MARKET EFFICIENCY STUDY PROCESS AND PROJECT EVALUATION TRAINING

December 22, 2014

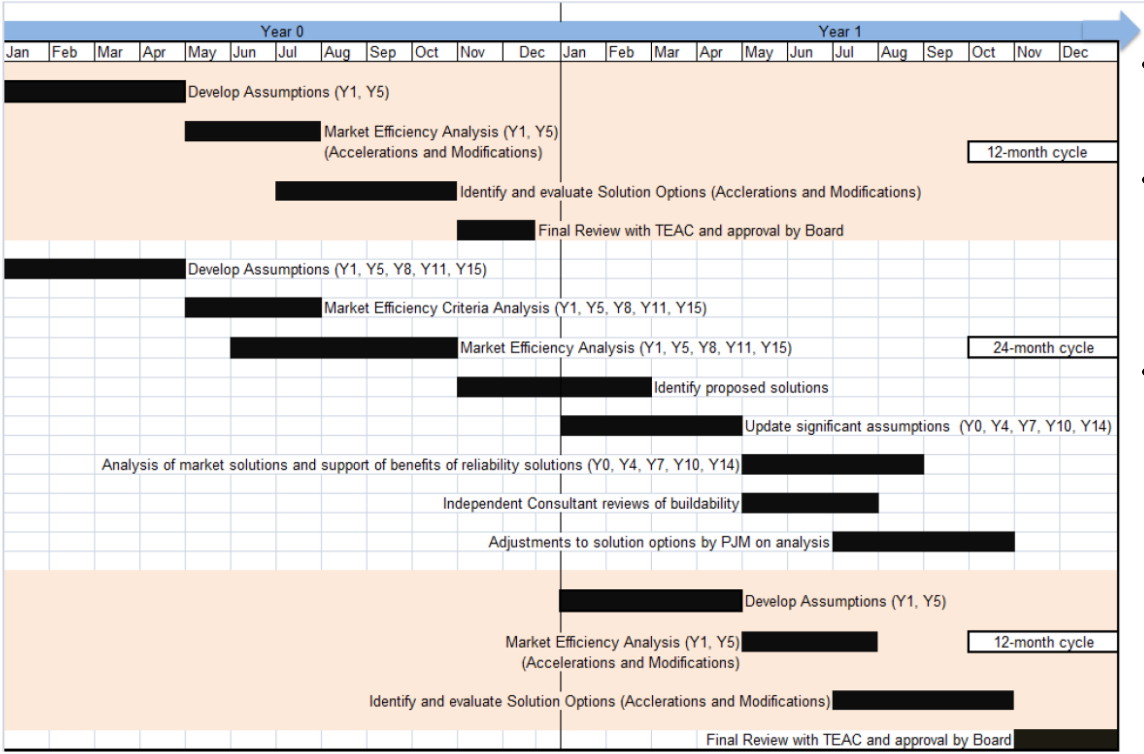
Training Objectives

To Provide an Overview of:

- The Market Efficiency proposal window process
- The critical modeling inputs used in simulations and reporting
- The primary set of reports used from PROMOD IV Report Agent
- The analysis required to assess the economic value of Market Efficiency projects

Section 1: Market Efficiency Proposal Window Process

Market Efficiency Cycle Timeline



- Enable input assumptions to be vetted by stakeholders
- Within each 12 month cycle complete near-term (year 1 through year 5) analysis to identify approved RTEP projects that can be accelerated or modified based on Market Efficiency criteria.
- Within 24 month cycle complete long-term Market Efficiency Analysis to identify transmission solutions that require longer lead times
  - Recommendations for congestion solutions identified in first year of 24-month cycle
  - Proposed solutions re-evaluated in 2nd year of 24 month cycle to determine continued need with updated assumptions

24-Month Cycle

- 6 month window to identify transmission solutions needed incrementally to the RTEP baseline reliability projects
- 4 month window for submission of transmission solutions by PJM members
- 8 months of analysis on proposed solutions and adjustments to solution options
  - Updates to input assumptions
  - Independent consultant review of ability to build
  - Review appropriate reliability projects for economic benefits
- Solutions approved at end of 24-month cycle are not expected to be in service before 3 ½ years
- Projects identified for year 5 may be delayed to year 6 if necessary
- Final review with TEAC and Board approval at end of 24-month cycle

