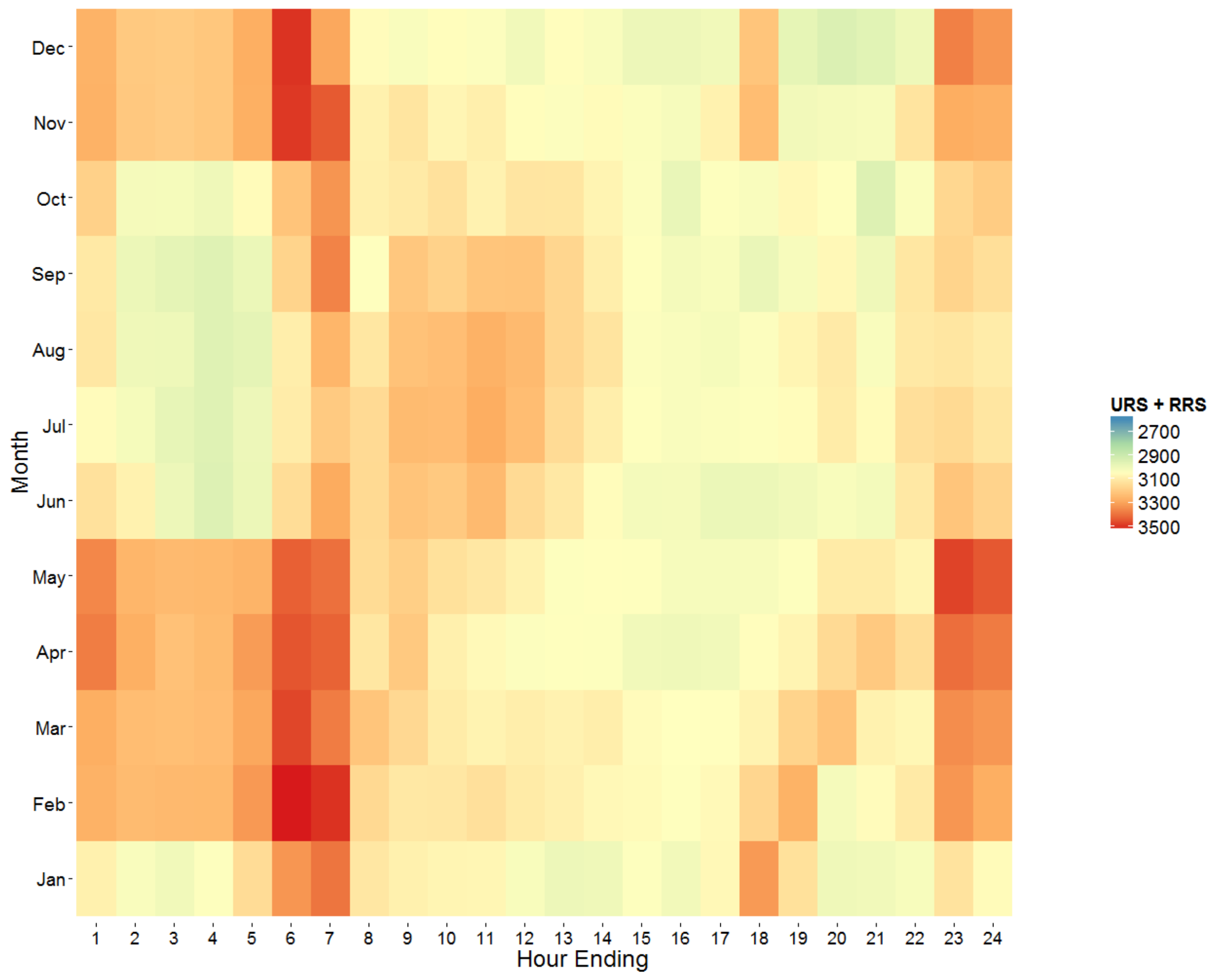


Figure 33. Heat map of URS + RRS with RRS floored at 2750 MW from 2016 AS Methodology

URS+RRS with 2750 MW RRS Floor												2016
HE	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	3088	3273	3282	3380	3361	3133	3056	3115	3110	3183	3272	3268
2	3030	3245	3239	3277	3261	3085	3020	3002	2994	3018	3208	3204
3	3008	3252	3234	3228	3250	2995	2980	3000	2975	3020	3198	3199
4	3042	3253	3241	3247	3253	2952	2955	2957	2957	3004	3211	3211
5	3149	3326	3297	3319	3267	2993	2995	2975	2992	3059	3277	3281
6	3332	3524	3474	3452	3433	3146	3101	3095	3172	3221	3494	3500
7	3343	3501	3382	3429	3404	3290	3202	3261	3370	3336	3443	3296
8	3062	3157	3216	3117	3150	3156	3153	3117	3045	3092	3088	3056
9	3034	3111	3159	3203	3188	3221	3245	3225	3210	3108	3124	3031
10	3022	3115	3102	3091	3135	3206	3241	3235	3179	3132	3073	3052
11	3018	3137	3079	3064	3115	3250	3284	3273	3216	3084	3093	3040
12	2974	3104	3096	3040	3086	3154	3239	3249	3221	3122	3053	3009
13	2941	3089	3083	3046	3042	3113	3152	3167	3167	3119	3039	3050
14	2949	3066	3095	3044	3048	3055	3096	3126	3094	3077	3058	3031
15	3043	3061	3056	3008	3045	3016	3046	3039	3045	3039	3036	2997
16	3011	3046	3047	3004	3022	3019	3030	3030	3017	2986	3022	2998
17	3066	3062	3049	3009	3023	2992	3037	3020	3027	3042	3086	3007
18	3323	3168	3079	3051	3025	2993	3044	3040	2988	3031	3240	3216
19	3080	3271	3172	3077	3041	3009	3055	3076	3025	3066	3010	2976
20	2949	3018	3223	3153	3105	3028	3102	3106	3066	3045	3019	2946
21	2953	3057	3086	3203	3105	3013	3058	3030	3001	2950	3025	2964
22	2972	3108	3070	3147	3075	3111	3138	3110	3118	3033	3125	3000
23	3128	3334	3351	3407	3479	3217	3156	3120	3172	3163	3284	3376
24	3058	3282	3329	3384	3446	3175	3120	3101	3140	3195	3274	3330

Table 36. URS + RRS with RRS floored at 2750 MW from 2016 AS Methodology

URS Requirements												2016
HE	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
1	280	273	282	380	361	383	306	365	360	375	272	268
2	222	245	239	277	261	335	270	252	244	210	208	204
3	200	252	234	228	250	245	230	250	225	212	198	199
4	234	253	241	247	253	202	205	207	207	196	211	211
5	341	326	297	319	267	243	245	225	242	251	277	281
6	524	524	474	452	433	396	351	345	422	413	494	500
7	647	693	574	621	596	540	452	511	620	586	635	546
8	366	349	408	309	342	406	403	367	295	342	280	306
9	338	303	351	395	380	471	495	475	460	358	316	281
10	326	307	294	283	327	456	491	485	429	382	265	302
11	322	329	271	314	365	500	534	523	466	334	285	290
12	278	296	288	290	336	404	489	499	471	372	245	259
13	245	281	275	296	292	363	402	417	417	369	231	300
14	253	258	287	294	298	305	346	376	344	327	250	281
15	235	253	248	258	295	266	296	289	295	289	228	247
16	203	238	239	254	272	269	280	280	267	236	214	248
17	258	254	241	259	273	242	287	270	277	292	278	257
18	515	360	271	301	275	243	294	290	238	281	432	466
19	384	463	364	269	291	259	305	326	275	316	202	226
20	253	210	415	345	355	278	352	356	316	295	211	196
21	257	249	278	395	355	263	308	280	251	200	217	214
22	276	300	262	339	325	361	388	360	368	283	317	250
23	320	334	351	407	479	467	406	370	422	355	284	376
24	250	282	329	384	446	425	370	351	390	387	274	330
RRS Requirements												**2016**
HE	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
1	2808	3000	3000	3000	3000	2696	2702	2702	2696	2808	3000	3000
2	2808	3000	3000	3000	3000	2696	2702	2702	2696	2808	3000	3000
3	2808	3000	3000	3000	3000	2696	2702	2702	2696	2808	3000	3000
4	2808	3000	3000	3000	3000	2696	2702	2702	2696	2808	3000	3000
5	2808	3000	3000	3000	3000	2696	2702	2702	2696	2808	3000	3000
6	2808	3000	3000	3000	3000	2696	2702	2702	2696	2808	3000	3000
7	2696	2808	2808	2808	2808	2702	2479	2479	2702	2696	2808	2696
8	2696	2808	2808	2808	2808	2702	2479	2479	2702	2696	2808	2696
9	2696	2808	2808	2808	2808	2702	2479	2479	2702	2696	2808	2696
10	2696	2808	2808	2808	2808	2702	2479	2479	2702	2696	2808	2696
11	2696	2808	2808	2696	2696	2538	2538	2300	2479	2702	2808	2696
12	2696	2808	2808	2696	2696	2538	2538	2300	2479	2702	2808	2696
13	2696	2808	2808	2696	2696	2538	2538	2300	2479	2702	2808	2696
14	2696	2808	2808	2696	2696	2538	2538	2300	2479	2702	2808	2696
15	2808	2808	2808	2696	2702	2538	2300	2300	2538	2702	2808	2696
16	2808	2808	2808	2696	2702	2538	2300	2300	2538	2702	2808	2696
17	2808	2808	2808	2696	2702	2538	2300	2300	2538	2702	2808	2696
18	2808	2808	2808	2696	2702	2538	2300	2300	2538	2702	2808	2696
19	2696	2808	2808	2808	2696	2479	2538	2538	2479	2696	2808	2696
20	2696	2808	2808	2808	2696	2479	2538	2538	2479	2696	2808	2696
21	2696	2808	2808	2808	2696	2479	2538	2538	2479	2696	2808	2696
22	2696	2808	2808	2808	2696	2479	2538	2538	2479	2696	2808	2696
23	2808	3000	3000	3000	3000	2696	2702	2702	2696	2808	3000	3000
24	2808	3000	3000	3000	3000	2696	2702	2702	2696	2808	3000	3000

Table 37. Individual URS and RRS tables from 2016 AS Methodology Requirements

ERCOT STEEL MILLS
COMMENTS REGARDING CHANGES TO THE ORDC
January 4, 2016

Nucor Steel, Commercial Metals Corporation, and Gerdau ("ERCOT Steel Mills"), submit that no changes to the Operating Reserves Demand Curve (ORDC) are necessary or appropriate at this time. We believe that the ORDC pricing mechanism is working as assigned and is fulfilling its intended function well.

The only problem, if there is a one, is the failure of some market participants and observers to fully appreciate the difference between the PRC and ORDC reserve measures. PRC and ORDC are not functional equivalents and were never designed to correlate closely in situations where significant Quick Start capability is available to be used but has not been started and actually placed into on-line service. Nor should they be. The fact that the PRC and ORDC reserve calculations do not always correlate closely does not mean that a deficiency exists with respect to either calculation.

To the extent that there exists some confusion over the reliability and market signaling functions of PRC and ORDC, there may be some value in reviewing the relationship between the definition of reserves used in the ORDC calculation and the measurements monitored by system operators when considering whether the system is approaching scarcity conditions. It may also be worthwhile to undertake a review ERCOT's procedures for interpreting and responding to declining PRC values, especially when significant Quick Start capacity is available but for some reason the market has not yet responded to the capacity need.

There Was Not a Scarcity Problem on August 13th

During the afternoon of Thursday, August 13, 2015, conditions certainly suggested the possibility that a scarcity problem could arise. The summer system peak had been set on the previous Monday. Generating unit outages and continued hot temperatures contributed to a drop in PRC on August 13th to less than 2500 MW, which led ERCOT's system operators to implement a Control Room Watch for part of the afternoon and to announce a Conservation Alert from 3 p.m. to 7 p.m. [1] These actions in themselves should have prompted QSEs to bring additional Quick Start capacity into service to take advantage of higher prices. An ample amount of off-line Quick Start capacity was available to be placed on line on August 13th, and an amount sufficient to avoid the declaration of an EEA did in fact come on line without need of any out of market action by ERCOT.

