Market Efficiency Process Scope and Input Assumptions
(May 2021 Update)

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I. Scope

Market Efficiency analysis is performed as part of the overall Regional Transmission Planning (RTEP) process to accomplish the following objectives:

- Determine which reliability-based transmission projects, if any, have an economic benefit if accelerated or modified.
- Identify new transmission projects that may result in economic benefits.
- Review cost and benefits of economic-based transmission projects included in the RTEP to assure that they continue to be cost beneficial.
- Identify economic benefits associated with modification to reliability-based transmission projects already included in the RTEP that when modified would relieve one or more economic constraints. Such projects, originally identified to resolve reliability criteria violations, may be designed in a more robust manner to provide economic benefit as well.

Market Efficiency analysis is conducted using market simulation software that models the market conditions and the hourly security-constrained commitment and dispatch of generation over a future annual period. Economic benefits of transmission upgrades are determined by comparing results of simulations with and without the proposed transmission enhancement or expansion. For the 2020/2021 Market Efficiency cycle, market simulations will be performed for the following years: 2021, 2025, 2028 and 2031. A forecast of annual benefits for years beyond 2031 will be based on an extrapolation of the years 2021, 2025, 2028 and 2031 simulation results. Market simulations may be performed for year 2035 to validate the extrapolation results.

II. Market Simulation Model and Input Assumptions

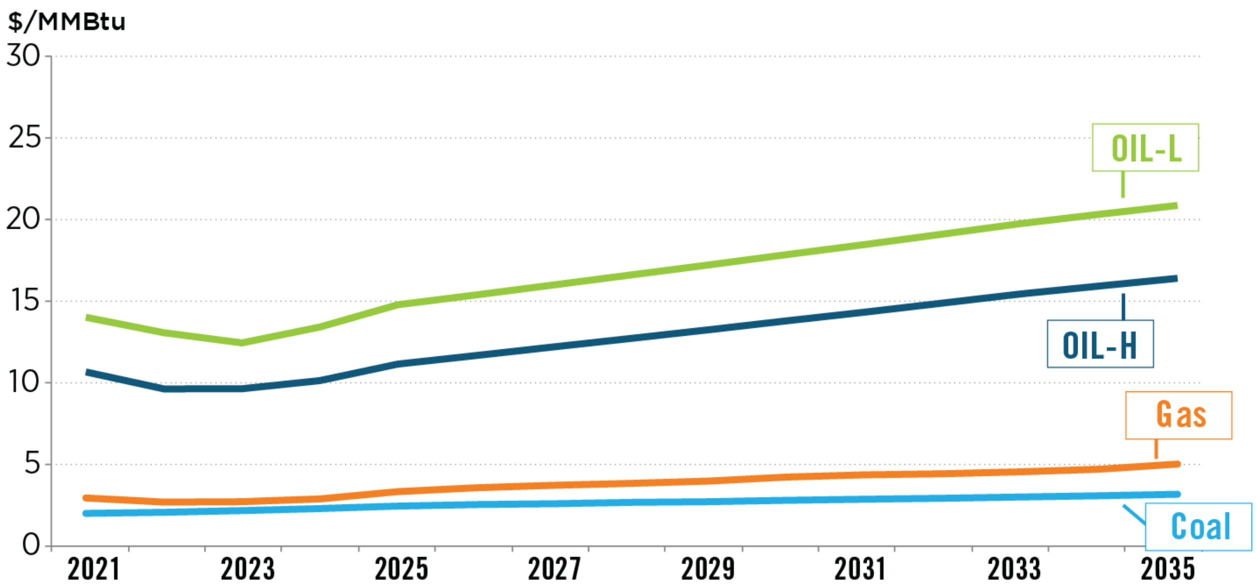
The primary analytical software used by PJM to determine potential Market Efficiency benefits is PROMOD IV from Hitachi ABB Power Grids. PROMOD IV is a production costing software application which simulates the hourly commitment and dispatch of generation to meet input load while recognizing and maintaining transmission system security limits. The underlying source of the initial PROMOD input database is the Simulation Ready Data from Hitachi ABB Power Grids. This data includes generating unit characteristics, fuel costs, emissions costs, load forecasts and a power flow case. The Simulation Ready Data for the 2020/2021 Market Efficiency cycle is from the fall 2019 base case release with Hitachi ABB Power Grids fuel and emission updates consistent with the spring 2021 release. PJM does tailor key aspects of the base release for RTEP Market Efficiency evaluation. These items would include an update of the power flow case, generation modification because of additional queued units and announced retirements, and utilization of the most recent load forecasts.

