Gap Analysis
Compensation – Incentives

FSSTF

September 20, 2019

Schedule

- **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

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

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

Bonus Credits - Capacity Performance

- 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

- 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

Expectations of Future Costs

- 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:

$$\text{Expected Cost} = \sum_{for\ all\ Scenarios\ i} (Cost_{Scenario\ i} \times Probability_{Scenario\ i})$$

- 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

Highest Cost Phase I Scenario Description

- 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.

- 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:

$$Probability_{Highest\ Cost\ Scenario} = \sum_{for\ all\ Scenarios\ j\ with\ non-zero\ cost} Probability_{Scenario\ j}$$

- Then:

$$\text{Max. Expected Cost} = Cost_{Highest\ Cost\ Scenario} \times Probability_{Highest\ Cost\ Scenario}$$

$$\geq Expected\ Cost = \sum_{for\ all\ Scenarios\ i} (Cost_{Scenario\ i} \times Probability_{Scenario\ i})$$

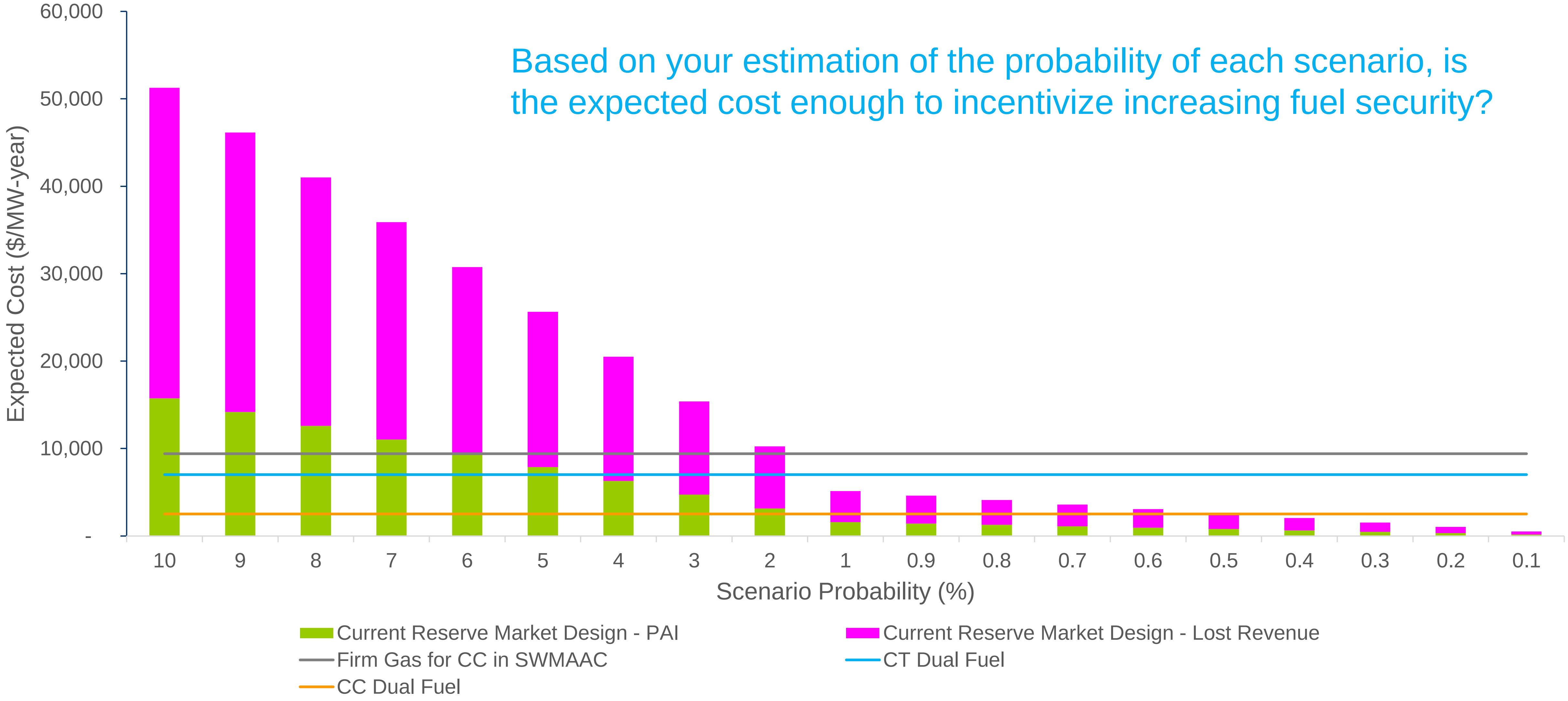
Example Costs to Increase Fuel Security

- 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

Phase I Highest Cost Scenario Expected Costs

Based on your estimation of the probability of each scenario, is the expected cost enough to incentivize increasing fuel security?



Phase I Scenario Expected Costs

- 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%

Incentive to Become Fuel Secure

- 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?

Self-Correcting Problem?

- 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.