No capacity shortage existed on August 13th, notwithstanding that PRC dropped to 2371 MW. PRC is a measurement of the quantity of generating capacity on governor response, and as such is a measurement of spinning reserve as opposed to total additional reserves that can be brought on line quickly (Quick Start capacity) to meet system demand. Although PRC on August 13th had declined to levels warranting vigilance by system operators, ample generating capacity remained available to avert any reliability problems. Over 1,500 MW of generating capacity

[1] See ERCOT press release at: http://www.ercot.com/news/press_releases/show/73261; http://www.ercot.com/news/pres_releases/show/73270

from Quick Start units was available to come on-line.[2] Given all of the off-line generating capacity available to the system, ORDC properly recognized a low Loss of Load Probability (LOLP) and correctly indicated the absence of scarcity conditions.

Consequently, a low PRC on August 13th did not imply, and should not be interpreted as implying, the existence of scarcity conditions on August 13th. Nor does the lack of close correlation between the low PRC that the ORDC on August 13th suggest that the ORDC in any way failed to properly reflect the presence of scarcity conditions. Both the PRC and the ORDC properly conveyed the information they are designed to convey to the system operator and market participants.

An interesting observation from the August 13th data worth noting is that a significant amount of the available but off-line Quick Start generating units on August 13th was available for SCED dispatch but was not dispatched because market prices did not reach the offer prices submitted for those units. As early as 2:50 p.m. on the 13th, ERCOT's Real Time Dispatch price projections showed that LMPs would be around $1,500 over the following 15 to 20 minutes under the prevailing generation capacity and load projections. An inspection of information contained within the 60 day generation data disclosure report shows offer prices from some Quick Start generation that was reported to be on-line and available to the Security-Constrained Economic Dispatch (SCED) model (but not actually on line)[3] ranging from $1,504 to $1,634 – just slightly above projected market prices.[4]

The high offer prices from those off-line Quick Start units treated as on-line for purposes of enabling their dispatch via SCED resulted in that capacity not being dispatched and consequently remaining off-line. These Resources were not counted in the PRC calculation monitored by ERCOT's system operators and used to declare Conservation Alerts and EEA events because no "governor response" could be provided by units which were not generating. Yet, this Quick Start capacity was properly included in the broader reserve calculation used to adjust market prices through the ORDC mechanism.

The Quick Start units with the high offer prices were indeed "ready, willing, and able" to provide generation at slightly higher market prices than those which were anticipated. Given the declining PRC, the likelihood of a price spike and that the time of day was several hours before peak, QSEs should have self-committed more of their Quick Start units instead of passively relying upon dispatch by SCED. In fact, some QSEs did so. Market reaction to existing system conditions was more than sufficient to avoid the occurrence of an EEA event.

From the system operator standpoint, tools available to the ERCOT Real Time Operators would have revealed declining PRC on the 13th, but other tools surely available to the operators would also have shown over 1500 MW of Quick Start capacity ready to come on-line if

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[2] Based on a review of 60-day generation data disclosure reports, the amounts available from 2 p.m. to 3:15 ranged from 1,647 MW to 1,809 MW. The amounts available later in the afternoon were lower, but always exceeded 1,000 MW. This was calculated by summing the HSL values of the quick start units and then subtracting the sum of the telemetered net output of those units.

[3] Some Quick Start units were providing active offers to SCED and telemetering on "On" status, though they were not generating electricity.

[4] Some Quick Start units offered generation at much lower prices. Generation from some of the older Quick Start units was offered at less than $50, and these units were self-committed by their QSE during this time.

committed. A failure to consider this additional Resource capacity may well have been a precipitating factor in the ERCOT decision to call a Conservation Alert that likely was not necessary given the absence of a scarcity situation. However, a Conservation Alert may have been the only tool available to ERCOT to notify QSEs of the current state of the system (wake-up call).

The bottom line is that there was a great deal of off-line generation available on the 13th that could have been brought on-line via self-commitment in response to the Conservation Alert from ERCOT, which would have brought that capacity into the PRC calculation. The ORDC reserve calculations properly reflected the lack of need for scarcity pricing because sufficient capacity was available and the pricing mechanism in ORDC worked as designed indicating such.

No Change in the ORDC Calculation is Necessary

On August 13, 2015, the ORDC performed properly. No scarcity condition existed and ORDC communicated that fact correctly. ORDC is functioning as designed and is fulfilling its intended purpose well. No change in the ORDC calculation is therefore necessary or warranted.

The difference between: 1) the Real-Time On-Line Reserve Capacity (RTOLCAP) calculation, used in the ORDC mechanism, and 2) the PRC calculation, used to trigger Conservation Alerts and EEAs, might conceivably leave a casual observer with the misimpression that in certain instances inconsistent scarcity signals are being conveyed to the market. There is, however, no inconsistency in the messages being signaled, given the difference in intended purpose of the two measurements. As noted in Resmi Surendran's presentation to TAC on October 29, 2015,[5] RTOLCAP includes capacity that is considered in the PRC calculation up to 100% of the High Sustained Limits (HSL) of generating units, as well as capacity from Quick Start units.[6] On August 13, 2015, these two measures of system reliability deviated from one another, but the two measures were not inconsistent with each other due to the fact that on-line capacity was declining but at the same time sufficient off-line capacity was available for system use within the time frame of the need.

In light of the events of August 13th, it may be useful to review whether Conservation Alerts should be declared in situations where Quick Start generation is readily available to start yet for some reason is being held off-line and not contributing to PRC. A simple notice to the market may be all that was needed, in which case ERCOT might wish to consider implementing an additional notice requirement to QSEs in that circumstance

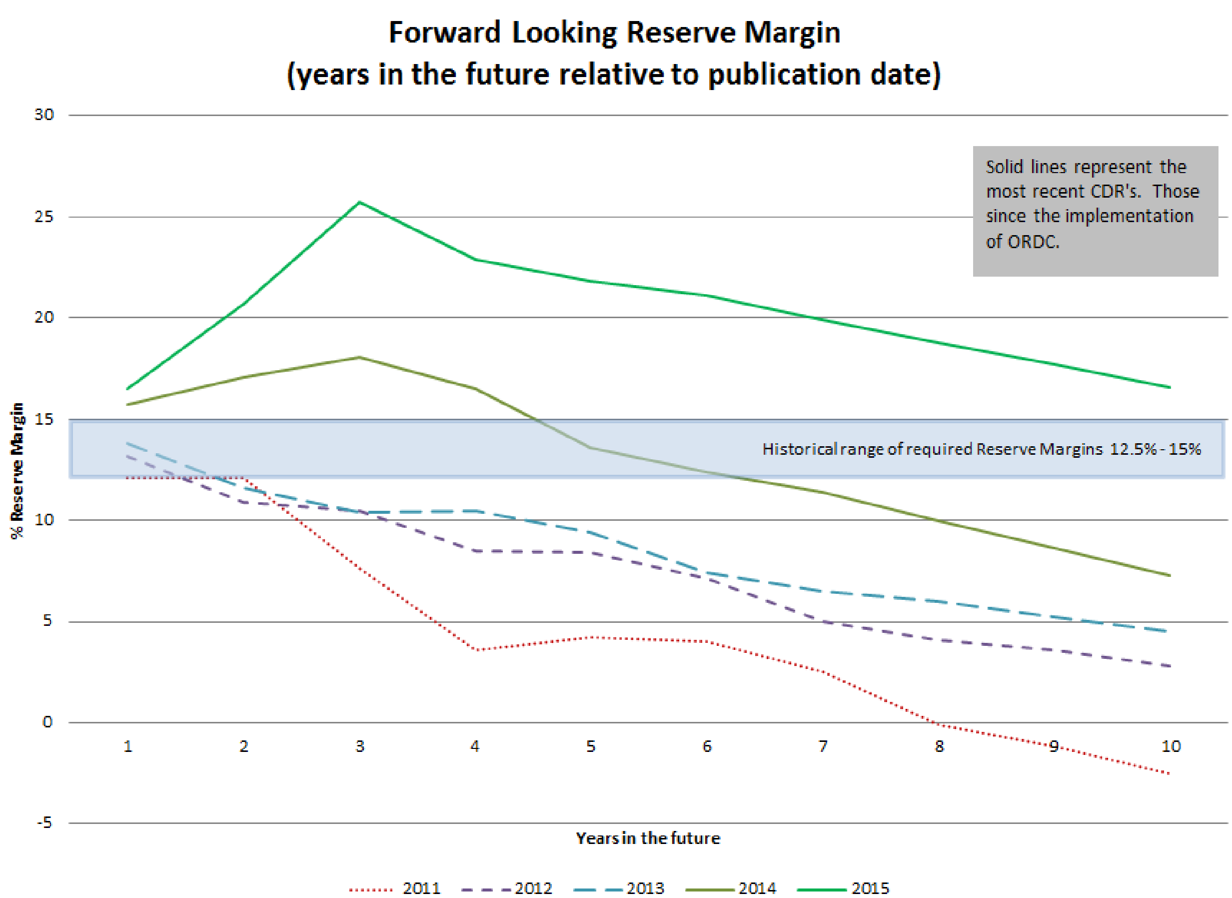
If any significant change is seen to be necessary or warranted, perhaps the one most worth further examination would be the removal of off-line generation from SCED, which would arguably result in a closer perceived alignment of calculated PRC and ORDC reserves and the encouragement of proactive Quick Start self-commitment rather than passive reliance on SCED dispatch of off-line Quick Start units.

[5] Resmi Surendran (ERCOT Staff), *Review of August 13, 2015*. TAC, October 29, 2015.
[6] Under some circumstances, some wind generation capacity might also be included in RTOLCAP.

DME welcomes the opportunity to respond to ERCOT's SAWG request for preliminary positions on potential changes or adjustments to the ORDC or ORDC components.

In response to the SAWGs request, DME's position is consistent with stakeholder observation 'A' as described in the ORDC white paper, i.e. – the ORDC is performing as intended and designed.

In support of our position, DME is also including a graph of reserve margins for the ten years into the future from the year of the report, as shown in ERCOT's CDR report.



Comments of Brazos Electric Power Cooperative, Inc. and Rayburn Country Electric Cooperative, Inc. on ORDC Options for Change
01.04.16

Brazos Electric Power Cooperative, Inc. and Rayburn Country Electric Cooperative, Inc. (collectively, the "Co-ops") appreciate the opportunity to review and comment on the functionality of the Operating Reserve Demand Curve (ORDC) in the ERCOT market, and to provide feedback on the options proposed by ERCOT stakeholders to address occasional events of perceived shortcomings of the current ORDC real-time price adder. The Co-ops are concerned about changing ORDC, at this time, as proposed in the various options for a number of reasons, and, therefore, provides these comments. The Co-ops' position can be summarized as follows:

1. The Co-ops are generally concerned regarding all suggested options for changing ORDC due to lack of reliability impact evaluation, including sufficient analysis supporting a reliability need for changing the ORDC, lack of analysis for all options proposed by stakeholders, and potentially high costs. The Co-ops, therefore, request further analysis and stakeholder participation before a decision is made to change the ORDC, and before any option is selected to change it.
2. The Co-ops are specifically opposed to implementing Options 2, 6, 7, 8, 9 and 10 at this time, because these options could result in drastic changes to the market and power costs without any demonstrable reliability benefit.

1. General Concerns about ORDC Changes

The Co-ops' top concern is the rushed manner in which this review is being completed, considering both the importance of the ORDC adder, in the ERCOT market, and the potential implications for unintended consequences, should changes to the ORDC be made without a complete record. The limited timeline assigned for this review brings another level of uncertainty, as stakeholders have not been able to perform a complete, thorough analysis of whether the issues raised in Commissioner Anderson's October 7, 2015 Memorandum represent a threat to ERCOT reliability, or some other dynamic, and how to best amend the ORDC, if a change is warranted. The Co-op's concerns are detailed below.