A. Fuel Cost

The PROMOD database contains a fuel cost forecast for each fuel type. The forecast prices for each fuel are developed by the Hitachi ABB Power Grids Fuels Group. For gas and oil, the prices are derived from a combination of NYMEX forward prices and a fundamental forecasting model. Hitachi ABB Power Grids coal forecasting model uses numerous factors such as mining costs, transportation routes and pricing, and coal quality to derive a coal forecast. The resulting coal price forecast is on a plant-specific delivered basis.

Figure 1 shows the average annual forecast values for light oil, heavy oil, natural gas and coal. The natural gas prices depicted are representative of the commodity cost. PROMOD uses basis adders to capture the gas transportation costs of the commodity to the different PJM zones. The oil prices are representative of burner tip prices and are the same throughout PJM. The coal prices in Figure 1 are the average of each PJM coal plant's burner tip price. The PROMOD coal price forecast is on an individual plant-specific delivered basis.

Figure 1. Fuel Price Assumptions



B. Peak Load and Annual Energy

Peak load and annual energy forecasts for the PJM RTO were developed by PJM's Resource Adequacy Planning Department and released in the January 2021 PJM Load Forecast Report. Table 1 shows the annual PJM peak and annual energy forecast that provides the basis for load input into the simulation.

Table 1. 2021 PJM Peak Load and Energy Forecast

Load	2021	2025	2028	2031	2035
Peak (MW)	149,224	151,928	152,971	153,759	154,620
Energy (GWh)	780,068	794,760	802,993	806,729	815,394

C. Demand Response

Table 2 shows the level of demand response resource available for each of the Market Efficiency study years. The values are consistent with the 2021 Load Forecast Report.

Table 2. 2021 PJM Demand Resource Forecast

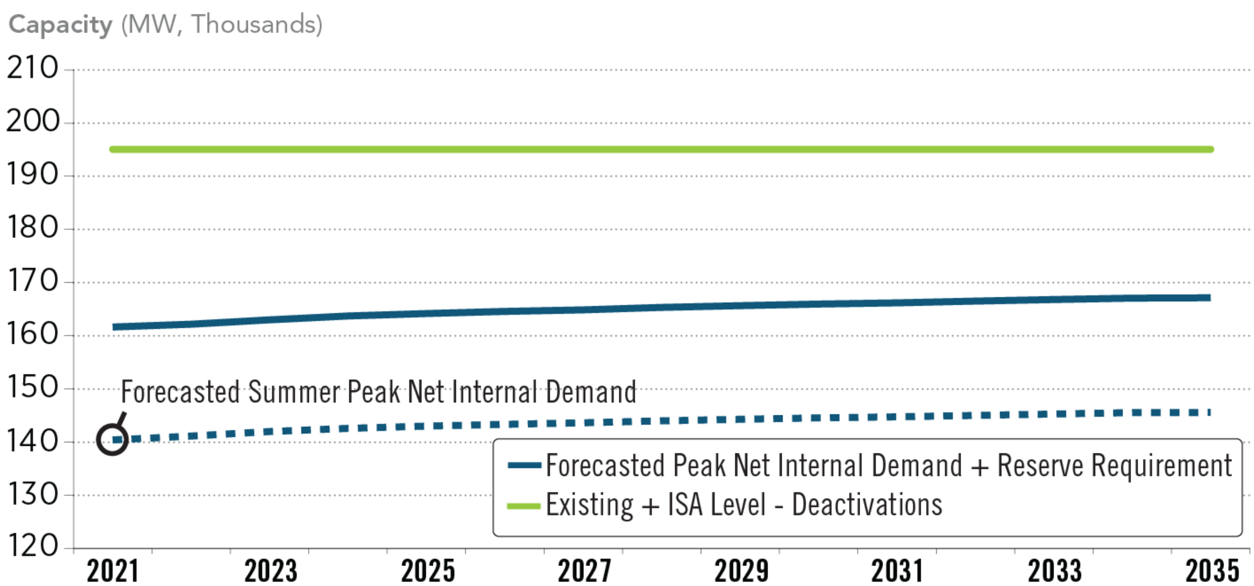
	2021	2025	2028	2031	2035
Demand Resource (MW)	8,779	8,910	8,947	8,982	9,022