Section 2: Critical Modeling Inputs

Market Efficiency Inputs

PROMOD SCED Simulation

- Generation Expansion Plan (ISA/FSA)
- Demand Response Forecast
- Fuel and Emissions Forecast
- Transmission Topology and Events
- Annual Peak Load and Energy
- Reactive Interface Calculation
- Hourly Demand and Intermittent Resource Shapes

Reporting Inputs

- RTO Weighted Average Cost of Capital
- RTO Fixed Carrying Charge Rate
- ARR Source Sink Paths and Cleared MW
- Project Cost and ISD

Generation Unit Modeling

Unit Heat Rates

Similar Technology
Similar Location
Similar Vintage
Similar Size and Configuration

Gas Fuel Assignment

Same Transmission Zone
Same Primary Fuel Type
Same State

Emission Assignment

Same State
Same Technology / Fuel Burn
Emission Reduction Equipment

Summer Maximum Capacity

Existing Unit: Machines List
New Unit: Interconnection Energy MW

Winter Maximum Capacity

Existing Unit: Historical Performance (EPA CEMS)
New Unit: Interconnection Energy MW

Bus Mapping

Machines List

Hourly & Monthly Profiles*

Similar Location
Similar Technology

Outage rates

Similar Technology
Similar Size and Configuration

* Only Applicable to Intermittent Resources

Generation Unit Modeling

Variable O&M

Similar Technology
Similar Location
Similar Vintage
Similar Size and Configuration

Curtailment Prices **

Production Tax Credit
Renewable Energy Credits
Market Bid Data Region Averages

Start-up Cost

Similar Technology
Similar Location
Similar Vintage
Similar Size and Configuration

Minimum Downtime

Similar Technology
Similar Vintage
Similar Size and Configuration

Minimum Runtime

Similar Technology
Similar Vintage
Similar Size and Configuration

Spinning Reserve Contribution

ABB Supplied
Similar Technology
Similar Vintage
Similar Size and Configuration

Must Run Units

Provided by ABB

** Only Applicable to Solar and Wind Generating Units

Fuel & Emissions Forecast

- ABB provides the Fuel and Emissions Forecast from their reference case model.
  - Validate gas unit mapping to appropriate basis price
  - Validate appropriate primary and start-up fuel mapping
  - Check for consistency with expected emissions legislation affecting PJM Generators
  - Validate mapping of generating units to emissions price
  - Validate installation of emissions reduction equipment and removal rates for generating units, if necessary

Annual Peak Load and Energy

- Map PJM Load Forecast Report Non-Coincident Peak Demand (MW) to PROMOD IV Powerbase Demand Areas

- Map PJM Load Forecast Report Annual Energy to PROMOD IV Powerbase Demand Areas

Hourly Demand and Intermittent Resource Profiles

- ABB provides synthetic load shapes for each demand area based on the average of several years of load shapes.
  - Hourly load shapes may be merged or disaggregated based on PROMOD IV Powerbase Demand Areas.
  - Same shape is used for all years of study.
- ABB provides hourly wind profiles.
  - New units are mapped to existing profiles based on technology and location.

Demand Response Modeling

- Level of Demand Response (DR) is based on the level cleared in the RPM BRA auction by delivery year, zone and product type.
- Demand Response is modeled as discrete units.
  - Locations (zip codes) of Demand Response are based on registration data submitted through PJM DR Hub system.
  - MW by Product Type are mapped to nearest BES facility.
  - Strike price modeled to ensure that DR is called at a level consistent with history and contractual requirements for the product type

Transmission Topology Modeling

- New project evaluation is performed using a current year + 5 RTEP transmission model.
  - All approved baseline upgrades
  - All FSA network and direct interconnection upgrades
  - Upgrades should be in service before the project's expected ISD
  - To evaluate a project expected to be in service in 2019, the same topology is used in the pre-2019 study years simulated in PROMOD IV
  - The generation (i.e. in-service or retired), fuel and emissions pricing will change by study year, but the topology is held constant

