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PROJECT NO. 52373

REVIEW OF WHOLESALE ELECTRIC MARKET DESIGN

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§137.55 ENGINEERS SHALL PROTECT THE PUBLIC

(a) Engineers shall be entrusted to protect the health, safety, property, and welfare of the public in the practice of their profession.

Texas Engineering Practices Act

References:

1. Wakeland, Richard, *The ERCOT ORDC Under-Estimates the LOLP Because of a Misapplication of Normal Distribution Probability Theory* (May 18, 2018). USAEE Working Paper No. 18-343, Available at SSRN: https://ssrn.com/abstract=3180714 or http://dx.doi.org/10.2139/ssrn.3180714

2. Wakeland, Richard, *Fundamental Problems with ERCOT's Operating Reserve Demand Curve and a Proposed Solution* (June 9, 2018). USAEE Working Paper, Available at SSRN: https://ssrn.com/abstract=3193493 or http://dx.doi.org/10.2139/ssrn.3193493

Comments to questions pertaining to Project 52373 – Review of Wholesale Electric Market Design

> "Consequently, replacing the ERCOT ORDC LOLP methodology with one that satisfies [Boundary Condition #2: When the reserve level is zero the loss of load probability is 1.0] will satisfy Hogan's identified criteria: (1) produce a much better first principles based ORDC design, (2) better fill the gap between scarcity prices and those arising from demand bidding alone, (3) further address in part the missing money problem, and (4) provide the benefit of improved operating conditions."[1]

I. How to increase revenue for generating units by changing the Operating Reserve Demand Curve (ORDC).

Question 1a: What specific changes, if any, should be made to the ORDC to drive investment in existing and new dispatchable generation?

Answer:

The existing methodology for determining an ORDC is mathematically incorrect and should be replaced.

The existing methodology for determining an ORDC should be eliminated. It is not based upon first principles because of the application of incorrect data to compute the Loss of Load Probability (LOLP).[2] The methodology used to create an ORDC should have a true first principles basis. The errors in the existing ORDC are worse than an underestimation; a mathematical fiction is created that coupled with a mathematical error has resulted in significant underpayment (approximately 55% less) over the life of the ORDC (since 2014) than a correctly calculated LOLP would have produced.

A first-principles based approach to constructing an ORDC should be employed.

When constructing an ORDC using first principles it is necessary to understand and utilize correct boundary conditions. The ORDC is, as its name implies, a curve. Boundary conditions are conditions that we place on the curve such that the curve must satisfy the conditions we impose on it. For instance, it is reasonable to say that if ERCOT were to have an infinite amount of operating reserve at any given moment in time, the ORDC should not contribute one penny of adder to the market price of energy during that moment of time because a loss of load (LOLP = 0.0) could not occur. This establishes boundary condition #1.

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[1] Wakeland, Richard, *The ERCOT ORDC Under-Estimates the LOLP Because of a Misapplication of Normal Distribution Probability Theory* at 12 (May 18, 2018). USAEE Working Paper No. 18-343, Available at SSRN: https://ssrn.com/abstract=3180714 or http://dx.doi.org/10.2139/ssrn.3180714. In these filed comments Boundary Condition #2 is identical to Corollary #1 found in note 1.

[2] Wakeland, Richard, *Fundamental Problems with ERCOT's Operating Reserve Demand Curve and a Proposed Solution* (June 9, 2018). USAEE Working Paper, Found at SSRN: https://ssrn.com/abstract=3193493 or http://dx.doi.org/10.2139/ssrn.3193493

Boundary Condition #1: When reserve level is infinite (or very large) the LOLP is zero and the ORDC should add zero dollars to the price of energy.

Likewise, should ERCOT find itself in a condition where there was zero operating reserve, the ORDC should contribute the difference between the system wide offer cap (SWOC) and the current market price of energy. The current ORDC doesn't do this because of yet another mathematical error. The LOLP is incorrectly calculated underestimating the LOLP by roughly a factor of two (calculating the LOLP to be roughly half of what it should be, thus underestimating the LOLP).[3] This means the ORDC has underpaid responsible generating capacity since its inception by 50%. This principle (and it is a very critical principle) establishes boundary condition #2.