D. PJM Generation

Figure 2 shows a comparison of the modeled generation capacity within PJM's footprint to the projected peak net internal demand with reserve margin. The modeled capacity (green line) includes capacity that is in-service plus active queue generation with Interconnection Service Agreements (ISA) minus announced future deactivations. No Facility Study Agreement (FSA) or Suspended ISA resources were included in the base case at the time of posting of this document.

The net internal demand (blue line) is derived from information included in the 2021 PJM Load Forecast Report and is equivalent to the PJM summer unrestricted peak forecast minus the projection of load management placed under PJM control.

Figure 2. PJM Market Efficiency Reserve Margin with Uniform Expansion



Note: Generation includes existing and projected PJM internal capacity resources. Solar and wind resource capacity at 38% and 13% of maximum capability, respectively.

E. Emission Allowance Price

The PROMOD database models three major effluents: SO_2, NOx, and CO_2. Effluents (by trading program) are assigned to generators based on generator location, and release rates are from a variety of sources including EPA CEMS data and the forecasted fuel used. Hitachi ABB Power Grids uses a proprietary Emission Forecast Model (EFM) to simulate emission control decisions, and this simultaneously results in the three cap-and-trade market price forecasts (SO_2, NOx annual, NOx seasonal). Hitachi ABB Power Grids uses a CO_2 emission forecast based on analysis associated with national and regional legislative proposals.

Forecasts for SO_2 and NOx now reflect legislation associated with the Cross State Air Pollution Rule (CSAPR). CSAPR results in a more stringent requirement than the previous Clean Air Interstate Rule (CAIR). However, other requirements, combined with low gas prices and subsequent coal retirements, have resulted in a very low marginal cost of compliance. Figure 3 and Figure 4 show graphs of SO_2 and NOx prices assumed in the Market Efficiency base case.