Transmission Event Modeling

- Historical Real-Time market constraints that were binding from previous three years modeled in PROMOD IV simulation
- Additional constraints modeled from NERC Book of Flow-gates
- Expand constraint set based on simulation
  - After initial simulation of multiple study years select a subset of constrained hours from both the summer and winter periods
  - Study PJM Transmission Planning single contingency (*.con) file against facilities (230 kV and above)
  - Remove constraints with very low likelihood of binding in any future year simulation and add constraints with increasing likelihood of binding

Transmission Event Modeling

- Excluded Constraints
  - Contingencies that cause load isolation
    - Will create two contingencies depending on largest contributor to flow on monitored line
    - If load is largest contributor then contingency will not be modeled
  - Double contingencies not modeled in a current PJM market model
  - Generator contingencies
  - Contingencies with a Special Protection Scheme
  - Switching scheme is available to mitigate flow on constraint.

Transmission Event Modeling

- Transmission Ratings Modeling
  - Ratings from corresponding PJM RTEP Summer Peak and Winter Peak powerflows

- Where an upgrade is not modeled
  - The current PJM rating is used for both the summer and winter period.

- When an upgrade is modeled
  - The upgraded rating from the RTEP Summer Peak model is used for the summer
  - The upgraded rating from the RTEP Winter Peak model for the same year and series is used for the winter

Reactive Interface Calculation

Objective: Develop summer and winter MW transfer limits for commercially significant interfaces in PJM

- **Analytical Tools**:
  - Powergem Transmission Adequacy and Reliability Assessment Tool (TARA) to analyze flows, bus voltage levels and as needed run contingency analysis for identification of transfer limits.
  - PROMOD IV to identify initial economic dispatch and simulate calculated limits to measure reasonability of congestion
- **Analytical Criteria:**
  - Identify low voltage, voltage deviation and non-convergence violations

- **Inputs:**
  - PJM RTEP Base Year Model
  - ERAG Summer Peak MMWG Model
- **Limits Calculated For:**
  - AEP-DOM Interface
  - AP South Interface
  - 5004/5005 Interface
  - Central Interface
  - Eastern Interface
  - Western Interface

