A Market-based Approach to Power System Expansion Planning

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Outline

• Revisiting of the generation capacity expansion planning process
• Stochastic Reliability Pricing Model: proposed design and key economic properties
• Conclusions
High Level Schematic of the Generation Expansion Planning Process

- **Resource Adequacy Criteria**
  - Probabilistic criteria expressed in terms of Loss of Load Probability (LOLP) or Loss of Load Expectation (LOLE). Measured in [days/10 years], [hours/10 years]
  - Some countries use Expected Unserved Energy (EUE) measured in MWh or in percent of total energy consumption
  - Determined via specialized probabilistic studies using Monte-Carlo simulations or algorithms based on convolution of probability distribution functions

- **Planning Reserve Margin**
  - Defined as the level of installed capacity in excess of peak demand required to maintain the required reserve adequacy criteria
  - Determined by iteratively running resource adequacy studies until the required level of LOLE or other indicator is satisfied

- **Selection of Generation Mix**
  - Integrated Resource Planning:
    - Stakeholder process
    - Long-term optimization software
    - Capacity expansion scenarios are driven by reserve margin requirements
  - Capacity Markets (ISO-NE, NYISO, PJM, Russian Federation)
    - Auction-based mechanism
    - Optimization-based market engine
    - Procured levels of reserves based on reserve margin requirements
The time has come to revisit the foundations of this approach

• Relevant technological advancements of the last two decades:
  – Increased computational and algorithmic power allows to address more complex and computationally intensive problems
  – Advancement in metering technologies and development of customer information systems geared toward SmartGrid – improved information on the economics of electricity use
  – Growing penetration of variable resources and energy limited resources, among them resources in the form of demand response, create significant challenges to old concepts

• Institutional advancements
  – Emerging competitive market mechanisms for energy, capacity and ancillary services, virtual power plants auctions, energy procurement auctions, derivative mechanisms (FTRs, virtual bidding)
  – Development of sophisticated market infrastructure supporting optimal operation of electricity markets over large footprints
  – Active participation of demand response in markets for energy, ancillary services, capacity
  – Emergence of highly sophisticated market participants

• Theoretical advancements
  – Theory of spot pricing of electricity, nodal economic theory of power systems
  – Use of auction theory and applications in design and operation of various power markets
“If it is not broken, don’t fix it…” But what if it is?

• Issue 1. Resource adequacy criteria do not fully reflect the economics of service interruption

• Issue 2. Resource adequacy criteria in the form of LOLE are inadequate indicators of optimal investment in transmission-constrained systems

• Issue 3. Local capacity requirements used in practice for transmission-constrained systems are not based on a sound economic theory and do not appear optimal
Issue 1. LOLE does not fully reflect the economics of service interruptions

- LOLE reflects the average frequency of the loss of load in the system as a whole
- LOLE does not reflect the frequency of interruption of individual end users or groups of end users
- LOLE does not take into account:
  - size of the system
  - depth of interruption
  - number, fraction, categories of end users being interrupted

1. Two Separate Systems

   System A
   
   \[ \text{LOLE}_A = 1 \text{ day in 10 yrs} \]

   System B
   
   \[ \text{LOLE}_B = 1 \text{ day in 10 yrs} \]

2. Systems are weakly connected

   System A
   \[ \sim 0 \text{ MW} \]
   System B

   \[ \text{LOLE}_{A+B} \approx 2 \text{ days in 10 yrs} \]

In the second case the frequency of interruption of individual end users is practically the same as in the first case but the LOLE no longer meets the 1 day in 10 years standard.
Issue 2: In a transmission-constrained system LOLE does not drive optimal investment decisions

In the absence of transmission constraints

LOLE (hours/yr) = P [S] x 8760 = ∂EUE/∂L,

P [S] – probability of all events in S

Optimal capacity addition rule:

LOLE x VOLL = ∂EUE/∂L x VOLL ≥ CRR

CRR – annualized capacity revenue requirement

In a constrained system LOLE does not drive the optimal capacity addition rule:

Optimal capacity addition rule for Zone A

P [S_A] x 8760 x VOLL = ∂EUE/∂L_A x VOLL ≥ CRR_A

Optimal capacity addition rule for Zone B

P [S_B] x 8760 x VOLL = ∂EUE/∂L_B x VOLL ≥ CRR_B

The right indicators are ∂EUE/∂L_A and ∂EUE/∂L_B

The relationship LOLE = ∂EUE/∂L only holds for an unconstrained system
Issue 3. How installed capacity requirements are set

• Example 1: PJM
  – Sets system-wide LOLE requirement of 1 day in 10 years and local LDA requirements at 1 day in 25 years
  – Effectively determines installed capacity requirements by zone on the basis of 1 day in 25 years LOLE criteria (subject to 100% availability of imports)

• Example 2: NYISO
  – Sets up system-wide LOLE requirement of 1 day in 10 years. Upstate/downstate split in capacity requirements are set on the relative trade-off basis: increasing downstate reserve margin by 1% while reducing system reserve margin by 1% must preserve the LOLE of 1 day in 10 yrs

Neither of these methods appears optimal
Proposed Approach: Stochastic Reliability Pricing Model

- Market-based: optimal generation mix is selected through a capacity procurement auction conducted on a regular basis (e.g. annually)
- Planning horizon: one- or multi-year
- Footprint: an RTO but preferably all interconnected RTOs
- Market engine:
  - Uses full transmission model and factors in security constraints;
  - Models generator availability as stochastic processes;
  - Models demand as stochastic processes;
  - Does not require regional reserve margins as an input;
  - Explicitly incorporates expected value of unserved energy $E(VUE)$ into the auctioneer’s objective function
- Auction outcome:
  - Optimal selection of the resource mix
  - Locational capacity prices for resources
  - Locational capacity prices for loads
Schematic of the Market Engine

Auctioneer’s Objective Function: \( \text{min} \ [(\text{Gen Cost} \ @\text{CRR}) + (\text{DR Cost} \ @\text{CRR}) + E(\text{VUE})] \)

Planning horizon: one- or multi-year

- Detailed transmission model
- Probabilistic (e.g. Monte-Carlo market engine)
  - Stochastic demand
  - Stochastic generator availabilities
  - Transmission outages
- Load shedding model
  - Generator offers
  - Demand response offers
- Optimal capacity selection
- Nodal capacity prices for resources and loads
## Market Engine Inputs

<table>
<thead>
<tr>
<th>Inputs</th>
<th>Explanation/source</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Detailed transmission model</td>
<td>• Transmission topology which may be changing over planning horizon by incorporating planned projects and a predetermined set of flowgates</td>
</tr>
<tr>
<td>• Transmission outages</td>
<td>• Based on historical statistics or engineering estimates</td>
</tr>
<tr>
<td>• Generator offers</td>
<td>• Price/quantity pairs: CRRs and installed capacity for existing and new capacities</td>
</tr>
<tr>
<td>• Stochastic generator availabilities</td>
<td>• Based on historical statistics or engineering estimates</td>
</tr>
<tr>
<td>• Stochastic demand</td>
<td>• Stochastic variations around demand forecasts developed by LSEs or System Operator</td>
</tr>
<tr>
<td>• Demand response offers</td>
<td>• Price/quantity pairs: CRRs and levels of demand reduction below forward contracts to purchase power</td>
</tr>
<tr>
<td>• Load shedding model</td>
<td>• Locational levels of load shedding potential and associated VOLLs set administratively and/or specified by large buyers</td>
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Auctioneer’s Optimization Problem