Figure 3. SO_2 Emission Price Assumption

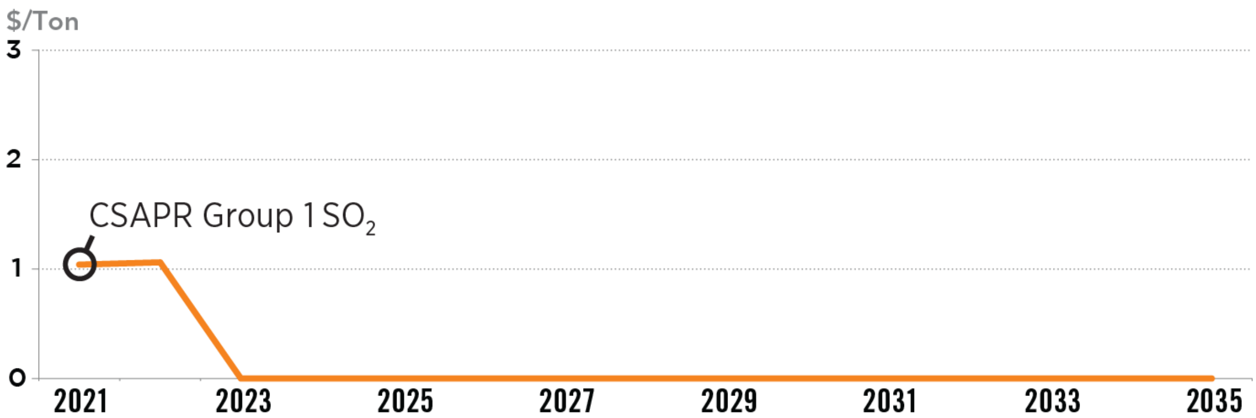
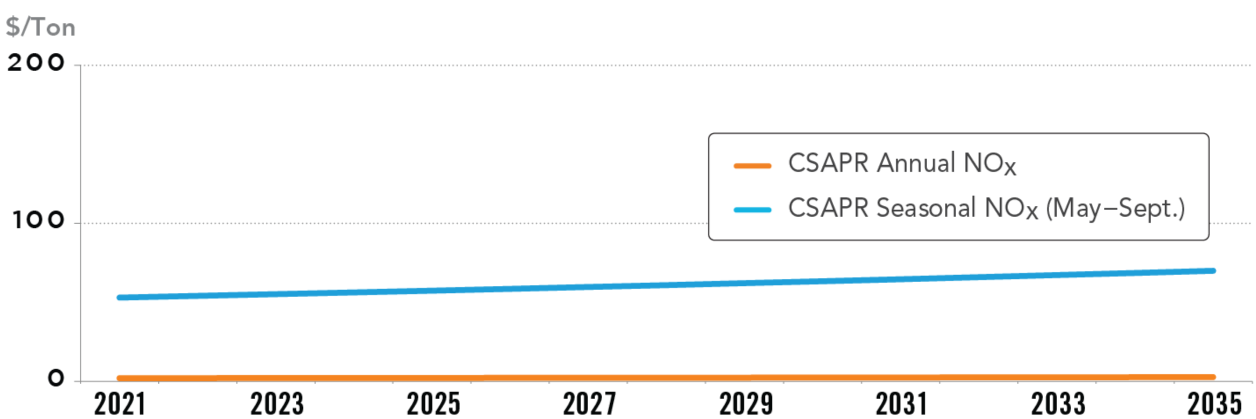
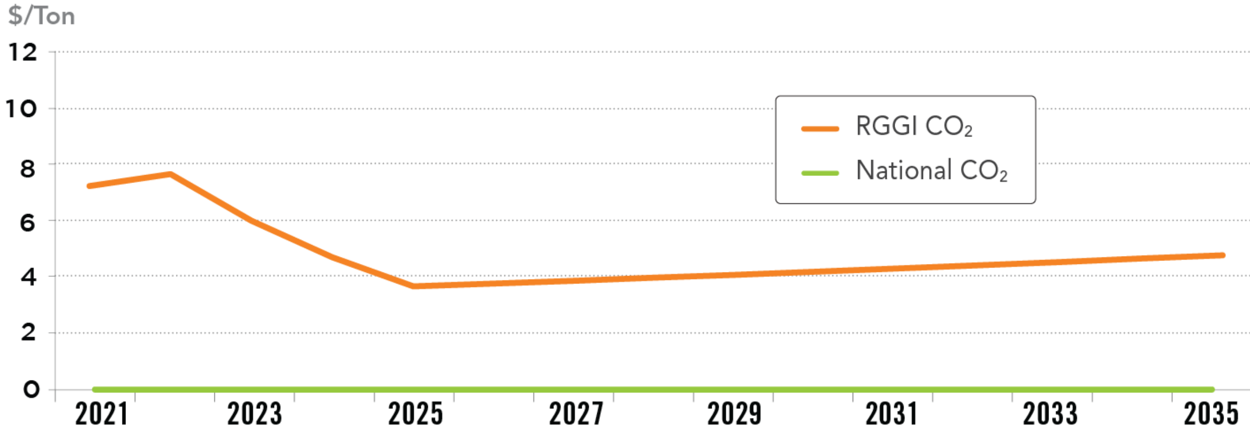