Boundary Condition #2: When reserve level is zero the LOLP is equal to 1.0 and the ORDC should bring the total cost of energy up to the SWOC. As reserve level approaches zero the LOLP must approach 1.0.

A way to think about this boundary condition, with a different wording, is this: If reserve level is zero, any tiny amount of increase in load, or any tiny amount of loss of generating capability, will result in a loss of load. Therefore, the probability of a loss of load is 100%, or 1.0 when reserve level is zero.

With these two boundary conditions, it would be possible to construct a curve for the ORDC. We would just draw a straight line between the two points (a straight line is a curve!). This would be a poor approximation to the LOLP however. It is easy to rationalize that as operating reserve gets closer and closer to zero, the LOLP increases at an increasing rate, not just that of a straight line. In fact, it increases at an exponential rate as operating reserve decreases (or approaches zero). Therefore, it makes sense to use an exponential curve to represent the LOLP. Since many, many exponential curves can be fitted between the two endpoint boundary conditions, who is to say which one of the many should be used? This logic points to the need for a third boundary condition. A point that the curve must pass through (or very near) somewhere between infinity (or a large reserve level) and a reserve level of zero.

*Boundary Condition #3: A point between zero reserve level and a very large reserve level (i.e., somewhere in the middle) where there is **a known effect** on the market price of energy.*

If there is a reserve level that we can associate with a parameter that is mathematically calculated from historical prices in ERCOT, then we can establish a third boundary condition and *it will be first principles based!* The proposed solution in Note 2 does just that to establish the third boundary condition.[4] The third boundary condition in Note 2 is established by determining the reserve level where the change of ERCOT's system lambda (system lambda = roughly the average price of energy in ERCOT) divided by the change in reserve level equals -1.0. In mathematical terms, it is where the slope of the system lambda (Y value) vs. reserve level (X value) equals -1.0. Using actual ERCOT data it can be calculated how the reserve level changed as the price changed

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[3] Note 1 at 8.

[4] Note 2 at 17.

over a given time-period. This is the ***known effect*** described in the third boundary condition. Feel free to call with questions at any time.

To determine the reserve level where this slope is equal to -1.0 Note 2 only uses data from 2015 and Note 2 doesn't (on purpose) disclose the reserve level at which point the boundary condition is met.[5] I specifically did not disclose the reserve level point because I felt it was important for ERCOT market participants to decide if they wanted to correct the failings of the ORDC without the knowledge of how the curve would be affected. Some market participants would see their costs go up (or down) and some market participants would see their revenue go up (or down). Polarization would take place and the change in the ORDC would be doomed at the outset.

Note 2 offers up a first principles-based curve for the ORDC that meets these three boundary conditions.

What was the value of the third boundary condition (the reserve level at a slope of -1.0) that was withheld in Note 2?

The reserve level using above-described method was calculated to be 3,100 MW. It was determined from over 105,000 data points from ERCOT for 2015 system lambda and reserve level and a least squares curve fit to determine where the slope of the line matched the criteria (a slope of -1.0) at what reserve level (3,100 MW was the determined result). 3,100 MW has never been disclosed until now. Does this mean more money paid out or less? It means a lot more. Have I calculated how much? No. Can it be calculated easily? Yes (with some caveats).

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[5] Note 2 at 19 and 22. See also Figure 9 at 19.

How would the proposed solution compare with an actual ORDC that was used by ERCOT?

Figure 1: Proposed exponential curve fit (3rd boundary condition constrained at 3,100 MW while using a minimum contingency level (MCL) of 2,000 MW)