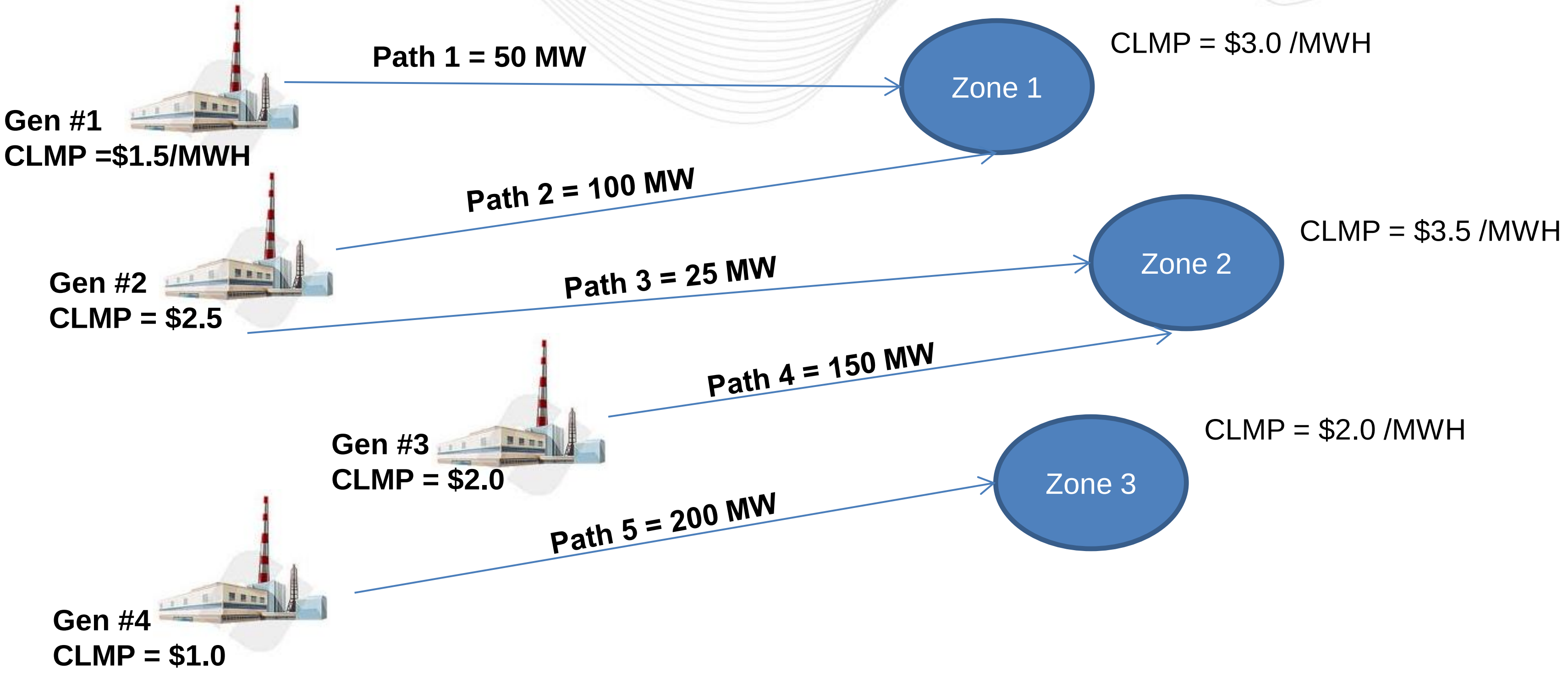
Auction Revenue Right Modeling

- **What are they:** Entitlements allocated annually to Firm/Network Transmission Service Customers that entitle the holder to receive an allocation of the revenues from the Annual FTR Auction. Provide a hedge against congestion incurred between where loads are sunk on the power system versus the supply sources that serve the loads.

- **Modeling Objective:** Through future year SCED modeling determine the value of Auction Revenue Rights (ARR). A reduction in value of these rights due to lower anticipated congestion diminishes the value of reductions in load payments to the holders of these rights. The project benefits to LSE's is therefore the net of the change in load payments due to LMP reductions and the change in value of the ARR's held by the LSE.

- **What does it mean:** The project benefits to LSE's are therefore limited to the unhedged congestion reductions.

Auction Revenue Right Example



Auction Revenue Right Valuation

Path	Source	Source CLMP	Sink	Sink CLMP	Cleared Path MW	ARR Value
1	GEN #1	$1.5	Zone 1	$3.0	50	$657,000
2	GEN #2	$2.5	Zone 1	$3.0	100	$438,000
3	GEN #2	$2.5	Zone 2	$3.5	25	$219,000
4	GEN #3	$2.0	Zone 2	$3.5	150	$1,971,000
5	GEN #4	$1.0	Zone 3	$2.0	200	$1,752,000

Path Value = $(\text{CLMP}_{sink} - \text{CLMP}_{source})$ x Cleared MW x 8760

Zone 1 ARR Valuation = Path 1 Value + Path 2 Value = $1.095 Million

Zone 2 ARR Valuation = Path 3 Value + Path 4 Value = $2.19 Million

Zone 3 ARR Valuation = Path 5 value = $1.752 Million

Section 3: Market Efficiency Analysis of Proposed Solutions

Market Efficiency Analysis Objectives

- Determine which reliability upgrades, if any, have an economic benefit if accelerated or modified.
- Identify new transmission upgrades that may result in economic benefits
- Identify economic benefits associated with “hybrid” transmission upgrades. Such hybrid upgrades resolve reliability issues but are intentionally designed in a more robust manner to provide economic benefits in addition to resolving those reliability issues.

Market Efficiency Post-Simulation Analysis

- To provide an overview of the analysis required to assess the economic value of Market Efficiency Projects
  - Identify inputs for analysis
  - Identify calculations used during the reporting stage of analysis
  - Identify outputs for each stage of analysis
  - Identify passing criteria for regional and low voltage projects

Benefit Cost Test Steps

Run PROMOD analysis with and without upgrade

Run PROMOD Report Agent

Run Market Efficiency Benefit Cost Test

- **Study years to simulate:** Market Efficiency Projects are studied incrementally to RTEP projects.
  - RTEP Year – 4, RTEP Year, RTEP Year + 3, RTEP year + 6
- **Variables to Retrieve:** Bus Load, Bus Load LMP, Bus Load, ARR Source Node/Bus LMP Congestion Component, ARR Sink (Zone) Congestion Component, Generator Production Costs (Fuel Cost, Variable O&M, Startup-Costs), Generator Output (MWH), Generator LMP, PJM Hourly Interchange (Sales/Purchases), PJM Hourly Gen Weighted LMP, PJM Hourly Load Weighted LMP
- **Variables to Retrieve:** PJM Weighted Average Cost of Capital, PJM Fixed Carrying Charge Rate