<table>
<thead>
<tr>
<th>Problem Structure</th>
<th>Comments</th>
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<tbody>
<tr>
<td>Master Problem</td>
<td>LP problem for capacity selection which is fixed over time and across stochastic scenarios</td>
</tr>
<tr>
<td>Scenario 1</td>
<td>One LP sub-problem for each stochastic scenario/hour (assuming no inter-temporal constraints)</td>
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<tr>
<td>Scenario 2</td>
<td>The sub-problem is “security constrained optimal dispatch” with all selected resources being committed, zero resource costs and positive costs of load shedding (reliability dispatch)</td>
</tr>
<tr>
<td>Scenario 3</td>
<td>Objective function is $VUE = VOLL \times UE$</td>
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<tr>
<td>Scenario N</td>
<td>Each scenario/hour yields nodal prices – Locational Stochastic Reliability Price (LSRP)</td>
</tr>
<tr>
<td></td>
<td>No load shedding anywhere $\Rightarrow$ LSRP = 0</td>
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<tr>
<td></td>
<td>Load shedding somewhere, no transmission congestion $\Rightarrow$ LSRP = $VOLL$ (if $VOLL$ is uniform)</td>
</tr>
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<td></td>
<td>Load shedding + transmission congestion $\Rightarrow$ LSRP vary by location</td>
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</tbody>
</table>
Resource Capacity Price (RCP)

\[ RCP_j = E \sum S_j(t, \omega) \max\left(0, LSRP_j(t, \omega)\right) - E \sum S_j(t, \omega) \max\left(0, -LSRP_j(t, \omega)\right) \]

- Resource capacity price is the difference between the reliability value of the option to use 1 MW of capacity when it is needed and the reliability cost of the obligation to use 1 MW of capacity when it is not needed.

\( \overline{S}_j(t, \omega) \) and \( S_j(t, \omega) \)
- p.u. maximum resource availability and low bound operational limitation, respectively.

- LSRPs and resource availabilities are negatively correlated! Existing practice of relying on historically estimated UCAP and multiplying it by capacity price is biased and may inadequately compensate generators in the capacity market.

- **Ultimately, the resource offer is**
  - Accepted fully if offer price is below \( RCP_j \)
  - Rejected fully if offer price is above \( RCP_j \)
  - Accepted partially (marginal) if offer price is equal to \( RCP_j \)

- In the auction settlement, resources are paid RCPs for each MW of accepted installed capacity.
Load Capacity Prices (LCP) and the Overall Settlement

\[ LCP_j = E \sum_t LSRP_j(t, \omega) \left[ \frac{L_j(t, \omega) - u_j(t, \omega)}{D_j} \right] \]

- Load payment depends on served load simulated in each scenario: *a load pays for reliability only to the extent it is not interrupted at the time when others are*
- Depending on consumption patterns and/or level of interruption loads at the same location may pay different capacity prices
- Prices are defined per unit of projected peak demand
- Projected peaks are used as a billing determinants in the auction settlement

\[ \sum_j D_j LCP_j = \sum_j X_j RCP_j + \text{CongRent}, \quad \text{CongRent} \geq 0 \]

- Congestion rent equals the expected value of total congestion costs of reliability dispatch and is never negative
- The Auctioneer is never revenue deficient
LSRPs, RCPs and LCPs are primarily driven by the economics of service interruptions.

To illustrate this, we consider several examples using a three-node system with all lines having identical impedance. By design, the system is short: total demand is 540 MW, total available capacity is 520 MW. In all examples flow on the line B-C is limited.
Summary of Examples

- For simplicity, we assume a single VOLL of $10,000/MWh at all locations

| Example 1. Although the system is only short for 20 MW, transmission constraint on a flow from C to B forces shedding of 35 MW of load at B. As a result, LSRPs at all nodes are different, but non-negative and do not exceed VOLL |
|-----------|--------|
| A         | $5,000 |
| B         | $10,000|
| C         | $0     |

- Example 2. Similar to Example 1, but load reduction at B is limited. As a result, prices at all nodes double and at node B price is twice the VOLL

| Example 2. Similar to Example 1, but load reduction at B is limited. As a result, prices at all nodes double and at node B price is twice the VOLL |
|-----------|--------|
| A         | $10,000|
| B         | $20,000|
| C         | $0     |