Figure 4. NOx Emission Price Assumption



The forecast of a national CO_2 emission price reflects the current federal legislation regarding greenhouse gases. Accordingly, the national CO_2 emission prices are set to zero for all study years. Currently, Maryland, Delaware, New Jersey and Virginia participate in the Regional Greenhouse Gas Initiative (RGGI). Forecast prices for RGGI CO_2 are shown in Figure 5.

Figure 5. CO_2 Emission Price Assumptions



F. Financial Parameters – Carrying Charge Rate and Discount Rate

Evaluation of proposed Market Efficiency projects requires a benefit-to-cost analysis. As part of this evaluation the present value of annual benefits projected for a 15-year period starting with the RTEP year are compared to the present value of the annual cost for the same period. If the benefit-to-cost ratio exceeds a threshold of at least 1.25:1, then the project can be recommended for inclusion in the PJM RTEP. The annual cost of the upgrade will be based on the total capital cost of the project multiplied by a levelized annual carrying charge rate. A discount rate will be used to determine the present value of the project's annual costs and annual benefits. The annual carrying charge rate and discount rate are developed using information contained in the transmission owners' formula rate sheets and incorporated in the Transmission Cost Information Center (TCIC) workbook. The annual carrying charge rate and discount rate for this year's analysis will be 11.81% and 7.26%, respectively.

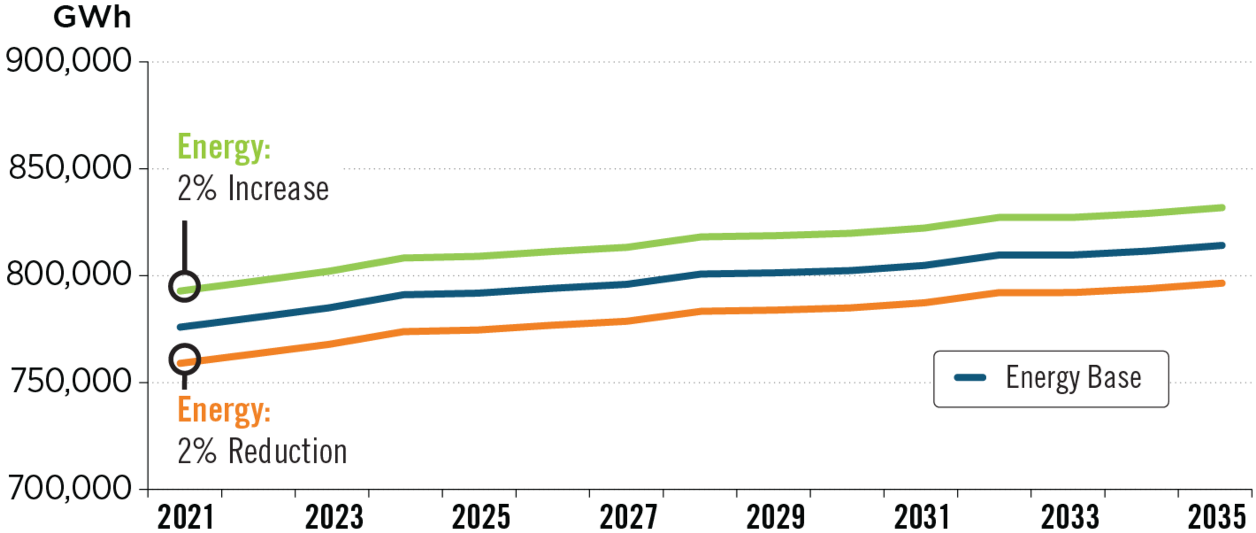
III. Input Assumption Sensitivities

Consistent with Schedule 6 of the PJM Operating Agreement, sensitivities of future assumptions are considered within the Market Efficiency project selection process in order to mitigate the potential for inappropriately including or excluding Market Efficiency projects. PJM typically will study impacts of load forecast variations and fuel cost variations on eligible proposals. Also, generation additions to the PJM system will be considered.