Net Load Payment Benefit By Zone & Simulation Year

Net Load Payment Benefit By Zone By Simulation Year

$$+\sum_{Zone} Hourly\ Bus\ Load\ MW \times Hourly\ Bus\ LMP \qquad \textit{(sum for all hours)}$$

$$-\sum_{Zone} ARR\ Path\ Cleared\ MW \times [Annual\ Sink\ Node\ CLMP - Annual\ Source\ Node\ CLMP] \times 8760$$

- The change in the Net Load Payment with the addition of the project versus without the project determines the project benefits to the demand zones

System Adjusted Production Cost Benefits

$$+\sum_{Unit}^{Project} Fuel\ Costs - \sum_{Unit}^{Base\ Case} Fuel\ Costs \quad (Fuel\ Costs\ includes\ startup\text{-}heat\ consumption)$$

$$+\sum_{Unit}^{Project} Emissions\ Costs - \sum_{Unit}^{Base\ Case} Emissions\ Costs \quad (SO_2,\ NOx,\ CO_2)$$

$$+\sum_{Unit}^{Project} Variable\ O\&M - \sum_{Unit}^{Base\ Case} Variable\ O\&M$$

$$+\sum_{Unit}^{Project} [PJM\ Purchase \times PJM\ Load\ Weighted\ LMP - PJM\ Sale \times PJM\ Gen\ Weighted\ LMP]$$

$$+\sum_{Unit}^{Project} [PJM\ Purchase \times PJM\ Load\ Weighted\ LMP - PJM\ Sale \times PJM\ Gen\ Weighted\ LMP]$$

- The change in the Adjusted Production Cost (APC) with the addition of the project versus without the project determines the APC project benefits to the pool

Total Market Benefit Criteria

- Energy Market Benefits + Capacity Market Benefits >= 1.25 * NPV of Project's Total Revenue Requirement for 15 years

- Load Payment Benefit is Based on Zones where the following is true:

$$\sum_{y=1}^{15}\left(NPV\ of\ Load\ Payment\ Benefit_y\right) > 0$$

- Adjusted Production cost benefits are measured at the system level.
  - Internal Generation Cost ($) **Add:** System Purchases ($) **Less:** System Sales ($)
    - System Purchase MWH are priced at the RTO Load-weighted LMP reflecting unwillingness of load to pay a higher price.
    - System Sale MWH are priced at the RTO Generation weighted cost reflecting unwillingness of generators to sell at a lower price.

*** For the purposes of training we will only assume Energy Market Benefits**

Energy Market Benefit Criteria

Project Class	Cost Allocation: Market Efficiency Projects	Energy Market Benefit Determination
Regional Projects	50% Load Ratio Share and 50% to zones with decreased net load payments	Energy Benefit: 50% change in production costs + 50% change in net load payments (only zones with decrease in net load payments)
Lower Voltage Projects	100% to zones with decreased net load payments	Energy Benefit: 100% change in net load payments (only zones with decrease in net load payments)

*** For the purposes of training we will only assume Energy Market Benefits**

Project Benefits for Non-Simulated Years

Regional Transmission Expansion Plan Model year: *2019*

Project In-service Year: *2019*

PROMOD IV Simulation Years: *2015 , 2019, 2022 & 2023*

2015	Period 1	2019	Period 2	2022	Period 3	2025	Period 4

Period 1 benefits
2016 - 2018

$$2015\ Benefit + \frac{(2019\ Benefit - 2015\ Benefit)}{2019 - 2015}\ x\ (year - 2015)$$

Period 2 benefits
2020 - 2021

$$2019\ Benefit + \frac{(2022\ Benefit - 2019\ Benefit)}{2022 - 2019}\ x\ (year - 2019)$$