A. Lack of Analysis

In ERCOT stakeholder discussions to date, there has been no review or analysis conducted to demonstrate which ORDC parameters, if any, need to be adjusted. Rather, analysis has only been performed on what the relative price impacts might be of the various changes proposed by stakeholders. The ERCOT analysis provided to stakeholders, along with the backcast tool, was helpful to see the marginal difference between in LMPs and PNM for each option proposed, but it did not show how each option would affect a market participant's individual portfolio. There were also many assumptions that went into the backcast tool that greatly impact the results. ERCOT stakeholders also do not know, with any degree of certainty, which ORDC parameter should change, if any, and why. For example, August 13, 2015 was a market day selected to be studied in which ERCOT found that it was not lacking responsive reserve service (RRS) at all. In fact, ERCOT had an abundance of RRS. What ERCOT was actually lacking on that day was physical responsive capability (PRC). This day presented was only one scenario among many possibilities, but serves to point out that ORDC is working as intended. Consequently, how does ERCOT or an individual ERCOT stakeholder come up with successful solutions to fix a problem, when it is not yet clear what the problem is, or if a problem in fact exists? While some of the proposals may have some merit, more time to study the basic issues is clearly warranted.

B. No Connection to Reliability

The Co-ops fundamentally believe that any changes to the ORDC intended to address reliability concerns described in the Supply Analysis Working Group whitepaper ("A Review of ORDC Options") should be the result of a thorough review from ERCOT or other appropriate entity. Currently, the exact reliability issue has not been identified and none of the proposed options clearly address reliability concerns. Such a review is necessary to ensure that an unbiased view of what, or if, there is a specific issue of concern, regarding the current design of the ORDC, the use of offline resources or the triggering of Energy Emergency Alerts events. Implementing any changes without conducting such a review will likely result in unintended consequences. The ERCOT market is simply too important to the Texas economy to experiment with changes, without a full understanding of the market impacts. The Co-ops, therefore, request that prior to moving forward with any attempts to make changes to the ORDC, that ERCOT or other suitable entity conduct a root cause analysis assessing whether or not the ERCOT market has a physical electric service reliability issue that needs to be addressed, along with recommending sound unbiased solutions.

C. Lack of Time for Proper Stakeholder Involvement

As market participants committed to the ERCOT stakeholder process, the Co-ops submit that stakeholders must have ample opportunity to fully vet any proposed changes to the ORDC, and why they are necessary. This means providing time for comments, reply comments, analysis, meetings and other tools to allow for a full vetting of all issues and options. The requested comments provide only one limited opportunity to respond with no opportunity to improve and refine concepts over time.

D. High Cost

The Co-ops have serious concerns over the true market impact and costs that will occur if some of the above options were to be implemented and the resulting harm to the Texas economy. Based on very preliminary analysis, the Co-ops have found that many of the options could significantly increase cost to load serving entities (LSEs). Further studies will also be needed to determine projected costs with more certainty and to compare those costs to expected reliability benefits.

2. Concerns About Specific Options

Given the lack of time to fully identify whether or not a true reliability problem exists, and the lack of time to vet the options proposed by ERCOT stakeholders, the Co-ops are opposed to amending the functionality of the ORDC by using *any* of the options proposed by stakeholders without further review. However, the Co-ops have particular objections to Options 2, 6, 7, 8, 9, and 10, as follows:

Options 6, 7, 8, 9, and 10 propose some combination of changes involving increasing VOLL, increasing the amount of RRS and/or PRC procured, with a corresponding change in the value of "x". The Co-ops are opposed to changing these values for the following reasons:

> **VOLL** – Several options include changing VOLL. Any increase to the VOLL will ultimately increase costs for end users and lead to more volatility. VOLL is supposed to represent the true costs of not serving load, not an experimental value to raise the ORDC adder. $12,000 and $18,000, as noted in the proposals above, appear to be arbitrary values selected to arrive at specific pricing outcomes (lowering the hockey stick curve and increasing the frequency of ORDC price-spikes), that are not tied to a deficiency risk in physical electric service reliability.

Increasing minimum RRS and/or PRC requirements, and changing the value of "X" – Prices will increase significantly, and sooner, due to the ORDC being in place, at a higher level of reserve sufficiency, perhaps higher than a true reliability event requires. Furthermore, options suggesting an increase to the minimum amount of RRS, appear to be in direct conflict with the recently announced changes to 2016 ERCOT Ancillary Services Methodology. For 2016, ERCOT proposed and stakeholders endorsed a minimum standard RRS procurement of 1,375 MW for on peak hours and zero for off peak hours. Several options require almost double the amount of RRS and represent a complete change from the current purpose of RRS to provide frequency response and capacity in the event of a unit trip.

Option 2. Add ORDC to the DAM. The ORDC curve would be used as the demand curve for AS procurement and pricing instead of today's inelastic procurement.

A DAM with ORDC, and without real-time co-optimization could force a must run of generation in real-time that may not be economic. This option could cause an even greater lack of DAM participation due to withholding. Scarcity pricing should be based on operational shortfalls and reliability instances, not on economic resource withholding by those choosing not to participate the in the DAM. Credit requirements would potentially increase significantly.

3. Conclusion

In conclusion, the Co-ops appreciate this opportunity to submit these comments on proposed changes to the ORDC adder. As detailed above, the Co-ops have not been presented with any reliability issues that would warrant a change to the ORDC adder, at this time. The Co-ops feel strongly that before we can responsibly move forward, we must have thorough analysis on the topics mentioned above and additional stakeholder participation and discussion with ERCOT and any other appropriate entities, which leads to clearly identifying issues of concern, if any, before any options to change ORDC are selected.

CPS Energy's position on the Operating Reserve Demand Curve

The Operating Reserve Demand Curve (ORDC) was chosen as the mechanism to provide resource adequacy in ERCOT's energy only market. It provides shortage pricing for online and offline reserves as well as energy and is functioning as intended. The ORDC mechanism coupled with the $9,000 System Wide Offer Cap have resulted in an increase in the amount of capacity available in the real time energy market. This increase in capacity is also reflected in the generous reserve margin projections over the next 10 years. Reports published by the Independent Market Monitor (IMM) and ERCOT staff have not provided any compelling evidence that the ORDC is broken nor do the parameters need to be modified to fix a specific problem.

While it may be prudent to adjust the parameters of the ORDC that result in a curve with a different shape, CPS Energy does not support changes that result in significantly higher ORDC charges and revenues.

The ORDC is by no means a perfect mechanism. This is apparent when examining operating days like August 13th, 2015 as noted by Commissioner Anderson in his memo filed in Project 40000 at the Public Utility Commission of Texas. While the issues raised by Commissioner Anderson are real, they are more symptomatic of inefficiencies outside of the ORDC mechanism rather than the ORDC mechanism itself. August 13th was an example of the ORDC adder not reflecting a reduction in Physical Responsive Capacity (PRC). While this is true, it should be noted that the capacity indicators in the ORDC mechanism were not designed to align exactly with the PRC. The main difference is that the PRC reflects the capacity that is available in the next few seconds while the ORDC indicators reflect the capacity to meet demand over the next 30 minutes which includes offline generation. One concern is the fact that there can be instances when the ERCOT control room is preparing for Energy Emergency Alert declaration with adequate reserves available but offline. This can be addressed is by requiring all generation to be online when being dispatched by SCED or when nonspin is deployed.

CPS Energy supports the ERCOT Ancillary Service Methodology as approved by the ERCOT Board of Directors and does not support proposals which seek to increase the quantity of Responsive Reserve Ancillary Service. Ancillary Services are a reliability tool and should not be modified to address a potential market problem. ERCOT effectively manages the requirements and risks based on the Ancillary Service Methodology. If ERCOT feels that there is a need to modify the Ancillary Service Methodology, those changes should be based on reliability alone.

Calpine Proposed Changes to the Operating Reserve Demand Curve (ORDC)

1 EXECUTIVE SUMMARY

On October 8, 2015, the Public Utility Commission of Texas (PUCT) agreed it is time to review the ORDC and determine if any changes are necessary to ensure the ORDC is working as intended. Calpine supports the use of the ORDC in conjunction with the PUCT mandated energy-only market. However, the history of pricing outcomes since the implementation of ORDC on June 1, 2014, point to a significant flaw in the current value of one of the three ORDC parameters. Commissioner Anderson raised some valid concerns about the performance of the ORDC on days like August 13, 2015 when the ORDC adder did not appropriately reflect the reduction in Physical Responsive Capacity (PRC), while ERCOT operators were taking out-of-market actions.

In order to address this shortcoming of the current ORDC described above, maintain consistency with NERC reliability standards, allow market mechanisms to function properly, and avoid unnecessary out-of-market price-suppressing actions by ERCOT, Calpine recommends the following changes to the ORDC design and the Responsive Reserve ancillary service requirement:

1. **Set the value of the Minimum Contingency Level ("X") equal to the sum of Responsive Reserve Service (RRS) and Regulation-Up Service (RUS) requirements;**
2. **Set the minimum RRS requirement at 2,750 MW.**

2 CORRECTING THE MINIMUM CONTINGENCY LEVEL ("X")

As noted by Commissioner Anderson in his October 7, 2015, memo, footnote 1:

For example, on August 13, 2015, the ORDC adder did not seem to reflect appropriately the reduction in physical responsive capacity (PRC) that occurred. A low level of PRC can drive ERCOT grid operators to take out-of-market actions, including implementing Energy Emergency Alerts (EEA) and related procedures.

In fact, on August 13, 2015, PRC went below 2,500 MW and ERCOT did take out-of-market action in deploying off-line Non-Spinning Reserve Service (NSRS) and was close to declaring EEA Step #1 as PRC fell close to 2,300 MW. Yet the ORDC online price adder (RTORPA) was only $444/MWh when PRC was 2,374 MW at 15:55. This market outcome points to an obvious shortcoming in the current setting of the value of "X" of the ORDC.

The contributing factors in this flaw in the current setting of "X" of the ORDC are summarized as follows:

1. The value of "X", currently set at 2,000 MWs, is too low to send meaningful signals timely for load and generation action and is set much lower than PRC when it is equal to 2,300 MW, when ERCOT declares EEA, and even lower by a greater amount than PRC equal to 2,500 MW, when ERCOT starts taking out-of-market action.
    a. As pointed out by ERCOT in their presentation[1] analyzing the events of August 13, 2015:
        - EEA1 is called based on PRC <2300 to enable the use of Resource that are only available in emergency in a series of steps to avoid load shedding**. PRC only considers frequency responsive capacity (max 20%HSL)**
        - ORDC is based on LOLP of reserves falling below 2000. ORDC reserve (RTOLCAP) includes capacity that is considered in PRC up to 100% HSL and it also includes QSGR, capacity from WGRs which are curtailed and NFRC. i.e. **ORDC reserves include all the remaining reserves in the system.**
        - PRC drops much faster than ORDC because PRC only considers a fraction of the available online capacity.

[1] *Review of August 13, 2015*, ERCOT Presentation to TAC 10/29/15, Slide 3

- Since EEA is based on PRC, ORDC reserves could be high and price adder could be low when we are near EEA unless ORDC converges to PRC.
- As we approach scarcity PRC will be around 2500 and ORDC will gradually approach PRC as prices increase causing QSGRs to come online, resources to put their duct firing online and SCED to move resources to the top making the remaining capacity within 20%HSL. However, since minimum RRS level is 2300MW there could be situations where PRC stays just above 2300MW for a long time and could drop below 2300 when we still have lot of quick starts physically offline but available to SCED.

b. During hot summer days, PRC calculation discounts HSL of resources by 2%. Thus PRC = 2,300 MW implies that there is about 2,500 MW of responsive capacity on the system and in RTOLCAP. On top of that, RTOLCAP has additional QSGR, capacity from WGRs which are curtailed for transmission congestion purposes and non-frequency responsive capacity (NFRC). On August 13, 2015, it was observed that there's a difference of more than 1,200 MW between PRC and RTOLCAP. Thus, a Value of “X” of 2,000 MW roughly translates to a PRC value of 1,000 MW or less - well below PRC threshold of 2,300 MW at which declaration of EEA Step #1 is triggered. Hence, the current Value of "X" does not reflect true scarcity when ERCOT declares EEA. In fact, on August 13, 2015, when PRC was 2,374 MW (close to EEA), RTOLCAP was 3,774 MW, the probability of falling below the Minimum Contingency Reserve (or LOLP) was less than 4% and the ORDC online reserve price adder was only $444/MWh.