- Example 3. Similar to Example 2, but transfer limit from C to B is reduced to 40 MW and load reduction at B above limit is priced at 3 x VOLL. As a result, LSRP at B goes up to 3 x VOLL, while generation at C is forced to zero, resulting in a negative price of – VOLL at that node.

| Example 3. Similar to Example 2, but transfer limit from C to B is reduced to 40 MW and load reduction at B above limit is priced at 3 x VOLL. As a result, LSRP at B goes up to 3 x VOLL, while generation at C is forced to zero, resulting in a negative price of – VOLL at that node. |
|-----------|--------|
| A         | $10,000|
| B         | $30,000|
| C         | -$10,000|

- Example 4. Same as Example 3, but generator at C is required to operate above 10 MW. LSRPs are the same as in Example 3 but a case like that reduces RCP for generator C
Example 1

Generator G1
Capacity = 200 MW of 240 MW
Dispatch = 200 MW
Load reduction = 0
Net = 30 MW
LSRP = $5,000

Load = 170 MW

Generator G2
Capacity = 200 MW of 220 MW
Dispatch 200 MW
Load reduction 35 MW
Net = -135 MW
LSRP = $10,000

Load = 370 MW

Generator G3
Capacity 120 MW of 130 MW
Dispatch 105 MW
LSRP = $0

VOLL = $10,000

UE = 35 MW
VUE $350,000
Example 2

**Generator G1**
Capacity = 200 MW of 240 MW

- Dispatch = 200 MW
- Load reduction = 10 MW
- Net = 40 MW
- LSRP = $10,000

**Load** = 170 MW

**Generator G2**
Capacity = 200 MW of 220 MW

- Dispatch = 200 MW
- Load reduction ≤ 30 MW
- Net = -140 MW
- LSRP = $20,000

**Load** = 370 MW

**Generator G3**
Capacity 120 MW of 130 MW

- Dispatch 100 MW
- LSRP = $0

**VOLL** = $10,000

UE = 40 MW
VUE $400,000
Example 3

Load = 170 MW

Generator G1
Capacity = 200 MW
Dispatch = 200 MW of 240 MW
Load reduction = 90
Net = 120 MW
LSRP = $10,000

Load = 370 MW
Load reduction ≤ 30 MW @ VOLL
Load reduction > 30 MW @ 3 x VOLL

Generator G2
Capacity = 200 MW
Dispatch 200 MW of 220 MW
Load reduction 50 MW
Net = - 120 MW
LSRP = $30,000

Generator G3
Capacity 120 MW of 130 MW
Dispatch 0 MW
LSRP = - $10,000

UE = 140 MW
VUE = $1,800,000
Example 4

**Generator G1**
Capacity 200 MW of 240 MW

- Dispatch = 200 MW
- Load reduction = 70
- Net = 100 MW
- LSRP = $10,000

**Generator G2**
Capacity = 200 MW of 220 MW

- Dispatch 200 MW
- Load reduction 60 MW
- Net = -110 MW
- LSRP = $30,000

**Generator G3**
Capacity 120 MW of 130 MW Gen ≥ 10 MW
- Dispatch 10 MW
- LSRP = -$10,000

UE = 130 MW
VUE = $1,900,000

Load = 170 MW
Load = 370 MW
Load reduction ≤ 30 MW @ VOLL
Load reduction > 30 MW @ 3 x VOLL

VOLL = $10,000
Market Outcome Example

- Examples 1 – 4 are the only instances of service interruption
- Each instance of interruption has a duration of 1 hour
- Each instance of interruption has a probability of 0.1 per year
## Summary of Scenario Outcomes