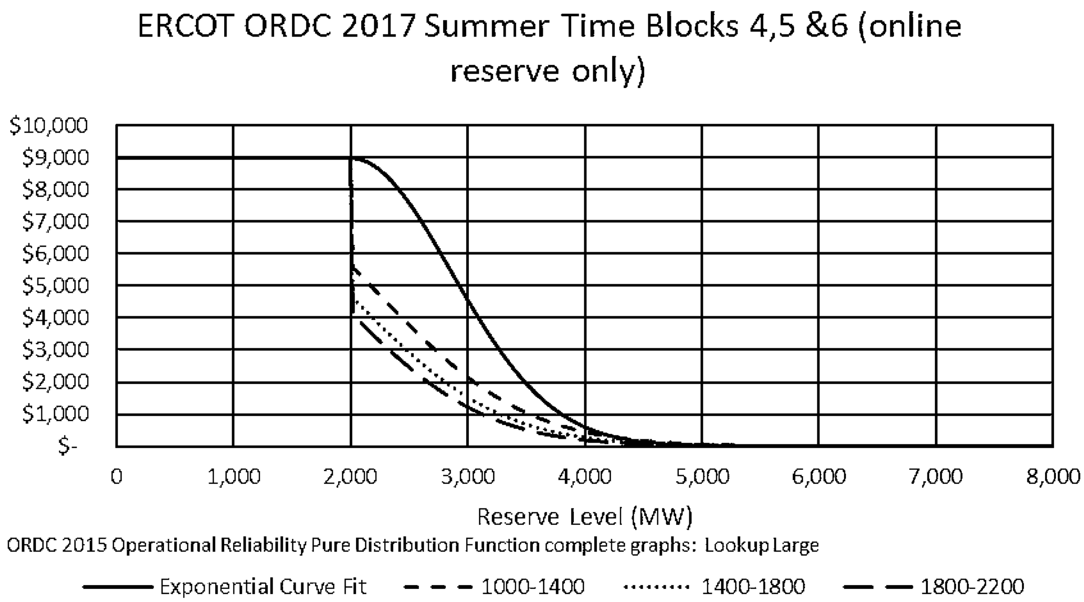
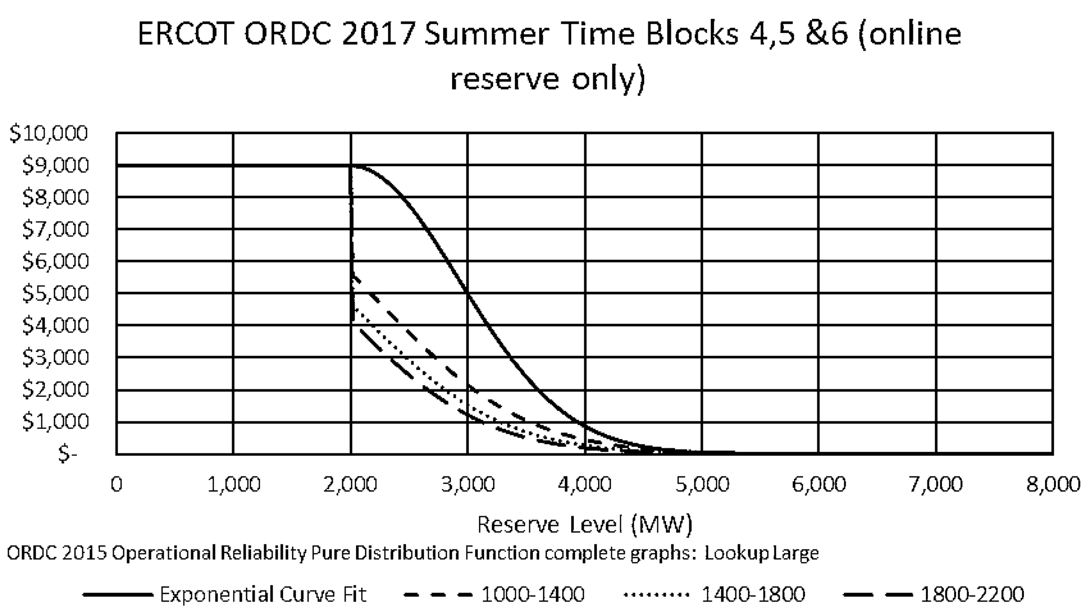


Figure 2: Boundary condition at 3,100 MW is allowed to be shifted by the 2,000 MW MCL.