2. As its name implies, the Operating Reserve Demand Curve should reflect the ERCOT system's willingness to pay for various operating reserves. Since the current ORDC has only one curve to represent the demand for all of the operating reserves, it must reflect ERCOT's willingness to pay for Regulation Up Service (RUS), Responsive Reserve Service (RRS), and Non-Spinning Reserve Service (NSRS) - in that order down the demand curve. And, since this demand curve is supposed to represent ERCOT's willing to pay for these reserves, ERCOT should have no concerns with using the same curve in the Day-Ahead Market (DAM) to actually procure these reserves. However, that is not the case today since the current ORDC was not designed taking into account ERCOT's willingness to pay or "demand" for each of these reserves. As described below, procuring reserves based on the current ORDC

could raise serious reliability issues therefor the current ORDC does not reflect ERCOT's willingness to pay for those reserves. Consequently, the operating reserve prices resulting from the current ORDC are also not consistent with ERCOT's willingness to pay or demand for those reserve and thus do not accurately reflect true market scarcity.

Responsive Reserve Service (RRS) Must Be Included in the Value of “X”.

The objective of Responsive Reserve Service (RRS) is to ensure Frequency is arrested above the Under-frequency Load Shedding (UFLS) threshold of 59.30 Hz and to meet NERC Frequency Response Obligation (FRO) Standard (BAL-003-1). FRO for ERCOT is determined based on instantaneous loss of the two largest nuclear units (2,750 MW). ERCOT has determined that the ERCOT system must maintain specified MW amounts of RRS in order to comply with BAL-003-1 requirements. These RRS requirements would be used to set the demand curves for RRS in Real-Time Co-optimization (RTC) and, as such, should also form the basis of designing the ORDC.

ERCOT, on behalf of load, is willing to pay up to the System-Wide Offer Cap (SWOC) to meet RRS capacity requirement in order to meet NERC FRO Standard (BAL-003-1). In other words, as long as there is capacity available on the system beyond what's required to meet load, ERCOT will acquire the required amount of RRS even if the capacity offer is at the SWOC. The current ORDC (Value of X set at 2,000 MW) does not produce a price signal that reflects the new NERC requirement.

As an example, assume ERCOT determines that the system requires 500 MW of RUS and 2,800 MW of RRS for certain hours to comply with NERC requirements. The price signal sent by the current ORDC is that ERCOT is willing to pay up to the SWOC for the first 2,000 MW of RUS plus RRS, but after that point ERCOT’s willingness to pay drops drastically. For the last MW of the total 3,300 MW of RUS plus RRS required by the system, ERCOT is willing to pay only up to $281/MW during the early afternoon hours in the summer months (Mu=-696 and Sigma=1,251). Thus, even if there are plenty of RRS offers at, for example, $400/MW, the current ORDC translates to ERCOT not being willing to "procure" that RRS at that offer price. Consequently, system reliability could be jeopardized and ERCOT would be non-compliant with NERC standards. This would be the outcome if the current ORDC curve was used as the demand curve to procure RRS in today's DAM or under RTC. However, currently RRS is not procured using the ORDC in DAM or in real-time (as it would be under RTC) and so ERCOT does not face this reliability dilemma, but ERCOT is sending the *wrong* price signal using the current ORDC’s value of “X”.

Regulation Up Service (RUS) Must Be Included in the Value of “X”

The power imbalance that develops between each SCED interval causes frequency deviations that require regulating reserves be deployed to correct frequency to 60.0 Hz. Resources providing regulating reserve should be able to closely follow ERCOT Load Frequency Control (LFC) signal for regulating reserves to be effective. ERCOT on an annual basis determines the MW amounts of Regulation-Up Service (Reg-Up) and Regulation-Down Service (Reg-Down) required to provide adequate regulating service for the system. These Reg-Up requirements would be used to set the demand curves for Reg-Up in Real-Time Co-optimization (RTC) and, as such, should also form the basis of designing the ORDC. ERCOT, on behalf of load, is willing to pay up to the SWOC to meet Reg-Up capacity requirement in order to meet its regulating requirements. In other words, as long as there is capacity available on the system beyond what's required to meet load, ERCOT will acquire the required amount of Reg-Up even if the capacity offer is at the SWOC.

Non-Spinning Reserve Service (NSRS) is a form of Supplemental Operating Reserve and Need Not Be Included in the Value of “X”

In contrast to the RRS and Reg-Up demand curves, Non-Spinning Reserve Service (NSRS) may be viewed as capacity reserve available to provide energy at its corresponding energy offer price to be deployed by Security Constrained Economic Dispatch (SCED) in order to meet uncertainties in demand. Since the Value of Lost Load (VOLL) represents the maximum price load is willing to pay for energy, the demand curve for NSRS should reflect the value of expected unserved energy (VEUE) avoided by the purchase of incremental amounts of NSRS capacity. This is the basis for the design of the ORDC. Unless there is scarcity on the system, ERCOT, on behalf of load, is willing to pay substantially below SWOC for NSRS and diminishing prices with increased supply of NSRS.

The translation of these separate demand curves for each AS in RTC into the current ORDC design that has only one "operating reserve" demand curve is that the value of the Minimum Contingency Level ("X") must be set equal to the sum of the RRS MW requirement plus the Reg-Up requirement in order to reflect NERC reliability requirements.

3 Setting Appropriate Minimum RRS Requirement - Ensures Proper Market Functioning & Price Formation during Scarcity

RRS requirements are not set appropriately to allow market mechanisms to work and for PRC levels to reflect true scarcity. The minimum RRS requirement should be set at 2,750 MW for the following reasons:

1. Due to the 2% HSL Reserve Discount Factor (RDF) applied in calculating PRC, a PRC value of 2,500 MW when ERCOT starts taking out-of-market action translates to RRS capacity of at least 2,750 MW.
2. SCED will dispatch non-frequency responsive capacity (including from expensive QSGR providing on-line NSRS) in order to follow load and try to protect 2,750 MW of RRS.
3. If SCED is unable to maintain 2,750 MW RRS (PRC < 2,500 MW), then it's appropriate to deploy off-line NSRS – ORDC prices should be very high at this stage.
4. Also, it is then very appropriate to declare EEA Step#1 if SCED is unable to maintain PRC at 2,300 MW (about 2,500-2,600MW responsive capacity) and the system is not projected to be recovered above PRC equal to 2,300 MW within 30 minutes.

There's also a reliability reason for setting the minimum RRS at 2,750 MW. The current NSRS can be provided by QSGR offering into SCED that can be dispatched by SCED and not reserved as NERC Contingency Reserve. By setting minimum RRS at 2,750 MW, even if all NSRS is already dispatched by SCED and 1,375 MW of generation trips off (ERCOT's interpretation of BAL-002 Most Severe Single Contingency), ERCOT should still be able to meet BAL-002 and BAL-003 requirements for arresting and returning frequency within given time limits and BAL-002 requirement of having at least 1,375 MW of NERC Contingency Reserves (in the form of RRS) within 90 minutes.

At 15:55 on August 13, 2015, if minimum RRS were set to 2,750 MW, SCED would have dispatched energy from the approximately 1,000 MW of QSGR and other NFRC in order to maintain 2,750 MW of RRS and 344 MW of Reg-Up capacity behind the respective units' High Ancillary Service Level (HASL) and still had an additional 718 MW of QSGR capacity remaining (3,812 MW total capacity[2] - 2,750 MW RRS capacity - 344 MW Reg-Up capacity). Setting minimum RRS at 2,750 MW would maintain PRC at or above 2,500 MW during this time - thus negating the unnecessary deployment of offline NSRS (an out-

[2] 3,774 MW of RTOLCAP divided by 0.99 to account for 1% resource discount factor

of-market action that causes price depression) since sufficient on-line and QSGR capacity was available even without the 300-400 MW of deployed offline NSRS.

Some are suggesting that making NSRS an offline capacity service or requiring QSGR providing NSRS while offering into SCED to commit whenever NSRS is deployed would somehow resolve this issue. The fact is that it would make this issue worse. With RRS requirement still at 2,300 MW, the system would have triggered the deployment of NSRS as it did on August 13, 2015, and even more resources providing NSRS (over 1,300 MW) would be unnecessarily committed with even greater market price suppression. To the contrary, having QSGR providing NSRS offering into SCED can actually help with price formation as long as SCED is instructed to maintain a consistent amount of RRS to not trigger unnecessary out-of-market actions by ERCOT.

4 RECOMMENDED ORDC CHANGES

In order to address the shortcomings in the current ORDC parameters described above, remain consistent with the new NERC reliability standards, allow scarcity pricing mechanisms to function properly, and avoid unnecessary out-of-market price-suppressing action, Calpine recommends the following changes to the ORDC design and Ancillary Service requirement for RRS:

1. **Set the value of the Minimum Contingency Level ("X") equal to the sum of RRS and Reg-Up requirements;**
2. **Set the minimum RRS requirement at 2,750 MW.**

5 PNM IMPACT OF RECOMMENDED ORDC CHANGES

The estimated additional Peaker Net Margin (PNM) resulting from the ORDC with the recommended changes described above using the spreadsheet model provided by ERCOT is $42,675 for the entire period of June 1, 2014, to October 31, 2015. That is approximately $30,124 per year. The market behavioral response that this estimate takes into account is the commitment of available offline units and units providing NSRS when System Lambda plus ORDC price adder is above $75/MWh. Of course, as we have learned from previous backcast estimates of PNM impacts of ORDC, it's difficult to capture market behavioral response to such changes to ORDC design.

According to the Brattle Group, under the current parameters of the energy-only market design in the ERCOT region, equilibrium planning reserve margins are estimated to range from 9 to 13 percent, with an additional year-to-year planning reserve margin variation of approximately 3 percentage points around that equilibrium.[3] The recommended changes to the ORDC would not guarantee or require the maintenance of a minimum planning reserve margin value; however, the changes would be expected to significantly reduce the probability of occurrence of outcomes at the lower end of the range of outcomes estimated by Brattle under the current design.

[3] *Estimating the Economically Optimal Reserve Margin in ERCOT*, The Brattle Group, at 65 (January 31, 2014) (filed in PUCT Project No. 40000, Item No. 649).

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January 4th, 2016

Via Email: ERCOT Supply Analysis Working Group

Subject: Comments regarding ORDC Analysis and Proposals

The LS Power Group ("LS Power") respectfully submits these comments to the Supply Analysis Working Group ("SAWG") and the Electric Reliability Council of Texas ("ERCOT") as part of the on-going analysis of the Operating Reserves Demand Curve ("ORDC"). Such analysis was requested by Commissioner Anderson in his 10-7-2015 memo[1]. LS Power appreciates the opportunity to comment with the objective of supporting adjustments to the ORDC that should provide appropriate incentives to electric generators and provide for a reliable electric grid in the ERCOT wholesale market.

Founded in 1990, LS Power is an independent power producer engaged in the development, acquisition, and management of power generation and electric transmission infrastructure throughout the U.S. LS Power, through its affiliates, is majority owner of the Sandy Creek Power Plant ("Sandy Creek"), which is a 945MW pulverized coal-fired power plant located in Riesel, Texas that began operating in the spring of 2013. Sandy Creek provides valuable benefits in helping ERCOT to achieve resource adequacy and meet energy demand while maintaining fuel diversity and efficiency.

LS Power provides these comments based on its unique perspective and expertise as an independent power producer (IPP). Specifically, LS Power would like to make the following comments:

1. LS Power supports Option 6 and Option 7

LS Power supports the proposals to increase the level of Minimum Contingency Reserves or "X" to equal the Responsive Reserves Service ("RRS") + Regulation Up Service ("RUS"), while also setting a minimum RRS procurement of 2,750MW. Specifically, such proposals are referred to in the 12-16-2015 ORDC Options Whitepaper[2] as Option 6 and Option 7. Adjusting the level of X will reflect the new NERC reliability standard, BAL-003-01 and makes ORDC consistent with Demand curves in Real-Time Co-Optimization, as also noted in the Whitepaper. We believe that resetting the level of X will have the most immediate and positive impact, providing appropriate signals to loads and resources when ERCOT approaches scarcity conditions.