<table>
<thead>
<tr>
<th></th>
<th>Probability</th>
<th>Bus A</th>
<th>Bus B</th>
<th>Bus C</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Generator capacities</strong></td>
<td></td>
<td>240</td>
<td>220</td>
<td>130</td>
</tr>
<tr>
<td><strong>Load capacity requirements</strong></td>
<td></td>
<td>170</td>
<td>370</td>
<td>0</td>
</tr>
<tr>
<td><strong>LRSPs by Scenario</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Example 1</td>
<td>0.1</td>
<td>5,000</td>
<td>10,000</td>
<td>0</td>
</tr>
<tr>
<td>Example 2</td>
<td>0.1</td>
<td>10,000</td>
<td>20,000</td>
<td>0</td>
</tr>
</tbody>
</table>
| Example 3            | 0.1         | 10,000| 30,000|(10,000)
| Example 4            | 0.1         | 10,000| 30,000|(10,000)
| **Loads Servable by Scenario** |     |       |       |       |
| Example 1            | 0.1         | 170   | 335   | NA    |
| Example 2            | 0.1         | 160   | 340   | NA    |
| Example 3            | 0.1         | 80    | 320   | NA    |
| Example 4            | 0.1         | 100   | 310   | NA    |
| **Generator Availabilities by Scenario** |     |       |       |       |
| Example 1            | 0.1         | 83%   | 91%   | 92%   |
| Example 2            | 0.1         | 83%   | 91%   | 92%   |
| Example 3            | 0.1         | 83%   | 91%   | 92%   |
| Example 4            | 0.1         | 83%   | 91%   | 92%   |
| **Generator low bound limitations** |     |       |       |       |
| Example 1            | 0.1         | 0.0%  | 0.0%  | 0.0%  |
| Example 2            | 0.1         | 0.0%  | 0.0%  | 0.0%  |
| Example 3            | 0.1         | 0.0%  | 0.0%  | 0.0%  |
| Example 4            | 0.1         | 0.0%  | 0.0%  | 7.7%  |
## Market Settlement

<table>
<thead>
<tr>
<th></th>
<th>Bus A</th>
<th>Bus B</th>
<th>Bus C</th>
<th>System</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mean LSRP ($/MW-yr)</td>
<td>3,500</td>
<td>9,000</td>
<td>(2,000)</td>
<td></td>
</tr>
<tr>
<td>Load Capacity Price ($/MW-yr)</td>
<td>2,500</td>
<td>7,851</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Resource Capacity Price ($/MW-yr)</td>
<td>2,917</td>
<td>8,182</td>
<td>(76.92)</td>
<td></td>
</tr>
<tr>
<td>Load Payments ($)</td>
<td>425,000</td>
<td>2,905,000</td>
<td>-</td>
<td>3,330,000</td>
</tr>
<tr>
<td>Generator Receipts ($)</td>
<td>700,000</td>
<td>1,800,000</td>
<td>(10,000)</td>
<td>2,490,000</td>
</tr>
<tr>
<td>Congestion Rent ($)</td>
<td></td>
<td></td>
<td></td>
<td>840,000</td>
</tr>
</tbody>
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Conclusions

• Technological, theoretical and institutional advancements of the last two decades create the need and opportunity to revisit certain foundations underlying the current practice of capacity expansion decisions in the power industry

• The concepts of Loss of Load Expectation and Planning Reserve Margins, while being useful indicators of resource adequacy, are not suitable for making optimal investment decisions in complex transmission-constrained systems

• The proposed approach to explicitly incorporate the resource adequacy assessment into the design of capacity auction overcomes existing methodological difficulties and promises a more efficient selection of generation and demand-side resources than current designs

• If implemented, this approach will:
  – Yield location-specific capacity prices consistent with actual transmission topology and limitations and helping resource developers make better siting decisions;
  – Adequately reflect stochastic and temporal properties of resource availabilities into their compensation in the capacity market – particularly important for variable resources and demand response;
  – Adequately compensate contribution of resources to system reliability based on their location on the grid and availability at the time of need;
  – Provide fair reliability pricing for loads consistent with their impact on system reliability at the time of resource scarcity;
  – Create the means for the demand-side to more fully participate in the capacity market not only in the form of demand-response but by explicitly incorporating into the market model the economics of service interruptions
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