Gap Analysis
Compensation – Incentives

FSSTF
September 20, 2019
• **June Meeting:**
  – Assessed what **current mechanisms exist today** that contribute toward fuel/energy/resource security and what uncertainties/risks are currently accounted for by these mechanisms

• **July Meeting:**
  – Given the credible risks to fuel/energy/resource security that were identified, determine which **uncertainties are not accounted for in the requirements** for the current mechanisms that exist today

• **August Meeting:**
  – Given the credible risks to fuel/energy/resource security that were identified, determine if any gaps exist in the **compensation in the form of cost-recovery** available for the current mechanisms to mitigate those risks

• **Today:**
  – Given the credible risks to fuel/energy/resource security that were identified, determine if any gaps exist in the **incentives provided by the compensation available** for the current mechanisms to mitigate those risks

• **October Meeting:**
  – Summarize key findings from the gap analysis
Relevant Risks Identified at June FSSTF Meeting

<table>
<thead>
<tr>
<th>Relevant Risks</th>
<th>Renewable Intermittency - Related</th>
<th>Forced Outages - Related</th>
</tr>
</thead>
<tbody>
<tr>
<td>Long Duration Cold Snap</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Short Duration Cold Snap</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Natural Gas Pipeline Disruptions</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Solar Intermittency</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wind Intermittency</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coal Refueling (Bridge Failure)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coal Refueling (Lock and Dam Failure)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coal Refueling (Rail Failure)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coal Refueling (River Freezing)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coal Unavailability (Coal Quality)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Natural Gas Unavailability Non-Firm Units</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil Refueling (Oil Terminal)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil Refueling (Truck Restrictions)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nuclear Regulatory Shutdown (Fuel Related)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nuclear Regulatory Shutdown (Non-Fuel Related)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nuclear Unavailability (High Winds)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydro Unavailability (Freezing Rivers)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>River Freezing (Cooling Water Impacts)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ice Storm (Transportation Impacts)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

For ease of exposition, some of the Relevant Risks are grouped in two categories: Renewable Intermittency and Forced Outages.
Incentives Provided by Current Mechanisms

- Incentives provided by the current mechanisms fall into two categories:

  1) Penalties for Not Performing

  2) Lost Revenue from Not Performing (or deviation charges for units with a day-ahead market obligation)
• Resources assessed penalties and bonus credits for performance during a Performance Assessment Interval (PAI)

• Approximate hourly penalty rate for not performing during a PAI for the 2021-2022 delivery year: $3,500/MWh

• Penalty Stop Loss = $157,500/MW-year
For an energy resource not subject to capacity performance, the lost opportunity cost from the bonus credits for a resource that doesn’t perform is approximately the same as the penalty cost for a capacity resource that doesn’t perform.
Lost Revenue - Emergency Procedures

- During the Phase I Analysis, to evaluate system performance in each scenario, the following emergency procedures were examined:
  1) Synchronized Reserve Shortage
  2) Voltage Reduction
  3) Demand Response Deployment
  4) Load Shed

- We can use the same triggers to determine the lost revenue (worst case scenario) a unit would be subject to from not performing.

- Question: What is the maximum price during each emergency event?
Synchronized Reserve Shortage Event

- Energy price during an RTO-wide Synchronized Reserve Shortage Event:
  - Current Reserve Market Design: $850/MWh
Voltage Reduction Event

- Energy price during an RTO-wide Voltage Reduction Event:
  - Current Reserve Market Design: $1,700/MWh
Demand Response Deployment Event

- Energy price if Demand Response is deployed:
  - $1,850/MWh
• Energy price during an RTO-wide Load Shed Event:

  – Current Reserve Market Design: $1,700/MWh (max. reserve price) + $2,000/MWh (max. energy offer) = $3,700/MWh
• Given that each scenario in Phase I has a probability of occurring, generator incentives to perform can be measured based on expectations of future costs, not on the costs themselves.

• Note: Expected costs are only one measure of risk that can be used for decision making.

• A generator may want to minimize expected cost:

\[
\text{Expected Cost} = \sum_{\text{for all scenarios } i} (Cost_{\text{Scenario } i} \times Probability_{\text{Scenario } i})
\]

• Question 1: How to determine the cost of each scenario occurring?
• Question 2: How to determine the probability of each scenario occurring?
Scenario Cost Calculation

- Scenario Cost = Performance Assessment Interval (PAI) penalty cost + Lost Revenue
  - PAI penalty cost for each scenario was determined by multiplying the number of hours with an emergency event by the penalty cost
  - Lost revenue for each scenario was determined by multiplying the maximum price during each emergency event by the number of hours of that event occurring
  - If multiple emergency events were triggered during an hour, then the price of the highest priced emergency event was used for that hour

- Note, the cost estimates for each Phase I scenario represent a worst case scenario as prices during some emergency events may be lower
Since we cannot calculate the probability of each Phase I scenario occurring, we can calculate the expected costs for a range of scenario probabilities and see the trends in expected cost.
The Phase I scenario with the highest cost had the following emergency procedures triggered:

- Demand Response Deployment Hours: 192
- Synchronized Reserve Shortage Hours: 77
- Voltage Reduction Hours: 108
- Manual Load Shed Hours: 83

All other scenarios had lower costs.
Maximum Expected Cost

• To calculate a Maximum Expected Cost (upper bound), we can assume a probability for the highest cost scenario that is equal to the sum of the probabilities of all the non-zero cost scenarios occurring.

• For example, let:

\[ \text{Probability}_{\text{Highest Cost Scenario}} = \sum_{\text{Probability}_{\text{Scenario } j}} \text{ for all Scenarios } j \text{ with non-zero cost} \]

• Then:

\[
\text{Max. Expected Cost} = \text{Cost}_{\text{Highest Cost Scenario}} \times \text{Probability}_{\text{Highest Cost Scenario}} \\
\geq \text{Expected Cost} = \sum_{\text{for all Scenarios } i} (\text{Cost}_{\text{Scenario } i} \times \text{Probability}_{\text{Scenario } i})
\]
Example Costs to Increase Fuel Security

- The following are some example costs for generator investments that may allow a resource to increase fuel security (these are provided for illustrative purposes only, actual costs may differ).

  - Cost for Firm Gas in SWMAAC for a CC = $9,400/MW-year

  - Cost to add dual fuel capability:
    - CT = $7,000/MW-year
    - CC = $2,500/MW-year

*Costs are from the Brattle Report*
Based on your estimation of the probability of each scenario, is the expected cost enough to incentivize increasing fuel security?
Current Reserve Market Design:

- Expected costs drop below $5,100/MW-year when the probability of the scenario drops below 1%

- Expected costs drop below $510/MW-year when the probability of the scenario drops below 0.1%
Based on your estimation of the probability of each scenario, is the expected cost enough to incentivize increasing fuel security?

- For example, under the current reserve market design, assuming the probability of all scenarios with a non-zero cost is less than 1%, is a maximum expected cost of $5,100/MW-year enough to incentivize a generator to increase fuel security?
• Is the problem self-correcting?
  – As more emergency events happen more frequently (for example, if the reserve margin is at the IRM), the probability and expected cost of each scenario will also increase providing a greater incentive for units to become fuel secure.

• At this point, is it already too late (due to lead time to become fuel secure)?

• At what probability would the expected cost be high enough to incentivize a unit to invest in fuel security measures?

• Answers will vary based on each participant’s investment costs to increase fuel security, estimation of expected costs and risk tolerances.