Figures 1 & 2 show how a first principles based ORDC (with correct mathematics) will contribute to the price of energy in ERCOT. The curves in both Figure 1 and Figure 2 provide an increase in the ORDC adder over the current methodology. Referring to σ solved for in equation 4 of Note 2 (not to be confused with "standard deviation" as no distribution is calculated using this method), Figure 1's calculated σ is 1,307 MW compared to Figure 2's σ of 1,215 MW (with the first boundary condition of reserve level of 10,000 MW producing a LOLP = 0.0).

In each figure the proposed curve is compared to actual ERCOT 2017 ORDC Summer-time block curves. Today's ORDC curves would be similarly situated in the figure.

Recommendation: Stick with the curve criteria in Figure 2 because it is easier for market participants to understand and implement the proposed solution identified in Note 2.

II. More money (for reliability) implies the need for more regulatory oversight.

In mid 2014 to early 2015 the need for a rigorous and methodical review of Independent Power Producer's (IPP) power plants was identified. The polar vortex event of January 2014 demonstrated that while IPPs had improved their performance over the cold weather event of February 2011 there was still great room for improvement in operational reliability in the ERCOT fleet. A proposed rigorous examination and review was developed to improve/ensure the best operational reliability achievable. This proposal was not further advanced for reasons unknown to me (my sense was that it was considered too draconian although there was an issue of how such a program would be paid for). The gist of the proposal was:

1. **A team of experienced individuals with expert knowledge in power plant operations, maintenance and accounting would conduct working examinations of all thermal fired generating units in ERCOT. The examination would consist of:**
    a. **Operational testing of a generating unit's capabilities.**
    b. **Detailed review of the unit's maintenance records.**
    c. **A failure mode analysis (what are the likely causes of the unit not being able to start up or the likely causes of a trip while online.)**
    d. **Detailed review of the units operating and emergency procedures.**
    e. **Interviews of plant operators to evaluate their level of knowledge of plant operating and emergency procedures.**
    f. **Cost center financial/accounting audit.**

The working examination would be a much scaled down version of the U.S. Nuclear Navy's Operational Reactor Safeguards Examination, which is conducted at least once every two years on every nuclear-powered vessel in the fleet.

With more money paid, more regulatory oversight is necessary to ensure the public is getting what they are paying for (RELIABILITY). An examination and review as described above is recommended in conjunction with the proposed modifications to the ORDC because these modifications will come close to doubling the adder payments.

Question 1b: Should that amount of ORDC-based dispatchability be adjusted to specific seasonal reliability needs?

Answer: No.

Question 2: Should ERCOT require all generation resources to offer a minimum commitment in the day-ahead market as a precondition for participating in the energy market?

Answer: No. However, all generating resources should be required to submit offer curves to participate in the market and must provide such offered generation if struck.

Question 6: How can the current market design be altered (e.g., by implementing new products) to provide tools to improve the ability to manage inertia, voltage support, or frequency?

Answer: The current market design falls short on valuing all the capabilities brought to the grid by generating resources. Since its inception, the ERCOT market has overlooked the varied attributes brought to the grid by the different types of generating resources contributing to grid reliability. Inertia, voltage support and frequency stability were disregarded as valuable contributions to the reliability of the grid. I would add that ramping ability should be included in the list. A way to monetize these attributes needs to be incorporated into the ERCOT market. There is great value to large generating units bringing reliability to the grid through their enormous mass. Some form of compensation is needed. The massive generating resources need to be paid for their mass.

Likewise, units that have tremendous ramping ability should be compensated because they can rapidly pick up load. That ramping ability has great value. One only needs to go back to January 2018 when following a high price event the Independent Market Monitor (IMM) presented results that showed that had units that had high ramp rates been available instead of confined to ancillary services the cost savings to the market would have been $60 million (IMM was arguing for co-optimization). What the IMM's statement underscores is that the IMM disregarded the value that a high ramp rate has. The cost savings of $60 million should be shared. The IMM presumed that it should all be saved in form of lower cost of energy (co-optimization). The IMM did not consider that some (25%, 50% or even 75%) of that "savings" should have been paid to those units that could provide the needed ramping capability. This is an example of how the market neglects to consider *how* the energy is provided (in this case it would have been provided very quickly as it was needed very quickly). Units should be compensated for the ramping ability they bring to the grid because that protects reliability in a different manner.

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