1 http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/40000_667_868214.PDF
2 http://www.ercot.com/calendar/2015/12/16/80832-SAWG

Additionally, LS Power requests that this change to the level of X used in the ORDC be implemented prior to summer 2016, if possible, as it would not require any market rule changes.

2. LS Power supports the continued development of the ORDC, to improve operational reliability and provide appropriate incentives.

While the inclusion of the ORDC as contemplated in Options 6 & 7 over the previous eighteen months has demonstrated the potential to incentivize the correct behavior of resources and load, we feel that it may not adequately provide appropriate incentives and the operational reliability intended by the ORDC may deteriorate over time. This deterioration of operational reliability is likely to become exacerbated particularly when giving consideration to current and proposed environmental regulations impacting electric generating units in ERCOT.

The potential negative impact of market forces and advancing environmental regulations has unintended consequences, particularly on the economics of highly-efficient and fuel-diverse generating units such as Sandy Creek. Such impact could be partially offset by providing more appropriate incentives, through the further development of the ORDC, to reliable and efficient power plants in the ERCOT wholesale market. Therefore, LS Power requests that the ORDC methodology be revisited on an annual basis to allow further refinements and consider changes in the market that may not currently be contemplated. An iterative approach to the development of the ORDC is a positive market signal.

ORDC Parameter Review and Discussion

NRG Comments

The ERCOT region relies on an effective scarcity pricing mechanism to create appropriate incentives for short-term and long-term behavior by resources and loads. The Public Utility Commission of Texas directed the implementation of the Operating Reserve Demand Curve (ORDC) to improve scarcity price formation in ERCOT. In October of 2015, Commissioner Anderson requested review of ORDC performance with an eye towards "minor adjustments" needed to address out-of-market influences.[1] In response to this request, NRG has evaluated ORDC performance and agrees that its implementation has improved scarcity price formation, but also believes modifications are justified to address challenges presented by the current market design, system operation, and various externalities. NRG appreciates the opportunity to review the performance of the ORDC and provide the comments below.

Principles vs. Objectives: Challenges in the ERCOT market

NRG recognizes the difficulty in upholding economic principles in market design while also meeting important, but unrelated objectives. This is especially true in power markets where the necessary influences of operating reliability and other well-intentioned objectives often interfere with rational market outcomes. The urge to avoid the scarcity events that are required to send effective price signals in power markets will never diminish and, therefore, must be managed from a pricing perspective. When reviewing market outcomes since ORDC implementation, NRG observes the impact of out-of-market actions and various externalities on ORDC performance and scarcity price formation. NRG also identifies design features which negatively impact market participation. The following challenges in the ERCOT market are observed:

- Out-of-market reliability actions continue to influence scarcity price formation in ERCOT: As reserves fall below 3,000MW, ERCOT begins to take actions which influence market outcomes (although minor) through the issuance of advisories. However, once reserves reach Energy Emergency Alert (EEA) Level 1 at 2,300MW, ERCOT follows procedures which execute numerous reliability actions that influence prices and reserve levels.[2] Reliability actions are necessary and should be expected, and an effective scarcity pricing mechanism must take all of these actions into consideration.
- ORDC performance and scarcity price formation are also influenced by externalities intended to achieve other objectives: Scarcity price formation and ORDC price performance in ERCOT are significantly influenced by non-market behavior driven by 4CP transmission cost allocation. 4CP demand reduction is not a response to expected or actual real-time energy prices. Instead, it is a methodology to allocate transmission costs in the ERCOT region. ERCOT recently estimated

[1] http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/40000_667_868214.PDF

[2] http://www.ercot.com/content/news/presentations/2015/Energy%20Emergency%20Alert%20Communications%20Matrix%202013_4262013.pdf

average 4CP response to be between 400MW-600MW during peak summer month hours.[3] In addition, Transmission and Distribution Service Providers (TDSPs) procure and deploy Load Management Programs as part of state-mandated energy efficiency programs. In the past, TDSPs in the ERCOT region typically procured over 200MW to fulfill this mandate.[4] Both 4CP and TDSP Load Management Programs are examples of behavior motivated by incentives external to market forces that exert influence on scarcity price formation.

- The ERCOT market is exposed to periods of crippling volatility that has far reaching impacts throughout the industry: A high level of volatility is expected in a well-designed energy market that exhibits scarcity prices which approach the Value-of-Lost-Load (VOLL). However, the ERCOT market possesses other features that exacerbates volatility and impairs liquidity.[5] When considering ORDC design changes, satisfying objectives such as partial mitigation of volatility should be considered.

NRG Proposal

1. Set the ORDC parameter value of X to be 2,500MW in the summer months of June, July, August, and September.
2. In all other months of the year, set the value of X to be 2,300MW.
3. Maintain the value of X as a static number and do not adopt a methodology that varies X.
4. Set the ORDC parameter VOLL to be $18,000/MWh, but maintain the effective price cap at no higher than $9,000/MWh.
5. Increase the minimum Responsive Reserve Service (RRS) procurement amount to be higher than the EEA Level 1 quantity of 2,300MW.
6. Implement these set of changes on June 1st, 2017.

Discussion

Value of X

As explained above, out-of-market actions and externalities significantly influence ORDC performance and scarcity price formation in ERCOT. NRG proposes that the value of X be set no lower than 2,300MW to reflect the heavy influence of out-of-market actions at EEA Level 1 (EEA1). NRG observes that by the time Physical Responsive Capability (PRC) degrades and EEA1 is declared, ERCOT is taking reliability actions to avoid load shed events which substantially influences pricing results. Therefore, sending an effective price signal at EEA1 reflects those actions and motivates the desired behavior.

NRG is also concerned about the impact of externalities on crucial price formation during the summer months. The 4CP transmission cost allocation mechanism results in significant non-market behavior during the four summer months of June, July, August, and September. Trends of increasing transmission

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[3]http://www.ercot.com/content/wcm/key_documents_lists/54223/11.__RMS_PriceResponsiveLoadERCOT_100615.pptx
[4]http://interchange.puc.texas.gov/WebApp/Interchange/application/dbapps/filings/pgSearch_Results.asp?TXT_CNTR_NO=40891&TXT_ITEM_NO=19
[5] http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/40000_421_758185.PDF

costs point to increasing participation in 4CP behavior in the future. In addition, the TDSP Load Management Programs are active in the summer months as well, although they are typically deployed during EEA events.[6,7] Both 4CP and TDSP Load Management Programs are examples of behavior motivated by incentives external to market forces that exert influence on scarcity price formation. To account for these influential factors at critical times in the summer, NRG proposes to increase the value of X to be 2,500MW during the months of June, July, August, and September. Although ERCOT's estimation of 4CP response could justify a value of X higher than 2,500MW (~2700MW-2900MW), NRG is concerned that distortionary effects on energy price from higher levels of X could lead to irrational market behavior. In addition, NRG recognizes that non-market behavior such as 4CP response will fluctuate and therefore a conservative adjustment to X such as 2,500MW is appropriate.

Maintain X as a Static Value

NRG proposes that X be a static value as described above and not vary by hour. Pricing outcomes are highly sensitive to the value of X and intra-day changes to X will cause hourly price swings that could be large, difficult for market participants to manage, and irrational. Price uncertainty resulting from varying the value of X in real-time would therefore negatively impact volatility and should be avoided.

Address Volatility

The current design of the ERCOT market will inherently be accompanied by extreme price volatility during scarcity events. One of the most important objectives to address in this ORDC parameter review is volatility. As noted by Commissioner Anderson, the current shape of the ORDC produces a step change in price as reserves approach the value of X.[8] The market struggles to react to such binary pricing outcomes which contributes to the excessive volatility observed in ERCOT. NRG proposes increasing the VOLL to $18,000/MWh to moderate that step change in the price curve, but agrees that the effective price cap should not be increased and should be no higher than $9,000/MWh.

Increase Minimum RRS Quantity to Force Convergence of PRC and ORDC Prior to EEA1

NRG recognizes that a gap exists between how PRC is measured and how reserves are measured in ORDC. Because out-of-market reliability actions are triggered by PRC levels, it is important to address this gap to ensure the ORDC is sending appropriate price signals at the right times. In the summer of 2015, this gap caused PRC levels to approach EEA1 even though reserve levels in ORDC remained relatively robust. The gap is primarily caused by approximately 1,000MW of Quick Start Resources that were included in ORDC reserves due to their ability to start in 10-minutes, but were not reflected in PRC since they were not actually online. These Quick Start Resource offers typically sit near the end of the SCED offer stack. Because the LMPs produced by SCED were not high enough to dispatch the Quick Starts, they remained offline causing a significant gap between PRC and ORDC reserves even as PRC

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[6] https://centerpoint.anbetrack.com/etrackcnp/PortalOpenfile.aspx?FilePath=http://172.16.2.237:8081/CNP/Production/Miscellaneous/2016%20Commercial%20Load%20Management%20Program%20Manual%20FINAL.pdf
[7] https://drive.google.com/viewerng/viewer?url=https%3A%2F%2Fwww.oncoreepm.com%3A8095%2Feepmdocs%2FPublished%2520Documents%2FApogee%2FCLM%2520Program%2520Manual.pdf
[8] http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/40000_667_868214.PDF

dipped near EEA1. Increasing the minimum Responsive Reserve Service (RRS) quantity above EEA1 would remove capacity from SCED and effectively shift the dispatch order by requiring SCED to exhaust all offers prior to reaching EEA1 (including the Quick Start offers which closes the gap). While increases to the value of X and VOLL are more important and given the lack of a better solution, NRG would support increasing the minimum RRS quantity to above EEA1 (i.e. 2,500MW) to address the gap between PRC and ORDC prior to reaching EEA1. If increasing the minimum RRS quantity is not desired, an alternative to address the gap between PRC and ORDC reserves would be to require Online NSRS to commit during NSRS deployments. However, this approach could introduce price reversal issues that would need to be managed.

Proposed Implementation Date

NRG proposes that any changes to the ORDC be implemented on June 1st 2017. Being only six months away from summer of 2016, Market Participants have already hedged a significant portion of their business and load contracts for the critical summer periods of 2016. Therefore, an implementation date sufficiently in the future and prior to the summer of 2017 would avoid “change in law” provisions in customer contracts potentially coming into play.

TEXAS INDUSTRIAL ENERGY CONSUMERS' COMMENTS
ON ORDC AND QUICK-START ISSUES

Texas Industrial Energy Consumers (TIEC) is invested in the success of ERCOT's energy-only market design, including the ORDC. TIEC would support necessary market modifications to improve market efficiency and increase the accuracy and effectiveness of scarcity pricing. However, after reviewing materials from ERCOT, participating in SAWG meetings, and discussing these issues with other stakeholders, TIEC has not been able to identify any shortcoming in the current market design that requires significant market modifications. If anything, minor changes to the current treatment of quick start units may be appropriate, but the aggressive changes to the ORDC parameters proposed by some stakeholders are unjustified and overreaching given observed market performance.

1. The current market design is performing well. ERCOT and the Commission should foster stability by declining to make additional significant market changes at this time.

ERCOT has seen a tremendous increase in generation investment since the Commission ceased discussing capacity markets and committed to the "energy-only" market design with the addition of the ORDC. This indicates that investors respond to market stability, and will hold off on making investment decisions in periods of regulatory uncertainty. In addition, many market participants entered into long-term bilateral contracts based on the ORDC parameters adopted by the Commission.

The most recent CDR shows that investment signals in ERCOT are robust, with reserve margins well in excess of the current 13.75% target for the foreseeable future. Here it is as a reminder:

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Reserve Margin	16.5%	20.7%	25.7%	22.9%	21.8%	21.1%	19.9%	18.8%	17.7%	16.6%

This demonstrates that the current scarcity pricing regime is adequately incentivizing generation investment, and there is no need for significant changes. Stakeholders and the Commission should allow the current market design to continue working, rather than injecting additional change or creating new uncertainty.

