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)
- Fuel and Emissions Forecast
- Annual Peak Load and Energy
- Hourly Demand and intermittent resource shapes

Demand Response Forecast
- Transmission Topology and Events
- Reactive Interface Calculation

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
- Same as Heat Rate Modeling

* 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

Must Run Units
- Provided by Ventyx

Spinning Reserve Contribution
- Ventyx Supplied
- Similar Technology
- Similar Vintage
- Similar Size and Configuration

** Only Applicable to Solar and Wind Generating Units
Ventyx 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
- If necessary validate installation of emissions reduction equipment and removal rates for generating units
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

- Adjust Peak Load and Annual Energy in each Powerbase Area by amount of Energy Efficiency cleared in RPM Auction for applicable delivery year.
Hourly Demand and Intermittent Resource Profiles

- Ventyx 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

- Ventyx 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 eLRS 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
  - Summer 95 degree day-time rating for Normal and Long-term Emergency
  - Winter 32 degree day-time rating for Normal and Long-term Emergency
- Where an upgrade is not modeled
  - The current PJM OASIS rating is used for both the summer and winter period
- When an upgrade is modeled
  - The upgraded rating from the RTEP model is used for the summer
  - The upgraded rating from the ERAG MMWG model for the same year and series is used for the winter
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
- BCPEP Interface
- Black Oak Bedington Interface
- 5004/5005 Interface
- Central Interface
- Cleveland Interface
- COMED 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 sunked 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

Zone 1
- CLMP = $3.0 /MWH
- Path 1 = 50 MW
- Gen #1 (CLMP = $1.5/MWH)
- Gen #2 (CLMP = $2.5)
- Gen #3 (CLMP = $2.0)
- Gen #4 (CLMP = $1.0)

Zone 2
- CLMP = $3.5 /MWH
- Path 2 = 100 MW
- Path 3 = 25 MW

Zone 3
- CLMP = $2.0 /MWH
- Path 4 = 150 MW
- Path 5 = 200 MW
### Auction Revenue Right Valuation

<table>
<thead>
<tr>
<th>Path</th>
<th>Source</th>
<th>Source CLMP</th>
<th>Sink</th>
<th>Sink CLMP</th>
<th>Cleared Path MW</th>
<th>ARR Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>GEN #1</td>
<td>$1.5</td>
<td>Zone 1</td>
<td>$3.0</td>
<td>50</td>
<td>$657,000</td>
</tr>
<tr>
<td>2</td>
<td>GEN #2</td>
<td>$2.5</td>
<td>Zone 1</td>
<td>$3.0</td>
<td>100</td>
<td>$438,000</td>
</tr>
<tr>
<td>3</td>
<td>GEN #2</td>
<td>$2.5</td>
<td>Zone 2</td>
<td>$3.5</td>
<td>25</td>
<td>$219,000</td>
</tr>
<tr>
<td>4</td>
<td>GEN #3</td>
<td>$2.0</td>
<td>Zone 2</td>
<td>$3.5</td>
<td>150</td>
<td>$1,971,000</td>
</tr>
<tr>
<td>5</td>
<td>GEN #4</td>
<td>$1.0</td>
<td>Zone 3</td>
<td>$2.0</td>
<td>200</td>
<td>$1,752,000</td>
</tr>
</tbody>
</table>

Path Value = (CLMP\text{sink} – CLMP\text{source}) \times \text{Cleared MW} \times 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: PROMOD IV Report Agent Variables
### Market Efficiency Reporting

<table>
<thead>
<tr>
<th>Market Efficiency Reporting</th>
<th>PROMOD IV Report Agent Data Structure</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Demand Cost By Zone</td>
<td>Demand &gt; Bus-Level Demand Cost &gt; Total Demand Cost (Bus)</td>
</tr>
<tr>
<td>Congestion Component of LMP</td>
<td>System &gt; Bus/Hub LMP &gt; Total Congestion Component &gt; Total Congestion Average</td>
</tr>
</tbody>
</table>