Period 3 benefits
2023 - 2024

$$2022\ Benefit + \frac{(2025\ Benefit - 2022\ Benefit)}{2025 - 2022}\ x\ (year - 2022)$$

Period 4 benefits

Excel Formula: trend (known y-values, known x-values, new x’s)

e.g. trend ([2015, 2019, 2022, 2025 Energy Market Benefits], [2015, 2019, 2022, 2025 years], 2026)

Determining Revenue Requirement

Project Voltage: 500 kV or 230 kV
Project Cost: $100 Million
Project Benefit Period: 15 years
PJM Fixed Carrying Charge Rate = 16.2%
PJM Discount Rate = 7.8%

Project Annual Revenue Requirement = Project Cost x Fixed Carrying Charge Rate
= $100 Million x 16.2% = $16.2 Million Annually

Excel Formula: NPV (rate,# periods, payment per period)

Net Present Value of Project Costs = NPV(7.8%, 15, -16.2) = $140 Million

Selecting Zones Based on Net Load Payment

The Project is not in-service until 2019. Therefore the benefits are evaluated between 2019 and 2033, the first 15 years of in-service life.

Zones 1, 2 and 4 all have Net Load Payment benefits with an NPV > 0 for the 15 year analysis period. These zones will be included in the total system benefit.

The Net Present Value of Net Load Payment Benefits in Zone 3 do not exceed zero for the 15 year analysis period. This zone will be excluded from the total system benefit calculation.

<u>Low Voltage Project Net Load Payment Benefit</u>

Zone 1 + Zone 2 + Zone 4 = $218 Million

<u>Regional Project Net Load Payment Benefit</u>

50% (Zone 1 + Zone 2 + Zone 4) = $109 Million

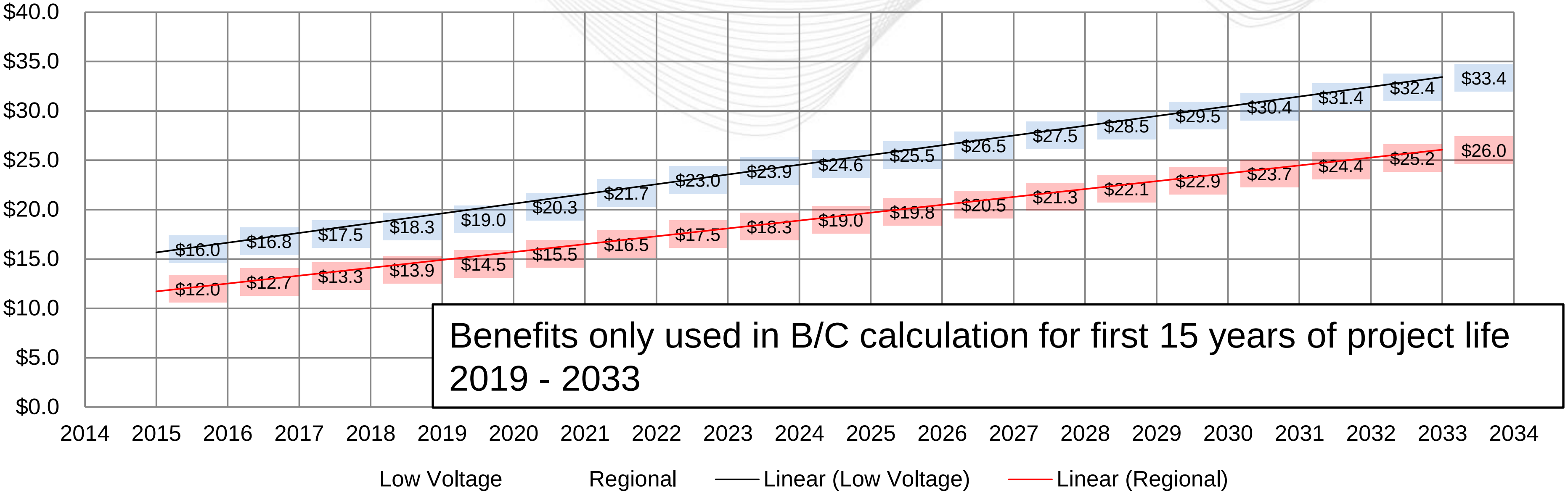
	Year	Zone 1	Zone 2	Zone 3	Zone 4
	2015	$8.00	$3.00	$0.50	$5.00
	2016	$9.00	$2.50	$0.40	$5.30
	2017	$10.00	$2.00	$0.30	$5.50
	2018	$11.00	$1.50	$0.20	$5.80
ISD	2019	$12.00	$1.00	$0.10	$6.00
	2020	$12.30	$1.30	($0.30)	$6.70
	2021	$12.70	$1.70	($0.60)	$7.30
	2022	$13.00	$2.00	($1.00)	$8.00
	2023	$14.00	$2.20	($1.70)	$7.70
	2024	$15.00	$2.30	($2.30)	$7.30
	2025	$16.00	$2.50	($3.00)	$7.00
	2026	$16.60	$2.00	($2.80)	$7.90
	2027	$17.40	$1.90	($3.20)	$8.20
	2028	$18.20	$1.90	($3.50)	$8.40
	2029	$18.90	$1.90	($3.80)	$8.70
	2030	$19.68	$1.84	($4.19)	$8.90
	2031	$20.45	$1.81	($4.53)	$9.15
	2032	$21.21	$1.78	($4.87)	$9.40
	2033	$21.97	$1.75	($5.22)	$9.64
	NPV (Millions)	**$135.16**	**$15.74**	**($19.07)**	**$66.91**