Given these CDR projections, proposals from certain stakeholders to dramatically increase the minimum contingency level (MCL) for the ORDC are unjustified and overreaching. In addition to deviating from the economic principles underlying the ORDC, as discussed below, these changes would cause an unjustified wealth transfer from loads to generators. ERCOT's backcasts indicate that even for the period from June 1, 2014 to October 31, 2015, with relatively mild weather, the most aggressive proposal would have increased peaker net margin (PNM) by more than $80,000, and would have increased the energy- and time-weighted ORDC adder by approximately $10/MWh. In a more extreme weather year such as 2011, ERCOT's analysis indicates that PNM could increase by more than $600,000 relative to the status quo, with corresponding increases to the energy- and time-weighted ORDC adder of more than $110/MWh. While TIEC understands that these backcasts do not account for behavioral changes or certain other variables, the magnitude of these projections indicates that the underlying proposals far exceed any reasonable modifications to our current market design.

With healthy reserve margins projected through 2025, attempts to dramatically increase market revenues by increasing the MCL could spawn over-investment, leading to undesirable market distortions, price suppression, and calls for additional change. Observed market performance does not support a need for these changes.

2. Proposals to increase the MCL are not based on economic principles or sound market design, but an end revenue goal.

The ORDC was adopted to provide the market with a value for reserves and compensate generators for providing these reserves in addition to ancillary service capacity. While the ORDC undoubtedly has an impact on revenue sufficiency, *in principle* it is not meant to target (much less guarantee) any specific level of PNM, aside from what market conditions economically justify. Attempts to engineer an MCL that will produce a certain level of generator revenues are misguided. The ORDC should be designed based on economic principles, and its parameters should be supported by actual data. These parameters should only be revisited if it becomes apparent that the underlying assumptions are inaccurate—for example, the Value of Lost Load (VOLL) or the level at which ERCOT might begin shedding firm load (the MCL).

Other than a contention by some generators that they should be earning greater revenues, there has been no indication that the values used to develop the ORDC have substantively changed since its adoption. Specifically, **there has been no study or other data to support increasing the VOLL beyond the current $9,000 level**. The MCL adopted at the time of initial ORDC implementation—2,000 MW—was already arguably too high, given information that ERCOT does not start actually shedding firm load until reserves are depleted to around 1,200 MW. **There has been no study or other new information to support increasing the MCL above 2,000, much less to 3,000 MW** as certain stakeholders are proposing. These proposals defy any economic rationale and have no principled basis or supporting data. Increasing the MCL or the VOLL simply to reverse-engineer a certain revenue outcome will lead to market distortions and additional volatility. The current market design is working well, and ERCOT and the Commission should let it continue to do so.

3. The ORDC and PRC are two different metrics. Confusion when these values do not converge suggests that market education is needed rather than additional changes to the ORDC.

TIEC generally agrees with the comments submitted by the ERCOT Steel Mills regarding the concerns that have been raised about August 13, 2015. Specifically, TIEC does not find anything surprising or objectionable about divergence in ORDC and Physical Responsive Capability (PRC) reserve values when more than 1,500 MW of quick start units were showing as available reserves for ORDC purposes, but were not physically online and therefore could not count toward PRC. If anything, this information may suggest that EEA deployments should be tied to ORDC reserves instead of PRC, or that ORDC reserves should at least be a factor ERCOT operators can consider before implementing emergency procedures.

Further, as noted by the ERCOT Steel Mills and others, the divergence between PRC and ORDC appears to have been caused primarily by extremely high offers from certain quick start units. Despite climbing prices, a significant portion of the quick-start capacity was not committed (and, therefore, was not counted in PRC) because offers for those units were in the $1,500 to $1,600 range. The ORDC should not be distorted in an effort to produce prices that would have struck these remarkably high offers, which are well in excess of marginal cost.

As the ERCOT Steel Mills accurately noted, the ORDC was properly valuing reserves based on available capacity on August 13, 2015. The divergence was only that the ORDC can see certain offline (but quickly available) reserves that PRC does not. ORDC and PRC were never expected to have full convergence, so TIEC does not see this as a problem warranting any further market changes. If anything, stakeholders may want to consider removing offline quick-start units from SCED and/or requiring physical commitment when non-spin is deployed, as others have suggested.

TIEC appreciates the opportunity to submit these comments and looks forward to further discussion tomorrow.

Direct Energy Comments on the Operating Reserve Demand Curve (ORDC)
January 4, 2016

Direct Energy believes the ORDC is functioning as intended by the Public Utility Commission (PUC) and does not believe significant changes are needed at this time. Data provided by the Independent Market Monitor at the October ERCOT Board meeting indicates that the ORDC is providing a reflection of the value of reserves as the reserves diminish and this change has resulted in an increase of the amount of capacity available in real-time.[1] These results are consistent with advantages of the ORDC discussed by the Commission.[2] Some stakeholders seem to focus on peaker net margin results as indicative of whether or not the ORDC is working as intended. Although peaker net margin is a data point for evaluating investment signals for generation, Direct Energy believes the recent Capacity, Demand, and Reserve Report (CDR) issued by ERCOT is an overriding data point that indicates the ERCOT market currently has more than adequate reserves for the next several years.[3] Therefore, Direct Energy does not believe there is a compelling reason to consider changes to the ORDC that could significantly increase energy prices.[4]

Direct Energy is unwilling to agree to changes that could significantly increase energy prices without clear direction from the PUC that significant changes are needed to address resource adequacy concerns. Regulatory certainty is important to Retail Electric Providers and retail customers. As described above, Direct Energy does not believe the data indicates there is an urgent problem that necessitates near term changes that create regulatory uncertainty. Any significant changes to the ORDC implemented prior to summer 2017 would unnecessarily harm Retail Electric Providers and retail customers that have already made commercial decisions based upon the current ORDC market design. If the Commission determines that significant changes designed to increase scarcity price signals are needed, then Direct Energy believes potential solutions should be thoroughly discussed and ultimately decided by the PUC. A final decision by the PUC should occur at least 12 months prior to the implementation of the changes to allow market participants adequate time to incorporate changes into future contracts and minimize impacts to current contracts.

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[1] Independent Market Monitor Report to the Board, October 2015
http://www.ercot.com/content/wcm/key_documents_lists/76342/6_IMM_Report.pdf

[2] Memo from Commissioner Anderson to Chairman Nelson Dated August 28, 2013.
http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/40000_451_765682.PDF

[3] ERCOT Capacity, Demand, and Reserves Report – December 2015
http://www.ercot.com/content/gridinfo/resource/2015/adequacy/cdr/CapacityDemandandReserveReport-December2015.pdf

[4] ERCOT December 15, 2015 SAWG ORDC Options Analysis
http://www.ercot.com/content/wcm/key_documents_lists/80833/20151216_SAWG_ORDC_Options_Analysis.pptx

Examining the performance of the ORDC and potential enhancements

Submitted to the Supply Analysis Working Group (SAWG)

By

Shell Energy North America (SENA)

Introduction:

In response to a memo issued by Commissioner Anderson, SENA has participated in the ERCOT stakeholder forums to consider the performance of the ORDC and any potential enhancements. Variables specifically mentioned in the memo include (1) the value of X, (2) the number of standard deviations used to formulate the loss of load probability curve (LOLP), (3) correlation between operating reserves and PRC, and (4) are the current inputs used to calculate the LOLP a sufficient approximation or should the methods and approximations be re-evaluated. ERCOT stakeholders, by way of participation in SAWG, expanded this list to be more comprehensive of potential ORDC changes and enhancements.

SENA concurs with Commissioner Anderson: the ORDC has altered behavior of resources and load. The ORDC, coupled with an increase in the System-wide Offer Cap, has encouraged loads to avoid exposure to high prices. SENA suspects that this risk aversion and associated hedging ultimately encourages correct behaviors, but attenuates the scarcity events that ERCOT's energy only marketplace depends upon for resource adequacy.

Price signals to support resource adequacy, however, seldom materialize. In addition to the market behavior changes described above, price responsive distributed generation continues to attenuate prices in real-time. Regardless of the cause, ERCOT's energy-only marketplace has not delivered sufficient scarcity pricing to sustain resource adequacy. The ORDC was designed to deliver sufficient scarcity pricing to achieve an economical target reserve margin. Forward price curves in ERCOT do not provide sufficient economic returns to sustain new construction of dispatchable generation. If ERCOT is to maintain the long-term success of the energy-only marketplace, then modification to the ORDC is critical. SENA believes that reconsidering the inputs and operation of the ORDC may provide improved scarcity pricing events when resource shortages play out in real time.

To support this effort, SENA briefly discusses modifications to (1) the value of X, (2) increasing the value of lost load variable while maintaining the system-wide offer cap, and (3) accommodating price-responsive distributed energy in a SCED dispatch.

Discussion:

Establishing the Value of X

SENA believes that the value of X should be set to a level sufficiently high to precede ERCOT market intervention to preserve reliability. SENA believes that a value of X between 2700 and 3000MW would (1) introduce more frequent scarcity events, and (2) more accurately reflect the real-time value of a reserve. Accordingly, it is appropriate to escalate the ORDC curve as reserves are depleted to a minimum contingency level prior to ERCOT's intervention to preserve reliability. ERCOT may take action when PRC is less than or equal to 2500MW, and declares an EEA at PRC levels less than or equal to 2300. These actions deliver emergency reserves to the system through an out-of-market action, which can deprive the market of a price signal when it is most needed. SENA believes the value of X should escalate the value of reserves prior to reliability intervention.

Consider increasing VOLL above SWOC

Price oscillation leading up to and following scarcity events is not easily managed by wholesale market participants. Offers at the 'top' of the stack in ERCOT vary greatly in both volume and price. Accordingly, price formation is not necessarily smooth as ERCOT enters or exits a scarcity event. Increasing VOLL above SWOC would accelerate the onset of scarcity, and potentially smooth price formation. SENA supports increasing VOLL above SWOC, provided that SWOC remains unchanged.

SENA strongly believes that prices should remain capped at SWOC. The existing $9,000 price cap aggressively encourages hedging from load participants. Higher levels of SWOC would further escalate the financial penalties for a real-time short position, and discourage marketers from offering the much desired load hedge. Similarly, the penalty for a resource contingency becomes increasingly crippling at and beyond $9,000 / MWHr.

Accommodate and encourage price-responsive distributed resources to participate in a SCED dispatch

SENA strongly believes that the existing portfolio of price-responsive distributed resources reduce prices during potential and realized scarcity events. These fossil-fueled resources are currently paid their load-zone price for net injections to the system. As load-zone prices sufficiently exceed the marginal cost of a fossil fueled reciprocating engine, distributed generation delivers to the ERCOT system. ERCOT's SCED system recognizes the DG response to price as a reduction in load, rather than a marginal resource serving system load. Accordingly, the SCED-observed reduction in load reduces prices.

SENA asserts that this is a rationale economic outcome, where load represents their willingness to consume *from ERCOT* as a function of *ERCOT price.* However, this is distinctly different from a curtailment. Price responsive resources are compensated when they inject (in excess of their load) to the ERCOT grid. Their contribution to the grid is an act of serving load, rather than reducing it. These resources, when injecting in response to price, should be modeled as a resource and reflect their willingness to sell as an offer in SCED. To do so would improve price formation in times of scarcity, rather than reduce it.

As noted in the previous paragraph, hundreds of megawatts of distributed generation are responding rationally to the ERCOT market design, which lacks a mechanism for DG to offer energy in a fashion that preserves price formation. SENA believes that much of the needed improvement to ORDC performance is tied to this market design flaw, where DG is encouraged to generate when load zone prices exceed their marginal cost. This is challenging for DG resources and market participants: DG can actually reduce their own price if they sufficiently reduce ERCOT system load when generating.

SENA believes that if the ORDC is to compensate for this less-than-ideal market feature, then DG location and participation should be carefully cataloged and transparent to market participants, such that the true impact of price responsive DG can be modeled and built-in to the ORDC enhancements. SENA believes that equitable opportunities for DG to participate in wholesale markets by way of a SCED dispatch would be more effective.