### Gross Demand Cost

- Reporting on Hubs created in Powerbase to represent the PJM demand zones
- Sum monthly demand cost by zone using reported column: “BusName” = Zone/Hub Name

### Congestion Component

- Calculate average sink (hub) price using reported column: “BusName” = Zone/Hub Name
- Calculate average source (gen bus) price using reported column: “BusNumber” = Generator Source Bus
### Production Cost Variables

<table>
<thead>
<tr>
<th>Market Efficiency Reporting</th>
<th>PROMOD IV Report Agent Data Structure</th>
</tr>
</thead>
</table>
| Generator Fuel Cost (Start-up Heat and Operating Heat Consumption) | System > System Summary > Cost Variables > Cost of Steam Generation  
System > System Summary > Cost Variables > Cost of Nuclear Generation  
System > System Summary > Cost Variables > Cost of Turbine Generation |
| Generator Variable O&M Cost | System > System Summary > Cost Variables > Variable O&M Cost  
System > System Summary > Cost Variables > Hydro Generation Cost  
System > System Summary > Cost Variables > Pumped Hydro Maintenance Cost |
| Generator Effluent Cost     | System > System Summary > Cost Variables > Emission Fee Tax |

- These variables are all reported by “Company” (a.k.a. demand zone) and month
- Production Cost Benefits are evaluated at the system level. Consequently, it is only necessary to ensure that the company belongs to the appropriate pool (i.e. PJM) when using these reports
Adjusted Production Cost Variables

<table>
<thead>
<tr>
<th>Market Efficiency Reporting</th>
<th>PROMOD IV Transaction CSV (*.TRN) File</th>
</tr>
</thead>
<tbody>
<tr>
<td>Economic Interchange (MWH)</td>
<td>Tariffs (Date, Hour in Week, From Pool, To Pool, MW)</td>
</tr>
</tbody>
</table>

- Interchange purchases and sales are priced on an hourly basis (Hourly MW x Hourly Price)
- To activate this report within Powerbase Custom Tables: Set Diagnostics > EMAB > CL2843 to “Yes” and Set the Client Specific > Client 28 > Record Output > CL2841 to “Yes”
Section 4: 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

- **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 By Simulation Year

\[ + \sum_{\text{Zone}} \text{Hourly Bus Load MW} \times \text{Hourly Bus LMP} \quad \text{(sum for all hours)} \]

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

- 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

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

\[ + \sum_{\text{Project Unit}} \text{Emissions Costs} - \sum_{\text{Base Case Unit}} \text{Emissions Costs} \quad (SO_2, NOx & CO_2) \]

\[ + \sum_{\text{Project Unit}} \text{Variable O&M} - \sum_{\text{Base Case Unit}} \text{Variable O&M} \]

\[ + \sum_{\text{Project Hour}} [\text{PJM Purchase x PJM Load Weighted LMP} - \text{PJM Sale x PJM Gen Weighted LMP}] \]

\[ - \sum_{\text{Base Case Hour}} [\text{PJM Purchase x PJM Load Weighted LMP} - \text{PJM Sale x PJM Gen Weighted LMP}] \]

- 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 \( \geq 1.25 \) NPV of Project’s Total Revenue Requirement for 15 years

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

\[
\sum_{y=1}^{15} (\text{NPV Load Payment Benefit}) > 0
\]

- Adjusted Production cost benefits are measured at a 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
<table>
<thead>
<tr>
<th>Project Class</th>
<th>Cost Allocation: Market Efficiency Projects</th>
<th>Energy Market Benefit Determination</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Regional Projects</strong></td>
<td>50% Load Ratio Share and 50% to zones with decreased net load payments</td>
<td>Energy Benefit $^{[1]}$: 50% change in production costs + 50% change in net load payments (only zones with decrease in net load payments)</td>
</tr>
<tr>
<td><strong>Lower Voltage Projects</strong></td>
<td>100% to zones with decreased net load payments</td>
<td>Energy Benefit $^{[1]}$: 100% change in net load payments (only zones with decrease in net load payments)</td>
</tr>
</tbody>
</table>