System Adjusted Production Cost Benefits

- The Project is not in-service until 2019. Therefore the benefits are evaluated between 2019 and 2033
- NPV Adjusted Production Cost Benefit = NPV(7.8%, Adjusted Production Cost Savings)
- Regional Adjusted Production Cost Benefits = 50% x $118 Million
- Low Voltage Adjusted Production Cost Benefits are not evaluated under the new rules

	Year	Net Adjusted Production Cost Benefit
	2015	$8.00
	2016	$8.50
	2017	$9.00
	2018	$9.50
ISD	2019	$10.00
	2020	$10.70
	2021	$11.30
	2022	$12.00
	2023	$12.70
	2024	$13.30
	2025	$14.00
	2026	$14.50
	2027	$15.10
	2028	$15.70
	2029	$16.30
	2030	$16.88
	2031	$17.48
	2032	$18.08
	2033	$18.68
	NPV (Millions)	**$118**

Trending Energy Market Benefits



SCED Simulation Years
2015, 2019, 2022, 2025

Interpolated Years
2016–2018, 2020-2021 and 2023-2024

Trended Years
2026 through 2033

Does Project Pass Criteria

- Regional Method
  - Total Energy Market Benefits = Load Payment Benefit x 50% + Production Cost Benefit x 50%
  - Total Benefits = $59 Million + $109 Million = $168 Million
  - **Does the Project Pass:** Benefits / Costs = $168 / $140 = 1.20 => **PROJECT FAILS**
- How about the Low Voltage Method
  - Total Benefits = 100% Load Payment Benefit = $218 Million
  - **Does the Project Pass:** Benefits / Costs = $218 / $140 = 1.56 => **PROJECT PASSES**

Now the hard part: Who's going to pay for it?

				Apportioned Cost ($Millions)	
LSE	**ΔNLP (> 0)**	**% of Total Benefit**	**Load Ratio Share**	**Low Voltage**	**Regional**
Zone 1	$135.2	62.1%	40.0%	$87.1	$71.6
Zone 2	$15.7	7.2%	20.0%	$10.1	$19.1
Zone 3	$0	0.0%	10.0%	$0	$7.0
Zone 4	$66.9	30.7%	30.0%	$43.1	$42.6
Total Benefit	**$218**				

- Low Voltage Project cost allocation is 100% based on each zone's proportion of Net Load Payment benefits. Only zones that benefit will share in cost.
- Regional cost allocation is based on 50% Load Ratio Share and 50% Net Load Payment Benefits. All zones are assigned some share of the cost but the share is reduced if the zone does not also have significant benefits.

Questions

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Terms and Acronyms

B/C – Benefit-to-Cost Ratio

FCR – Fixed Carrying Charge Rate

NLP – Net Load Payment

NPV – Net Present Value; in excel: NPV(discount rate, revenue or cost stream)

PV – Present Value

SCED – Security Constrained Economic Dispatch