Conclusion:

SENA appreciates the opportunity to opine on improving the performance of the ORDC. As illustrated above, modifications to the value of X and VOLL will undoubtedly improve the performance of the ORDC and potentially limit the need for out-of-market intervention. Other features, such as improved SCED dispatch of price-responsive distributed generation will undoubtedly improve price formation in times of scarcity. These changes are critical to the preservation of the energy-only marketplace, which has yet to deliver revenues that support sustainable development of dispatchable resources. SENA will actively support further ORDC improvements, and appreciates ERCOT stakeholder and/or PUC direction on these issues.

POSITION PAPER ON ORDC OPTIONS WHITEPAPER

Apex CAES, LLC, Calpine Corporation, First Solar Inc., GDF Suez Energy Marketing North America Inc., Lower Colorado River Authority, Luminant Energy Company LLC, SunEdison Inc., SunPower Corporation, and Talen Energy (collectively, "Coalition members") appreciate the opportunity to review and evaluate the performance of the Operating Reserve Demand Curve (ORDC) and to support certain adjustments that the Coalition believes are necessary to ensure continued robust wholesale participation in ERCOT's energy-only market design.

The Coalition members agree with Commissioner Anderson's memo[1] that since the ORDC has been in effect, it has improved operational reliability by providing an incentive to loads to hedge forward, and an incentive to resources to be available during peak hours. However, Coalition members believe that the ORDC's *pricing* signals are not correct. Modifications to the ORDC will help to address the concern that Commissioner Anderson observed: that during certain days in August of 2015, the ORDC adder did not seem to appropriately reflect the operational scarcity that ERCOT experienced.

In an energy-only market it is vital that energy prices accurately reflect system conditions, especially as operating reserves are being depleted. In ERCOT, the ORDC has improved scarcity price formation, but additional adjustments are necessary to ensure that prices align with operational realities, and to improve convergence between the Day-Ahead and Real-Time markets.

I. Proposal

Modifications to the ORDC should have two primary objectives: first, the probability of reserves falling below the minimum contingency level, referred to as the PBMCL, should be established with the minimum contingency (i.e., "Value of X")[2] set at a number that values and maintains contingency reserves under steady state conditions, and second, the ORDC should be modified to create a more efficient pricing outcome for the market. Focusing on these objectives will address the concerns raised in Commissioner Anderson's memo, by better aligning the ORDC reserves (Real-Time On-Line Capacity, i.e., RTOLCAP) with Physical Responsive Capability (PRC) during scarcity and by developing pricing signals that both loads and resources can respond to before emergency conditions develop.

A. Adjust Ancillary Services Procurement to Establish a Floor of 2,750 MW of Responsive Reserve Service in Each Hour

The Coalition members have evaluated the ORDC parameters and the events from August 2015, and recommend first, that ERCOT amend the Nodal Operating Guides and the Ancillary Services Methodology to establish a minimum procurement of Responsive Reserve Service (RRS) at 2,750 MW in

[1] *Commission Proceeding to Ensure Resource Adequacy in Texas*, P.U.C. Project No. 40000, Commissioner Anderson Memo, Item 667 (October 7, 2015).

[2] *Methodology for Implementing Operating Reserve Demand Curve (ORDC) to Calculate Real-Time Reserve Price Adder*, pg.1 (October22, 2015), available on ERCOT's website at: http://www.ercot.com/mktinfo/rtm/kd/Methodology%20for%20Implementing%20ORDC%20to%20Calculate%20Real-Time%20Res.zip

each hour. One of the direct benefits of procuring at least 2,750 MW of RRS is that it will ensure that SCED can work to deploy all market reserves, including Non-Spinning Reserve Service (Non-Spin), before ERCOT depletes its frequency responsive reserves to a level that triggers emergency conditions. As a result of direction from the PUC, from April 2012 through June 2015, ERCOT transferred 500 MW from the minimum Non-Spin requirement to the minimum RRS requirement, resulting in the procurement of 2,800 MW of RRS in each hour.[3] The benefit of that change, as described by Commissioner Anderson in his November 10, 2011 memo, was to "signal[] scarcity more quickly, ideally before ERCOT begins to release Emergency Alerts."[4] We agree, and the Coalition members' proposal to set the minimum RRS requirement at 2,750 MW in each hour will provide that same benefit.

Making this change will also automatically result in a better convergence of RTOLCAP and PRC as scarcity conditions develop. Because PRC measures only frequency-responsive reserves, and because RRS must be frequency responsive, ERCOT will be able to deploy all other on-line reserves and quick-start reserves through SCED before PRC drops below 2,750 MW and before ERCOT declares an Energy Emergency Alert.

This change would also be consistent with ERCOT's long history of planning for the simultaneous loss of two nuclear units as a single contingency for determining the amount of RRS to purchase and for ERCOT's Real-Time Contingency Analysis. Since at least 2002, as far back as ERCOT has public records on its website, the ERCOT Board has approved a minimum purchase of RRS "derived based on studies done in the past to determine the amount of Responsive Reserve that might be required to prevent the shedding of firm load upon the simultaneous loss of the two largest generation units in ERCOT."[5] At that time, the two largest generation units in ERCOT were South Texas Project Units 1 & 2, with approximately 2,300 MW gross capacity. In more recent years, both South Texas Project Units and Comanche Peak Units 1 & 2 have undergone a series of component upgrades that have increased their output by several hundred megawatts. Thus, it makes sense to re-align the minimum RRS value with the current simultaneous loss of the two largest generation units in ERCOT. This would also make RRS procurements match the values that ERCOT uses for its Real-Time Contingency Analysis, which evaluates the simultaneous loss of the two STP units as a credible single contingency, so that ERCOT's Security Constrained Economic Dispatch (SCED) manages dispatch to ensure that ERCOT can reliably serve load even if that contingency occurs.

Finally, ERCOT's RRS procurement needs to adequately protect grid reliability in the conditions expected in the future. One important consideration that must be accounted for is the significant increases in non-synchronous wind generation that ERCOT has experienced since the build-out of the Competitive

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[3] *See* "2012 ERCOT Methodologies for Determining Ancillary Service Requirements," adopted by the ERCOT Board on February 21, 2012, and available on ERCOT's website at: http://www.ercot.com/calendar/2012/2/21/33724-BOARD

[4] *Commission Proceeding to Ensure Resource Adequacy in Texas*, P.U.C. Project No. 40000, Commissioner Anderson Memo, Item 64 (November 20, 2011).

[5] *See* "2003 ERCOT Methodologies for Determining Ancillary Service Requirements," adopted by the ERCOT Board on October 15, 2002, and available on ERCOT's website at: http://www.ercot.com/calendar/2002/10/15/41199-BOARD.

Renewable Energy Zones. According to ERCOT's most recent Capacity Demand and Reserves Report, ERCOT has 15,035 MW of installed wind capacity currently, and expects to add 9,810 MW of installed wind capacity by the peak season of 2017 – a 65% increase in just two years.[6] ERCOT has also repeatedly broken records in 2015 for increasing the amount of load served by wind; the most recent set on November 16, 2015, when the actual average wind penetration for the entire day was 32%.[7] These resources along with all thermal resources, except the marginal unit and units reserving RRS, typically operate at or very near their HSL and as a result will not contribute governor-like primary frequency response on peak, absent local congestion. As wind generation increasingly replaces thermal generation on the system, less frequency responsive generation will be available to help the system recover from contingency events. Moreover, ERCOT's methodology for determining RRS obligations yields the lowest values during the summer super-peak hours: the average obligation for Hours Ending 15-19 for June through September in 2016 is 2,493 MW. This methodology assumes a very high participation in RRS supply by load resources based on the previous year's hourly participation rates. However, on days when the system is likely to set a Coincident Peak (e.g., temperatures are forecasted to be very hot across the system), many load resources choose to not participate in the RRS market in order to reduce load voluntarily to avoid future transmission charges, which are based on demand during the highest four Coincident Peak intervals during the summer. Establishing a minimum RRS obligation of 2,750 MW would help to mitigate these issues by ensuring more availability of frequency responsive reserves during peak hours.

B. Set the Minimum Contingency Value for the Operating Reserve Demand Curve to Equal the Sum of Responsive Reserve Service and Up Regulation Service

The Coalition members recommend setting the Value of X in the PBMCL calculation for the ORDC to equal the sum of RRS and Up-Regulation Service (URS) that ERCOT is buying each hour, to reflect their critical reliability reserve importance. In effect, the contingency constraint provides a vertical demand curve that adds horizontally to the probabilistic operating reserve demand curve. Because ERCOT must maintain RRS and URS reserves for reliable system operation, and URS is reserved from SCED dispatch, it is important that the ORDC reflect their value. Setting the Value of X equal to the sum of RRS and URS will create the opportunity for market prices to reflect the reliability value of the reserves, and will protect those reserves from being deployed at discounted prices during steady state conditions to serve energy demand. It also allows for scarcity price formation to occur while ERCOT protects those reserves.

The current minimum contingency value of 2,000 MW allows the potential for deploying RRS and URS when real time prices are approximately 25% of the System Wide Offer Cap (SWOC). Because these reserves are purchased and maintained for reliability, prices should reflect scarcity conditions before the reliability reserves are depleted and ERCOT is in emergency conditions.

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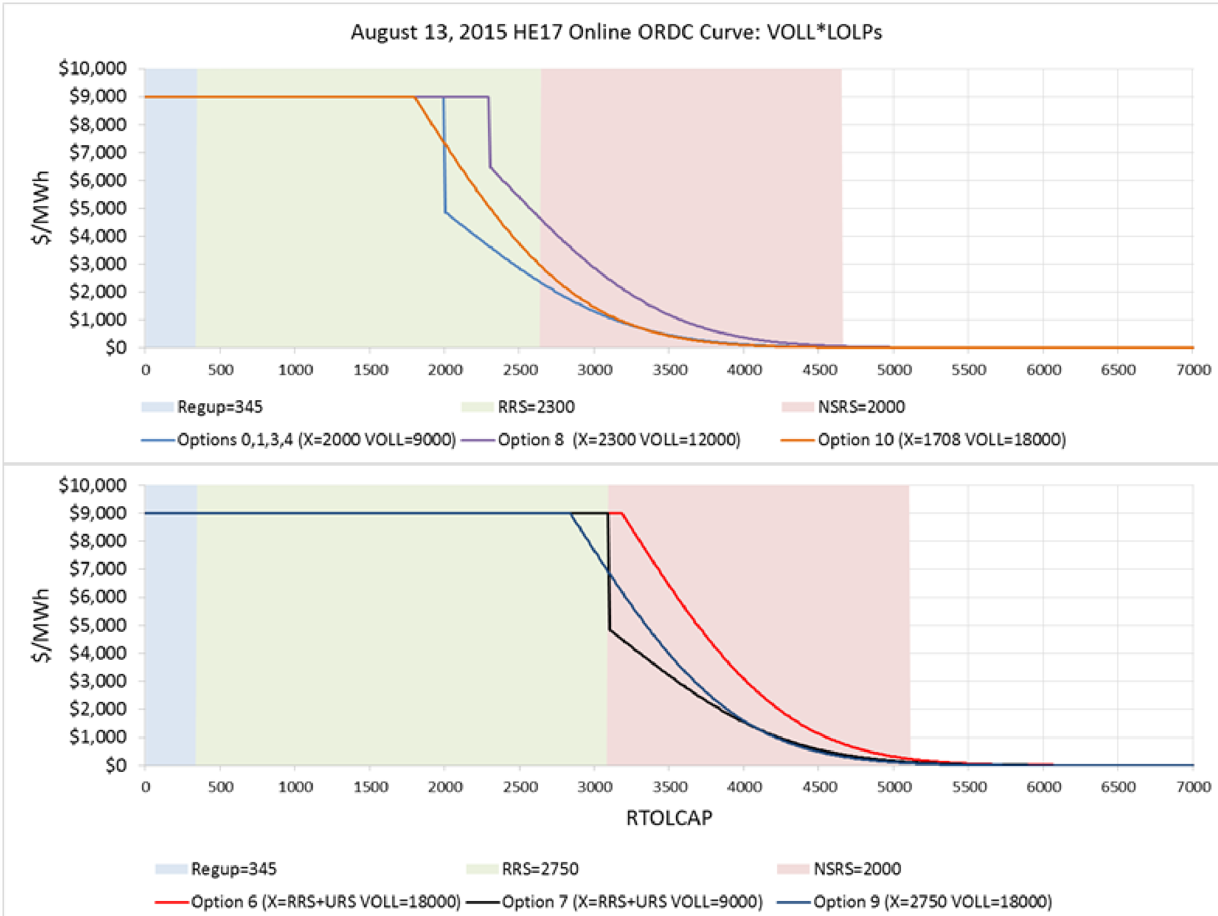
[6] *See* "Report on the Capacity, Demand and Reserves (CDR) in the ERCOT Region, 2016-2025," (December 1, 2015), available on ERCOT's website at: http://www.ercot.com/content/gridinfo/resource/2015/adequacy/cdr/CapacityDemandandReserveReport-December2015.pdf

[7] *See* "CEO Update," (December 8, 2015), available on ERCOT's website at: http://www.ercot.com/content/wcm/key_documents_lists/76324/4.1_CEO_Update.pdf.