$^{[1]}$ New Benefit Calculation Method Pending FERC APPROVAL

* 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

<table>
<thead>
<tr>
<th>Year</th>
<th>Period</th>
<th>Period</th>
<th>Period</th>
<th>Period</th>
<th>Period</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>Period 1</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2019</td>
<td>Period 2</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2022</td>
<td>Period 3</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2025</td>
<td>Period 4</td>
<td></td>
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<td></td>
</tr>
</tbody>
</table>

### Period 1 Benefits

2016 - 2018

\[
2015 \text{ Benefit} + \frac{(2019 \text{ Benefit} - 2015 \text{ Benefit})}{2019 - 2015} \times (\text{year} - 2015)
\]

### Period 2 Benefits

2020 - 2021

\[
2019 \text{ Benefit} + \frac{(2022 \text{ Benefit} - 2019 \text{ Benefit})}{2022 - 2019} \times (\text{year} - 2019)
\]

### Period 3 Benefits

2023 - 2024

\[
2022 \text{ Benefit} + \frac{(2025 \text{ Benefit} - 2022 \text{ Benefit})}{2025 - 2022} \times (\text{year} - 2022)
\]

### 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 Dollars  **Project Benefit Period:** 15 yrs

**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:**  \( pv(\text{rate}, \# \text{ periods}, \text{payment per period}) \)

**Net Present Value of Project Costs**  =  \( pv(7.8\%, 15, -16.2) = $140 Million \)
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.

**Low Voltage Project Net Load Payment Benefit**

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

**Regional Project Net Load Payment Benefit**

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

<table>
<thead>
<tr>
<th>Year</th>
<th>Net Adjusted Production Cost Benefit</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>$8.00</td>
</tr>
<tr>
<td>2016</td>
<td>$8.50</td>
</tr>
<tr>
<td>2017</td>
<td>$9.00</td>
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<tr>
<td>2018</td>
<td>$9.50</td>
</tr>
<tr>
<td>2019</td>
<td>$10.00</td>
</tr>
<tr>
<td>2020</td>
<td>$10.70</td>
</tr>
<tr>
<td>2021</td>
<td>$11.30</td>
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<td>$12.00</td>
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<tr>
<td>2030</td>
<td>$16.88</td>
</tr>
<tr>
<td>2031</td>
<td>$17.48</td>
</tr>
<tr>
<td>2032</td>
<td>$18.08</td>
</tr>
<tr>
<td>2033</td>
<td>$18.68</td>
</tr>
</tbody>
</table>

NPV (Millions) $118

[1] Pending FERC Approval
Trending Energy Market Benefits

Benefits only used in B/C calculation for first 15 years of project life
2019 - 2033

SCED Simulation Years
2015, 2019, 2022, 2025

Interpolated Years

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?

<table>
<thead>
<tr>
<th>LSE</th>
<th>ΔNLP ( &gt; 0)</th>
<th>% of Total Benefit</th>
<th>Load Ratio Share</th>
<th>Low Voltage</th>
<th>Regional</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zone 1</td>
<td>$135.2</td>
<td>62.1%</td>
<td>40.0%</td>
<td>$87.1</td>
<td>$71.6</td>
</tr>
<tr>
<td>Zone 2</td>
<td>$15.7</td>
<td>7.2%</td>
<td>20.0%</td>
<td>$10.1</td>
<td>$19.1</td>
</tr>
<tr>
<td>Zone 3</td>
<td>$0</td>
<td>0.0%</td>
<td>10.0%</td>
<td>$0</td>
<td>$7.0</td>
</tr>
<tr>
<td>Zone 4</td>
<td>$66.9</td>
<td>30.7%</td>
<td>30.0%</td>
<td>$43.1</td>
<td>$42.6</td>
</tr>
<tr>
<td>Total Benefit</td>
<td>$218</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

- 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.
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