G. Load Forecast Sensitivity

A +/- 2% variation of the base PJM load forecast model is used to test the robustness of eligible solution proposals. Figure 6 shows a graph of PJM's annual energy forecast for the base case and the two sensitivity cases (2% PJM load reduction and 2% PJM load increase) for years 2021 through 2035.

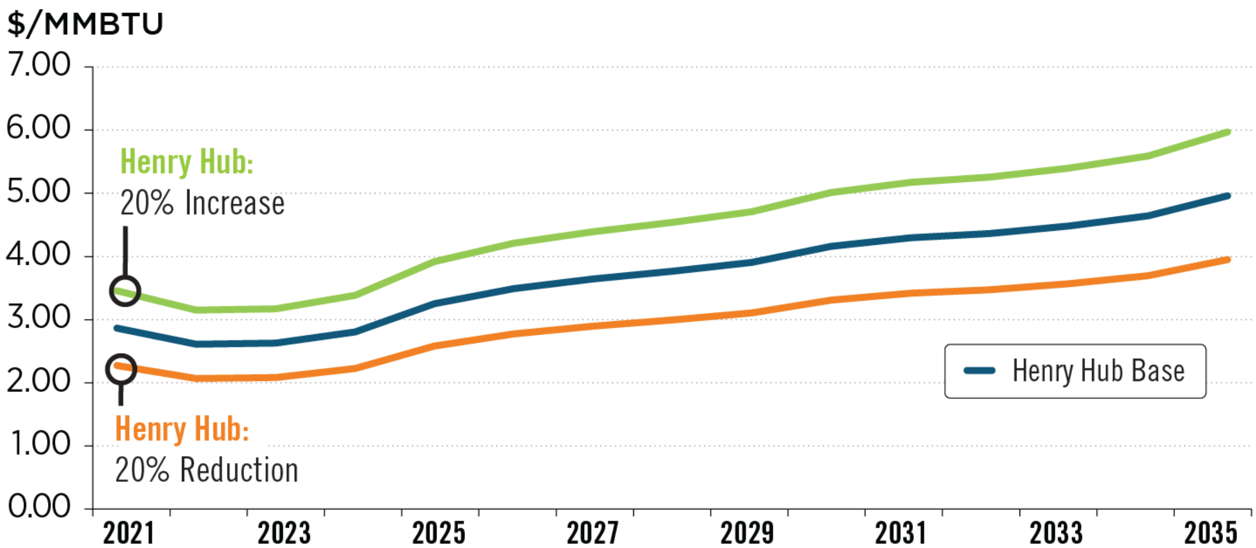
Figure 6. Load Sensitivity



H. Gas Forecast Sensitivity

A +/- 20% variation of the Henry Hub gas price is used to test the robustness of eligible solution proposals. Figure 7 shows a graph of the annual Henry Hub price for the base case and the two sensitivity cases (20% Henry Hub reduction and 20% Henry Hub increase) for years 2021 through 2035.

Figure 7. Gas Sensitivity



I. Generation Sensitivity – Facility Study Agreement (FSA) Level

Additional modeled generating capacity will be considered to test the robustness of eligible solution proposals. Figure 8 shows a comparison of the modeled generation capacity within PJM's footprint to the projected peak net internal demand with reserve margin. The base case modeled capacity (green line) includes capacity that is in-service plus active queue generation at the ISA level minus announced future deactivations. The generation sensitivity (black line) includes active queue generation at the FSA level.

Figure 8. PJM Market Efficiency Reserve Margin with Uniform Expansion