As illustrated in the chart above,[8] making the Value of X equal the sum of RRS and URS will reestablish the principle that the Commissioners recognized back in 2011 – when they set the offer floor for RRS and URS at the System-Wide Offer Cap – namely that prices should reflect the reliability actions that ERCOT takes to maintain the system.

The Coalition members' proposal to make the value of X equal the sum of RRS + URS will ensure that these critical operating reserves will not be compromised at price levels below the SWOC.

C. Mitigate the Abrupt Price Escalation in the ORDC

Under the current ORDC, where the Value of Lost Load (VOLL) and SWOC are both $9,000/MWh, the ORDC has a sharp "knee" that drives the price from $4,500/MWh to $9,000/MWh with the loss of one megawatt of capacity. The Coalition members recommend making changes to the ORDC parameters in order to achieve a smoother transition of prices up to the SWOC during scarcity events.

There are various ways to tackle this issue, including by increasing the Value of Lost Load (VOLL) in the ORDC calculation while capping effective prices at SWOC. Alternatively, the Loss of Load Probability

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[8] Extracted from "ORDC Options Analysis," p. 27 (December 16, 2015), available on ERCOT's website at: http://www.ercot.com/content/wcm/key_documents_lists/80833/20151216_SAWG_ORDC_Options_Analysis.pptx).

(LOLP) calculation can be modified, or the ORDC could use a linear function as an approximation of LOLP.

The lack of a smoother transition of prices impairs the ability of market participants to respond to scarcity price signals, so Coalition members recommend that VOLL be increased to $18,000/MWh while effective energy prices continue to be capped at $9,000/MWh, or that some other modifications be made to achieve a less binary ORDC.

D. Add the Operating Reserve Demand Curve to the Day Ahead Market

The Coalition members also recommend adding the ORDC to the ERCOT Day Ahead Market (DAM) to match the Real-Time Market (RTM) ORDC. The original ORDC proposals included adding an ORDC to both the DAM and RTM.[9] In order to expedite implementation, however, the ORDC was only established for the RTM.

Adding the ORDC in the DAM will make it easier for ancillary services prices to converge with ORDC prices between the DAM and RTM, especially during periods of scarcity. During periods of extreme scarcity in the DAM, when an insufficient amount of RRS is offered, having an ORDC in the DAM will allow RRS to rise to the price cap, and ensure that ERCOT can purchase adequate reserves by making resources indifferent to potentially higher prices in the RTM. Stakeholders discussed adding the ORDC in DAM when designing ORDC in 2013, and it was concept that many stakeholders wanted to revisit once the market had operational experience with ORDC in the RTM. Discussion of implementing the ORDC in the DAM is timely and consistent with good market design principles.

Second, adding the ORDC to the DAM will allow the markets to more effectively value incremental ancillary services capacity and appropriately reflect the vertical demand curve for those high quality reserves that ERCOT must procure for reliability (RRS and Up Regulation Service). The California Independent System Operator, the Midcontinent Independent System Operator, the PJM Regional Transmission Operator, the New York Independent System Operator and the Southwest Power Pool each have a demand curve for ancillary services in both their day-ahead and real-time markets. Without adding a demand curve for ancillary services to the DAM, the market is reliant on the offers and bids of market participants to set clearing prices, whereas adding the ORDC to the DAM will act as a penalty function that will appropriately value reserves when energy shortages are expected in Real-Time.

Adding ORDC to the DAM sequence, while a significant improvement in seeking convergence between the DAM and RT sequence pricing outcomes, can certainly be viewed as an independent recommendation that can be implemented simultaneous with or following our other recommended changes.

[9] *See* "Back Cast of Interim Solution B+ to Improve Real-Time Scarcity Pricing," available on ERCOT's website at http://www.ercot.com/content/gridinfo/resource/2013/mktanalysis/White_Paper_Back%20Cast%20of%20Interim%20Solution%20B+%20to%20Improve%20Re.pdf. ("Implementing this proposal in Real-Time will require a change to the DAM to incorporate an ORDC in order for the markets to converge").

II. Results

A. Revenue Impacts of Proposal

ERCOT has evaluated the impacts of the Coalition members' proposal (represented by a combination of Options 2 and 6) in its back cast analysis.[10] The average annualized increase in Peaker Net Margin (PNM) that would have been expected from the proposal is $47,195/MW-year.[11] The total PNM actually achieved in 2014 was just under $47,000/MW-year and in 2015 is trending below $30,000/MW-year.[12] Thus, even if generators realized all of the incremental PNM calculated in ERCOT's analysis,[13] the total PNM would still have been just within range in 2014 and significantly less in 2015 than the $90,000 - $116,000/MW-year that generation developers must expect to earn *on average over many years* in order to justify building a simple cycle gas-fired combustion turbine.[14] Perhaps more relevant, the average energy price would have increased to $40.15/MWh for On-Peak hours and $22.09/MWh for Off-Peak hours. These are not excessive prices, even in a relatively mild weather year, in an energy-only market.

B. It is Inappropriate to Predict Outcomes Based on 2011 Data

The model back cast using system load and weather data from the time period where ORDC has been in place is the only relevant analysis. Some market participants requested that the scenarios be modeled by ERCOT using load and weather data from 2011. The outcome of ERCOT's analysis using data from that extreme "black swan" weather year yielded hyperbolic results.[15] The objective function of running modeling scenarios is to better approximate the expected incremental impact on PNM from the different scenarios. The 2011 data results are not useful for this purpose because the market structure was quite different in 2011, including that there was no ORDC in place. Attempting to adjust for these

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[10] *See* "ORDC Options Analysis," (December 16, 2015), available on ERCOT's website at: http://www.ercot.com/content/wcm/key_documents_lists/80833/20151216_SAWG_ORDC_Options_Analysis.pptx).

[11] Because there is only 17 months of available data, Coalition members annualized the data and averaged it between two years. In comparison, the annualized incremental PNM for options 7, 8 and 9 yielded only $27,932/MW-year, $2,366/MW-year, and $21,742/MW-year, respectively. Options 4 & 10 would have reduced PNM from the ORDC as compared to that achieved with the current parameters.

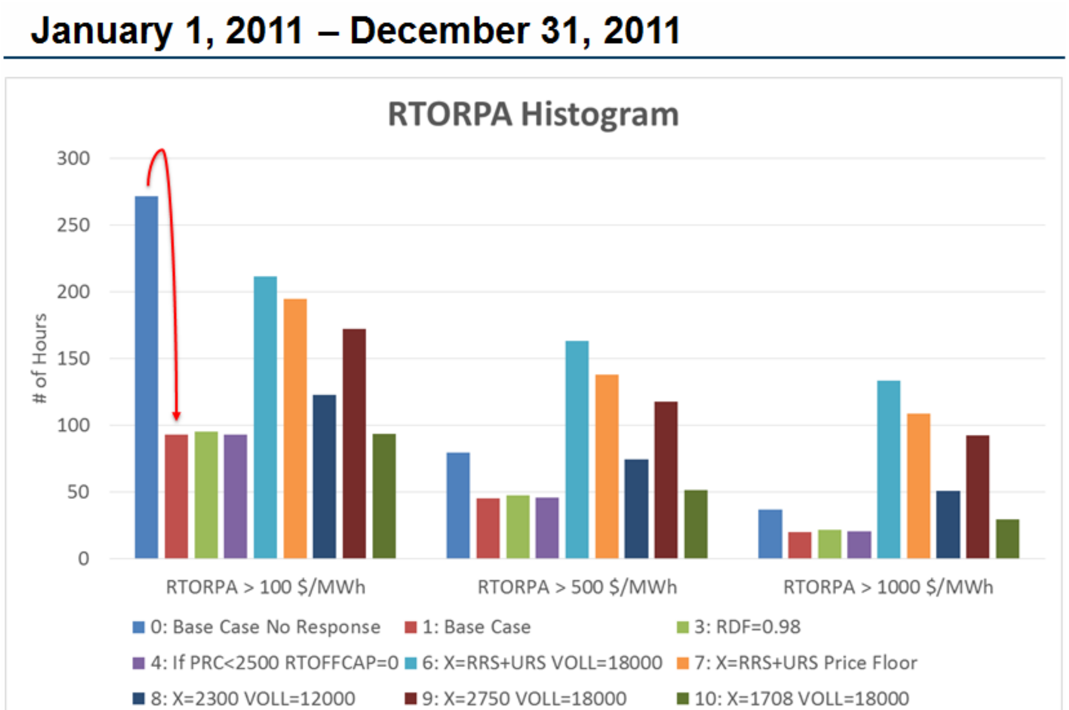
[12] *See* Potomac Economics, "ERCOT Wholesale Electricity Market Monthly Report," (November 17, 2015), available on ERCOT's website at:
http://www.ercot.com/content/wcm/key_documents_lists/76324/5_IMM_Report__PUCT_.pdf.

[13] Although ERCOT has created a sophisticated tool, it is difficult to capture the complete impact of market participants' behavioral changes in a back cast. It is likely that competitive forces will work to eliminate excess ORDC revenues in all but a few hours each year, when resources are truly scarce.

[14] *See* The Brattle Group, "ERCOT Investment Incentives and Resource Adequacy," pp. 48, 54 (June 1, 2012), available on ERCOT's website at:
http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/Brattle_ERCOT_Resource_Adequacy_Review_2012-06-01.pdf.

[15] Philip Oldham, on behalf of Texas Industrial Energy Consumers, represented that 2011 weather was a "black swan" event in the market. *See* "Finding the 'Sweet Spot' to Solve Texas' Resource Adequacy Concerns," quoting Mr. Oldham, and available at: http://www.poweracrosstexas.org/finding-the-sweet-spot-to-solve-texas-resource-adequacy-concerns-full-report/

differences is nigh impossible. The graph below[16] demonstrates this point, by illustrating that even in 2011 there were a number of hours where there was additional capacity that could have been committed (the reduction of RTORPA hours between Scenarios 0 and 1 is a result of the model committing additional available offline generation), if the ORDC pricing and incentive structures had existed in 2011.



Furthermore, it should be noted that if market participants are concerned about the risk of financial impacts from an event similar to the extreme weather of 2011, it must follow that ERCOT should also be concerned about the potential reliability impacts of such an event, which would be similarly severe. The Coalition members' proposed changes are intended to support better alignment between prices and operational realities and to improve convergence between the DAM and RTM. In promoting a more efficient and competitive market these recommendations will also support a market that is responsive to any future reliability needs. Thus, to the extent that market participants are concerned about the recurrence of events similar to those experienced in 2011, these recommendations will help mitigate the potential reliability concerns associated with such events.

II. Conclusion

The Coalition members appreciate the opportunity to provide input on this important issue and believe that the modifications to the ORDC proposed above will appropriately value ERCOT's contingency

[16] Extracted from "ORDC Options Analysis," p. 18 (December 16, 2015), available on ERCOT's website at: http://www.ercot.com/content/wcm/key_documents_lists/80833/20151216_SAWG_ORDC_Options_Analysis.pptx).

reserves under steady state conditions, and will create a more efficient pricing outcome for the market. This proposal will address the concerns raised in Commissioner Anderson's memo, by better aligning the RTOLCAP with PRC during scarcity and by developing pricing signals that both loads and resources can respond to before emergency conditions develop.